CARRIZO OIL & GAS INC
Form 10-Q
November 03, 2016

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

FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2016
o TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission File Number: 000-29187-87

CARRIZO OIL & GAS, INC.
(Exact name of registrant as specified in its charter)

Texas	76-0415919
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
500 Dallas Street, Suite 2300, Houston, Texas	77002
(Address of principal executive offices)	(Zip Code)
(713) 328-1000	
(Registrant's telephone number)	

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 x NO ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES x NO ¨

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

Large accelerated filer x	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES ¨ NO x

The number of shares outstanding of the registrant's common stock, par value $0.01 per share, as of October 28, 2016 was 65,129,295.

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CARRIZO OIL & GAS, INC.
CONSOLIDATED BALANCE SHEETS
(In thousands, except share and per share data)
(Unaudited)

	September 30, 2016	December 31, 2015
Assets		
Current assets		
Cash and cash equivalents	$3,235	$42,918
Accounts receivable, net	49,294	54,721
Derivative assets	20,146	131,100
Other current assets	4,838	3,443
Total current assets	77,513	232,182
Property and equipment		
Oil and gas properties, full cost method		
Proved properties, net	1,127,264	1,369,151
Unproved properties, not being amortized	196,738	335,452
Other property and equipment, net	10,693	12,258
Total property and equipment, net	1,334,695	1,716,861
Deferred income taxes	—	46,758
Derivative assets	—	1,115
Other assets	8,299	10,330
Total Assets	$1,420,507	$2,007,246
Liabilities and Shareholders’ Equity (Deficit)		
Current liabilities		
Accounts payable	$57,302	$74,065
Revenues and royalties payable	43,838	67,808
Accrued capital expenditures	68,583	39,225
Accrued interest	20,956	21,981
Deferred income taxes	—	46,758
Other current liabilities	39,083	35,647
Total current liabilities	229,762	285,484
Long-term debt	1,333,801	1,236,017
Asset retirement obligations	17,534	16,183
Derivative liabilities	29,354	12,648
Other liabilities	15,415	12,860
Total liabilities	1,625,866	1,563,192
Commitments and contingencies		
Shareholders’ equity (deficit)		
Common stock, $0.01 par value, 90,000,000 shares authorized; 59,117,696 issued and outstanding as of September 30, 2016 and 58,332,993 issued and outstanding as of December 31, 2015	591	583
Additional paid-in capital	1,436,355	1,411,081
Accumulated deficit	(1,642,305)	(967,610)
Total shareholders’ equity (deficit)	(205,359)	444,054
Total Liabilities and Shareholders’ Equity (Deficit)	$1,420,507	$2,007,246

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

CARRIZO OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share data)
(Unaudited)

	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Revenues				
Crude oil	$95,154	$95,237	$254,758	$289,552
Natural gas liquids	5,616	3,330	15,119	11,602
Natural gas	10,407	7,670	29,886	28,627
Total revenues	111,177	106,237	299,763	329,781
Costs and Expenses				
Lease operating	24,282	22,213	71,071	67,304
Production taxes	4,886	4,264	12,940	13,313
Ad valorem taxes	1,426	2,256	3,950	7,012
Depreciation, depletion and amortization	48,949	81,256	160,492	234,458
General and administrative, net	18,119	4,207	59,046	54,879
(Gain) loss on derivatives, net	(11,744)	(28,752)	29,938	(42,596)
Interest expense, net	21,190	16,208	58,913	51,403
Impairment of proved oil and gas properties	105,057	812,752	576,540	812,752
Loss on extinguishment of debt	—	—	—	38,137
Other expense, net	499	3,516	1,568	10,789
Total costs and expenses	212,664	917,920	974,458	1,247,451
Loss From Continuing Operations Before Income Taxes	(101,487)	(811,683)	(674,695)	(917,670)
Income tax benefit	313	102,915	—	140,456
Loss From Continuing Operations	(101,174)	(708,768)	(674,695)	(777,214)
Income From Discontinued Operations, Net of Income Taxes	—	1,121	—	2,225
Net Loss	($101,174)	($707,647)	($674,695)	($774,989)
Net Loss Per Common Share - Basic				
Loss from continuing operations	($1.72)	($13.75)	($11.49)	($15.62)
Income from discontinued operations, net of income taxes	—	0.02	—	0.04
Net loss	($1.72)	($13.73)	($11.49)	($15.58)
Net Loss Per Common Share - Diluted				
Loss from continuing operations	($1.72)	($13.75)	($11.49)	($15.62)
Income from discontinued operations, net of income taxes	—	0.02	—	0.04
Net loss	($1.72)	($13.73)	($11.49)	($15.58)
Weighted Average Common Shares Outstanding				
Basic	58,945	51,543	58,705	49,742
Diluted	58,945	51,543	58,705	49,742

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

CARRIZO OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)
(Unaudited)

	Nine Months Ended September 30, 2016	2015
Cash Flows From Operating Activities		
Net loss	($674,695)	($774,989)
Income from discontinued operations, net of income taxes	—	(2,225)
Adjustments to reconcile loss from continuing operations to net cash provided by operating activities from continuing operations		
Depreciation, depletion and amortization	160,492	234,458
Impairment of proved oil and gas properties	576,540	812,752
(Gain) loss on derivatives, net	29,938	(42,596)
Cash received for derivative settlements, net	98,820	141,909
Loss on extinguishment of debt	—	38,137
Stock-based compensation expense, net	30,834	9,203
Deferred income taxes	—	(140,538)
Non-cash interest expense, net	3,105	3,564
Other, net	2,427	4,554
Changes in components of working capital and other assets and liabilities-		
Accounts receivable	1,768	27,395
Accounts payable	(20,294)	(18,115)
Accrued liabilities	(7,954)	(5,614)
Other assets and liabilities, net	(3,134)	(3,676)
Net cash provided by operating activities from continuing operations	197,847	284,219
Net cash used in operating activities from discontinued operations	—	(1,247)
Net cash provided by operating activities	197,847	282,972
Cash Flows From Investing Activities		
Capital expenditures - oil and gas properties	(346,245)	(541,616)
Proceeds from sales of oil and gas properties, net	15,331	7,934
Other, net	(661)	(5,390)
Net cash used in investing activities from continuing operations	(331,575)	(539,072)
Net cash used in investing activities from discontinued operations	—	(2,125)
Net cash used in investing activities	(331,575)	(541,197)
Cash Flows From Financing Activities		
Issuance of senior notes	—	650,000
Tender and redemption of senior notes	—	(626,681)
Payment of deferred purchase payment	—	(150,000)
Borrowings under credit agreement	510,116	1,045,521
Repayments of borrowings under credit agreement	(414,116)	(889,031)
Payments of debt issuance costs	(1,150)	(11,665)
Sale of common stock, net of offering costs	—	231,316
Proceeds from stock options exercised	—	46
Other, net	(805)	(115)
Net cash provided by financing activities from continuing operations	94,045	249,391
Net cash provided by financing activities from discontinued operations	—	—
Net cash provided by financing activities	94,045	249,391
Net Decrease in Cash and Cash Equivalents	(39,683)	(8,834)

Cash and Cash Equivalents, Beginning of Period	42,918	10,838
Cash and Cash Equivalents, End of Period	$3,235	$2,004

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

CARRIZO OIL & GAS, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation

Nature of Operations

Carrizo Oil & Gas, Inc. is a Houston-based energy company which, together with its subsidiaries (collectively, the "Company"), is actively engaged in the exploration, development, and production of oil and gas primarily from resource plays located in the United States. The Company's current operations are principally focused in proven, producing oil and gas plays primarily in the Eagle Ford Shale in South Texas, the Delaware Basin in West Texas, the Niobrara Formation in Colorado, the Utica Shale in Ohio, and the Marcellus Shale in Pennsylvania.

Consolidated Financial Statements

The accompanying unaudited interim consolidated financial statements include the accounts of the Company after elimination of intercompany transactions and balances and have been prepared pursuant to the rules and regulations of the U.S. Securities and Exchange Commission (the "SEC") and therefore do not include all disclosures required for financial statements prepared in conformity with accounting principles generally accepted in the U.S. ("GAAP"). In the opinion of management, these financial statements include all adjustments (consisting of normal recurring accruals and adjustments) necessary to present fairly, in all material respects, the Company's interim financial position, results of operations and cash flows. However, the results of operations for the periods presented are not necessarily indicative of the results of operations that may be expected for the full year. These financial statements and related notes included in this Quarterly Report on Form 10-Q should be read in conjunction with the Company's audited Consolidated Financial Statements and related notes included in the Company's Annual Report on Form 10-K for the year ended December 31, 2015 ("2015 Annual Report"). Certain reclassifications have been made to prior period amounts to conform to the current period presentation. Such reclassifications had no material impact on prior period amounts.

2. Summary of Significant Accounting Policies

The Company has provided a discussion of significant accounting policies, estimates, and judgments in "Note 2. Summary of Significant Accounting Policies" of the Notes to Consolidated Financial Statements in its 2015 Annual Report. There have been no changes to the Company's significant accounting policies since December 31, 2015, other than the recently adopted accounting pronouncements described below.

Recently Adopted Accounting Pronouncements

In November 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2015-17, Balance Sheet Classification of Deferred Taxes ("ASU 2015-17"). ASU 2015-17 requires that all deferred tax liabilities and assets, as well as any related valuation allowance, be classified in the balance sheet as noncurrent. Effective January 1, 2016, the Company early adopted ASU 2015-17 which was applied prospectively and therefore the adoption had no impact on the consolidated balance sheet as of December 31, 2015.

In April 2015, the FASB issued ASU 2015-03, Simplifying the Presentation of Debt Issuance Costs ("ASU 2015-03"). ASU 2015-03 is to simplify the presentation of debt issuance costs in financial statements by presenting such costs in the balance sheet as a direct deduction from the related debt rather than as an asset. In August 2015, the FASB issued ASU 2015-15, Interest-Imputation of Interest (Subtopic 835-30) ("ASU 2015-15"), which allows debt issuance costs associated with line-of-credit agreements to be deferred and presented as an asset in the balance sheet, subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings. Effective January 1, 2016, the Company adopted ASU 2015-03 and ASU 2015-15 and reclassified $19.7 million of unamortized debt issuance costs related to the Company's senior notes from long-term assets to long-term debt in the consolidated balance sheet as of December 31, 2015. Debt issuance costs associated with the Company's revolving credit facility remain classified as a long-term asset in the consolidated balance sheets.

Recently Issued Accounting Pronouncements

In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows (Topic 230) ("ASU 2016-15"), which is intended to reduce diversity in practice in how certain transactions are classified in the statement of cash flows. The guidance addresses eight specific cash flow issues for which current GAAP is either unclear or does not include specific guidance. ASU 2016-15 is effective for interim and annual periods beginning after December 15, 2017, with early adoption permitted, provided that it is adopted in its entirety in the same period. The Company is evaluating ASU 2016-15 to determine what impact adoption of the new standard will have on its consolidated statements of cash flows.

In March 2016, the FASB issued ASU No. 2016-09, Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting ("ASU 2016-09"), which amends certain aspects of accounting for share-based payment arrangements. ASU 2016-09 revises or provides alternative accounting for the tax impacts of share-based payment arrangements, forfeitures, minimum statutory tax withholdings, and prescribes certain disclosures to be made in the period of adoption. ASU 2016-09 is effective for interim and annual periods beginning after December 15, 2016, with early adoption permitted. The Company is evaluating ASU 2016-09 to determine what impact adoption of the new standard will have on its consolidated financial statements and related disclosures.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842) ("ASU 2016-02"), which significantly changes accounting for leases by requiring that lessees recognize a right-of-use asset and a related lease liability representing the obligation to make lease payments, for virtually all lease transactions. Additional disclosures about an entity's lease transactions will also be required. ASU 2016-02 defines a lease as "a contract, or part of a contract, that conveys the right to control the use of identified property, plant or equipment (an identified asset) for a period of time in exchange for consideration." ASU 2016-02 is effective for interim and annual periods beginning after December 15, 2018 with early adoption permitted. Lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented in the financial statements using a modified retrospective approach. The Company is evaluating ASU 2016-02 to determine what impact adoption of the new standard will have on its consolidated financial statements and related disclosures.

In May 2014, the FASB issued ASU No. 2014-09, Revenue From Contracts With Customers (Topic 606) ("ASU 2014-09"), which will require entities to recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 will supersede most current guidance related to revenue recognition when it becomes effective. The new standard also will require expanded disclosures regarding the nature, timing, amount and certainty of revenue and cash flows from contracts with customers. ASU 2014-09 is effective for interim and annual periods beginning after December 15, 2017 with early adoption permitted for interim and annual periods beginning after December 31, 2016. Companies are permitted to adopt ASU 2014-09 through the use of either the full retrospective approach or a modified retrospective approach. The Company does not currently intend to early-adopt ASU 2014-09 and has not determined which transition method it will use. The Company is evaluating ASU 2014-09 to determine what impact adoption of the new standard will have on its consolidated financial statements and related disclosures.

3. Property and Equipment, Net

As of September 30, 2016 and December 31, 2015, total property and equipment, net consisted of the following:

	September 30, 2016	December 31, 2015
	(In thousands)	
Proved properties	$4,467,760	$3,976,511
Accumulated depreciation, depletion and amortization and impairments	(3,340,496)	(2,607,360)
Proved properties, net	1,127,264	1,369,151
Unproved properties, not being amortized		
Unevaluated leasehold and seismic costs	163,915	280,263
Exploratory wells in progress	2,051	9,432
Capitalized interest	30,772	45,757
Total unproved properties, not being amortized	196,738	335,452
Other property and equipment	23,106	22,677
Accumulated depreciation	(12,413)	(10,419)
Other property and equipment, net	10,693	12,258
Total property and equipment, net	$1,334,695	$1,716,861

Average depreciation, depletion and amortization ("DD&A") per Boe of proved properties was $12.72 and $24.19 for the three months ended September 30, 2016 and 2015, respectively, and $13.79 and $23.82 for the nine months ended September 30, 2016 and 2015, respectively.

The Company capitalized internal costs of employee compensation and benefits, including stock-based compensation, directly associated with acquisition, exploration and development activities totaling $2.7 million and $3.1 million for the three months ended September 30, 2016 and 2015, respectively, and $8.5 million and $14.0 million for the nine months ended September 30, 2016 and 2015, respectively.

Unproved properties, not being amortized, include unevaluated leasehold and seismic costs associated with specific unevaluated properties, the cost of exploratory wells in progress and related capitalized interest. The Company capitalized interest costs associated with its unevaluated leasehold and seismic costs and exploratory well costs totaling $2.9 million and $7.5 million for the three months ended September 30, 2016 and 2015, respectively, and $13.4 million and $26.2 million for the nine months ended September 30, 2016 and 2015, respectively.

Impairment of Proved Oil and Gas Properties

At the end of each quarter, the net book value of oil and gas properties, less related deferred income taxes, are limited to the “cost center ceiling” equal to (i) the sum of (A) the present value of estimated future net revenues from proved oil and gas reserves, less estimated future expenditures to be incurred in developing and producing the proved reserves computed using a discount factor of 10%, (B) the costs of unproved properties not being amortized, and (C) the lower of cost or estimated fair value of unproved properties included in the costs being amortized; less (ii) related income tax effects. Any excess of the net book value of oil and gas properties, less related deferred income taxes, over the cost center ceiling is recognized as an impairment of proved oil and gas properties. An impairment recognized in one period may not be reversed in a subsequent period even if higher commodity prices in the future result in a cost center ceiling in excess of the net book value of oil and gas properties, less related deferred income taxes.

The estimated future net revenues used in the cost center ceiling are calculated using the average realized prices for sales of crude oil, natural gas liquids and natural gas on the first calendar day of each month during the 12-month period prior to the end of the current quarter (“12-Month Average Realized Price”), held flat for the life of the production, except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts. Prices do not include the impact of derivative instruments as the Company elected not to meet the criteria to qualify derivative instruments for hedge accounting treatment.

Primarily due to declines in the 12-Month Average Realized Price of crude oil, the Company recognized impairments of proved oil and gas properties for the three and nine months ended September 30, 2016 and 2015 as summarized in the table below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Impairment of proved oil and gas properties (in thousands)	$105,057	$712,752	$576,540	$812,752
End of period price ($/Bbl)	$38.36	$56.05	$38.36	$56.05
Beginning of period price ($/Bbl)	$39.84	$68.92	$47.24	$92.24
Percent decrease in price	(4%)	(19 %)	(19%)	(39 %)

The Company's estimated range of the fourth quarter cost center ceiling, at the high end, would exceed the net book value of oil and gas properties, less related deferred income taxes, and at the low end, would result in an impairment of proved oil and gas properties of $50.0 million. This estimated range of the fourth quarter cost center ceiling is based on the estimated 12-Month Average Realized Price of crude oil of $39.26 per barrel as of December 31, 2016, which is based on the average realized price for sales of crude oil on the first calendar day of each month for the first 11 months and an estimate for the twelfth month based on a quoted forward price. Declines in the 12-Month Average Realized Price of crude oil in subsequent quarters would result in a lower present value of the estimated future net revenues from proved oil and gas reserves and may result in additional impairments of proved oil and gas properties.

4. Income Taxes

The Company’s estimated annual effective income tax rates are used to allocate expected annual income tax expense or benefit to interim periods. The rates are the ratio of estimated annual income tax expense or benefit to estimated annual income or loss before income taxes by taxing jurisdiction, except for discrete items, which are significant, unusual or infrequent items for which income taxes are computed and recorded in the interim period in which the discrete item occurs. The estimated annual effective income tax rates are applied to the year-to-date income or loss before income taxes by taxing jurisdiction to determine the income tax expense or benefit allocated to the interim period. The Company updates its estimated annual effective income tax rates on a quarterly basis considering the geographic mix of income or loss attributable to the tax jurisdictions in which the Company operates.

The Company's income tax benefit from continuing operations differs from the income tax benefit computed by applying the U.S. federal statutory corporate income tax rate of 35% to loss from continuing operations before income taxes as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In thousands)			
Loss from continuing operations before income taxes	($101,487)	($811,683)	($674,695)	($917,670)
Income tax benefit at the statutory rate	35,520	284,089	236,143	321,185
State income tax benefit, net of U.S. federal income taxes	575	6,542	3,859	6,321
Deferred tax assets valuation allowance	(36,696)	(187,607)	(240,897)	(187,607)
Texas Franchise Tax rate reduction, net of U.S. federal income taxes	—	—	—	1,671
Other	914	(109)	895	(1,114)
Income tax benefit from continuing operations	$313	$102,915	$—	$140,456

Deferred Tax Assets Valuation Allowance

Deferred tax assets are recorded for net operating losses and temporary differences between the book and tax basis of assets and
liabilities expected to produce tax deductions in future periods. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those deferred tax assets would be deductible. The Company assesses the realizability of its deferred tax assets on a quarterly basis by considering whether it is more likely than not that all or a portion of the deferred tax assets will not be realized. The Company considers all available evidence (both positive and negative) when determining whether a valuation allowance is required. In making this assessment, the Company evaluated possible sources of taxable income that may be available to realize the deferred tax assets, including projected future taxable income, the reversal of existing temporary differences, taxable income in carryback years and available tax planning strategies.

A significant item of objective negative evidence considered was the cumulative historical three year pre-tax loss and a net deferred tax asset position at September 30, 2016, driven primarily by the impairments of proved oil and gas properties recognized during the second half of 2015 and throughout 2016, which limits the ability to consider other subjective evidence such as the Company's potential for future growth. Based on evaluation of the evidence available during the three months ended September 30, 2016, the Company's previous conclusion that it is more likely than not the net deferred tax assets will not be realized remained unchanged and an additional valuation allowance of $36.7 million was recorded for the three months ending September 30, 2016, reducing the net deferred tax assets to zero. This additional valuation allowance increased the total valuation allowance recorded during the nine months ended September 30, 2016 to $240.9 million.

The Company will continue to evaluate whether the valuation allowance is needed in future reporting periods. The valuation allowance will remain until the Company can conclude that the net deferred tax assets are more likely than not to be realized. Future events or new evidence which may lead the Company to conclude that it is more likely than not its net deferred tax assets will be realized include, but are not limited to, cumulative historical pre-tax earnings, improvements in crude oil prices, and taxable events that could result from one or more transactions. The valuation allowance does not preclude the Company from utilizing the tax attributes if the Company recognizes taxable income. As long as the Company continues to conclude that the valuation allowance against its net deferred tax assets is necessary, the Company will have no significant deferred income tax expense or benefit.

5. Long-Term Debt

Long-term debt consisted of the following as of September 30, 2016 and December 31, 2015:

	September 30, 2016	December 31, 2015
	(In thousands)	
Senior Secured Revolving Credit Facility due 2018	$96,000	$—
7.50% Senior Notes due 2020	600,000	600,000
Unamortized premium for 7.50% Senior Notes	1,080	1,251

Unamortized debt issuance costs for 7.50% Senior Notes	(7,950)	(9,048)
6.25% Senior Notes due 2023	650,000	650,000
Unamortized debt issuance costs for 6.25% Senior Notes	(9,754)	(10,611)
Other long-term debt due 2028	4,425	4,425
Long-term debt	$1,333,801	$1,236,017

Senior Secured Revolving Credit Facility

The Company has a senior secured revolving credit facility with a syndicate of banks that, as of September 30, 2016, had a borrowing base of $600.0 million, with $96.0 million of borrowings outstanding at a weighted average interest rate of 2.46%. As of September 30, 2016, the Company also had $0.4 million in letters of credit outstanding, which reduce the amounts available under the revolving credit facility. The credit agreement governing the revolving credit facility provides for interest-only payments until July 2, 2018, when the credit agreement matures and any outstanding borrowings are due. The borrowing base under the credit agreement is subject to regular redeterminations in the Spring and Fall of each year, as well as special redeterminations described in the credit agreement, in each case which may reduce the amount of the borrowing base. The amount the Company is able to borrow with respect to the borrowing base is subject to compliance with the financial covenants and other provisions of the credit agreement. Each of the capitalized terms which are not defined in this note shall have the meaning given to such terms in the credit agreement.

On May 3, 2016, the Company entered into an amendment to the credit agreement (the "Eighth Amendment") to, among other things (i) replace the Total Debt to EBITDA ratio covenant with a Total Secured Debt to EBITDA ratio covenant that requires such ratio not to exceed 2.00 to 1.00, (ii) add a covenant requiring a minimum EBITDA to Interest Expense ratio of at least 2.50 to 1.00, (iii) reduce the Borrowing Base under the credit facility from $685.0 million to $600.0 million until the next redetermination thereof, (iv) increase the required mortgage coverage on the total value of the oil and gas properties included in the Company's most recent reserve report from 80% to 90%, (v) require that the Company's deposit accounts and securities accounts (subject to certain exclusions) become subject to control agreements, (vi) limit the amount of additional senior notes that can be issued by the Company to $400.0 million, (vii) restrict the Company from making borrowings under the credit facility if the Company has or, after giving effect to the borrowing, will have a Consolidated Cash Balance in excess of $50.0 million, (viii) require mandatory prepayment of borrowings to the extent the Consolidated Cash Balance exceeds $50.0 million if either (a) the Company's ratio of Total Debt to EBITDA exceeds 3.50 to 1.00 or (b) the availability under the credit facility is equal to or less than 20% of the then effective Borrowing Base, (ix) increase the margin on all loans by 0.50%, and (x) increase the commitment fee from 0.375% to 0.50% when utilization of lender commitments is less than 50%.

The obligations of the Company under the credit agreement are guaranteed by the Company's material domestic subsidiaries and are secured by liens on substantially all of the Company's assets, including a mortgage lien on oil and gas properties having at least 90% of the total value of the oil and gas properties included in the Company's most recent reserve report.

Borrowings outstanding under the credit agreement bear interest at the Company's option at either (i) a base rate for a base rate loan plus the margin set forth in the table below, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.50% and the adjusted LIBO rate plus 1.00%, or (ii) an adjusted LIBO rate for a Eurodollar loan plus the margin set forth in the table below. The Company also incurs commitment fees as set forth in the table below based on the unused portion of lender commitments, which are included in interest expense, net.

Ratio of Outstanding Borrowings and Letters of Credit to Lender Commitments	Applicable Margin for Base Rate Loans	Applicable Margin for Eurodollar Loans	Commitment Fee
Less than 25%	1.00%	2.00%	0.500%
Greater than or equal to 25% but less than 50%	1.25%	2.25%	0.500%
Greater than or equal to 50% but less than 75%	1.50%	2.50%	0.500%
Greater than or equal to 75% but less than 90%	1.75%	2.75%	0.500%
Greater than or equal to 90%	2.00%	3.00%	0.500%

As discussed above, the Company is subject to certain covenants under the terms of the credit agreement, which include the maintenance of the following financial covenants determined as of the last day of each quarter: (1) a ratio of Total Secured Debt to EBITDA of not more than 2.00 to 1.00; (2) a Current Ratio of not less than 1.00 to 1.00; and (3) a ratio of EBITDA to Interest Expense of not less than 2.50 to 1.00. As defined in the credit agreement, EBITDA includes the last four quarters after giving pro forma effect to EBITDA for material acquisitions and dispositions of oil and gas properties, Interest Expense is comprised of the aggregate interest expense paid in cash for the last four quarters, and the Current Ratio includes an add back of the unused portion of lender commitments. As of

September 30, 2016, the ratio of Total Secured Debt to EBITDA was 0.24 to 1.00, the Current Ratio was 2.63 to 1.00 and the ratio of EBITDA to Interest Expense was 4.35 to 1.00. Because the financial covenants are determined as of the last day of each quarter, the ratios can fluctuate significantly period to period as the level of borrowings outstanding under the credit agreement are impacted by the timing of cash flows from operations, capital expenditures, acquisitions and dispositions of oil and gas properties and securities offerings.

The credit agreement also places restrictions on the Company and certain of its subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of the Company’s common stock, redemptions of senior notes, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters.

The credit agreement is subject to customary events of default, including in connection with a change in control. If an event of default occurs and is continuing, the lenders may elect to accelerate amounts due under the credit agreement (except in the case of a bankruptcy event of default, in which case such amounts will automatically become due and payable).

6. Commitments and Contingencies

From time to time, the Company is party to certain legal actions and claims arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not currently expect these matters to have a materially adverse effect on the financial position or results of operations of the Company.

The results of operations and financial position of the Company continue to be affected from time to time in varying degrees by domestic and foreign political developments as well as legislation and regulations pertaining to restrictions on crude oil and natural gas production, imports and exports, natural gas regulation, tax increases, environmental regulations and cancellation of contract rights. Both the likelihood and overall effect of such occurrences on the Company vary greatly and are not predictable.

7. Stock-Based Compensation

Stock-Based Compensation Expense (Benefit), Net

The Company recognized the following stock-based compensation expense (benefit), net for the periods indicated which is reflected as "General and administrative, net" in the consolidated statements of operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In thousands)			
Restricted stock awards and units	$5,487	$6,013	$23,079	$17,242
Stock appreciation rights	3,361	(11,557)	9,581	(5,666)
Performance share awards	722	598	2,052	1,363
	9,570	(4,946)	34,712	12,939
Less: amounts capitalized to oil and gas properties	(1,150)	(647)	(3,878)	(3,736)
Total stock-based compensation expense (benefit), net	$8,420	($5,593)	$30,834	$9,203
Income tax benefit (expense) at the U.S. federal statutory rate	$2,947	($1,958)	$10,792	$3,221

8. Loss From Continuing Operations Per Common Share

Supplemental loss from continuing operations per common share information is provided below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In thousands, except per share amounts)			
Loss from Continuing Operations	($101,174)	($708,768)	($674,695)	($777,214)
Basic weighted average common shares outstanding	58,945	51,543	58,705	49,742
Effect of dilutive instruments	—	—	—	—
Diluted weighted average common shares outstanding	58,945	51,543	58,705	49,742
Loss from Continuing Operations Per Common Share				
Basic	($1.72)	($13.75)	($11.49)	($15.62)
Diluted	($1.72)	($13.75)	($11.49)	($15.62)

For the three and nine months ended September 30, 2016 and 2015, the Company reported a loss from continuing operations. As a result, the calculation of diluted weighted average common shares outstanding excluded the anti-dilutive effect of 0.7 million and 0.4 million potentially dilutive common shares outstanding for the three months ended September 30, 2016 and 2015, respectively, and 0.7 million potentially dilutive common shares outstanding for the nine months ended September 30, 2016 and 2015.

9. Derivative Instruments

The Company uses commodity derivative instruments to reduce its exposure to commodity price volatility for a portion of its forecasted crude oil and natural gas production and thereby achieve a more predictable level of cash flows to support the Company’s drilling and completion capital expenditure program. The Company does not enter into derivative instruments for speculative or

trading purposes. As of September 30, 2016, the Company's commodity derivative instruments consisted of fixed price swaps, costless collars, and purchased and sold call options, which are described below.
Fixed Price Swaps: The Company receives a fixed price and pays a variable market price to the counterparties over specified periods for contracted volumes.
Costless Collars: A collar is a combination of options including a purchased put option (fixed floor price) and a sold call option (fixed ceiling price) and allows the Company to benefit from increases in commodity prices up to the fixed ceiling price and protect the Company from decreases in commodity prices below the fixed floor price. At settlement, if the market price is below the fixed floor price or is above the fixed ceiling price, the Company receives the fixed price or pays the market price, respectively. If the market price is between the fixed floor price and fixed ceiling price, no payments are due from either party. These contracts were executed contemporaneously with the same counterparties and were premium neutral such that no payments were paid to or received from the counterparties.
Sold Call Options: These contracts give the counterparties the right, but not the obligation, to buy contracted volumes from the Company over specified periods and prices in the future. At settlement, if the market price exceeds the fixed price of the call option, the Company pays the counterparty the excess. If the market price settles below the fixed price of the call option, no payment is due from either party.
Purchased Call Options: These contracts give the Company the right, but not the obligation, to buy contracted volumes from the counterparties over specified periods and prices in the future. At settlement, if the market price exceeds the fixed price of the call option, the counterparties pay the Company the excess. If the market price settles below the fixed price of the call option, no payment is due from either party. The Company purchases call options contemporaneously with sales of call options to increase the fixed price of existing sold call options and therefore are presented on a net basis in the summary of open crude oil derivative positions below.
The following sets forth a summary of the Company's open crude oil derivative positions at average NYMEX prices as of September 30, 2016:

Period	Type of Contract	Crude Oil Volumes (in Bbls/d)	Weighted Average Floor Price ($/Bbl)	Weighted Average Ceiling Price ($/Bbl)
Q4 2016	Fixed Price Swaps	9,750	$60.03	
Q4 2016	Costless Collars	4,000	$50.00	$76.50
Q1 2017	Fixed Price Swaps	12,000	$50.13	
Q2 2017	Fixed Price Swaps	12,000	$50.13	
FY 2018	Sold Call Options	2,488		$60.00
FY 2018	Net Sold Call Options	900		$75.00
FY 2019	Sold Call Options	2,975		$62.50
FY 2019	Net Sold Call Options	900		$77.50
FY 2020	Sold Call Options	3,675		$65.00
FY 2020	Net Sold Call Options	900		$80.00

The following sets forth a summary of the Company's open natural gas derivative positions at average NYMEX prices as of September 30, 2016:

Period	Type of Contract	Natural Gas Volumes (in MMBtu/d)	Weighted Average Ceiling Price ($/MMBtu)
FY 2017	Sold Call Options	33,000	$3.00
FY 2018	Sold Call Options	33,000	$3.25
FY 2019	Sold Call Options	33,000	$3.25
FY 2020	Sold Call Options	33,000	$3.50

See "Note 13. Subsequent Events" for details of derivative positions entered into subsequent to September 30, 2016.

In February 2015, the Company entered into derivative transactions offsetting its then existing crude oil derivative positions covering the periods from March 2015 through December 2016. As a result of the offsetting derivative transactions, the Company locked in $166.4 million of cash flows, of which $9.3 million and $40.0 million were received due to contract settlements during the three months ended September 30, 2016 and 2015, respectively, and $36.9 million and $79.9 million during the nine months ended September 30, 2016 and 2015, respectively, and are included in the “Cash received for derivative settlements, net” in the consolidated statements of cash flows. As of September 30, 2016, the remaining locked in cash flows are $10.6 million, of which approximately $7.9 million will be received during the fourth quarter of 2016 and approximately $2.7 million will be received in the first quarter of 2017, as the applicable contracts settle. All of the remaining locked in cash flows are current assets and are classified as “Derivative assets” in the consolidated balance sheets. The derivative assets associated with the offsetting derivative transactions are not subject to price risk. The offsetting derivative transactions are not included in the table above.

In February 2016, the Company sold out-of-the-money natural gas call options for the years 2017 through 2020 and used the associated premium value to obtain in-the-money crude oil fixed price swaps with a weighted average price of $50.27 per Bbl on 6,000 Bbls/d for the first half of 2017. These out-of-the-money natural gas call options and in-the-money crude oil fixed price swaps were executed contemporaneously with the same counterparty, therefore, no cash premiums were paid to or received from the counterparty as the premium value associated with the natural gas call options was immediately applied to the crude oil fixed price swaps.

In March 2016, the Company sold 6,000 Bbls/d of in-the-money crude oil fixed price swaps for the first half of the year 2017 at a weighted average fixed price of $50.00 per Bbl. The associated net premiums totaled approximately $5.6 million, of which approximately $2.8 million was paid during the second quarter of 2016 and the remaining $2.8 million was paid during the third quarter of 2016 and are included in the “Cash received for derivative settlements, net” in the consolidated statements of cash flows.

The Company typically has numerous hedge positions that span several time periods and often result in both fair value asset and liability positions held with that counterparty, which positions are all offset to a single fair value asset or liability at the end of each reporting period, including the deferred premiums associated with its hedge positions. The Company nets its derivative instrument fair values executed with the same counterparty pursuant to ISDA master agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract. The fair value of derivative instruments where the Company is in a net asset position with its counterparties as of September 30, 2016 and December 31, 2015 totaled $6.8 million and $119.6 million, respectively, and is summarized by counterparty in the table below:

Counterparty	September 30, 2016		December 31, 2015	
Regions	40	%	9	%
Wells Fargo	34	%	35	%
Union Bank	26	%	5	%
Capital One	—	%	1	%
Societe Generale	—	%	37	%
Citibank	—	%	13	%
Total	100	%	100	%

The counterparties to the Company’s derivative instruments are also lenders under the Company’s credit agreement which allows the Company to satisfy any need for margin obligations associated with derivative instruments where the Company is in a net liability position with its counterparties with the collateral securing the credit agreement, thus eliminating the need for independent collateral posting.

Because each of the counterparties have investment grade credit ratings, the Company believes it does not have significant credit risk and accordingly does not currently require its counterparties to post collateral to support the net asset positions of its derivative instruments. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties to its derivative instruments. Although the Company does not currently anticipate such nonperformance, it continues to monitor the credit ratings of its counterparties.

10. Fair Value Measurements

Accounting guidelines for measuring fair value establish a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

Level 1 – Observable inputs such as quoted prices in active markets at the measurement date for identical, unrestricted assets or liabilities.
Level 2 – Other inputs that are observable directly or indirectly such as quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability.
Level 3 – Unobservable inputs for which there is little or no market data and which the Company makes its own assumptions about how market participants would price the assets and liabilities.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The following tables summarize the Company's assets and liabilities measured at fair value on a recurring basis as presented in the consolidated balance sheets as of September 30, 2016 and December 31, 2015. All items included in the tables below are Level 2 inputs within the fair value hierarchy:

	September 30, 2016		
	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
	(In thousands)		
Derivative assets			
Derivative assets-current	$31,742	($11,596)	$20,146
Derivative assets-non current	1,992	(1,992)	—
Derivative liabilities			
Other current liabilities	(11,596)	11,596	—
Derivative liabilities-non current	(31,346)	1,992	(29,354)
Total	($9,208)	$—	($9,208)

	December 31, 2015		
	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
	(In thousands)		
Derivative assets			
Derivative assets-current	$159,447	($28,347)	$131,100
Derivative assets-non current	10,780	(9,665)	1,115
Derivative liabilities			
Other current liabilities	(28,364)	28,347	(17)
Derivative liabilities-non current	(22,313)	9,665	(12,648)
Total	$119,550	$—	$119,550

The fair values of the Company's derivative assets and liabilities are based on a third-party industry-standard pricing model that uses market data obtained from third-party sources, including quoted forward prices for crude oil and natural gas, discount rates and volatility factors. The fair values are also compared to the values provided by the counterparties for reasonableness and are adjusted for the counterparties' credit quality for derivative assets and the Company's credit quality for derivative liabilities.

The derivative asset and liability fair values reported in the consolidated balance sheets that pertain to the Company's derivative instruments are as of the balance sheet date and subsequently change to reflect actual results, changes in market conditions and other factors. However, the fair value of the net derivative asset attributable to the offsetting crude oil derivative transactions are not subject to price risk as changes in the fair value of the original positions are offset by changes in the fair value of the offsetting positions. The Company typically has numerous hedge positions that span several time periods and often result in both derivative assets and liabilities with the same counterparty, which positions are all offset to a single derivative asset or liability in the consolidated balance sheets, including the deferred premiums associated with its hedge positions. The Company nets the fair values of its derivative assets and liabilities associated with derivative instruments executed with the same counterparty pursuant to ISDA master agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract. The Company had no transfers into Level 1 and no transfers into or out of Level 2 for the nine months ended September 30, 2016 and 2015.

Fair Value of Other Financial Instruments

The Company's other financial instruments consist of cash and cash equivalents, receivables, payables and long-term debt, which are classified as Level 1 under the fair value hierarchy. The carrying amounts of cash and cash equivalents, receivables, and payables approximate fair value due to the highly liquid or short-term nature of these instruments. The carrying amount of long-term debt associated with borrowings outstanding under the Company's revolving credit facility approximates fair value as borrowings bear interest at variable rates. The following table presents the carrying amounts of the Company's senior notes and other long-term debt, net of debt premiums and debt issuance costs, with the fair values of each based on quoted market prices.

	September 30, 2016		December 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
7.50% Senior Notes due 2020	$593,130	$615,000	$592,203	$528,000
6.25% Senior Notes due 2023	640,246	643,500	639,389	533,000
Other long-term debt due 2028	4,425	4,337	4,425	4,182

11. Condensed Consolidating Financial Information

The rules of the SEC require that condensed consolidating financial information be provided for a subsidiary that has guaranteed the debt of a registrant issued in a public offering, where the guarantee is full, unconditional and joint and several and where the voting interest of the subsidiary is 100% owned by the registrant. The Company is, therefore, presenting condensed consolidating financial information on a parent company, combined guarantor subsidiaries, combined non-guarantor subsidiaries and consolidated basis and should be read in conjunction with the consolidated financial statements. The financial information may not necessarily be indicative of results of operations, cash flows, or financial position had such guarantor subsidiaries operated as independent entities.

CARRIZO OIL & GAS, INC.
CONDENSED CONSOLIDATING BALANCE SHEETS
(In thousands)
(Unaudited)

	September 30, 2016				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Total current assets	$2,551,367	$50,479	$—	($2,524,333)	$77,513
Total property and equipment, net	42,759	1,291,991	3,800	(3,855)	1,334,695
Investment in subsidiaries	(1,338,051)	—	—	1,338,051	—
Other assets	8,143	156	—	—	8,299
Total Assets	$1,264,218	$1,342,626	$3,800	($1,190,137)	$1,420,507
Liabilities and Shareholders' Deficit					
Current liabilities	$94,952	$2,658,363	$3,800	($2,527,353)	$229,762
Long-term liabilities	1,357,911	22,314	—	15,879	1,396,104
Total shareholders' deficit	(188,645)	(1,338,051)	—	1,321,337	(205,359)
Total Liabilities and Shareholders' Deficit	$1,264,218	$1,342,626	$3,800	($1,190,137)	$1,420,507

	December 31, 2015				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Total current assets	$2,578,034	$52,067	$—	($2,397,919)	$232,182
Total property and equipment, net	44,499	1,671,774	3,059	(2,471)	1,716,861
Investment in subsidiaries	(815,836)	—	—	815,836	—
Other assets	74,679	156	—	(16,632)	58,203
Total Assets	$1,881,376	$1,723,997	$3,059	($1,601,186)	$2,007,246
Liabilities and Shareholders' Equity					
Current liabilities	$161,792	$2,521,572	$3,059	($2,400,939)	$285,484
Long-term liabilities	1,260,200	18,261	—	(753)	1,277,708
Total shareholders' equity	459,384	(815,836)	—	800,506	444,054
Total Liabilities and Shareholders' Equity	$1,881,376	$1,723,997	$3,059	($1,601,186)	$2,007,246

CARRIZO OIL & GAS, INC.
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(In thousands)
(Unaudited)

	Three Months Ended September 30, 2016				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$105	$111,072	$—	$—	$111,177
Total costs and expenses	28,551	184,047	—	66	212,664
Loss from continuing operations before income taxes	(28,446)	(72,975)	—	(66)	(101,487)
Income tax benefit	—	—	—	313	313
Equity in loss of subsidiaries	(72,975)	—	—	72,975	—
Loss from continuing operations	(101,421)	(72,975)	—	73,222	(101,174)
Income from discontinued operations, net of income taxes	—	—	—	—	—
Net loss	($101,421)	($72,975)	$—	$73,222	($101,174)

	Three Months Ended September 30, 2015				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$235	$106,002	$—	$—	$106,237
Total costs and expenses	(6,718)	890,350	—	34,288	917,920
Income (loss) from continuing operations before income taxes	6,953	(784,348)	—	(34,288)	(811,683)
Income tax (expense) benefit	(25,496)	119,847	—	8,564	102,915
Equity in loss of subsidiaries	(664,501)	—	—	664,501	—
Loss from continuing operations	(683,044)	(664,501)	—	638,777	(708,768)
Income from discontinued operations, net of income taxes	1,121	—	—	—	1,121
Net loss	($681,923)	($664,501)	$—	$638,777	($707,647)

CARRIZO OIL & GAS, INC.
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(In thousands)
(Unaudited)

	Nine Months Ended September 30, 2016				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$349	$299,414	$—	$—	$299,763
Total costs and expenses	151,445	822,582	—	431	974,458
Loss from continuing operations before income taxes	(151,096)	(523,168)	—	(431)	(674,695)
Income tax benefit	—	—	—	—	—
Equity in loss of subsidiaries	(523,168)	—	—	523,168	—
Loss from continuing operations	(674,264)	(523,168)	—	522,737	(674,695)
Income from discontinued operations, net of income taxes	—	—	—	—	—
Net loss	($674,264)	($523,168)	$—	$522,737	($674,695)

	Nine Months Ended September 30, 2015				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$1,485	$328,296	$—	$—	$329,781
Total costs and expenses	116,793	1,101,671	—	28,987	1,247,451
Loss from continuing operations before income taxes	(115,308)	(773,375)	—	(28,987)	(917,670)
Income tax benefit	17,296	116,006	—	7,154	140,456
Equity in loss of subsidiaries	(657,369)	—	—	657,369	—
Loss from continuing operations	(755,381)	(657,369)	—	635,536	(777,214)
Income from discontinued operations, net of income taxes	2,225	—	—	—	2,225
Net loss	($753,156)	($657,369)	$—	$635,536	($774,989)

CARRIZO OIL & GAS, INC.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(In thousands)
(Unaudited)

	Nine Months Ended September 30, 2016				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities from continuing operations	($10,882)	$208,729	$—	$—	$197,847
Net cash used in investing activities from continuing operations	(122,846)	(331,351)	(740)	123,362	(331,575)
Net cash provided by financing activities from continuing operations	94,045	122,622	740	(123,362)	94,045
Net cash used in discontinued operations	—	—	—	—	—
Net decrease in cash and cash equivalents	(39,683)	—	—	—	(39,683)
Cash and cash equivalents, beginning of period	42,918	—	—	—	42,918
Cash and cash equivalents, end of period	$3,235	$—	$—	$—	$3,235

	Nine Months Ended September 30, 2015				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities from continuing operations	($8,817)	$293,036	$—	$—	$284,219
Net cash used in investing activities from continuing operations	(396,036)	(529,046)	—	386,010	(539,072)
Net cash provided by financing activities from continuing operations	399,391	236,010	—	(386,010)	249,391
Net cash used in discontinued operations	(3,372)	—	—	—	(3,372)
Net decrease in cash and cash equivalents	(8,834)	—	—	—	(8,834)
Cash and cash equivalents, beginning of period	10,838	—	—	—	10,838
Cash and cash equivalents, end of period	$2,004	$—	$—	$—	$2,004

12. Supplemental Cash Flow Information

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

	Nine Months Ended September 30,	
	2016	2015
	(In thousands)	
Non-cash investing activities:		
Increase (decrease) in capital expenditure payables and accruals	$7,316	($71,967)
Other non-cash investing activities (1)	12,468	23,737

(1) Other non-cash investing activities includes items such as property exchanges, capitalized asset retirement obligations, capital lease transactions and other non-cash activity.

13. Subsequent Events

Sanchez Acquisition

On October 24, 2016, the Company entered into a purchase and sale agreement with Sanchez Energy Corporation and SN Cotulla Assets, LLC, a subsidiary of Sanchez Energy Corporation, to acquire oil and gas properties in the Eagle Ford Shale primarily in LaSalle, Frio and McMullen Texas counties (the "Sanchez Acquisition") for a purchase price of approximately $181.0 million in cash, subject to customary purchase price adjustments. The transaction has an effective date of June 1, 2016, and is currently expected to close on or about December 14, 2016. On October 24, 2016, the Company paid $10.0 million as a deposit, which was funded from borrowings under the revolving credit facility that were repaid with net proceeds from the common stock offering discussed below. The remaining purchase price is due on the closing date. The Company intends to fund the remaining purchase price at closing with cash remaining from the common stock offering described below and borrowings under its revolving credit facility. Upon consummation of the Sanchez Acquisition, the Company will become the operator of all the acquired properties.

Common Stock Offering

On October 28, 2016, the Company completed a public offering of 6.0 million shares of its common stock at a price of $37.32 per share, for proceeds of $223.9 million, net of underwriting discounts. The Company used the net proceeds from the common stock offering to repay borrowings under the revolving credit facility and intends to use any remaining proceeds to fund a portion of the purchase price of the Sanchez Acquisition due on the closing date.

Fall 2016 Borrowing Base Redetermination

On October 24, 2016, as a result of the Fall 2016 borrowing base redetermination, the borrowing base was reaffirmed at $600.0 million until the next redetermination thereof. The borrowing base under the credit agreement is subject to regular redeterminations in the Spring and Fall of each year, as well as special redeterminations described in the credit agreement, in each case which may reduce the amount of the borrowing base.

Hedging Update

In October 2016, the Company entered into the following crude oil and natural gas derivative positions:

Period	Type of Contract	Volumes (in Bbls/d)	Weighted Average Floor Price ($/Bbl)
Q3 2017	Fixed Price Swaps	6,000	$54.15
Q4 2017	Fixed Price Swaps	3,000	$55.01

Period	Type of Contract	Volumes	Weighted Average

		(in MMBtu/d)	Floor Price ($/MMBtu)
FY 2017	Fixed Price Swaps	20,000	$3.30

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

The following is management's discussion and analysis of the significant factors that affected the financial position and results of operations of Carrizo Oil & Gas, Inc. and its subsidiaries (collectively, the "Company") during the periods included in the accompanying unaudited consolidated financial statements. You should read this in conjunction with the unaudited interim consolidated financial statements included in this Quarterly Report on Form 10-Q and the discussion under "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the audited Consolidated Financial Statements included in our Annual Report on Form 10-K for the year ended December 31, 2015 ("2015 Annual Report").

General Overview

Production, Commodity Prices and Revenue. Total production for the three months ended September 30, 2016 increased 13% to 40,762 Boe/d from the total production for the three months ended September 30, 2015 of 35,948 Boe/d, due primarily to increased production from new wells in the Eagle Ford and Delaware Basin as well as increased production in the Marcellus due to a lower level of voluntary curtailments compared to the third quarter of 2015. Production from the Eagle Ford comprised 71% of our total production for the third quarter of 2016. Crude oil production for the three months ended September 30, 2016 was 24,488 Bbls/d, an increase of 4% from the three months ended September 30, 2015, primarily driven by increased production from new wells in the Eagle Ford, which averaged 21,649 Bbls/d. Revenues for the third quarter of 2016 of $111.2 million increased as compared to revenues from third quarter of 2015 of $106.2 million driven primarily by the increased production described above and an increase in average realized NGL prices, partially offset by a decrease in average realized crude oil prices. For further discussion of production, commodity prices and revenue, see "—Results of Operations" below.

Operational Highlights. See the table below for details of our operated drilling and completion activity by region:

	Three Months Ended September 30, 2016				September 30, 2016				
	Drilled		Wells Brought on Production		Waiting on Completion		Producing		Rig count
Region	Gross	Net	Gross	Net	Gross	Net	Gross	Net	
Eagle Ford	17	14.9	24	23.2	26	23.8	315	279.2	2
Niobrara	—	—	9	5.2	—	—	132	59.0	—
Marcellus	—	—	—	—	11	4.3	81	26.0	—
Utica	—	—	—	—	—	—	4	3.1	—
Delaware Basin	—	—	2	1.9	—	—	6	5.6	—
Total	17	14.9	35	30.3	37	28.1	538	372.9	2

Recent Developments

Sanchez Acquisition. On October 24, 2016, we entered into a purchase and sale agreement with Sanchez Energy Corporation and SN Cotulla Assets, LLC, a subsidiary of Sanchez Energy Corporation, to acquire oil and gas properties in the Eagle Ford Shale primarily in LaSalle, Frio and McMullen Texas counties (the "Sanchez Acquisition") for an agreed upon purchase price of approximately $181.0 million in cash, subject to customary purchase price adjustments. The properties to be acquired include approximately 15,000 net acres and 112 gross (93.0 net) wells. Based on information provided by the seller, we estimate that net production from the properties to be acquired was approximately 3,100 Boe/d for the month ended September 30, 2016.

The transaction had an effective date of June 1, 2016, and is currently expected to close on or about December 14, 2016. On October 24, 2016, we paid $10.0 million as a deposit, which was funded from borrowings under the revolving credit facility that were repaid with net proceeds from the common stock offering discussed below. The remaining purchase price is due on the closing date. We intend to fund the remaining purchase price at closing with cash remaining from the common stock offering described below and borrowings under its revolving credit facility. Upon consummation of the Sanchez Acquisition, we will become the operator of all the acquired properties.

Financing Activities. On October 28, 2016, we completed a public offering of 6.0 million shares of our common stock at a price of $37.32 per share, which generated proceeds of $223.9 million, net of underwriting discounts. We used the net proceeds from the common stock offering to repay borrowings under the revolving credit facility and intend to use any remaining proceeds to fund a portion of the purchase price of the Sanchez Acquisition due on the closing date.

On October 24, 2016, as a result of the Fall 2016 borrowing base redetermination, the borrowing base was reaffirmed at $600.0 million until the next redetermination thereof. The borrowing base under the credit agreement is subject to regular redeterminations in the Spring and Fall of each year, as well as special redeterminations described in the credit agreement, in each case which may change the amount of the borrowing base.

Results of Operations

Three Months Ended September 30, 2016, Compared to the Three Months Ended September 30, 2015

The following table summarizes total production volumes, daily production volumes, average realized prices and revenues for the three months ended September 30, 2016 and 2015:

	Three Months Ended September 30,		2016 Period Compared to 2015 Period		
	2016	2015	Increase (Decrease)	% Increase (Decrease)	
Total production volumes -					
Crude oil (MBbls)	2,253	2,169	84	4	%
NGLs (MBbls)	435	346	89	26	%
Natural gas (MMcf)	6,372	4,757	1,615	34	%
Total barrels of oil equivalent (MBoe)	3,750	3,307	443	13	%
Daily production volumes by product -					
Crude oil (Bbls/d)	24,488	23,573	915	4	%
NGLs (Bbls/d)	4,730	3,757	973	26	%
Natural gas (Mcf/d)	69,262	51,710	17,552	34	%
Total barrels of oil equivalent (Boe/d)	40,762	35,948	4,814	13	%
Daily production volumes by region (Boe/d) -					
Eagle Ford	29,110	26,913	2,197	8	%
Niobrara	2,576	2,735	(159)	(6	%)
Marcellus	6,811	4,443	2,368	53	%
Utica	843	1,707	(864)	(51	%)
Delaware Basin and other	1,422	150	1,272	848	%
Total barrels of oil equivalent (Boe/d)	40,762	35,948	4,814	13	%
Average realized prices -					
Crude oil ($ per Bbl)	$42.23	$43.91	($1.68)	(4	%)
NGLs ($ per Bbl)	12.91	9.62	3.29	34	%
Natural gas ($ per Mcf)	1.63	1.61	0.02	1	%
Total average realized price ($ per Boe)	$29.65	$32.12	($2.47)	(8	%)
Revenues (In thousands) -					
Crude oil	$95,154	$95,237	($83)	—	%
NGLs	5,616	3,330	2,286	69	%
Natural gas	10,407	7,670	2,737	36	%
Total revenues	$111,177	$106,237	$4,940	5	%

Production volumes for the three months ended September 30, 2016 and 2015 were 40,762 Boe/d and 35,948 Boe/d, respectively, an increase of 13%. The increase is primarily due to increased production from new wells in the Eagle Ford and Delaware Basin as well as increased production in the Marcellus due to a lower level of voluntary curtailments compared to the third quarter of 2015. Revenues for the three months ended September 30, 2016 increased 5% to $111.2 million from $106.2 million for the same period in 2015 due primarily to the increased production described above as well as increased average realized NGL prices, partially offset by a decrease in average realized crude oil prices.

Lease operating expenses for the three months ended September 30, 2016 increased to $24.3 million ($6.48 per Boe) from $22.2 million ($6.72 per Boe) for the same period in 2015. The increase in lease operating expenses is primarily due to increased production from new wells in the Eagle Ford. The decrease in lease operating expense per Boe is primarily due to lower produced water disposal costs.

Production taxes increased to $4.9 million (or 4.4% of revenues) for the three months ended September 30, 2016 from $4.3 million (or 4.0% of revenues) for the same period in 2015 primarily as a result of the increase in natural gas and NGL revenues. The increase in production taxes as a percentage of revenues for the three months ended September 30, 2016 as compared to the same period in 2015 is due primarily to an increased proportion of total revenues attributable to natural gas and NGL production in Eagle Ford, which is taxed at a higher rate than crude oil.

Ad valorem taxes decreased to $1.4 million for the three months ended September 30, 2016 from $2.3 million for the same period in 2015. The decrease in ad valorem taxes is due to lower property tax valuations received during 2016 as compared to 2015, partially offset by an increase attributable to new wells drilled in Eagle Ford in 2015.

Depreciation, depletion and amortization ("DD&A") expense for the third quarter of 2016 decreased $32.4 million to $48.9 million ($13.05 per Boe) from the DD&A expense for the third quarter of 2015 of $81.3 million ($24.57 per Boe). The decrease in DD&A expense is attributable to the decrease in the DD&A rate per Boe, which is due primarily to the impairments of proved oil and gas properties recorded in the second half of 2015 and the first half of 2016 as well as reductions in estimated future development costs primarily as a result of reduced service costs that have occurred since the third quarter of 2015. The components of our DD&A expense were as follows:

	Three Months Ended September 30,	
	2016	2015
	(In thousands)	
DD&A of proved oil and gas properties	$47,702	$80,016
Depreciation of other property and equipment	656	521
Amortization of other assets	251	432
Accretion of asset retirement obligations	340	287
Total DD&A	$48,949	$81,256

We recorded an impairment of proved oil and gas properties of $105.1 million for the three months ended September 30, 2016 due primarily to a 4% decrease in the 12-Month Average Realized Price, as defined in "Note 3. Property and Equipment, Net," of crude oil from $39.84 per barrel as of June 30, 2016 to $38.36 per barrel as of September 30, 2016. We recorded an impairment of proved oil and gas properties of $812.8 million for the three months ended September 30, 2015 due primarily to a 19% decrease in the 12-Month Average Realized Price of crude oil from $68.92 per barrel as of June 30, 2015 to $56.05 per barrel as of September 30, 2015.

General and administrative expense, net increased to $18.1 million for the three months ended September 30, 2016 from $4.2 million for the corresponding period in 2015. The increase was primarily due to an increase in stock-based compensation expense, net as a result of an increase in the fair value of stock appreciation rights for the three months ended September 30, 2016 compared to a decrease in fair value for the three months ended September 30, 2015.

The gain on derivatives, net for the three months ended September 30, 2016 amounted to $11.7 million due primarily to the downward shift in the futures curve of forecasted commodity prices for crude oil and natural gas from July 1, 2016 to September 30, 2016. The gain on derivatives, net for the three months ended September 30, 2015 amounted to $28.8 million due primarily to new crude oil hedge positions executed during the third quarter of 2015 and the downward shift in the futures curve of forecasted commodity prices for crude oil from July 1, 2015 to September 30, 2015.

Interest expense, net for the three months ended September 30, 2016 was $21.2 million as compared to $16.2 million for the same period in 2015. The increase was due primarily to the decrease in capitalized interest as a result of lower average balances of unevaluated leasehold and seismic costs and exploratory well costs in the third quarter of 2016 as compared to the third quarter of 2015. The components of our interest expense, net were as follows:

	Three Months Ended September 30,	
	2016	2015
	(In thousands)	
Interest expense on Senior Notes	$21,454	$21,455
Interest expense on revolving credit facility	1,161	1,131
Amortization of debt issuance costs, premiums, and discounts	1,186	1,000
Other interest expense	340	140

Capitalized interest	(2,951)	(7,518)
Interest expense, net	$21,190	$16,208

The effective income tax rates for the third quarter of 2016 and 2015 were 0.3% and 12.7%, respectively. This reduction in the effective income tax rate is primarily a result of a full valuation allowance against our net deferred tax assets driven by the impairments of proved oil and gas properties described above.

Results of Operations

Nine Months Ended September 30, 2016, Compared to the Nine Months Ended September 30, 2015

The following table summarizes total production volumes, daily production volumes, average realized prices and revenues for the nine months ended September 30, 2016 and 2015:

	Nine Months Ended September 30,		2016 Period Compared to 2015 Period	
	2016	2015	Increase (Decrease)	% Increase (Decrease)
Total production volumes -				
Crude oil (MBbls)	6,780	6,120	660	11 %
NGLs (MBbls)	1,324	981	343	35 %
Natural gas (MMcf)	19,502	15,637	3,865	25 %
Total barrels of oil equivalent (MBoe)	11,354	9,708	1,646	17 %
Daily production volumes by product -				
Crude oil (Bbls/d)	24,744	22,418	2,326	10 %
NGLs (Bbls/d)	4,831	3,594	1,237	34 %
Natural gas (Mcf/d)	71,174	57,280	13,894	24 %
Total barrels of oil equivalent (Boe/d)	41,438	35,559	5,879	17 %
Daily production volumes by region (Boe/d) -				
Eagle Ford	30,101	25,473	4,628	18 %
Niobrara	2,845	3,063	(218)	(7 %)
Marcellus	6,451	5,484	967	18 %
Utica	1,184	1,308	(124)	(9 %)
Delaware Basin and other	857	231	626	271 %
Total barrels of oil equivalent (Boe/d)	41,438	35,559	5,879	17 %
Average realized prices -				
Crude oil ($ per Bbl)	$37.57	$47.31	($9.74)	(21 %)
NGLs ($ per Bbl)	11.42	11.83	(0.41)	(3 %)
Natural gas ($ per Mcf)	1.53	1.83	(0.30)	(16 %)
Total average realized price ($ per Boe)	$26.40	$33.97	($7.57)	(22 %)
Revenues (In thousands) -				
Crude oil	$254,758	$289,552	($34,794)	(12 %)
NGLs	15,119	11,602	3,517	30 %
Natural gas	29,886	28,627	1,259	4 %
Total revenues	$299,763	$329,781	($30,018)	(9 %)

Production volumes for the nine months ended September 30, 2016 and 2015 were 41,438 Boe/d and 35,559 Boe/d, respectively. The increase in production from the nine months ended September 30, 2015 to the nine months ended September 30, 2016 was primarily due to increased production from new wells in the Eagle Ford. Revenues for the nine months ended September 30, 2016 decreased 9% to $299.8 million from $329.8 million for the same period in 2015 primarily due to the decrease in average realized crude oil prices, partially offset by the increase in crude oil production.

Lease operating expenses for the nine months ended September 30, 2016 increased to $71.1 million ($6.26 per Boe) from $67.3 million ($6.93 per Boe) for the same period in 2015. The increase in lease operating expenses is primarily due to increased production from new wells in the Eagle Ford, partially offset by reduced costs due primarily to a decrease in produced water disposal costs as a result of an increase in the proportion of produced water volumes being transported to disposal sites via pipeline instead of truck. The decrease in lease operating expense per Boe is primarily due to the lower produced water disposal costs described above.

Production taxes decreased to $12.9 million (or 4.3% of revenues) for the nine months ended September 30, 2016 from $13.3 million (or 4.0% of revenues) for the same period in 2015 primarily as a result of the decrease in crude oil revenues related to the decrease in average realized crude oil prices, partially offset by increased crude oil production. The increase in production taxes as a percentage of revenues for the nine months ended September 30, 2016 is primarily due to an increased proportion of total revenues attributable to natural gas and NGL production in Eagle Ford, which is taxed at a higher rate than crude oil.

Ad valorem taxes decreased to $4.0 million for the nine months ended September 30, 2016 from $7.0 million for the same period in 2015. The decrease in ad valorem taxes is due to lower property tax valuations received during 2016 as compared to 2015, partially offset by an increase attributable to new wells drilled in Eagle Ford in 2015.

DD&A expense for the nine months ended September 30, 2016 decreased $74.0 million to $160.5 million ($14.14 per Boe) from $234.5 million ($24.15 per Boe) for the same period in 2015. The decrease in DD&A expense is attributable to the decrease in the DD&A rate per Boe, which is due primarily to impairments of our proved oil and gas properties recorded in the second half of 2015 and the first half of 2016 as well as reductions in estimated future development costs primarily as a result of reduced service costs that have occurred since the third quarter of 2015. The components of our DD&A expense were as follows:

	Nine Months Ended September 30,	
	2016	2015
	(In thousands)	
DD&A of proved oil and gas properties	$156,595	$231,250
Depreciation of other property and equipment	1,994	1,271
Amortization of other assets	892	1,123
Accretion of asset retirement obligations	1,011	814
Total DD&A	$160,492	$234,458

We recorded impairments of proved oil and gas properties of $576.5 million for the nine months ended September 30, 2016 due primarily to a 19% decrease in the 12-Month Average Realized Price of crude oil from $47.24 per barrel as of December 31, 2015 to $38.36 per barrel as of September 30, 2016. We recorded an impairment of proved oil and gas properties of $812.8 million for the nine months ended September 30, 2015 due primarily to a 39% decrease in the 12-Month Average Realized Price of crude oil from $92.24 per barrel as of December 31, 2014 to $56.05 per barrel as of September 30, 2015.

General and administrative expense, net increased to $59.0 million for the nine months ended September 30, 2016 from $54.9 million for the same period in 2015. The increase was primarily due to an increase in stock-based compensation expense, net as a result of an increase in the fair value of stock appreciation rights for the nine months ended September 30, 2016 compared to a decrease in fair value for the nine months ended September 30, 2015, partially offset by lower annual bonuses awarded in the first quarter of 2016 compared to the first quarter of 2015.

The loss on derivatives, net for the nine months ended September 30, 2016 amounted to $29.9 million primarily due to crude oil and natural gas hedge positions executed during 2016 as well as the upward shift in the futures curve of forecasted commodity prices for crude oil from January 1, 2016 (or the subsequent date on which new contracts were entered into) to September 30, 2016. The gain on derivatives, net for the nine months ended September 30, 2015 amounted to $42.6 million primarily due to new crude oil hedge positions executed during 2015, the downward shift in the futures curve of forecasted commodity prices for crude oil during the first quarter of 2015 prior to our lock-in of our then existing crude oil derivative positions as well as during the third quarter of 2015, and the downward shift in the futures curve of forecasted commodity prices for natural gas from January 1, 2015 to September 30, 2015.

Interest expense, net for the nine months ended September 30, 2016 was $58.9 million as compared to $51.4 million for the same period in 2015. The increase was due primarily to the decrease in capitalized interest as a result of lower average balances of unevaluated leasehold and seismic costs and exploratory well costs for the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015, partially offset by lower interest associated with the $650.0 million of 6.25% Senior Notes that were issued in April 2015 as compared to the interest associated with the $600.0 million of 8.625% Senior Notes that were redeemed in April 2015. The components of our interest expense, net were as follows:

Nine Months
Ended

	September 30,	
	2016	2015
	(In thousands)	
Interest expense on Senior Notes	$64,364	$69,428
Interest expense on revolving credit facility	2,827	3,296
Amortization of debt issuance costs, premiums, and discounts	4,296	3,622
Other interest expense	854	1,247
Capitalized interest	(13,428)	(26,190)
Interest expense, net	$58,913	$51,403

The effective income tax rates for the nine months ended September 30, 2016 and 2015 were 0.0% and 15.3%, respectively. This reduction in the effective income tax rate is primarily a result of a full valuation allowance against our net deferred tax assets driven by the impairments of proved oil and gas properties described above.

Liquidity and Capital Resources

2016 Capital Expenditure Plan and Funding Strategy. In November, our 2016 drilling and completion capital expenditure plan was increased to $400.0 million to $410.0 million from the previous range of $370.0 million to $380.0 million as a result of planned additional spending in the Eagle Ford and Delaware Basin. Our 2016 leasehold and seismic capital expenditure plan has been increased from $20.0 million to $25.0 million. The 2016 drilling and completion capital expenditure plan and the 2016 leasehold and seismic capital expenditure plan exclude any impact of the Sanchez Acquisition. We currently intend to finance our 2016 capital expenditure plan primarily from the sources described below under "—Sources and Uses of Cash." Our capital program could vary depending upon various factors, including the availability and cost of drilling rigs, land and industry partner issues, our available cash flow and financing, success of drilling programs, weather delays, commodity prices, market conditions, the acquisition of leases with drilling commitments and other factors. Below is a summary of capital expenditures through September 30, 2016:

	Three Months Ended			Nine Months Ended
	March 31, 2016	June 30, 2016	September 30, 2016	September 30, 2016
	(In thousands)			
Drilling and completion				
Eagle Ford	$72,417	$82,451	$100,820	$255,688
Other areas	12,431	20,814	24,945	58,190
Total drilling and completion	84,848	103,265	125,765	313,878
Leasehold and seismic	5,911	6,427	6,190	18,528
Total (1)	$90,759	$109,692	$131,955	$332,406

(1) Our capital expenditure plan and the capital expenditures included above exclude capitalized general and administrative expense, capitalized interest and capitalized asset retirement obligations.

Sources and Uses of Cash. Our primary use of cash is related to our drilling and completion capital expenditure plan and, to a lesser extent, our leasehold and seismic capital expenditure plan. For the nine months ended September 30, 2016, we funded our capital expenditures with cash provided by operations and borrowings under our revolving credit facility. Potential sources of future liquidity include the following:

- Cash provided by operations. Cash flows from operations are highly dependent on crude oil prices. As such, we hedge a portion of our forecasted production to reduce our exposure to commodity price volatility in order to achieve a more predictable level of cash flows.
- Borrowings under our revolving credit facility. As of October 28, 2016, our revolving credit facility had a borrowing base of $600.0 million, with no borrowings outstanding and $0.4 million in letters of credit issued, which reduce the amounts available under our revolving credit facility. The amount we are able to borrow is subject to compliance with the financial covenants and other provisions of the credit agreement governing our revolving credit facility.
- Securities offerings. As situations or conditions arise, we may choose to issue debt, equity or other securities to supplement our cash flows. However, we may not be able to obtain such financing on terms that are acceptable to us, or at all. In October 2016, we sold 6.0 million shares of our common stock in a public offering at a price of $37.32 per share. We used the proceeds of $223.9 million, net of underwriting discounts, to repay borrowings under the revolving credit facility and intend to use any remaining proceeds to fund a portion of the purchase price of the Sanchez Acquisition due on the closing date.
- Asset sales. In order to fund our capital expenditure plan, we may consider the sale of certain properties or assets that are not part of our core business or are no longer deemed essential to our future growth, provided we are able to sell

such assets on terms that are acceptable to us. We continue to explore sales of non-core properties. We may also consider the sale of properties in areas we have viewed as core, such as the Delaware Basin, particularly if we believe that sales prices for such assets would allow us to deploy capital more effectively in other basins or other parts of the same basin. There can be no assurance, however, that any sales will occur on terms we find to be acceptable, or at all.

- Joint ventures. Joint ventures with third parties through which such third parties fund a portion of our exploration activities to earn an interest in our exploration acreage or purchase a portion of interests, or both.

Overview of Cash Flow Activities. Net cash provided by operating activities from continuing operations was $197.8 million and $284.2 million for the nine months ended September 30, 2016 and 2015, respectively. The change was due primarily to a decrease in crude oil revenues, resulting primarily from lower average realized crude oil prices in 2016 as compared to 2015, a decrease in the net cash received from derivative settlements, and an increase in working capital requirements, partially offset by a decrease in cash general and administrative expense.

Net cash used in investing activities from continuing operations was $331.6 million and $539.1 million for the nine months ended September 30, 2016 and 2015, respectively. The decrease was due primarily to a reduction in our capital expenditures in 2016 as compared to 2015.

Net cash provided by financing activities from continuing operations was $94.0 million and $249.4 million for the nine months ended September 30, 2016 and 2015, respectively. The decrease was primarily due to the proceeds from the issuance of common stock in March 2015 and the issuance of the 6.25% Senior Notes in April 2015, as well as increased borrowings net of repayments under our revolving credit facility for the nine months ended September 30, 2015 as compared to the same period in 2016, partially offset by the tender and redemption of the 8.625% Senior Notes during the second quarter of 2015 and the payment of the deferred purchase payment in February 2015.

Liquidity/Cash Flow Outlook. Economic downturns may adversely affect our ability to access capital markets in the future. Cash flows from operations are primarily driven by crude oil production, commodity prices and settlements of our commodity derivatives. As a result of the significant decline in crude oil prices, our revenues and thus our cash flows from operations have also declined. However, this decline in our cash flows from operations was partially offset due to the net cash we received from derivative settlements. We currently believe that cash flows from operations and borrowings under our revolving credit facility provide adequate financial flexibility and will be sufficient to fund our immediate cash flow requirements.

- Revolving credit facility. As of October 28, 2016, our revolving credit facility had a borrowing base of $600.0 million, with no borrowings outstanding and $0.4 million in letters of credit issued, which reduce the amounts available under our revolving credit facility. The borrowing base under our revolving credit facility is affected by assumptions with respect to, among other things, future crude oil and natural gas prices, which are determined by the administrative agent of our revolving credit facility. Our borrowing base may decrease if our administrative agent reduces its expectations with respect to future crude oil and natural gas prices from those used to determine our existing borrowing base.

On October 24, 2016, as a result of our Fall 2016 borrowing base redetermination, our borrowing base was reaffirmed at $600.0 million. The amount we are able to borrow is subject to compliance with the financial covenants and other provisions of the credit agreement governing the revolving credit facility.

- Hedging. To manage our exposure to commodity price risk and to provide a level of certainty in the cash flows to support our drilling and completion capital expenditure plan, we hedge a portion of our forecasted production.

In February 2015, we entered into derivative transactions offsetting our then existing crude oil derivative positions, which locked in $166.4 million of cash flows. As of September 30, 2016, the remaining locked in cash flows from the offsetting derivative transactions was approximately $10.6 million, of which approximately $7.9 million will be received during the fourth quarter of 2016 and approximately $2.7 million will be received in the first quarter of 2017, as the applicable contracts settle.

As of October 28, 2016, we had the following crude oil and natural gas derivative positions:

Period	Type of Contract	Crude Oil Volumes (in Bbls/d	Weighted Average Floor Price ($/Bbl)	Weighted Average Ceiling Price ($/Bbl)
Q4 2016	Fixed Price Swaps	9,750	$60.03	
Q4 2016	Costless Collars	4,000	$50.00	$76.50
Q1 2017	Fixed Price Swaps	12,000	$50.13	
Q2 2017	Fixed Price Swaps	12,000	$50.13	
Q3 2017	Fixed Price Swaps	6,000	$54.15	
Q4 2017	Fixed Price Swaps	3,000	$55.01	
FY 2018	Sold Call Options	2,488		$60.00
FY 2018	Net Sold Call Options	900		$75.00
FY 2019	Sold Call Options	2,975		$62.50
FY 2019	Net Sold Call Options	900		$77.50
FY 2020	Sold Call Options	3,675		$65.00
FY 2020	Net Sold Call Options	900		$80.00

Period	Type of Contract	Natural Gas Volumes (in MMBtu/d	Weighted Average Floor Price ($/MMBtu)	Weighted Average Ceiling Price ($/MMBtu)
FY 2017	Fixed Price Swaps	20,000	$3.30	
FY 2017	Sold Call Options	33,000		$3.00
FY 2018	Sold Call Options	33,000		$3.25
FY 2019	Sold Call Options	33,000		$3.25
FY 2020	Sold Call Options	33,000		$3.50

Based on existing market conditions and our expected liquidity needs, among other factors, we may use a portion of our cash flows from operations, proceeds from asset sales, securities offerings or borrowings to reduce debt prior to scheduled maturities through debt repurchases, either in the open market or in privately negotiated transactions, through debt redemptions or tender offers, or through repayments of bank borrowings.

Contractual Obligations

The following table sets forth estimates of our contractual obligations as of September 30, 2016 (in thousands):

	October - December 2016	2017	2018	2019	2020	2021 and Thereafter	Total
Long-term debt (1)	$—	$—	$96,000	$—	$600,000	$654,425	$1,350,425
Cash interest on senior notes and other long-term debt (2)	20,409	85,819	85,819	85,819	85,819	102,998	466,683
Cash interest and commitment fees on revolving credit facility (3)	1,241	4,889	2,469	—	—	—	8,599
Capital leases	464	1,856	1,823	1,800	1,050	—	6,993
Operating leases	1,125	4,438	4,430	4,412	4,463	6,304	25,172
Drilling rig contracts (4)	5,840	20,513	3,957	—	—	—	30,310
Pipeline volume commitments	1,923	8,432	8,428	6,919	4,300	3,655	33,657
Asset retirement obligations and other (5)	1,109	1,595	360	184	307	16,828	20,383
Total Contractual Obligations	$32,111	$127,542	$203,286	$99,134	$695,939	$784,210	$1,942,222

(1) Long-term debt consists of the principal amounts of the 7.50% Senior Notes due 2020, the 6.25% Senior Notes due 2023, other long-term debt due 2028, and borrowings outstanding under our revolving credit facility which matures in 2018.

(2) Cash interest on senior notes and other long-term debt includes cash payments for interest on the 7.50% Senior Notes due 2020, the 6.25% Senior Notes due 2023 and other long-term debt due 2028.

(3) Cash payments for interest on our revolving credit facility were calculated using the weighted average interest rate of the outstanding borrowings under the revolving credit facility as of September 30, 2016 of 2.46%. Commitment fees on our revolving credit facility were calculated based on the unused portion of lender commitments as of September 30, 2016, at the commitment fee rate of 0.500%.

(4) Drilling rig contracts represent gross contractual obligations and accordingly, other joint owners in the properties operated by us will generally be billed for their working interest share of such costs.

(5) Asset retirement obligations and other are based on estimates and assumptions that affect the reported amounts as of September 30, 2016. Certain of such estimates and assumptions are inherently unpredictable and will differ from actual results.

Financing Arrangements

Senior Secured Revolving Credit Facility

We have a senior secured revolving credit facility with a syndicate of banks that, as of September 30, 2016, had a borrowing base of $600.0 million, with $96.0 million of borrowings outstanding with a weighted average interest rate of 2.46% and $0.4 million in letters of credit outstanding. The credit agreement governing our senior secured revolving credit facility provides for interest-only payments until July 2, 2018, when the credit agreement matures and any outstanding borrowings are due. The borrowing base under our credit agreement is subject to regular redeterminations in the Spring and Fall of each year, as well as special redeterminations described in the credit agreement, in each case which may reduce the amount of the borrowing base. As a result of the Fall redetermination, effective October 24, 2016, the borrowing base was reaffirmed at $600.0 million.

See “Note 5. Long-Term Debt” for additional details of the senior secured revolving credit facility including rates of interest on outstanding borrowings, commitment fees on the unused portion of lender commitments, and the financial covenants we are subject to under the terms of the credit agreement.

7.50% Senior Notes due 2020

Since September 15, 2016, we had the right to redeem all or a portion of the 7.50% Senior Notes at redemption prices decreasing from 103.75% to 100% of the principal amount on September 15, 2018, plus accrued and unpaid interest. In connection with any redemption or repurchase of notes, we could enter into other transactions, which include refinancing of the 7.50% Senior Notes.

Common Stock Offering

In October 2016, we sold 6.0 million shares of our common stock in a public offering at a price of $37.32 per share. We used the proceeds of $223.9 million, net of underwriting discounts, to repay borrowings under the revolving credit facility and intend to use any remaining proceeds to fund a portion of the purchase price of the Sanchez Acquisition due on the closing date.

Critical Accounting Policies

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods reported. Certain of such estimates and assumptions are inherently unpredictable and will differ from actual results. We have identified the following critical accounting policies and estimates used in the preparation of our financial statements: use of estimates, oil and gas properties, oil and gas reserve estimates, derivative instruments, income taxes and commitments and contingencies. These policies and estimates are described in “Note 2. Summary of Significant Accounting Policies” of the Notes to Consolidated Financial Statements in our 2015 Annual Report. We evaluate subsequent events through the date the financial statements are issued.

Impairment of Proved Oil and Gas Properties

At the end of each quarter, the net book value of oil and gas properties, less related deferred income taxes, are limited to the “cost center ceiling” equal to (i) the sum of (A) the present value of estimated future net revenues from proved oil and gas reserves, less estimated future expenditures to be incurred in developing and producing the proved reserves computed using a discount factor of 10%, (B) the costs of unproved properties not being amortized, and (C) the lower of cost or estimated fair value of unproved properties included in the costs being amortized; less (ii) related income tax effects. Any excess of the net book value of oil and gas properties, less related deferred income taxes, over the cost center ceiling is recognized as an impairment of proved oil and gas properties. An impairment recognized in one period may not be reversed in a subsequent period even if higher commodity prices in the future result in a cost center ceiling in excess of the net book value of oil and gas properties, less related deferred income taxes.

The estimated future net revenues used in the cost center ceiling are calculated using the average realized prices for sales of crude oil, natural gas liquids and natural gas on the first calendar day of each month during the 12-month period prior to the end of the current quarter (“12-Month Average Realized Price”), held flat for the life of the production, except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts. Prices do not include the impact of derivative instruments as we elected not to meet the criteria to qualify derivative instruments for hedge accounting treatment.

Primarily due to declines in the 12-Month Average Realized Price of crude oil, we recognized impairments of proved oil and gas properties for the three and nine months ended September 30, 2016 and 2015 as summarized in the table below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Impairment of proved oil and gas properties (in thousands)	$105,0[illegible]	$812,752	$576,54[illegible]	$812,752
End of period price ($/Bbl)	$38.36	$56.05	$38.36	$56.05
Beginning of period price ($/Bbl)	$39.84	$68.92	$47.24	$92.24
Percent decrease in price	(4%)	(19 %)	(19%)	(39 %)

The decrease in the 12-Month Average Realized price of crude oil was primarily responsible for a negative revision to our proved reserves for the third quarter of 2016 totaling 0.8 MMBoe (less than 1% of December 31, 2015 proved reserves), all of which was attributable to proved developed reserves of producing wells and proved undeveloped reserves with shorter economic lives. There were no proved undeveloped reserve locations that became uneconomic as a result of the decrease in the 12-Month Average Realized Price as of September 30, 2016.

The table below presents various pricing scenarios to demonstrate the sensitivity of our September 30, 2016 cost center ceiling to changes in the 12-month average benchmark crude oil and natural gas prices underlying the 12-Month Average Realized Prices. The sensitivity analysis is as of September 30, 2016 and, accordingly, does not consider the results of drilling and completion activity, production, changes in oil and gas prices, and changes in development and operating costs occurring subsequent to September 30, 2016 which may require revisions to estimates of proved reserves.

	12-Month Average Realized Prices		Excess (deficit) of cost center ceiling over net book value, less related deferred income taxes	Increase (decrease) of cost center ceiling over net book value, less related deferred income taxes
Full Cost Pool Scenarios	Crude Oil ($/Bbl)	Natural Gas ($/Mcf)	(In millions)	(In millions)
September 30, 2016 Actual	$38.36	$1.67	$—	
Crude Oil and Natural Gas Price Sensitivity				
Crude Oil and Natural Gas +10%	$42.53	$1.91	$293	$293
Crude Oil and Natural Gas -10%	$34.20	$1.46	($293)	($293)
Crude Oil Price Sensitivity				
Crude Oil +10%	$42.53	$1.67	$263	$263
Crude Oil -10%	$34.20	$1.67	($263)	($263)
Natural Gas Price Sensitivity				
Natural Gas +10%	$38.36	$1.91	$30	$30
Natural Gas -10%	$38.36	$1.46	($30)	($30)

Our estimated range of the fourth quarter cost center ceiling, at the high end, would exceed the net book value of oil and gas properties, less related deferred income taxes, and at the low end, would result in an impairment of proved oil and gas properties of $50.0 million. This estimated range of the fourth quarter cost center ceiling is based on the estimated 12-Month Average Realized Price of crude oil of $39.26 per barrel as of December 31, 2016, which is based on the average realized price for sales of crude oil on the first calendar day of each month for the first 11 months and an estimate for the twelfth month based on a quoted forward price. We estimate that we will not have any negative revisions of proved reserves for the fourth quarter of 2016 as a result of the 12-Month Average Realized Price of crude oil used in our forecast. Declines in the 12-Month Average Realized Price of crude oil in subsequent quarters would result in a lower present value of the estimated future net revenues from proved oil and gas reserves and may result in additional impairments of proved oil and gas properties.

The key factors and assumptions we used to estimate proved reserves and a potential impairment for the fourth quarter of 2016 include planned drilling and completion activity, forecasted production, oil and gas price differentials and development and production costs. Given the uncertainty associated with these key factors and assumptions, these estimates should not necessarily be construed as indicative of our future results.

Income Taxes

Income taxes are recognized based on earnings reported for tax return purposes in addition to a provision for deferred income taxes. Deferred income taxes are recognized at the end of each reporting period for the future tax consequences of cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in our financial statements based on existing tax laws and enacted statutory tax rates applicable to the periods in which the temporary differences are expected to affect taxable income. We assess the realizability of our deferred tax assets on a quarterly basis by considering whether it is more likely than not that all or a portion of the deferred tax assets will not be realized. We consider all available evidence (both positive and negative) when determining whether a valuation allowance is required. In making this assessment, we evaluated possible sources of taxable income that may be available to realize the benefit of deferred tax assets, including projected future taxable income, the reversal of existing temporary differences, taxable income in carryback years and available tax planning strategies.

A significant item of objective negative evidence considered was the cumulative historical three year pre-tax loss and a net deferred tax asset position at September 30, 2016, driven primarily by the impairments of proved oil and gas properties recognized during the second half of 2015 and throughout 2016, which limits the ability to consider other subjective evidence such as our potential for future growth. We also have estimated U.S. federal net operating loss carryforwards of $611.1 million as of

September 30, 2016. Based on evaluation of the evidence available during the three months ended September 30, 2016, our previous conclusion that it is more likely than not the net deferred tax assets will not be realized remained unchanged and an additional valuation allowance of $36.7 million was recorded for the three months ending September 30, 2016, reducing the net deferred tax assets to zero. This additional valuation allowance increased the total valuation allowance recorded during the nine months ended September 30, 2016 to $240.9 million.

We will continue to evaluate whether the valuation allowance is needed in future reporting periods. The valuation allowance will remain until we can conclude that the net deferred tax assets are more likely than not to be realized. Future events or new evidence which may lead us to conclude that it is more likely than not our net deferred tax assets will be realized include, but are not limited to, cumulative historical pre-tax earnings, improvements in crude oil prices, and taxable events that could result from one or more transactions. The valuation allowance does not preclude us from utilizing the tax attributes if we recognize taxable income. As long as we continue to conclude that the valuation allowance against our net deferred tax assets is necessary, we will have no significant deferred income tax expense or benefit.

We classify interest and penalties associated with income taxes as interest expense. We follow the tax law ordering approach to determine the sequence in which deferred tax assets and other tax attributes are utilized.

Recently Adopted and Recently Issued Accounting Pronouncements

See “Note 2. Summary of Significant Accounting Policies” for discussion of the accounting pronouncements we recently adopted and the accounting pronouncements recently issued by the FASB.

Volatility of Crude Oil and Natural Gas Prices

Our revenues, future rate of growth, results of operations, financial position and ability to borrow funds or obtain additional capital are substantially dependent upon prevailing prices of crude oil and natural gas, which are affected by changes in market supply and demand, overall economic activity, global political environment, weather, inventory storage levels, basis differentials and other factors, as well as the level and prices at which we have hedged our future production.

We review the carrying value of our oil and gas properties on a quarterly basis under the full cost method of accounting. See “—Critical Accounting Policies—Impairment of Proved Oil and Gas Properties” and “Note 3. Property and Equipment, Net” for additional details.

We use commodity derivative instruments to reduce our exposure to commodity price volatility for a substantial, but varying, portion of our forecasted crude oil and natural gas production and thereby achieve a more predictable level of cash flows to support our drilling and completion capital expenditure plan. We do not enter into derivative instruments for speculative or trading purposes. As of September 30, 2016, our commodity derivative instruments consisted of fixed price swaps, costless collars, and purchased and sold call options. See “Note 9. Derivative Instruments” for further details of our crude oil and natural gas derivative positions as of September 30, 2016 and “Note 13. Subsequent Events—Hedging Update” for further details of the crude oil and natural gas derivative positions entered into subsequent to September 30, 2016.

Forward-Looking Statements

This quarterly report contains statements concerning our intentions, expectations, projections, assessments of risks, estimations, beliefs, plans or predictions for the future, objectives, goals, strategies, future events or performance and underlying assumptions and other statements that are not historical facts. These statements are “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. These forward-looking statements include, among others, statements regarding:

- our growth strategies;
- our ability to explore for and develop oil and gas resources successfully and economically;
- our estimates and forecasts of the timing, number, profitability and other results of wells we expect to drill and other exploration activities;
- our estimates regarding timing and levels of production;
- changes in working capital requirements, reserves, and acreage;
- commodity hedging activities and the impact on our average realized prices;
- anticipated trends in our business;
- availability of pipeline connections and water disposal on economic terms;

- effects of competition on us;

- our future results of operations;
- profitability of drilling locations;
- our liquidity and our ability to finance our exploration and development activities, including accessibility of borrowings under our revolving credit facility, our borrowing base, modification to financial covenants, and the result of any borrowing base redetermination;
- our planned expenditures, prospects and capital expenditure plan;
- future market conditions in the oil and gas industry;
- our ability to make, integrate and develop acquisitions including the Sanchez Acquisition and realize any expected benefits or effects of any acquisitions or the timing, final purchase price, financing or consummation of any acquisitions including the Sanchez Acquisition;
- possible future sales or other transactions;
- the benefits, results, effects, availability of and results of new and existing joint ventures and sales transactions;
- our ability to maintain a sound financial position;
- receipt of receivables and proceeds from sales;
- our ability to complete planned transactions on desirable terms;
- the impact of governmental regulation, taxes, market changes and world events; and
- our use of proceeds and any benefits or effects thereof.

You generally can identify our forward-looking statements by the words “anticipate,” “believe,” budgeted,” “continue,” “could,” “estimate,” “expect,” “forecast,” “goal,” “intend,” “may,” “objective,” “plan,” “potential,” “predict,” “projection,” “sc other similar words. Such statements rely on assumptions and involve risks and uncertainties, many of which are beyond our control, including, but not limited to, those relating to a worldwide economic downturn, availability of financing, our dependence on our exploratory drilling activities, the volatility of and changes in crude oil and natural gas prices, the need to replace reserves depleted by production, impairments of proved oil and gas properties, operating risks of crude oil and natural gas operations, our dependence on our key personnel, factors that affect our ability to manage our growth and achieve our business strategy, results, delays and uncertainties that may be encountered in drilling, development or production, interpretations and impact of oil and gas reserve estimation and disclosure requirements, activities and approvals of our partners and parties with whom we have alliances, technological changes, capital requirements, the timing and amount of borrowing base determinations (including determinations by lenders) and availability under our revolving credit facility, evaluations of us by lenders under our revolving credit facility, other actions by lenders, the potential impact of government regulations, including current and proposed legislation and regulations related to hydraulic fracturing, crude oil and natural gas drilling, air emissions and climate change, regulatory determinations, litigation, competition, the uncertainty of reserve information and future net revenue estimates, failure of the Sanchez Acquisition to close, integration and other acquisition risks, other factors affecting our ability to reach agreements or complete acquisitions or dispositions, actions by sellers and buyers, effects of purchase price adjustments, availability of equipment and crews, actions by midstream and other industry participants, weather, our ability to obtain permits and licenses, the results of audits and assessments, the failure to obtain certain bank and lease consents, the existence and resolution of title defects, new taxes and impact fees, delays, costs and difficulties relating to our joint ventures, actions by joint venture parties, results of exploration activities, the availability, market conditions and completion of land acquisitions and dispositions, costs of oilfield services, completion and connection of wells, and other factors detailed in this quarterly report.

We have based our forward-looking statements on our management’s beliefs and assumptions based on information available to our management at the time the statements are made. We caution you that assumptions, beliefs, expectations, intentions and projections about future events may and often do vary materially from actual results. Therefore, we cannot assure you that actual results will not differ materially from those expressed or implied by our forward-looking statements.

Some of the factors that could cause actual results to differ from those expressed or implied in forward-looking statements are described under Part I, “Item 1A. Risk Factors” and other sections of our 2015 Annual Report and in our other filings with the SEC, including this quarterly report. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by reference to these risks and uncertainties. You should not place undue reliance on our forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement, and, except as required by law, we undertake no duty to update or revise any forward-looking statement.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

For information regarding our exposure to certain market risks, see “Item 7A. Quantitative and Qualitative Disclosures about Market Risk” of our 2015 Annual Report. Except as disclosed in this report, there have been no material changes from the disclosure made in our 2015 Annual Report regarding our exposure to certain market risks.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. Our Chief Executive Officer and Chief Financial Officer performed an evaluation of our disclosure controls and procedures, which have been designed to provide reasonable assurance that the information required to be disclosed by the Company in the reports it files or submits under the Exchange Act is accumulated and communicated to the Company’s management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure. They concluded that the controls and procedures were effective as of September 30, 2016 to provide reasonable assurance that the information required to be disclosed by the Company in reports it files under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC’s rules and forms and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. While our disclosure controls and procedures provide reasonable assurance that the appropriate information will be available on a timely basis, this assurance is subject to limitations inherent in any control system, no matter how well it may be designed or administered.

Changes in Internal Controls. There was no change in our internal control over financial reporting during the quarter ended September 30, 2016 that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

From time to time, the Company is party to certain legal actions and claims arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not currently expect these matters to have a materially adverse effect on the financial position or results of operations of the Company.

Item 1A. Risk Factors

Except as disclosed below, there were no material changes to the factors discussed in “Part I. Item 1A. Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2015.

We may not consummate the Sanchez Acquisition.

There can be no assurances that the Sanchez Acquisition will be consummated on the terms described herein or at all, or that the consummation of the Sanchez Acquisition will not be delayed beyond the expected closing date. If we do not complete the Sanchez Acquisition, we will not have the opportunity to attempt to realize the benefits we believe the acquisition will afford us.

We have performed only a limited investigation of the properties to be acquired in the Sanchez Acquisition. The completion of the Sanchez Acquisition is subject to specified closing conditions and to the right of one or both of the parties to terminate the transaction including in the event that more than specified adjustments to the purchase price are required. If one or more of the closing conditions are not satisfied, or if the transaction is otherwise terminated, the Sanchez Acquisition may not be completed. Some of these conditions are beyond our control. Some of these conditions are in part within our control; other conditions are all or in part within the control of Sanchez; and we may elect not to take actions necessary to satisfy these conditions or to ensure that the transaction is not otherwise terminated.

If the Sanchez Acquisition is not consummated, our management will have broad discretion in the application of the net proceeds of our recent equity offering and could apply the proceeds in ways that shareholders may not approve, which could also adversely affect the market price of our common stock. In addition such application may not be as beneficial to us as the Sanchez Acquisition may have been. If the Sanchez Acquisition is delayed, not consummated or consummated in a manner different than described herein, the price of our common stock may decline.

We may not be able to achieve the expected benefits of the Sanchez Acquisition and may have difficulty integrating with the Sanchez Acquisition.

Even if we consummate the Sanchez Acquisition, we may not be able to achieve the expected benefits of the Sanchez Acquisition. There can be no assurance that the Sanchez Acquisition will be beneficial to us. We may not be able to integrate the properties to be acquired without increases in costs, losses in revenues or other difficulties. Any unexpected costs or delays incurred in connection with the integration could have an adverse effect on our business, results of operations, financial condition and prospects, as well as the price of our common stock.

Our assessment of properties to be acquired to date has been limited and, even by the time of closing, it will not reveal all existing or potential problems, nor will it permit us to become familiar enough with the properties to assess fully their capabilities and deficiencies. In the course of our assessment, we will not receive an independent reserve engineer report related to the properties to be acquired. We may incur costs or experience problems related to the properties to be acquired in the Sanchez Acquisition and we may not have adequate recourse against Sanchez. Although we will inspect the properties being sold to us, inspections may not reveal all structural or environmental problems. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations. Our ability to make specified claims against Sanchez in the Sanchez Acquisition generally expires over time and we may be left with no recourse for liabilities and other problems associated with the Sanchez Acquisition that we do not discover prior to the expiration date related to such matters under the purchase and sale agreement.

The market price of our common stock may decline as a result of the Sanchez Acquisition if, among other things, the integration of the properties to be acquired is unsuccessful or if the liabilities, expenses, title, environmental and other defects, or transaction costs related to the Sanchez Acquisition are greater than expected or the properties to be acquired do not yield the anticipated returns. The market price of our common stock may decline if we do not achieve the perceived benefits of the Sanchez Acquisition as rapidly or to the extent anticipated by us or by securities market participants or if the effect of the Sanchez Acquisition on our business results of operations or financial condition or prospects is not consistent with our expectations or those of securities market participants.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

The following exhibits are required by Item 601 of Regulation S-K and are filed as part of this report:

Exhibit Number	Exhibit Description
*31.1	–CEO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	–CFO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	–CEO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	–CFO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*101	–Interactive Data Files

* Filed herewith.

Signatures

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

Carrizo Oil & Gas, Inc.
(Registrant)

Date:	November 3, 2016	By:	/s/ David L. Pitts
			Vice President and Chief Financial Officer
			(Principal Financial Officer)
Date:	November 3, 2016	By:	/s/ Gregory F. Conaway
			Vice President and Chief Accounting Officer
			(Principal Accounting Officer)