CARRIZO OIL & GAS INC
Form 10-Q
August 07, 2018

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

FORM 10-Q

þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2018
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 þ NO ¨

Indicate by check mark whether the registrant has submitted electronically, if any, every Interactive Data File required to be submitted 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 such files). YES þ NO ¨

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

Large accelerated filer þ	Accelerated filer ¨
Non-accelerated filer ¨	Smaller reporting company ¨
	Emerging growth company ¨

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

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

The number of shares outstanding of the registrant’s common stock, par value $0.01 per share, as of August 1, 2018 was 82,114,492.

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Item 1. Consolidated Financial Statements (Unaudited)
CARRIZO OIL & GAS, INC.
CONSOLIDATED BALANCE SHEETS
(In thousands, except share and per share amounts)
(Unaudited)

	June 30, 2018	December 31, 2017
Assets		
Current assets		
Cash and cash equivalents	$2,099	$9,540
Accounts receivable, net	111,100	107,441
Derivative assets	10,928	—
Other current assets	8,378	5,897
Total current assets	132,505	122,878
Property and equipment		
Oil and gas properties, full cost method		
Proved properties, net	1,959,951	1,965,347
Unproved properties, not being amortized	597,892	660,287
Other property and equipment, net	10,582	10,176
Total property and equipment, net	2,568,425	2,635,810
Other assets	20,909	19,616
Total Assets	$2,721,839	$2,778,304
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable	$113,651	$74,558
Revenues and royalties payable	53,280	52,154
Accrued capital expenditures	117,934	119,452
Accrued interest	21,126	28,362
Derivative liabilities	145,520	57,121
Other current liabilities	52,020	41,175
Total current liabilities	503,531	372,822
Long-term debt	1,502,307	1,629,209
Asset retirement obligations	16,305	23,497
Derivative liabilities	87,933	112,332
Deferred income taxes	4,164	3,635
Other liabilities	8,273	51,650
Total liabilities	2,122,513	2,193,145
Commitments and contingencies		
Preferred stock		
Preferred stock, $0.01 par value, 10,000,000 shares authorized; 200,000 issued and outstanding as of June 30, 2018 and 250,000 issued and outstanding as of December 31, 2017	172,858	214,262
Shareholders' equity		
Common stock, $0.01 par value, 180,000,000 shares authorized; 82,107,544 issued and outstanding as of June 30, 2018 and 81,454,621 issued and outstanding as of December 31, 2017	821	815
Additional paid-in capital	1,918,820	1,926,056
Accumulated deficit	(1,493,173)	(1,555,974)

Total shareholders’ equity	426,468	370,897
Total Liabilities and Shareholders’ Equity	$2,721,839	$2,778,304

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Revenues				
Crude oil	$229,798	$142,806	$424,717	$270,898
Natural gas liquids	21,269	7,786	38,171	15,211
Natural gas	12,906	15,891	26,365	31,729
Total revenues	263,973	166,483	489,253	317,838
Costs and Expenses				
Lease operating	35,151	36,048	74,424	65,893
Production taxes	12,487	7,143	23,062	13,351
Ad valorem taxes	3,640	1,073	5,613	4,040
Depreciation, depletion and amortization	72,430	59,072	136,897	113,454
General and administrative, net	18,265	11,596	45,557	33,299
(Gain) loss on derivatives, net	67,714	(26,065)	97,310	(51,381)
Interest expense, net	15,599	21,106	31,116	41,677
Loss on extinguishment of debt	—	—	8,676	—
Other expense, net	2,895	204	2,995	1,178
Total costs and expenses	228,181	110,177	425,650	221,511
Income Before Income Taxes	35,792	56,306	63,603	96,327
Income tax expense	(483)	—	(802)	—
Net Income	$35,309	$56,306	$62,801	$96,327
Dividends on preferred stock	(4,474)	—	(9,337)	—
Accretion on preferred stock	(740)	—	(1,493)	—
Loss on redemption of preferred stock	—	—	(7,133)	—
Net Income Attributable to Common Shareholders	$30,095	$56,306	$44,838	$96,327
Net Income Attributable to Common Shareholders Per Common Share				
Basic	$0.37	$0.86	$0.55	$1.47
Diluted	$0.36	$0.85	$0.54	$1.46
Weighted Average Common Shares Outstanding				
Basic	82,058	65,767	81,802	65,479
Diluted	83,853	65,908	83,240	65,866

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

CARRIZO OIL & GAS, INC.
CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY
(In thousands, except share amounts)
(Unaudited)

	Common Stock		Additional Paid-in Capital	Accumulated Deficit	Total Shareholders' Equity
	Shares	Amount			
Balance as of December 31, 2017	81,454,621	$815	$1,926,056	($1,555,974)	$370,897
Stock-based compensation expense	—	—	10,757	—	10,757
Issuance of common stock upon grants of restricted stock awards and vestings of restricted stock units and performance shares	652,923	6	(30)	—	(24)
Dividends on preferred stock	—	—	(9,337)	—	(9,337)
Accretion on preferred stock	—	—	(1,493)	—	(1,493)
Loss on redemption of preferred stock	—	—	(7,133)	—	(7,133)
Net income	—	—	—	62,801	62,801
Balance as of June 30, 2018	82,107,544	$821	$1,918,820	($1,493,173)	$426,468

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

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

	Six Months Ended June 30, 2018		2017	
Cash Flows From Operating Activities				
Net income	$62,801		$96,327	
Adjustments to reconcile net income to net cash provided by operating activities				
Depreciation, depletion and amortization	136,897		113,454	
(Gain) loss on derivatives, net	97,310		(51,381	)
Cash (paid) received for derivative settlements, net	(38,448	)	1,258	
Loss on extinguishment of debt	8,676		—	
Stock-based compensation expense, net	10,724		3,596	
Deferred income taxes	529		—	
Non-cash interest expense, net	1,262		2,074	
Other, net	3,975		2,767	
Changes in components of working capital and other assets and liabilities-				
Accounts receivable	2,437		(8,094	)
Accounts payable	3,878		14,486	
Accrued liabilities	(12,883	)	5,650	
Other assets and liabilities, net	(1,286	)	(982	)
Net cash provided by operating activities	275,872		179,155	
Cash Flows From Investing Activities				
Capital expenditures	(430,639	)	(290,625	)
Acquisitions of oil and gas properties	—		(16,533	)
Deposit for acquisition of oil and gas properties	—		(75,000	)
Proceeds from divestitures of oil and	345,789		18,201	

gas properties, net				
Other, net	(1,096	)	(2,479	)
Net cash used in investing activities	(85,946	)	(366,436	)
Cash Flows From Financing Activities				
Redemptions of senior notes	(330,435	)	—	
Redemption of preferred stock	(50,030	)	—	
Borrowings under credit agreement	1,126,856		919,097	
Repayments of borrowings under credit agreement	(933,156	)	(723,797	)
Payments of debt issuance costs	(627	)	(4,368	)
Payment of commitment fee for issuance of preferred stock	—		(5,000	)
Payments of dividends on preferred stock	(9,337	)	—	
Other, net	(638	)	(617	)
Net cash provided by (used in) financing activities	(197,367	)	185,315	
Net Decrease in Cash and Cash Equivalents	(7,441	)	(1,966	)
Cash and Cash Equivalents, Beginning of Period	9,540		4,194	
Cash and Cash Equivalents, End of Period	$2,099		$2,228	

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 crude oil, NGLs, and natural gas from resource plays located in the United States. The Company's current operations are principally focused in proven, producing oil and gas plays in the Eagle Ford Shale in South Texas and the Permian Basin in West Texas.

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, 2017 ("2017 Annual Report"). Except as disclosed herein, there have been no material changes to the information disclosed in the notes in the 2017 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

Revenue Recognition

Impact of ASC 606 Adoption. Effective January 1, 2018, the Company adopted ASU No. 2014-09, Revenue From Contracts With Customers (Topic 606) ("ASC 606") using the modified retrospective method and has applied the standard to all existing contracts. ASC 606 supersedes previous revenue recognition requirements in ASC 605 - Revenue Recognition ("ASC 605") and includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration in exchange for those goods or services. As a result of adopting ASC 606, the Company did not have a cumulative-effect adjustment in retained earnings. The comparative information for the three and six months ended June 30, 2017 has not been recast and continues to be reported under the accounting standards in effect for that period. Additionally, adoption of ASC 606 did not impact net income attributable to common shareholders and the Company does not expect that it will do so in future periods.

The tables below summarizes the impact of adoption for the three and six months ended June 30, 2018:

	Three Months Ended June 30, 2018			
	Under ASC 606	Under ASC 605	Increase	% Increase
	(In thousands)			
Revenues				
Crude oil	$229,798	$229,658	$140	0.1 %
Natural gas liquids	21,269	20,139	1,130	5.6 %
Natural gas	12,906	12,272	634	5.2 %
Total revenues	263,973	262,069	1,904	0.7 %
Costs and Expenses				
Lease operating	35,151	33,247	1,904	5.7 %
Income Before Income Taxes	$35,792	$35,792	$—	— %

	Six Months Ended June 30, 2018			
	Under ASC 606	Under ASC 605	Increase	% Increase
	(In thousands)			
Revenues				
Crude oil	$424,717	$424,452	$265	0.1 %
Natural gas liquids	38,171	36,235	1,936	5.3 %
Natural gas	26,365	25,159	1,206	4.8 %
Total revenues	489,253	485,846	3,407	0.7 %
Costs and Expenses				
Lease operating	74,424	71,017	3,407	4.8 %
Income Before Income Taxes	$63,603	$63,603	$—	— %

Changes to crude oil, NGL, and natural gas revenues and lease operating expense are due to the conclusion that the Company controls the product throughout processing before transferring to the customer for certain natural gas processing arrangements. Therefore, any transportation, gathering, and processing fees incurred prior to transfer of control are included in lease operating expense.

The Company's revenues are comprised solely of revenues from customers and include the sale of crude oil, NGLs, and natural gas. The Company believes that the disaggregation of revenue into these three major product types appropriately depicts how the nature, amount, timing and uncertainty of revenue and cash flows are affected by economic factors based on our single geographic location. Crude oil, NGL, and natural gas revenues are recognized at a point in time when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, control has transferred and collectability of the revenue is probable. The transaction price used to recognize revenue is a function of the contract billing terms. Revenue is invoiced by calendar month based on volumes at contractually based rates with payment typically required within 30 days of the end of the production month. At the end of each month when the performance obligation is satisfied, the variable consideration can be reasonably estimated and amounts due from customers are accrued in "Accounts receivable, net" in the consolidated balance sheets. As of June 30, 2018 and December 31, 2017, receivables from contracts with customers were $87.1 million and $85.6 million, respectively. Taxes assessed by governmental authorities on crude oil, NGL, and natural gas sales are presented separately from such revenues in the consolidated statements of income.

Crude oil sales. Crude oil production is primarily sold at the wellhead at an agreed upon index price, net of pricing differentials. Revenue is recognized when control transfers to the purchaser at the wellhead, net of transportation costs incurred by the purchaser.

Natural gas and NGL sales. Natural gas is delivered to a midstream processing entity at the wellhead or the inlet of the midstream processing entity's system. The midstream processing entity gathers and processes the natural gas and remits proceeds for the resulting sales of NGLs and residue gas. The Company evaluates whether it is the principal or agent in the transaction and has concluded it is the principal and the ultimate third party is the customer. Revenue is recognized on a gross basis, with gathering, processing and transportation fees presented in "Lease operating expense" in the consolidated statements of income as the Company maintains control throughout processing.

Transaction Price Allocated to Remaining Performance Obligations. The Company applied the practical expedient in ASC 606 exempting the disclosure of the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Each unit of product typically represents a separate performance obligation, therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Recently Adopted Accounting Pronouncements

Business Combinations. In January 2017, the Financial Accounting Standards Board ("FASB") issued ASU No. 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business ("ASU 2017-01"), which clarifies the definition of a business to assist entities with evaluating whether transactions should be accounted for as acquisitions (or divestitures) of assets or businesses. Effective January 1, 2018, the Company adopted ASU 2017-01 using the prospective method and will apply the clarified definition of a business to future acquisition and divestitures.

Statement of Cash Flows. In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments ("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. Effective January 1, 2018, the Company adopted ASU 2016-15 using the retrospective approach as prescribed by ASU 2016-15. There were no changes to the statement of cash flows as a result of adoption.

Recently Issued Accounting Pronouncements

Leases. 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. ASU 2016-02 does not apply to leases of mineral rights to explore for or use crude oil and natural gas. 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. ASU 2016-02 requires companies 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 in the process of reviewing and determining the contracts to which ASU 2016-02 applies with the assistance of a third party consultant. These include contracts such as non-cancelable leases, drilling rig contracts, pipeline gathering, transportation and gas processing agreements, and contracts for the use of vehicles and well equipment. The Company continues to review current accounting policies, controls, processes, and disclosures that will change as a result of adopting the new standard. Based upon its initial assessment, the Company expects the adoption of ASU 2016-02 will result in: (i) an increase in assets and liabilities due to the required recognition of right-of-use ("ROU") assets and corresponding lease liabilities, (ii) increases in depreciation, depletion and amortization and interest expense, (iii) decreases in lease operating and general and administrative expense and (iv) additional disclosures, however, the full impact to the Company's consolidated financial statements and related disclosures is still being evaluated. Currently, the Company plans to make certain elections allowing the Company not to reassess contracts that commenced prior to adoption, to continue applying its current accounting policy for land easements, and not to recognize ROU assets or lease liabilities for short-term leases. The Company plans to adopt the guidance on the effective date of January 1, 2019. As permitted by ASU No. 2018-11, Leases (Topic 842): Targeted Improvements, the Company does not expect to adjust comparative-period financial statements.

Other than as disclosed above or in the Company's 2017 Form 10-K, there are no other accounting standard updates applicable to the Company that would have a material effect on the Company's consolidated financial statements and related disclosures that have been issued but not yet adopted by the Company as of June 30, 2018, and through the filing of this report.

Net Income Attributable to Common Shareholders Per Common Share

Supplemental net income attributable to common shareholders per common share information is provided below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(In thousands, except per share amounts)			
Net Income Attributable to Common Shareholders	$30,095	$56,306	$44,838	$96,327
Basic weighted average common shares outstanding	82,058	65,767	81,802	65,479
Effect of dilutive instruments	1,795	141	1,438	387
Diluted weighted average common shares outstanding	83,853	65,908	83,240	65,866
Net Income Attributable to Common Shareholders Per Common Share				
Basic	$0.37	$0.86	$0.55	$1.47
Diluted	$0.36	$0.85	$0.54	$1.46

The table below presents the a reconciliation of the basic weighted average common shares outstanding to diluted weighted average common shares outstanding for the three and six months ended June 30, 2018 and 2017:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(In thousands)			
Basic weighted average common shares outstanding	82,058	65,767	81,802	65,479
Dilutive unvested restricted stock awards and units	833	141	640	387
Dilutive unvested performance shares	134	—	158	—
Dilutive exercisable common stock warrants	828	—	640	—
Diluted weighted average common shares outstanding	83,853	65,908	83,240	65,866

The table below presents a summary of the common shares outstanding that were excluded from the computation of diluted net income attributable to common shareholders per common share for the three and six months ended June 30, 2018 and 2017, as their inclusion would be anti-dilutive:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(In thousands)			
Anti-dilutive unvested restricted stock awards and units	16	101	17	16
Anti-dilutive unvested performance shares	—	108	2	62
Anti-dilutive exercisable common stock warrants	—	—	—	—
Total anti-dilutive	16	209	19	78

3. Acquisitions and Divestitures of Oil and Gas Properties

Acquisitions

ExL Acquisition. On August 10, 2017, the Company closed on the acquisition of oil and gas properties located in the Delaware Basin in Reeves and Ward Counties, Texas (the “ExL Properties”) from ExL Petroleum Management, LLC and ExL Petroleum Operating Inc. (together “ExL”) for aggregate cash consideration of $679.8 million (the “ExL Acquisition”). See “Note 10. Derivative Instruments” for information regarding the contingent consideration arrangement associated with the ExL Acquisition.

The consolidated statements of income for the three and six months ended June 30, 2018 include total revenues and net income attributable to common shareholders from the ExL Acquisition, representing activity of the acquired properties as shown in the table below:

	Three Months Ended	Six Months Ended
	June 30, 2018	
	(In thousands)	
Total revenues	$52,771	$96,239
Net income attributable to common shareholders	$42,048	$76,851

Divestitures

Eagle Ford. On January 31, 2018, the Company sold a portion of its assets in the Eagle Ford Shale to EP Energy E&P Company, L.P. The Company received aggregate net proceeds of $245.7 million, which represents an agreed upon price of $245.0 million plus purchase price adjustments, which were primarily related to the net cash flows from the effective date to the closing date.

Niobrara. On January 19, 2018, the Company sold substantially all of its assets in the Niobrara Formation. Estimated aggregate net proceeds are $134.7 million, subject to post-closing adjustments. See "Note 10. Derivative Instruments" for information regarding the contingent consideration arrangement associated with this divestiture.

The aggregate net proceeds for each of the divestitures above were recognized as a reduction of proved oil and gas properties.

Marcellus. Effective August 2008, the Company's wholly-owned subsidiary, Carrizo (Marcellus) LLC, entered into a joint venture with ACP II Marcellus LLC ("ACP II"), an affiliate of Avista Capital Partners, LP, a private equity fund (Avista Capital Partners, LP, together with its affiliates, "Avista"). As of June 30, 2018, the Avista Marcellus joint venture holds no material assets or obligations, has no interest in any wells or leases, and intends to divest all remaining immaterial assets. There have been no revenues, expenses, or operating cash flows in the Avista Marcellus joint venture during the years ended December 31, 2015, 2016 and 2017 or during the six months ended June 30, 2018. Concurrently with the sale of the remaining immaterial assets, the Avista Marcellus joint venture and associated joint venture agreements will terminate.

Steven A. Webster, Chairman of the Company's Board of Directors, serves as Co-Managing Partner and President of Avista Capital Holdings, LP. ACP II's Board of Managers has the sole authority for determining whether, when and to what extent any cash distributions will be declared and paid to members of ACP II. Mr. Webster is not a member of ACP II's Board of Managers. The terms of the Avista Marcellus joint venture were approved by a special committee of the Company's independent directors.

4. Property and Equipment, Net

As of June 30, 2018 and December 31, 2017, total property and equipment, net consisted of the following:

	June 30, 2018	December 31, 2017
	(In thousands)	
Oil and gas properties, full cost method		
Proved properties	$5,744,434	$5,615,153
Accumulated depreciation, depletion and amortization and impairments	(3,784,483)	(3,649,806)
Proved properties, net	1,959,951	1,965,347
Unproved properties, not being amortized		
Unevaluated leasehold and seismic costs	539,836	612,589
Capitalized interest	58,056	47,698
Total unproved properties, not being amortized	597,892	660,287
Other property and equipment	27,223	25,625
Accumulated depreciation	(16,641)	(15,449)
Other property and equipment, net	10,582	10,176

Total property and equipment, net	$2,568,425	$2,635,810

Average depreciation, depletion and amortization (“DD&A”) per Boe of proved properties was $13.74 and $12.43 for the three months ended June 30, 2018 and 2017, respectively, and $13.73 and $12.55 for the six months ended June 30, 2018 and 2017, respectively.

The Company capitalized internal costs of employee compensation and benefits, including stock-based compensation, directly associated with acquisition, exploration and development activities totaling $6.1 million and $1.9 million for the three months ended June 30, 2018 and 2017, respectively, and $12.7 million and $7.3 million for the six months ended June 30, 2018 and 2017, respectively.

Unproved properties, not being amortized, include unevaluated leasehold and seismic costs associated with specific unevaluated properties and related capitalized interest. The Company capitalized interest costs associated with its unproved properties totaling $8.7 million and $4.0 million for the three months ended June 30, 2018 and 2017, respectively, and $19.1 million and $7.8 million for the six months ended June 30, 2018 and 2017, respectively.

5. 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 the estimated annual income or loss attributable to the tax jurisdictions in which the Company operates.

The Company's income tax expense differs from the income tax expense computed by applying the U.S. federal statutory corporate income tax rate of 21% for the three and six months ended June 30, 2018 and 35% for the three and six months ended June 30, 2017, to income before income taxes as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(In thousands)			
Income before income taxes	$35,792	$56,306	$63,603	$96,327
Income tax expense at the statutory rate	(7,517)	(19,707)	(13,357)	(33,714)
State income tax expense, net of U.S. federal income taxes	(487)	(1,017)	(806)	(1,727)
Tax shortfalls from stock-based compensation expense	(16)	(164)	(2,542)	(2,756)
Decrease in deferred tax assets valuation allowance	8,048	20,948	16,449	38,317
Other	(511)	(60)	(546)	(120)
Income tax expense	($483)	$—	($802)	$—

Significant changes in the Company's operations, including the ExL Acquisition in the Delaware Basin in the third quarter of 2017 and divestitures of substantially all of the Company's assets in the Utica and Marcellus in the fourth quarter of 2017 and the Niobrara in the first quarter of 2018, resulted in changes to the Company's state apportionment for estimated state deferred tax liabilities. As a result of these changes, the Company recorded current and deferred state income tax expense of $0.5 million and $0.8 million for the three and six months ended June 30, 2018, respectively.

Tax Cuts and Jobs Act

On December 22, 2017, the U.S. Congress enacted the Tax Cuts and Jobs Act (the "Act") which made significant changes to U.S. federal income tax law, including lowering the U.S. federal statutory corporate income tax rate to 21% from 35% beginning January 1, 2018. Due to the uncertainty regarding the application of ASC 740 in the period of enactment of the Act, the SEC issued Staff Accounting Bulletin 118 which allowed the Company to provide a provisional estimate of the impacts of the Act in earnings for the year ended December 31, 2017 and also provided a one-year measurement period in which the Company would record additional impacts from the enactment of the Act as they are identified. As of June 30, 2018, the Company has not made any changes to the provisional estimate recorded in earnings for the year ended December 31, 2017. While the Company has made a reasonable estimate of the effects on its existing deferred tax balances, it has not completed its accounting for the tax effects of the enactment of the Act and will continue to monitor provisions with discrete rate impacts, such as the limitation on executive compensation for subsequent events and additional guidance provided within the one year measurement period.

Deferred Tax Assets Valuation Allowance

Primarily as a result of the impairments of proved oil and gas properties recognized beginning in the third quarter of 2015 and continuing through the third quarter of 2016, the Company had a cumulative historical three year pre-tax loss and a net deferred tax asset position at June 30, 2018. The Company then assessed the realizability of its deferred tax assets and, beginning in the third quarter of 2015 and continuing through the second quarter of 2018, the Company concluded that it was more likely than not the deferred tax assets will not be realized and that a valuation allowance was required to reduce the net deferred tax assets to zero. As of June 30, 2018 and December 31, 2017, the valuation allowance was $316.5 million and $333.0 million, respectively. See the table above for changes in the valuation allowance for the three and six months ended June 30, 2018 and 2017, which primarily related to activity during each respective period and, for the three and six months ended June 30, 2017, the effect of adopting ASU 2016-09, Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting.

6. Long-Term Debt

Long-term debt consisted of the following as of June 30, 2018 and December 31, 2017:

	June 30, 2018	December 31, 2017
	(In thousands)	
Senior Secured Revolving Credit Facility due 2022	$485,000	$291,300
7.50% Senior Notes due 2020	130,000	450,000
Unamortized premium for 7.50% Senior Notes	139	579
Unamortized debt issuance costs for 7.50% Senior Notes	(1,095)	(4,492)
6.25% Senior Notes due 2023	650,000	650,000
Unamortized debt issuance costs for 6.25% Senior Notes	(7,554)	(8,208)
8.25% Senior Notes due 2025	250,000	250,000
Unamortized debt issuance costs for 8.25% Senior Notes	(4,183)	(4,395)
Other long-term debt due 2028	—	4,425
Long-term debt	$1,502,307	$1,629,209

Senior Secured Revolving Credit Facility

The Company has a senior secured revolving credit facility with a syndicate of banks that, as of June 30, 2018, had a borrowing base of $1.0 billion, with an elected commitment amount of $900.0 million, and borrowings outstanding of $485.0 million at a weighted average interest rate of 3.74%. The credit agreement governing the revolving credit facility provides for interest-only payments until May 4, 2022 (subject to a springing maturity date of June 15, 2020 if the 7.50% Senior Notes due 2020 (the “7.50% Senior Notes”) have not been redeemed or refinanced on or prior to such time), 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, which in each case 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. The capitalized terms which are not defined in this description of the revolving credit facility, shall have the meaning given to such terms in the credit agreement.

On January 31, 2018, as a result of the divestiture in the Eagle Ford Shale discussed above, the Company’s borrowing base under the senior secured revolving credit facility was reduced from $900.0 million to $830.0 million, however, the elected commitment amount remained unchanged at $800.0 million.

On May 4, 2018, the Company entered into the twelfth amendment to its credit agreement governing the revolving credit facility to, among other things, (i) establish the borrowing base at $1.0 billion, with an elected commitment amount of $900.0 million, until the next redetermination thereof, (ii) reduce the applicable margin for Eurodollar loans from 2.0%-3.0% to 1.5%-2.5%, depending on level of facility usage, (iii) amend the covenant limiting payment of dividends and distributions on equity to increase the Company’s ability to make dividends and distributions on its equity interests and (iv) amend certain other provisions, in each case as set forth therein.

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 reserve report used in its most recent redetermination.

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 at rates as set forth in the table below on the unused portion of lender commitments, which are included in "Interest expense, net" in the consolidated statements of income.

Ratio of Outstanding Borrowings to Lender Commitments	Applicable Margin for Base Rate Loans	Applicable Margin for Eurodollar Loans	Commitment Fee
Less than 25%	0.50%	1.50%	0.375%
Greater than or equal to 25% but less than 50%	0.75%	1.75%	0.375%
Greater than or equal to 50% but less than 75%	1.00%	2.00%	0.500%
Greater than or equal to 75% but less than 90%	1.25%	2.25%	0.500%
Greater than or equal to 90%	1.50%	2.50%	0.500%

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 Debt to EBITDA of not more than 4.00 to 1.00 and (2) a Current Ratio of not less than 1.00 to 1.00. As defined in the credit agreement, Total Debt excludes debt premiums and debt issuance costs and is net of cash and cash equivalents, EBITDA will be calculated based on the last four fiscal quarters after giving pro forma effect to EBITDA for material acquisitions and divestitures of oil and gas properties, and the Current Ratio includes an add back of the unused portion of lender commitments. As of June 30, 2018, the ratio of Total Debt to EBITDA was 2.53 to 1.00 and the Current Ratio was 1.49 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 divestitures 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 and divestitures of oil and gas properties, mergers, 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).

Redemptions of 7.50% Senior Notes

During the first quarter of 2018, the Company redeemed $320.0 million of the outstanding aggregate principal amount of its 7.50% Senior Notes at a price equal to 101.875% of par. Upon the redemptions, the Company paid $336.9 million, which included redemption premiums of $6.0 million as well as accrued and unpaid interest of $10.9 million from the last interest payment date up to, but not including, the redemption date. As a result of the redemptions, the Company recorded a loss on extinguishment of debt of $8.7 million, which included the redemption premiums of $6.0 million paid to redeem the notes and non-cash charges of $2.7 million attributable to the write-off of unamortized premium and debt issuance costs.

Redemption of Other Long-Term Debt

On May 3, 2018, the Company redeemed the remaining $4.4 million outstanding principal amount of its 4.375% Convertible Senior Notes due 2028 at a price equal to 100% of par. Upon redemption, the Company paid $4.5 million, which included accrued and unpaid interest of $0.1 million from the last interest payment date up to, but not including, the redemption date.

7. 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 oil and 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.

8. Preferred Stock and Warrants

On August 10, 2017, the Company closed on the issuance and sale in a private placement of (i) $250.0 million initial liquidation preference (250,000 shares) of 8.875% redeemable preferred stock, par value $0.01 per share (the "Preferred Stock") and (ii) warrants for 2,750,000 shares of the Company's common stock, with a term of ten years and an exercise price of $16.08 per share, exercisable only on a net share settlement basis (the "Warrants"), for a cash purchase price equal to $970.00 per share of Preferred Stock, to certain funds managed or sub-advised by GSO Capital Partners LP and its affiliates (the "GSO Funds").

The Preferred Stock has a liquidation preference of $1,000.00 per share and bears an annual cumulative dividend rate of 8.875%, payable on March 15, June 15, September 15 and December 15 of any given year. The Company may elect to pay all or a portion of the Preferred Stock dividends in shares of its common stock in decreasing percentages as follows with respect to any preferred stock dividend declared by the Company's Board of Directors and paid in respect of a quarter ending:

Period	Percentage
September 15, 2018	100 %
On or after December 15, 2018 and on or prior to September 15, 2019	75 %
On or after December 15, 2019 and on or prior to September 15, 2020	50 %

If the Company fails to satisfy the Preferred Stock dividend on the applicable dividend payment date, then the unpaid dividend will be added to the liquidation preference until paid.

The Preferred Stock outstanding is not mandatorily redeemable, but can be redeemed at the Company's option and, in certain circumstances, at the option of the holders of the Preferred Stock. On or prior to August 10, 2018, the Company had the right to redeem up to 50,000 shares of Preferred Stock, in cash, at $1,000.00 per share, plus accrued and unpaid dividends in an amount not to exceed the sum of the cash proceeds of divestitures of oil and gas properties and related assets, the sale or issuance of the Company's common stock and the sale of any of the Company's wholly owned subsidiaries. In the first quarter of 2018, the Company redeemed 50,000 shares of Preferred Stock, representing 20% of the issued and outstanding Preferred Stock. Upon redemption, the Company paid $50.5 million, which consisted of $1,000.00 per share of Preferred Stock redeemed, plus accrued and unpaid dividends, with a portion of the proceeds from the divestitures of oil and gas properties. See "Note 3. Acquisitions and Divestitures of Oil and Gas Properties" for information regarding divestitures.

In addition, at any time on or prior to August 10, 2020, the Company may redeem all or part of the Preferred Stock in cash at a redemption premium of 104.4375%, plus accrued and unpaid dividends and the present value on the redemption date of all quarterly dividends that would be payable from the redemption date through August 10, 2020. After August 10, 2020, the Company may redeem all or part of the Preferred Stock in cash at redemption premiums, as presented in the table below, plus accrued but unpaid dividends.

Period	Percentage
After August 10, 2020 but on or prior to August 10, 2021	104.4375 %
After August 10, 2021 but on or prior to August 10, 2022	102.21875 %
After August 10, 2022	100 %

The holders of the Preferred Stock have the option to cause the Company to redeem the Preferred Stock under the following conditions:

- Upon the Company's failure to pay a quarterly dividend within three months of the applicable payment date;
- On or after August 10, 2024, if the Preferred Shares remain outstanding; or
- Upon the occurrence of certain changes of control.

For the first two conditions described above, the Company has the option to settle any such redemption in cash or shares of its common stock and the holders of the Preferred Stock may elect to revoke or reduce the redemption if the Company elects to settle in shares of common stock.

The Preferred Stock are non-voting shares except as required by the Company's articles of incorporation or bylaws. However, so long as the GSO Funds beneficially own more than 50% of the Preferred Stock, the consent of the holders of the Preferred Stock will be required prior to issuing stock senior to or on parity with the Preferred Stock, incurring indebtedness subject to a leverage ratio, agreeing to certain restrictions on dividends on, or redemption of, the Preferred Stock and declaring or paying dividends on the Company's common stock in excess of $15.0 million per year subject to a leverage ratio. Additionally, if the Company does not redeem the Preferred Stock before August 10, 2024, in connection with a change of control or failure to pay a quarterly dividend within three months of the applicable payment date, the holders of the Preferred Stock are entitled to additional rights including:

- Increasing the dividend rate to 12.0% per annum until August 10, 2024 and thereafter to the greater of 12.0% per annum and the one-month LIBOR plus 10.0%;
- Electing up to two directors to the Company's Board of Directors; and
- Requiring approval by the holders of the Preferred Stock to incur indebtedness subject to a leverage ratio, declaring or paying dividends on the Company's common stock in excess of $15.0 million per year or issuing equity of the Company's subsidiaries to third parties.

The Preferred Stock is presented as temporary equity in the consolidated balance sheets with the issuance date fair value accreted to the redemption value using the effective interest method.

The table below summarizes changes in the carrying amount of Preferred Stock for the six months ended June 30, 2018:

	June 30, 2018 (In thousands)
Preferred Stock, beginning of period	$214,262
Redemption of preferred stock	(42,897)
Accretion on Preferred Stock	1,493
Preferred Stock, end of period	$172,858

Preferred Stock Dividends, Accretion, and Loss on Redemption

Dividends, accretion, and loss on redemption of preferred stock are presented in the consolidated statements of income as a reduction of net income to compute net income attributable to common shareholders.

For the three months ended June 30, 2018, the Company declared and paid $4.5 million of cash dividends to the holders of record of the Preferred Stock on June 15, 2018. For the six months ended June 30, 2018, the Company declared and paid $9.3 million of cash dividends to the holders of the Preferred Stock on June 15, 2018 and March 15, 2018.

For the three and six months ended June 30, 2018, the Company recorded accretion on Preferred Stock of $0.7 million and $1.5 million, respectively.

As a result of the redemption described above, the Company recorded a loss on redemption of preferred stock of $7.1 million, which included $0.1 million of direct costs incurred as a result of the redemption and a non-cash charge of $7.0 million attributable to the difference between $50.0 million, which was the consideration transferred to the holders of the Preferred Stock excluding accrued and unpaid dividends, and $42.9 million, which was 20% of the carrying value of the Preferred Stock on the date of redemption.

9. Stock-Based Compensation

Equity-Based Incentive Awards Plans

The Company grants equity-based incentive awards under the 2017 Incentive Plan of Carrizo Oil & Gas, Inc. (the "2017 Incentive Plan") and the Carrizo Oil & Gas, Inc. Cash-Settled Stock Appreciation Rights Plan ("Cash SAR Plan"). The 2017 Incentive Plan replaced the Incentive Plan of Carrizo Oil & Gas, Inc., as amended and restated effective May 15, 2014 (the "Prior Incentive Plan") and, from the effective date of the 2017 Incentive Plan, no further awards may be granted under the Prior Incentive Plan. However, awards previously granted under the Prior Incentive Plan will remain outstanding in accordance with their terms. Under the 2017 Incentive Plan, the Company can grant restricted stock awards and units, stock appreciation rights that can be settled in shares of common stock or cash at the option of the Company, performance shares, stock options, and cash awards to employees, independent contractors, and non-employee directors. Under the Cash SAR Plan, the Company can grant stock appreciation rights that may only be settled in cash (“Cash SARs”) to employees and independent contractors.

The 2017 Incentive Plan provides that up to 2,675,000 shares of the Company’s common stock, plus the shares remaining available for awards under the Prior Incentive Plan at the effective date of the 2017 Incentive Plan, may be issued (the “Maximum Share Limit”). Each restricted stock award, restricted stock unit, or performance share granted under the 2017 Incentive Plan counts as

1.35 shares against the Maximum Share Limit. Each stock option and stock appreciation right to be settled in shares of common stock ("Stock SAR") granted under the 2017 Incentive Plan counts as 1.00 share against the Maximum Share Limit. Each stock appreciation right to be settled in shares of common stock or cash ("Incentive SAR") granted under the 2017 Incentive Plan counts as 1.00 share against the Maximum Share Limit up to the date the Company, if it so chooses, affirmatively elects to settle the stock appreciation right in cash. Each stock appreciation right to be settled in cash ("Incentive Cash SAR") granted under the 2017 Incentive Plan or Cash SAR does not count against the Maximum Share Limit. As of June 30, 2018, there were 326,774 common shares remaining available for grant under the 2017 Incentive Plan.

Restricted Stock Awards and Units

As of June 30, 2018, unrecognized compensation costs related to unvested restricted stock awards and units was $30.5 million and will be recognized over a weighted average period of 2.2 years.

The table below summarizes restricted stock award and unit activity for the six months ended June 30, 2018:

	Restricted Stock Awards and Units	Weighted Average Grant Date Fair Value
Unvested restricted stock awards and units, beginning of period	1,482,655	$28.07
Granted	1,348,415	$14.68
Vested	(608,904)	$31.43
Forfeited	(10,993)	$19.17
Unvested restricted stock awards and units, end of period	2,211,173	$19.02

During the six months ended June 30, 2018, the Company granted 1,348,415 restricted stock awards and units primarily consisting of 1,343,412 restricted stock units to employees and independent contractors as part of its annual grant of long-term equity incentive awards during the first quarter of 2018. These restricted stock units had a grant date fair value of $19.7 million and will vest ratably over a three-year period.

Stock Appreciation Rights ("SARs")

As of June 30, 2018, all outstanding SARs are either Cash SARs or Incentive Cash SARs and will be settled in cash. The liability for SARs as of June 30, 2018 was $8.7 million, all of which was classified as "Other current liabilities," in the consolidated balance sheets. As of December 31, 2017, the liability for SARs was $4.4 million, all of which was classified as "Other liabilities" in the consolidated balance sheets. Unrecognized compensation costs related to unvested SARs was $11.3 million as of June 30, 2018, and will be recognized over a weighted average period of 2.6 years.

The table below summarizes the activity for SARs for the six months ended June 30, 2018:

	SARs	Weighted Average Exercise Prices	Weighted Average Remaining Life (In years)	Aggregate Intrinsic Value (In millions)	Aggregate Intrinsic Value of Exercises (In millions)
Outstanding, beginning of period	714,238	$27.12			
Granted	616,686	$14.67			
Exercised	—	$—			$—
Forfeited	—	$—			
Expired	—	$—			
Outstanding, end of period	1,330,924	$21.35	4.8	$9.1	
Vested, end of period	543,018	$27.18			
Vested and exercisable, end of period	543,018	$27.18	3.04	$0.5	

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During the six months ended June 30, 2018, the Company granted 616,686 Incentive Cash SARs to certain employees and independent contractors, all of which occurred in the first quarter of 2018 as part of the Company's annual grant of long-term equity incentive awards. These Incentive Cash SARs will vest ratably over a three-year period and expire approximately seven years from the grant date.

The grant date fair value of the Incentive Cash SARs, calculated using the Black-Scholes-Merton option pricing model, was $4.9 million. The following table summarizes the assumptions used to calculate the grant date fair value of the Incentive Cash SARs granted during the six months ended June 30, 2018:

	Grant Date Fair Value Assumptions	
Expected term (in years)	6.0	
Expected volatility	54.3	%
Risk-free interest rate	2.8	%
Dividend yield	—	%

Performance Shares

As of June 30, 2018, unrecognized compensation costs related to unvested performance shares was $2.9 million and will be recognized over a weighted average period of 2.2 years.

The table below summarizes performance share activity for the six months ended June 30, 2018:

	Target Performance Shares (1)		Weighted Average Grant Date Fair Value
Unvested performance shares, beginning of period	144,955		$47.14
Granted	93,771		$19.09
Vested at end of performance period	(49,458	)	$65.51
Did not vest at end of performance period	(7,059	)	$65.51
Forfeited	—		$—
Unvested performance shares, end of period	182,209		$27.01

(1) The number of performance shares that vest may vary from the number of target performance shares granted depending on the Company's final TSR ranking for the approximate three-year performance period.

During the six months ended June 30, 2018, the Company granted 93,771 target performance shares to certain employees and independent contractors, all of which occurred in the first quarter of 2018 as part of the Company's annual grant of long-term equity incentive awards. Each performance share represents the right to receive one share of common stock, however, the number of performance shares that will vest ranges from zero to 200% of the target performance shares granted based on the total shareholder return ("TSR") of the Company's common stock relative to the TSR achieved by a specified industry peer group over an approximate three-year performance period, the last day of which is also the vesting date.

Also during the six months ended June 30, 2018, the Company vested 49,458 performance shares that were granted in 2015. As a result of the Company's final TSR ranking during the performance period, a multiplier of 88% was applied to the 56,517 target performance shares that were granted in 2015, resulting in 7,059 performance shares that did not vest.

The grant date fair value of the performance shares, calculated using a Monte Carlo simulation, was $1.8 million. The following table summarizes the assumptions used to calculate the grant date fair value of the performance shares granted during the six months ended June 30, 2018:

Grant Date
Fair Value
Assumptions

Number of simulations	500,000	
Expected term (in years)	3.0	
Expected volatility	61.5	%
Risk-free interest rate	2.4	%
Dividend yield	—	%

Stock-Based Compensation Expense, Net

Stock-based compensation expense associated with restricted stock awards and units, SARs and performance shares is reflected as "General and administrative expense, net" in the consolidated statements of income.

The Company recognized the following stock-based compensation expense, net for the three and six months ended June 30, 2018 and 2017:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(In thousands)			
Restricted stock awards and units	$4,720	$5,024	$9,804	$10,873
SARs	5,788	(3,783)	4,373	(7,469)
Performance shares	406	574	963	1,280
	10,914	1,815	15,140	4,684
Less: amounts capitalized to oil and gas properties	(3,708)	(233)	(4,416)	(1,088)
Total stock-based compensation expense, net	$7,206	$1,582	$10,724	$3,596

10. Derivative Instruments

Commodity Derivative Instruments

The Company uses commodity derivative instruments to reduce its exposure to commodity price volatility for a portion of its forecasted production and thereby achieve a more predictable level of cash flows to support the Company's capital expenditure program and fixed costs.

The Company does not enter into derivative instruments for speculative or trading purposes. The Company's commodity derivative instruments consist of price swaps, three-way collars, basis swaps, and purchased and sold call options, which are described below.

Price Swaps: The Company receives a fixed price and pays an index price to the counterparty over specified periods for contracted volumes.

Three-Way Collars: A three-way collar is a combination of options including a purchased put option (fixed floor price), a sold call option (fixed ceiling price) and a sold put option (fixed sub-floor price). These contracts offer a higher fixed ceiling price relative to a costless collar but limit the Company's protection from decreases in commodity prices below the fixed floor price. At settlement, if the published index price is between the fixed floor price and the fixed sub-floor price or is above the fixed ceiling price, the Company receives the fixed floor price or pays the index price, respectively. If the index price is below the fixed sub-floor price, the Company receives the index price plus the difference between the fixed floor price and the fixed sub-floor price. If the index price is between the fixed floor price and fixed ceiling price, no payments are due from either party. The Company has incurred premiums on certain of these contracts in order to obtain a higher floor price and/or ceiling price.

Basis Swaps: Basis swaps fix the price differential between a published index price and the applicable local index price under which our production is sold. For the Company's Permian oil production, the basis swaps fix the price differential between the Midland WTI price and the Cushing WTI price and for the Company's Eagle Ford oil production, the basis swaps fix the price differential between the LLS price and the Cushing WTI price.

Sold Call Options: These contracts give the counterparty 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 index price exceeds the fixed price of the call option, the Company pays the counterparty the excess. If the index price settles below the fixed price of the call option, no payment is due from either party. These contracts require the counterparty to pay premiums to the Company that represent the fair value of the call option as of the date of sale. All of the Company's natural gas sold call options were executed contemporaneously with certain crude oil price swaps to increase the fixed price on those crude oil price swaps. Those certain crude oil price swaps settled prior to 2018.

Purchased Call Options: These contracts give the Company the right, but not the obligation, to buy contracted volumes from the counterparty over specified periods and prices in the future. At settlement, if the index price exceeds the fixed price of the call option, the counterparty pays the Company the excess. If the index price settles below the fixed price of the call option, no payment is due from either party. These contracts require the Company to pay premiums to the counterparty that represent the fair value of the call option as of the date of purchase. All of the Company's purchased crude oil call options were executed contemporaneously with sold crude oil call options to increase the fixed price on a portion of the existing sold crude oil call options and therefore are presented on a net basis as "Net Sold Call Options" in the table below.

Premiums: In order to increase the fixed price on a portion of the Company's existing sold call options, the Company incurred premiums on its purchased call options. Additionally, in order to obtain a higher floor price and/or ceiling price, the Company incurred premiums on certain of its three-way collars. Payment of these premiums are deferred until the applicable contracts settle on a monthly basis throughout the term of the contract or, in some cases, during the final 12 months of the contract and are referred to as deferred premium obligations.

The following table sets forth a summary of the Company's outstanding crude oil derivative positions as of June 30, 2018 at weighted average contract prices:

Period	Type of Contract	Index	Volumes (Bbls/d)	Fixed Price ($/Bbl)	Sub-Floor Price ($/Bbl)	Floor Price ($/Bbl)	Ceiling Price ($/Bbl)
2018							
Q3-Q4	Price Swaps	NYMEX WTI	6,000	$49.55	$—	$—	$—
Q3-Q4	Three-Way Collars	NYMEX WTI	24,000	—	39.38	49.06	60.14
Q3-Q4	Basis Swaps	LLS-Cushing WTI (1)	18,000	5.11	—	—	—
Q3-Q4	Basis Swaps	Midland WTI-Cushing WTI (2)	6,000	(0.10)	—	—	—
Q3-Q4	Net Sold Call Options	NYMEX WTI	3,388	—	—	—	71.33
2019							
Q1-Q4	Three-Way Collars	NYMEX WTI	15,000	—	41.00	49.72	62.48
Q1-Q2	Basis Swaps	Midland WTI-Cushing WTI (2)	3,000	(3.83)	—	—	—
Q3	Basis Swaps	Midland WTI-Cushing WTI (2)	3,500	(4.18)	—	—	—
Q4	Basis Swaps	Midland WTI-Cushing WTI (2)	6,000	(3.71)	—	—	—
Q1-Q4	Net Sold Call Options	NYMEX WTI	3,875	—	—	—	73.66
2020							
Q1-Q4	Net Sold Call Options	NYMEX WTI	4,575	—	—	—	75.98

(1) The index price paid under these basis swaps is LLS and the index price received is Cushing WTI plus the fixed price differential.

(2) The index price paid under these basis swaps is Midland WTI and the index price received is Cushing WTI less the fixed price differential.

The following table sets forth a summary of the Company's outstanding NGL derivative positions as of June 30, 2018 at weighted average contract prices:

Period	Type of Contract	Index	Volumes (Bbls/d)	Fixed Price ($/Bbl)
2018				
Q3-Q4	Price Swaps	Ethane - OPIS Mont Belvieu Non-TET	2,200	$12.01
Q3-Q4	Price Swaps	Propane - OPIS Mont Belvieu Non-TET	1,500	34.23
Q3-Q4	Price Swaps	Butane - OPIS Mont Belvieu Non-TET	200	38.85
Q3-Q4	Price Swaps	Isobutane - OPIS Mont Belvieu Non-TET	600	38.98
Q3-Q4	Price Swaps	Natural Gasoline - OPIS Mont Belvieu Non-TET	600	55.23

The following table sets forth a summary of the Company's outstanding natural gas derivative positions as of June 30, 2018 at weighted average contract prices:

Period	Type of Contract	Index	Volumes (MMBtu/d)	Fixed Price ($/MMBtu)	Ceiling Price ($/MMBtu)
2018					
Q3-Q4	Price Swaps	NYMEX HH	25,000	$3.01	$—
Q3-Q4	Sold Call Options	NYMEX HH	33,000	—	3.25
2019					
Q1-Q4	Sold Call Options	NYMEX HH	33,000	—	3.25

2020					
Q1-Q4	Sold Call Options	NYMEX HH	33,000	—	3.50

The Company typically has numerous hedge positions that span several time periods and often result in both commodity derivative asset and liability positions held with that counterparty. The Company nets its commodity derivative instrument fair values executed with the same counterparty, along with deferred premium obligations, to a single asset or liability 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.

Counterparties to the Company's commodity derivative instruments who are also lenders under the Company's credit agreement ("Lender Counterparty") allow the Company to satisfy any need for margin obligations associated with commodity derivative instruments where the Company is in a net liability position with the Lender Counterparty with the collateral securing the credit agreement, thus eliminating the need for independent collateral posting.

Counterparties to the Company's commodity derivative instruments who are not lenders under the Company's credit agreement ("Non-Lender Counterparty") can require commodity derivative instruments where the Company's net liability position exceeds the Company's unsecured credit limit with the Non-Lender Counterparty to be novated to a Lender Counterparty and therefore do not require the posting of cash collateral.

Because each Lender Counterparty has an investment grade credit rating and the Company has obtained a guaranty from each Non-Lender Counterparty's parent company which has an investment grade credit rating, 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 commodity derivative instruments. Although the Company does not currently anticipate nonperformance from its counterparties, it continually monitors the credit ratings of each Lender Counterparty and each Non-Lender Counterparty's parent company.

Contingent Consideration Arrangements

In connection with the ExL Acquisition and in each of the divestitures of the Company's assets in the Niobrara in the first quarter of 2018 and the Marcellus and Utica in the fourth quarter of 2017, the Company agreed to contingent consideration arrangements that could allow the Company to receive or be required to pay certain amounts if commodity prices are above specific thresholds, which are summarized in the table below. See "Note 3. Acquisitions and Divestitures of Oil and Gas Properties" included in this Quarterly Report on Form 10-Q as well as "Note 3. Acquisitions and Divestitures of Oil and Gas Properties" included in the 2017 Annual Report for details of the ExL Acquisition and each of the divestitures discussed above.

Contingent Consideration Arrangements	Years	Threshold [1]	Contingent Receipt (Payment) - Annual	Contingent Receipt (Payment) - Aggregate Limit
			(In thousands)	
Contingent ExL Consideration	2018	$50.00	($50,000)	
	2019	50.00	(50,000)	
	2020	50.00	(50,000)	
	2021	50.00	(50,000)	($125,000)
Contingent Niobrara Consideration	2018	$55.00	$5,000	
	2019	55.00	5,000	
	2020	60.00	5,000	—
Contingent Marcellus Consideration	2018	$3.13	$3,000	
	2019	3.18	3,000	
	2020	3.30	3,000	$7,500
Contingent Utica Consideration	2018	$50.00	$5,000	
	2019	53.00	5,000	
	2020	56.00	5,000	—

(1) The price used to determine whether the specific threshold for each year has been met is the average daily closing spot price of a barrel of West Texas Intermediate crude oil as measured by the U.S. Energy Information Administration for the Contingent ExL Consideration, Contingent Niobrara Consideration, and Contingent Utica Consideration and the average settlement price of a MMBtu of Henry Hub natural gas for the next calendar month, as determined on the last business day preceding each calendar month as measured by the CME Group Inc. for the Contingent Marcellus Consideration.

Derivative Assets and Liabilities

All commodity derivative instruments are recorded in the consolidated balance sheets as either an asset or liability measured at fair value. The deferred premium obligations associated with the Company’s commodity derivative instruments are recorded in the period in which they are incurred and are netted with the commodity derivative instrument fair value asset or liability pursuant to the netting arrangements described above. Each of the contingent consideration arrangements discussed above were determined to be embedded derivatives and are recorded in the consolidated balance sheets as either an asset or liability measured at fair value at the acquisition or divestiture date, as well as each subsequent balance sheet date.

The combined derivative instrument fair value assets and liabilities, including deferred premium obligations, recorded in the consolidated balance sheets as of June 30, 2018 and December 31, 2017 are summarized below:

	June 30, 2018		
	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
	(In thousands)		
Commodity derivative instruments	$32,422	($31,259)	$1,163
Contingent Niobrara Consideration	4,820	—	4,820
Contingent Marcellus Consideration	130	—	130
Contingent Utica Consideration	4,815	—	4,815
Derivative assets	$42,187	($31,259)	$10,928
Commodity derivative instruments	13,418	(13,418)	—
Contingent Niobrara Consideration	5,150	—	5,150
Contingent Marcellus Consideration	1,400	—	1,400
Contingent Utica Consideration	5,730	—	5,730
Other assets	$25,698	($13,418)	$12,280
Commodity derivative instruments	($118,953)	$21,813	($97,140)
Deferred premium obligations	(9,446)	9,446	—
Contingent ExL Consideration	(48,380)	—	(48,380)
Derivative liabilities-current	($176,779)	$31,259	($145,520)
Commodity derivative instruments	(40,006)	5,748	(34,258)
Deferred premium obligations	(7,670)	7,670	—
Contingent ExL Consideration	(53,675)	—	(53,675)
Derivative liabilities-non current	($101,351)	$13,418	($87,933)

	December 31, 2017		
	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
	(In thousands)		
Commodity derivative instruments	$4,869	($4,869)	$—
Derivative assets	$4,869	($4,869)	$—
Commodity derivative instruments	9,505	(9,505)	—
Contingent Niobrara Consideration	—	—	—
Contingent Marcellus Consideration	2,205	—	2,205
Contingent Utica Consideration	7,985	—	7,985
Other assets	$19,695	($9,505)	$10,190
Commodity derivative instruments	($52,671)	($4,450)	($57,121)
Deferred premium obligations	(9,319)	9,319	—
Derivative liabilities-current	($61,990)	$4,869	($57,121)
Commodity derivative instruments	(24,609)	(2,098)	(26,707)
Deferred premium obligations	(11,603)	11,603	—
Contingent ExL Consideration	(85,625)	—	(85,625)
Derivative liabilities-non current	($121,837)	$9,505	($112,332)

See “Note 11. Fair Value Measurements” for additional information regarding the fair value of the Company’s derivative instruments.

(Gain) Loss on Derivatives, Net

The Company has elected not to meet the criteria to qualify its commodity derivative instruments for hedge accounting treatment. Therefore, all gains and losses as a result of changes in the fair value of the Company’s commodity derivative instruments, as well as its contingent consideration arrangements, are recognized as “(Gain) loss on derivatives, net” in the consolidated statements of income in the period in which the changes occur. All deferred premium obligations associated with the Company’s commodity derivative instruments are recognized in “(Gain) loss on derivatives, net” in the consolidated statements of income in the period in which the deferred premium obligations are incurred. The effects of commodity derivative instruments, deferred premium obligations and contingent consideration arrangements in the consolidated statements of income for the three and six months ended June 30, 2018 and 2017 are summarized below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(In thousands)			
(Gain) Loss on Derivatives, Net				
Crude oil derivatives	$53,437	($29,736)	$82,948	($48,163)
NGL derivatives	6,564	—	4,799	—
Natural gas derivatives	153	(3,883)	(2,892)	(10,719)
Deferred premium obligations	—	7,554	—	7,501
Contingent ExL Consideration	10,600	—	16,430	—
Contingent Niobrara Consideration	(1,705)	—	(2,090)	—
Contingent Marcellus Consideration	205	—	675	—
Contingent Utica Consideration	(1,540)	—	(2,560)	—
(Gain) Loss on Derivatives, Net	$67,714	($26,065)	$97,310	($51,381)

Cash Received (Paid) for Derivative Settlements, Net

Cash flows are impacted to the extent that settlements of commodity derivatives, including deferred premium obligations, and settlements of contingent consideration arrangements result in cash receipts or payments during the period and are presented as “Cash received (paid) for derivative settlements, net” in the consolidated statements of cash flows. Cash payments made to settle contingent consideration liabilities are classified as cash flows from financing activities up to the divestiture or acquisition date fair value with any excess classified as cash flows from operating activities. For the three and six months ended June 30, 2018 and 2017, the Company did not receive or pay cash for the contingent consideration arrangements. The net cash received (paid) for settlements of commodity derivatives and deferred premium obligations in the consolidated statements of cash flows for the three and six months ended June 30, 2018 and 2017 are summarized below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Cash Flows from Operating Activities	(In thousands)			
Cash Received (Paid) for Derivative Settlements, Net				
Crude oil derivatives	($21,210)	$409	($33,333)	$3,441
NGL derivatives	(756)	—	(1,188)	—
Natural gas derivatives	488	(104)	540	(1,253)
Deferred premium obligations	(2,605)	(566)	(4,467)	(930)
Cash Received (Paid) for Derivative Settlements, Net	($24,083)	($261)	($38,448)	$1,258

11. 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 commodity derivative instrument and contingent consideration arrangement assets and liabilities measured at fair value on a recurring basis as of June 30, 2018 and December 31, 2017:

	June 30, 2018		
	Level 1	Level 2	Level 3
	(In thousands)		
Assets			
Commodity derivative instruments	$—	$1,163	$—
Contingent Niobrara Consideration	—	—	9,970
Contingent Marcellus Consideration	—	—	1,530
Contingent Utica Consideration	—	—	10,545
Liabilities			
Commodity derivative instruments	$—	($131,398)	$—
Contingent ExL Consideration	—	—	(102,055)

	December 31, 2017		
	Level 1	Level 2	Level 3
	(In thousands)		
Assets			
Commodity derivative instruments	$—	$—	$—
Contingent Niobrara Consideration	—	—	—
Contingent Marcellus Consideration	—	—	2,205
Contingent Utica Consideration	—	—	7,985
Liabilities			
Commodity derivative instruments	$—	($83,828)	$—
Contingent ExL Consideration	—	—	(85,625)

The commodity derivative and contingent consideration arrangement asset and liability fair values reported in the consolidated balance sheets are as of the balance sheet date and subsequently change as a result of changes in commodity prices, market conditions and other factors.
Commodity derivative instruments. The fair value of the Company's commodity derivative instruments is based on a third-party industry-standard pricing model which uses contract terms and prices and assumptions and inputs that are substantially observable in active markets throughout the full term of the instruments including forward oil and gas price curves, discount rates and volatility factors, and are therefore designated as Level 2 within the valuation hierarchy. The fair values are also compared to the values provided by the counterparties for reasonableness and are adjusted for the counterparties' credit quality for commodity derivative assets and the Company's credit quality for commodity derivative liabilities.
The Company typically has numerous hedge positions that span several time periods and often result in both commodity derivative asset and liability positions held with that counterparty. Deferred premium obligations are netted with the commodity derivative asset and liability positions, which are all offset to a single asset or liability, at the end of each reporting period. The Company nets the fair values of its assets and liabilities associated with commodity derivative instruments executed with the same counterparty, along with deferred premium obligations, 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 six months ended June 30, 2018 and 2017.
Contingent consideration arrangements. The fair values of the contingent consideration arrangements were determined by a third-party valuation specialist using Monte Carlo simulations including significant inputs such as forward oil

and gas price curves, discount rates and volatility factors. As some of these assumptions are not observable throughout the full term of the contingent consideration arrangements, the contingent consideration arrangements were designated as Level 3 within the valuation hierarchy. The Company reviewed the valuations, including the related inputs, and analyzed changes in fair value measurements between periods.

The following table presents the reconciliation of changes in the fair values of the contingent consideration arrangements, which were designated as Level 3 within the valuation hierarchy, for the six months ended June 30, 2018:

	Contingent Consideration Arrangements	
	Assets	Liability
For the Six Months Ended June 30, 2018	(In thousands)	
Beginning of period	$10,190	($85,625)
Recognition of divestiture date fair value	7,880	—
Gain (loss) on changes in fair value, net(1)	3,975	(16,430)
Transfers into (out of) Level 3	—	—
End of period	$22,045	($102,055)

(1) Included in "(Gain) loss on derivatives, net" in the consolidated statements of income.

See "Note 10. Derivative Instruments" for additional information regarding the contingent consideration arrangements.

Assets and Liabilities Measured at Fair Value on a Non-Recurring Basis

The fair value measurements of asset retirement obligations are measured as of the date a well is drilled or when production equipment and facilities are installed using a discounted cash flow model based on inputs that are not observable in the market and therefore are designated as Level 3 inputs. Significant inputs to the fair value measurement of asset retirement obligations include estimates of the costs of plugging and abandoning oil and gas wells, removing production equipment and facilities and restoring the surface of the land as well as estimates of the economic lives of the oil and gas wells and future inflation rates.

Fair Value of Other Financial Instruments

The Company's other financial instruments consist of cash and cash equivalents, receivables, payables, and long-term debt. 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, which are designated as Level 1 under the fair value hierarchy, net of unamortized premiums and debt issuance costs, with the fair values measured using quoted secondary market trading prices.

	June 30, 2018		December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
7.50% Senior Notes due 2020	$129,044	$130,325	$446,087	$459,518
6.25% Senior Notes due 2023	642,446	656,500	641,792	674,375
8.25% Senior Notes due 2025	245,817	266,250	245,605	274,375
Other long-term debt due 2028	—	—	4,425	4,445

12. 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)

	June 30, 2018				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Total current assets	$3,128,244	$120,425	$—	($3,116,164)	$132,505
Total property and equipment, net	6,445	2,562,799	3,028	(3,847)	2,568,425
Investment in subsidiaries	(743,363)	—	—	743,363	—
Other assets	8,630	12,279	—	—	20,909
Total Assets	$2,399,956	$2,695,503	$3,028	($2,376,648)	$2,721,839
Liabilities and Shareholders' Equity					
Current liabilities	$257,137	$3,362,551	$3,028	($3,119,185)	$503,531
Long-term liabilities	1,526,788	76,315	—	15,879	1,618,982
Preferred stock	172,858	—	—	—	172,858
Total shareholders' equity	443,173	(743,363)	—	726,658	426,468
Total Liabilities and Shareholders' Equity	$2,399,956	$2,695,503	$3,028	($2,376,648)	$2,721,839

	December 31, 2017				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Total current assets	$3,441,633	$105,533	$—	($3,424,288)	$122,878
Total property and equipment, net	5,953	2,630,707	3,028	(3,878)	2,635,810
Investment in subsidiaries	(999,793)	—	—	999,793	—
Other assets	9,270	10,346	—	—	19,616
Total Assets	$2,457,063	$2,746,586	$3,028	($2,428,373)	$2,778,304
Liabilities and Shareholders' Equity					
Current liabilities	$165,701	$3,631,401	$3,028	($3,427,308)	$372,822
Long-term liabilities	1,689,466	114,978	—	15,879	1,820,323
Preferred stock	214,262	—	—	—	214,262
Total shareholders' equity	387,634	(999,793)	—	983,056	370,897
Total Liabilities and Shareholders' Equity	$2,457,063	$2,746,586	$3,028	($2,428,373)	$2,778,304

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

	Three Months Ended June 30, 2018				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$19	$263,954	$—	$—	$263,973
Total costs and expenses	106,335	121,869	—	(23)	228,181
Income (loss) before income taxes	(106,316)	142,085	—	23	35,792
Income tax expense	—	(483)	—	—	(483)
Equity in income of subsidiaries	141,602	—	—	(141,602)	—
Net income	$35,286	$141,602	$—	($141,579)	$35,309
Dividends on preferred stock	(4,474)	—	—	—	(4,474)
Accretion on preferred stock	(740)	—	—	—	(740)
Loss on redemption of preferred stock	—	—	—	—	—
Net income attributable to common shareholders	$30,072	$141,602	$—	($141,579)	$30,095

	Three Months Ended June 30, 2017				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$174	$166,309	$—	$—	$166,483
Total costs and expenses	7,731	102,415	—	31	110,177
Income (loss) before income taxes	(7,557)	63,894	—	(31)	56,306
Income tax expense	—	—	—	—	—
Equity in income of subsidiaries	63,894	—	—	(63,894)	—
Net income	$56,337	$63,894	$—	($63,925)	$56,306
Dividends on preferred stock	—	—	—	—	—
Accretion on preferred stock	—	—	—	—	—
Loss on redemption of preferred stock	—	—	—	—	—
Net income attributable to common shareholders	$56,337	$63,894	$—	($63,925)	$56,306

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

	Six Months Ended June 30, 2018				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$39	$489,214	$—	$—	$489,253
Total costs and expenses	193,700	231,982	—	(32)	425,650
Income (loss) before income taxes	(193,661)	257,232	—	32	63,603
Income tax expense	—	(802)	—	—	(802)
Equity in income of subsidiaries	256,430	—	—	(256,430)	—
Net income	$62,769	$256,430	$—	($256,398)	$62,801
Dividends on preferred stock	(9,337)	—	—	—	(9,337)
Accretion on preferred stock	(1,493)	—	—	—	(1,493)
Loss on redemption of preferred stock	(7,133)	—	—	—	(7,133)
Net income attributable to common shareholders	$44,806	$256,430	$—	($256,398)	$44,838

	Six Months Ended June 30, 2017				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$256	$317,582	$—	$—	$317,838
Total costs and expenses	26,599	194,871	—	41	221,511
Income (loss) before income taxes	(26,343)	122,711	—	(41)	96,327
Income tax expense	—	—	—	—	—
Equity in income of subsidiaries	122,711	—	—	(122,711)	—
Net income	$96,368	$122,711	$—	($122,752)	$96,327
Dividends on preferred stock	—	—	—	—	—
Accretion on preferred stock	—	—	—	—	—
Loss on redemption of preferred stock	—	—	—	—	—
Net income attributable to common shareholders	$96,368	$122,711	$—	($122,752)	$96,327

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

	Six Months Ended June 30, 2018				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities	($158,309)	$434,181	$—	$—	$275,872
Net cash provided by (used in) investing activities	348,235	(84,355)	—	(349,826)	(85,946)
Net cash used in financing activities	(197,367)	(349,826)	—	349,826	(197,367)
Net decrease in cash and cash equivalents	(7,441)	—	—	—	(7,441)
Cash and cash equivalents, beginning of period	9,540	—	—	—	9,540
Cash and cash equivalents, end of period	$2,099	$—	$—	$—	$2,099

	Six Months Ended June 30, 2017				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities	($77,501)	$256,656	$—	$—	$179,155
Net cash used in investing activities	(109,780)	(364,887)	—	108,231	(366,436)
Net cash provided by financing activities	185,315	108,231	—	(108,231)	185,315
Net decrease in cash and cash equivalents	(1,966)	—	—	—	(1,966)
Cash and cash equivalents, beginning of period	4,194	—	—	—	4,194
Cash and cash equivalents, end of period	$2,228	$—	$—	$—	$2,228

13. Supplemental Cash Flow Information

Supplemental cash flow disclosures and non-cash investing activities are presented below:

	Six Months Ended June 30,	
	2018	2017
	(In thousands)	
Supplemental cash flow disclosures:		
Cash paid for interest, net of amounts capitalized	$29,853	$39,603
Non-cash investing activities:		
Increase in capital expenditure payables and accruals	$35,543	$48,395
Contingent consideration arrangement related to divestitures of oil and gas properties	(7,880)	—

14. Subsequent Events

Divestiture of Non-Operated Delaware Basin Assets

In July 2018, the Company closed on the divestiture of certain non-operated assets in the Delaware Basin for estimated aggregate net proceeds of $31.4 million. The proceeds from this divestiture will be recognized as a reduction of proved oil and gas properties.

Hedging

In August 2018, the Company entered into the following crude oil derivative positions at the weighted average contract prices summarized below:

Period	Type of Contract	Index	Volumes (Bbls/d)	Fixed Price ($/Bbl)
2019				
Q1	Basis Swaps	Midland WTI-Cushing WTI (1)	2,500	($6.94)
Q2	Basis Swaps	Midland WTI-Cushing WTI (1)	3,000	(6.94)
Q3	Basis Swaps	Midland WTI-Cushing WTI (1)	3,500	(6.94)
Q4	Basis Swaps	Midland WTI-Cushing WTI (1)	5,000	(4.00)
2020				
Q1	Basis Swaps	Midland WTI-Cushing WTI (1)	1,000	(1.90)

(1) The index price paid under these basis swaps is Midland WTI and the index price received is Cushing WTI less the fixed price differential.

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

The following discussion and analysis of the financial condition and results of operations of the Company should be read in conjunction with the unaudited interim consolidated financial statements and related notes included in "Item 1. Consolidated Financial Statements (Unaudited)" 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 audited Consolidated Financial Statements included in our 2017 Annual Report. The following discussion and analysis contains statements, including, but not limited to, statements related to our plans, strategies, objectives, and expectations. Please see "Forward-Looking Statements" for further details about these statements.

General Overview

Second Quarter 2018 Highlights

- Total production for the three months ended June 30, 2018 was 57,077 Boe/d, an increase of 12% from the three months ended June 30, 2017, primarily due to the addition of production from the ExL Acquisition in the third quarter of 2017, partially offset by the divestitures in the Utica and Marcellus Shales in the fourth quarter of 2017 and the Niobrara Formation and Eagle Ford in the first quarter of 2018 and normal production declines.
- Operated drilling and completion activity for the three months ended June 30, 2018 along with our drilled but uncompleted and producing wells as of June 30, 2018 are summarized in the table below.

	Three Months Ended June 30, 2018				June 30, 2018			
	Drilled		Completed		Drilled But Uncompleted		Producing	
Region	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Eagle Ford	19	17.7	18	15.6	15	14.0	485	434.9
Delaware Basin	9	7.8	12	9.3	10	8.6	46	37.6
Total	28	25.5	30	24.9	25	22.6	531	472.5

- Drilling and completion expenditures for the second quarter of 2018 were $218.0 million, of which nearly 55% was in the Delaware Basin with the balance in the Eagle Ford. We currently expect to operate an average of six rigs, with four located in the Eagle Ford and two located in the Delaware Basin, and 2-3 completion crews for the remainder of 2018. Given the faster cycle times in the Eagle Ford, as well as the Company's decision to maintain a six rig program for the remainder of the year, our current 2018 drilling, completion, and infrastructure capital expenditure plan has been increased from $750.0 million to $800.0 million to $800.0 million to $825.0 million. See "—Liquidity and Capital Resources—2018 Drilling, Completion, and Infrastructure Capital Expenditure Plan and Funding Strategy" for additional details.
- In May 2018, we entered into the twelfth amendment to our credit agreement governing the revolving credit facility to, among other things, (i) establish the borrowing base at $1.0 billion, with an elected commitment amount of $900.0 million, until the next redetermination thereof, (ii) reduce the margins applied to Eurodollar loans from 2.0%-3.0% to 1.5%-2.5%, depending on level of facility usage, (iii) amend the covenant limiting payment of dividends and distributions on equity to increase our ability to make dividends and distributions on our equity interests and (iv) amend certain other provisions, in each case as set forth therein.
- We recorded net income attributable to common shareholders for the three months ended June 30, 2018 of $30.1 million, or $0.36 per diluted share, as compared to net income attributable to common shareholders for the three months ended June 30, 2017 of $56.3 million, or $0.85 per diluted share. The reduction in net income attributable to common shareholders for the second quarter of 2018 as compared to the net income attributable to common shareholders for the second quarter of 2017 was driven primarily by a loss on derivatives, net of $67.7 million in the second quarter of 2018 as compared to a gain on derivatives, net of $26.1 million in the second quarter of 2017 and an increase in our depreciation, depletion and amortization ("DD&A") expense for the second quarter of 2018 due to the addition of proved oil and gas properties related to the ExL Acquisition and increased production, partially offset by higher production volumes and commodity prices in the second quarter of 2018 compared to the second quarter of 2017. See "—Results of Operations" below for further details.

Recent Developments

- In July 2018, we closed on the divestiture of certain non-operated assets in the Delaware Basin for estimated aggregate net proceeds of $31.4 million.

Results of Operations

Three Months Ended June 30, 2018, Compared to the Three Months Ended June 30, 2017

The following table summarizes total production volumes, daily production volumes, average realized prices and revenues for the three months ended June 30, 2018 and 2017:

	Three Months Ended June 30,		2018 Period Compared to 2017 Period	
	2018	2017	Increase (Decrease)	% Increase (Decrease)
Total production volumes -				
Crude oil (MBbls)	3,445	3,060	385	13 %
NGLs (MBbls)	853	453	400	88 %
Natural gas (MMcf)	5,372	6,775	(1,403)	(21 %)
Total barrels of oil equivalent (MBoe)	5,193	4,643	550	12 %
Daily production volumes by product -				
Crude oil (Bbls/d)	37,860	33,629	4,231	13 %
NGLs (Bbls/d)	9,379	4,982	4,397	88 %
Natural gas (Mcf/d)	59,029	74,451	(15,422)	(21 %)
Total barrels of oil equivalent (Boe/d)	57,077	51,019	6,058	12 %
Daily production volumes by region (Boe/d) -				
Eagle Ford	37,039	38,055	(1,016)	(3 %)
Delaware Basin	19,783	2,151	17,632	820 %
Other	255	10,813	(10,558)	(98 %)
Total barrels of oil equivalent (Boe/d)	57,077	51,019	6,058	12 %
Average realized prices -				
Crude oil ($ per Bbl)	$66.70	$46.67	$20.03	43 %
NGLs ($ per Bbl)	24.93	17.19	7.74	45 %
Natural gas ($ per Mcf)	2.40	2.35	0.05	2 %
Total average realized price ($ per Boe)	$50.83	$35.86	$14.97	42 %
Revenues (In thousands) -				
Crude oil	$229,798	$142,806	$86,992	61 %
NGLs	21,269	7,786	13,483	173 %
Natural gas	12,906	15,891	(2,985)	(19 %)
Total revenues	$263,973	$166,483	$97,490	59 %

Production volumes for the three months ended June 30, 2018 were 57,077 Boe/d, an increase of 12% from 51,019 Boe/d for the same period in 2017. The increase is primarily due to production from new wells in the Eagle Ford and the addition of production from the ExL Acquisition in the third quarter of 2017, partially offset by the divestitures in the Utica and Marcellus Shales in the fourth quarter of 2017 and the Niobrara Formation and Eagle Ford in the first quarter of 2018 and normal production declines. Revenues for the three months ended June 30, 2018 increased 59% to $264.0 million compared to $166.5 million for the same period in 2017 primarily due to higher crude oil prices and increased crude oil and NGL production, primarily as a result of the ExL Acquisition.

Lease operating expenses for the three months ended June 30, 2018 decreased to $35.2 million ($6.77 per Boe) from $36.0 million ($7.76 per Boe) for the same period in 2017. The decrease in lease operating expenses is primarily due to a reduction in workover costs for the three months ended June 30, 2018 when compared to the same period in 2017. The decrease in lease operating expense per Boe is primarily due to the addition of production from the ExL Acquisition beginning in the third quarter of 2017, which has a lower operating cost per Boe than our other crude oil properties, partially offset by an increased proportion of total production from crude oil properties, which have a higher operating cost per Boe than natural gas properties, as a result of the divestiture in the Marcellus Shale in the fourth quarter of 2017, as well as processing fees for certain of our natural gas and NGL processing contracts that are now presented in lease operating expenses as a result of the adoption of ASC 606.

Production taxes increased to $12.5 million (or 4.7% of revenues) for the three months ended June 30, 2018 from $7.1 million (or 4.3% of revenues) for the same period in 2017 primarily as a result of the increase in crude oil and NGL revenues. The increase in production taxes as a percentage of revenues is primarily due to the divestiture of substantially all of our assets in the Marcellus Shale in the fourth quarter of 2017, as production in Marcellus was not subject to production taxes.

Ad valorem taxes increased to $3.6 million for the three months ended June 30, 2018 from $1.1 million for the same period in 2017. The increase in ad valorem taxes is due to new wells drilled in the Eagle Ford and new wells drilled or acquired in the Delaware Basin as well as an increase in our annual estimate of ad valorem taxes for 2018 due to higher expected property tax valuations as a result of the increase in crude oil prices.

DD&A expense for the second quarter of 2018 increased $13.4 million to $72.4 million ($13.95 per Boe) from the DD&A expense for the second quarter of 2017 of $59.1 million ($12.72 per Boe). The increase in DD&A expense is attributable to increased production and an increase in the DD&A rate per Boe. The increase in the DD&A rate per Boe is due primarily to increases in future development cost assumptions that occurred subsequent to the second quarter of 2017 as well as an increase to proved oil and gas properties related to the ExL Acquisition in the third quarter of 2017, partially offset by the reduction in proved oil and gas properties as a result of the divestitures in the Utica and Marcellus Shales in the fourth quarter of 2017 and the Niobrara Formation and Eagle Ford in the first quarter of 2018. The components of our DD&A expense were as follows:

	Three Months Ended June 30,	
	2018	2017
	(In thousands)	
DD&A of proved oil and gas properties	$71,346	$57,695
Depreciation of other property and equipment	613	612
Amortization of other assets	140	321
Accretion of asset retirement obligations	331	444
Total DD&A	$72,430	$59,072

General and administrative expense, net increased to $18.3 million for the three months ended June 30, 2018 from $11.6 million for the corresponding period in 2017. 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 June 30, 2018 compared to a decrease in fair value for the same period in 2017.

We recorded a loss on derivatives, net of $67.7 million and a gain on derivatives, net of $26.1 million for the three months ended June 30, 2018 and 2017, respectively. The components of our (gain) loss on derivatives, net were as follows:

	Three Months Ended June 30,	
	2018	2017
	(In thousands)	
Crude oil derivative positions:		
(Gain) loss due to (downward) upward shift in the futures curve of forecasted crude oil prices during the period on derivative positions outstanding at the beginning of the period	$59,602	($10,122)
Gain due to new derivative positions executed during the period	(6,165)	(19,614)
Loss due to deferred premium obligations incurred	—	7,554
NGL derivative positions:		
Loss due to upward shift in the futures curve of forecasted NGL prices during the period on derivative positions outstanding at the beginning of the period	6,564	—
Natural gas derivative positions:		
(Gain) loss due to (downward) upward shift in the futures curve of forecasted natural gas prices during the period on derivative positions outstanding at the beginning of the period	153	(3,883)

Contingent consideration arrangements:		
Net loss primarily due to upward shift in the futures curve of forecasted crude oil prices during the period	7,560	—
(Gain) loss on derivatives, net	$67,714	($26,065)

Interest expense, net for the three months ended June 30, 2018 was $15.6 million as compared to $21.1 million for the same period in 2017. The decrease was due primarily to an increase in capitalized interest as a result of higher average balances of unevaluated leasehold and seismic costs for the three months ended June 30, 2018 as compared to the three months ended June 30, 2017, primarily as a result of the ExL Acquisition in the third quarter of 2017, as well as reduced interest expense as a result of the redemptions of the 7.50% Senior Notes in the fourth quarter of 2017 and first quarter of 2018. The decrease was partially offset by interest expense on $250.0 million aggregate principal amount of our 8.25% Senior Notes that were issued in the third quarter of 2017 and an increase in interest expense on our revolving credit facility as a result of increased borrowings for the three months ended June 30, 2018 as compared to the three months ended June 30, 2017. The components of our interest expense, net were as follows:

	Three Months Ended June 30,	
	2018	2017
	(In thousands)	
Interest expense on Senior Notes	$17,767	$21,455
Interest expense on revolving credit facility	5,490	2,261
Amortization of premiums and debt issuance costs	937	1,079
Other interest expense	133	298
Interest capitalized	(8,728)	(3,987)
Interest expense, net	$15,599	$21,106

The effective income tax rates for the second quarter of 2018 and 2017 were 1.3% and 0.0%, respectively. The variance in the effective income tax rate results from current state and deferred income tax expense of $0.5 million recognized during the second quarter of 2018. The tax expense was driven by changes to our state apportionment for estimated state deferred tax liabilities as a result of the significant changes in our areas of operation that occurred in late 2017 and early 2018, whereby all remaining operations are located in Texas. The effective income tax rate was 0.0% during the second quarter of 2017 as a result of a full valuation allowance against our net deferred tax assets driven by impairments of proved oil and gas properties recognized in the third quarter of 2015 and continuing through the third quarter of 2016.

For the three months ended June 30, 2018, we declared and paid $4.5 million of cash dividends on our Preferred Stock, which reduced net income to compute net income attributable to common shareholders.

Results of Operations

Six Months Ended June 30, 2018, Compared to the Six Months Ended June 30, 2017

The following table summarizes total production volumes, daily production volumes, average realized prices and revenues for the six months ended June 30, 2018 and 2017:

	Six Months Ended June 30,		2018 Period Compared to 2017 Period	
	2018	2017	Increase (Decrease)	% Increase (Decrease)
Total production volumes -				
Crude oil (MBbls)	6,517	5,656	861	15 %
NGLs (MBbls)	1,593	859	734	85 %
Natural gas (MMcf)	10,182	13,803	(3,621)	(26 %)
Total barrels of oil equivalent (MBoe)	9,807	8,816	991	11 %
Daily production volumes by product -				
Crude oil (Bbls/d)	36,008	31,250	4,758	15 %
NGLs (Bbls/d)	8,800	4,746	4,054	85 %
Natural gas (Mcf/d)	56,252	76,260	(20,008)	(26 %)
Total barrels of oil equivalent (Boe/d)	54,183	48,706	5,477	11 %
Daily production volumes by region (Boe/d) -				
Eagle Ford	36,335	35,332	1,003	3 %
Delaware Basin	17,522	2,284	15,238	667 %
Other	326	11,090	(10,764)	(97 %)
Total barrels of oil equivalent (Boe/d)	54,183	48,706	5,477	11 %
Average realized prices -				
Crude oil ($ per Bbl)	$65.17	$47.90	$17.27	36 %
NGLs ($ per Bbl)	23.96	17.71	6.25	35 %
Natural gas ($ per Mcf)	2.59	2.30	0.29	13 %
Total average realized price ($ per Boe)	$49.89	$36.05	$13.84	38 %
Revenues (In thousands) -				
Crude oil	$424,717	$270,898	$153,819	57 %
NGLs	38,171	15,211	22,960	151 %
Natural gas	26,365	31,729	(5,364)	(17 %)
Total revenues	$489,253	$317,838	$171,415	54 %

Production volumes for the six months ended June 30, 2018 were 54,183 Boe/d, an increase of 11% from 48,706 Boe/d for the same period in 2017. The increase is primarily due to production from new wells in the Eagle Ford and the addition of production from the ExL Acquisition in the third quarter of 2017, partially offset by the divestitures in the Utica and Marcellus Shales in the fourth quarter of 2017 and the Niobrara Formation and Eagle Ford in the first quarter of 2018 and normal production declines. Revenues for the six months ended June 30, 2018 increased 54% to $489.3 million from $317.8 million for the same period in 2017 primarily due to higher crude oil prices and increased crude oil and NGL production, primarily as a result of the ExL Acquisition.

Lease operating expenses for the six months ended June 30, 2018 increased to $74.4 million ($7.59 per Boe) from $65.9 million ($7.47 per Boe) for the same period in 2017. The increase in lease operating expenses is primarily due to costs associated with new wells completed in the Eagle Ford and Delaware Basin since the second quarter of 2017, partially offset by the divestitures in the Utica and Marcellus Shales in the fourth quarter of 2017 and the Niobrara Formation and Eagle Ford in the first quarter of 2018. The increase in lease operating expense per Boe is primarily due to an increased proportion of total production from crude oil properties, which have a higher operating cost per Boe than natural gas properties, as a result of the divestiture in the Marcellus Shale in the fourth quarter of 2017 as well as processing fees for certain of our natural gas and NGL processing contracts that are now presented in lease operating expenses as a result of the adoption of ASC 606.

Production taxes increased to $23.1 million (or 4.7% of revenues) for the six months ended June 30, 2018 from $13.4 million (or 4.2% of revenues) for the same period in 2017 primarily as a result of the increase in crude oil and NGL revenues. The increase in production taxes as a percentage of revenues is primarily due to the divestiture of substantially all of our assets in the Marcellus Shale in the fourth quarter of 2017, as production in Marcellus was not subject to production taxes.

Ad valorem taxes increased to $5.6 million for the six months ended June 30, 2018 from $4.0 million for the same period in 2017. The increase in ad valorem taxes is due to new wells drilled in the Eagle Ford and new wells drilled or acquired in the Delaware Basin as well as an increase in our annual estimate of ad valorem taxes for 2018 due to higher expected property tax valuations as a result of the increase in crude oil prices.

DD&A expense for the six months ended June 30, 2018 increased $23.4 million to $136.9 million ($13.96 per Boe) from $113.5 million ($12.87 per Boe) for the same period in 2017. The increase in DD&A expense is attributable to increased production as well as an increase in the DD&A rate per Boe. The increase in the DD&A rate per Boe is due primarily to increases in future development cost assumptions that occurred subsequent to the second quarter of 2017 as well as an increase to proved oil and gas properties related to the ExL Acquisition in the third quarter of 2017, partially offset by the reduction in proved oil and gas properties as a result of the divestitures in the Utica and Marcellus Shales in the fourth quarter of 2017 and the Niobrara Formation and Eagle Ford in the first quarter of 2018. The components of our DD&A expense were as follows:

	Six Months Ended June 30,	
	2018	2017
	(In thousands)	
DD&A of proved oil and gas properties	$134,676	$110,655
Depreciation of other property and equipment	1,194	1,258
Amortization of other assets	374	672
Accretion of asset retirement obligations	653	869
Total DD&A	$136,897	$113,454

General and administrative expense, net increased to $45.6 million for the six months ended June 30, 2018 from $33.3 million for the same period in 2017. 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 six months ended June 30, 2018 compared to a decrease in fair value for the six months ended June 30, 2017 as well as an increase in personnel costs and higher annual bonuses awarded in the first quarter of 2018 compared to the first quarter of 2017.

We recorded a loss on derivatives, net of $97.3 million and a gain on derivatives, net of $51.4 million for the six months ended June 30, 2018 and 2017, respectively. The components of our (gain) loss on derivatives, net were as follows:

	Six Months Ended June 30,	
	2018	2017
	(In thousands)	
Crude oil derivative positions:		
(Gain) loss due to (downward) upward shift in the futures curve of forecasted crude oil prices during the period on derivative positions outstanding at the beginning of the period	$89,802	($28,549)
Gain due to new derivative positions executed during the period	(6,854)	(19,614)
Loss due to deferred premium obligations incurred	—	7,501
NGL derivative positions:		
Loss due to upward shift in the futures curve of forecasted NGL prices during the period on derivative positions outstanding at the beginning of the period	4,799	—
Natural gas derivative positions:		
Gain due to downward shift in the futures curve of forecasted natural gas prices during the period on derivative positions outstanding at the beginning of the period	(2,641)	(10,719)
Gain due to new derivative positions executed during the period	(251)	—

Contingent consideration arrangements:		
Net loss primarily due to upward shift in the futures curve of forecasted crude oil prices during the period	12,455	—
(Gain) loss on derivatives, net	$97,310	($51,381)

Interest expense, net for the six months ended June 30, 2018 was $31.1 million as compared to $41.7 million for the same period in 2017. The decrease was due primarily to an increase in capitalized interest as a result of higher average balances of unevaluated leasehold and seismic costs for the six months ended June 30, 2018 as compared to the six months ended June 30, 2017, primarily as a result of the ExL Acquisition in the third quarter of 2017, as well as reduced interest expense as a result of the redemptions of the 7.50% Senior Notes in the fourth quarter of 2017 and first quarter of 2018. The decrease was partially offset by interest expense on $250.0 million aggregate principal amount of our 8.25% Senior Notes that were issued in the third quarter of 2017 and an increase in interest expense on our revolving credit facility as a result of increased borrowings for the six months ended June 30, 2018 as compared to the six months ended June 30, 2017. The components of our interest expense, net were as follows:

	Six Months Ended June 30,	
	2018	2017
	(In thousands)	
Interest expense on Senior Notes	$39,253	$42,910
Interest expense on revolving credit facility	8,649	3,687
Amortization of debt issuance costs, premiums, and discounts	2,040	2,265
Other interest expense	270	583
Capitalized interest	(19,096)	(7,768)
Interest expense, net	$31,116	$41,677

As a result of our redemption of $320.0 million aggregate principal amount of our 7.50% Senior Notes, we recorded a loss on extinguishment of debt of $8.7 million for the six months ended June 30, 2018, which included redemption premiums $6.0 million paid to redeem the notes and non-cash charges of $2.7 million attributable to the write-off of unamortized premium and debt issuance costs.

The effective income tax rate for the six months ended June 30, 2018 and 2017 was 1.3% and 0.0% respectively. The variance in the effective income tax rate results from current state and deferred income tax expense of $0.8 million recognized during the six months ended June 30, 2018. This was due to changes to our state apportionment for estimated state deferred tax liabilities as a result of the significant changes in our areas of operation that occurred in late 2017 and early 2018 as well as current period activity. The effective income tax rate was 0.0% during the six months ended June 30, 2017 as a result of a full valuation allowance against our net deferred tax assets driven by impairments of proved oil and gas properties recognized in the third quarter of 2015 and continuing through the third quarter of 2016.

For the six months ended June 30, 2018, we declared and paid $9.3 million of cash dividends on our Preferred Stock, which reduced net income to compute net income attributable to common shareholders.

As a result of our redemption of 50,000 shares of Preferred Stock at $1,000.00 per share, or $50.0 million, we recorded a loss on redemption of preferred stock of $7.1 million for the six months ended June 30, 2018, which reduced net income to compute net income attributable to common shareholders. The loss on redemption of preferred stock included $0.1 million of direct costs incurred as a result of the redemption and a non-cash charge of $7.0 million attributable to the difference between $50.0 million, which was the consideration transferred to the holders of the Preferred Stock excluding accrued and unpaid dividends, and $42.9 million, which was 20% of the carrying value of the Preferred Stock on the date of redemption.

Liquidity and Capital Resources

2018 Drilling, Completion, and Infrastructure Capital Expenditure Plan and Funding Strategy. Our 2018 drilling, completion, and infrastructure capital expenditure plan has been increased from $750.0 million to $800.0 million to $800.0 million to $825.0 million. We currently intend to finance the remainder of our 2018 drilling, completion, and infrastructure 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, but not limited to, the availability of drilling rigs and completion crews, the cost of completion services, acquisitions and divestitures of oil and gas properties, 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. The following is a summary of our capital expenditures for the three and six months ended June 30, 2018:

	Three Months Ended		Six Months Ended
	March 31, 2018	June 30, 2018	June 30, 2018
	(In thousands)		
Drilling, completion, and infrastructure			
Eagle Ford	$135,677	$101,249	$236,926
Delaware Basin	73,892	116,743	190,635
All other regions	284	—	284
Total drilling, completion, and infrastructure	209,853	217,992	427,845
Leasehold and seismic	5,520	6,129	11,649
Total Capital Expenditures (1)	$215,373	$224,121	$439,494

(1) Capital expenditures exclude acquisitions of oil and gas properties, capitalized general and administrative expense, interest expense and asset retirement costs.

Sources and Uses of Cash. Our primary use of cash is related to our drilling, completion and infrastructure capital expenditures and, to a lesser extent, our leasehold and seismic capital expenditures. For the six months ended June 30, 2018, 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 revolving credit facility. As of August 1, 2018, our revolving credit facility had a borrowing base of $1.0 billion, with an elected commitment amount of $900.0 million, with $513.4 million of borrowings outstanding. 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. See "Note 6. Long-Term Debt" for further details of the recent twelfth amendment.
- 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.
- Divestitures. We may consider divesting 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 divest such assets on terms that are acceptable to us. See "Note 3. Acquisitions and Divestitures of Oil and Gas Properties" for details of the divestitures that occurred in early 2018 and "Note 14. Subsequent Events" for details of the divestiture that occurred subsequent to June 30, 2018.
- 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 was $275.9 million and $179.2 million for the six months ended June 30, 2018 and 2017, respectively. The change was driven primarily by an increase in revenues as a result of higher production and commodity prices, partially offset by an increase in the net cash paid for derivative settlements, an increase in operating expenses and cash general and administrative expense and an increase in working capital requirements.

Net cash used in investing activities was $85.9 million for the six months ended June 30, 2018 and $366.4 million for the six months ended June 30, 2017. The change was due primarily to cash received from the divestitures in the Niobrara Formation and Eagle Ford in early 2018, as well as a decrease in cash payments for acquisitions of oil and gas properties, partially offset by an increase in capital expenditures in the Delaware Basin.

Net cash used in financing activities was $197.4 million for the six months ended June 30, 2018 and net cash provided by financing activities for the six months ended June 30, 2017 was $185.3 million. The increase in net cash used in financing activities was primarily due to payments for the redemptions of the 7.50% Senior Notes and the Preferred Stock as well as dividends paid on the Preferred Stock.

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, crude oil prices, and settlements of our crude oil derivatives. We currently believe that cash flows from operations and borrowings under our revolving credit facility will provide adequate financial flexibility and will be sufficient to fund our immediate cash flow requirements.

- Revolving credit facility. The borrowing base under our revolving credit facility is affected by assumptions of the administrative agent with respect to, among other things, crude oil and, to a lesser extent, natural gas prices. Our borrowing base may decrease if our administrative agent reduces the crude oil and natural gas prices from those used to determine our existing borrowing base. See "—Sources and Uses of Cash—Borrowings under revolving credit facility" and "—Financing Arrangements—Senior Secured Revolving Credit Facility" for further details of our revolving credit facility.
- Contingent consideration arrangements. As part of the ExL Acquisition, as well as in each of the divestitures of our assets in Niobrara, Marcellus, and Utica, we agreed to contingent consideration arrangements, where we will receive or be required to pay certain amounts if commodity prices are greater than specified thresholds. See "Note 10. Derivative Instruments" for further details of each of these contingent consideration arrangements. See also "Item 3. Quantitative and Qualitative Disclosures About Market Risk" for details of the sensitivities to commodity price of each contingent consideration arrangement.
- Hedging. We use commodity derivative instruments to reduce our exposure to commodity price volatility for a portion of our forecasted production and thereby achieve a more predictable level of cash flows to support our capital expenditure program and fixed costs.

The following table sets forth a summary of our outstanding crude oil derivative positions at weighted average contract prices as of August 7, 2018:

Period	Type of Contract	Index	Volumes (Bbls/d)	Fixed Price ($/Bbl)	Sub-Floor Price ($/Bbl)	Floor Price ($/Bbl)	Ceiling Price ($/Bbl)
2018							
Q3-Q4	Price Swaps	NYMEX WTI	6,000	$49.55	$—	$—	$—
Q3-Q4	Three-Way Collars	NYMEX WTI	24,000	—	39.38	49.06	60.14
Q3-Q4	Basis Swaps	LLS-Cushing WTI (1)	18,000	5.11	—	—	—
Q3-Q4	Basis Swaps	Midland WTI-Cushing WTI (2)	6,000	(0.10)	—	—	—
Q3-Q4	Net Sold Call Options	NYMEX WTI	3,388	—	—	—	71.33
2019							
Q1-Q4	Three-Way Collars	NYMEX WTI	15,000	—	41.00	49.72	62.48
Q1	Basis Swaps	Midland WTI-Cushing WTI (2)	5,500	(5.24)	—	—	—
Q2	Basis Swaps	Midland WTI-Cushing WTI (2)	6,000	(5.38)	—	—	—
Q3	Basis Swaps	Midland WTI-Cushing WTI (2)	7,000	(5.56)	—	—	—
Q4	Basis Swaps	Midland WTI-Cushing WTI (2)	11,000	(3.84)	—	—	—
Q1-Q4	Net Sold Call Options	NYMEX WTI	3,875	—	—	—	73.66
2020							
Q1	Basis Swaps	Midland WTI-Cushing WTI (2)	1,000	(1.90)	—	—	—
Q1-Q4	Net Sold Call Options	NYMEX WTI	4,575	—	—	—	75.98

(1) The index price paid under these basis swaps is LLS and the index price received is Cushing WTI plus the fixed price differential.

(2) The index price paid under these basis swaps is Midland WTI and the index price received is Cushing WTI less the fixed price differential.

The following table sets forth a summary of our outstanding NGL derivative positions at weighted average contract prices as of August 7, 2018:

Period	Type of Contract	Index	Volumes (Bbls/d)	Fixed Price ($/Bbl)
2018				
Q3-Q4	Price Swaps	Ethane - OPIS Mont Belvieu Non-TET	2,200	$12.01
Q3-Q4	Price Swaps	Propane - OPIS Mont Belvieu Non-TET	1,500	34.23
Q3-Q4	Price Swaps	Butane - OPIS Mont Belvieu Non-TET	200	38.85
Q3-Q4	Price Swaps	Isobutane - OPIS Mont Belvieu Non-TET	600	38.98
Q3-Q4	Price Swaps	Natural Gasoline - OPIS Mont Belvieu Non-TET	600	55.23

The following table sets forth a summary of our outstanding natural gas derivative positions at weighted average contract prices as of August 7, 2018:

Period	Type of Contract	Index	Volumes (MMBtu/d)	Fixed Price ($/MMBtu)	Ceiling Price ($/MMBtu)
2018					
Q3-Q4	Price Swaps	NYMEX HH	25,000	$3.01	$—
Q3-Q4	Sold Call Options	NYMEX HH	33,000	—	3.25
2019					
Q1-Q4	Sold Call Options	NYMEX HH	33,000	—	3.25
2020					
Q1-Q4	Sold Call Options	NYMEX HH	33,000	—	3.50

If cash flows from operations and borrowings under our revolving credit facility and the other sources of cash described under "—Sources and Uses of Cash" are insufficient to fund our remaining 2018 drilling, completion, and infrastructure capital expenditure plan, we may need to reduce our capital expenditure plan or seek other financing alternatives. We may not be able to obtain financing needed in the future on terms that would be acceptable to us, or at all. If we cannot obtain adequate financing, we may be required to limit or defer a portion of our remaining 2018 drilling, completion, and infrastructure capital expenditure plan, thereby potentially adversely affecting the recoverability and ultimate value of our oil and gas properties. 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 divestitures, 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 June 30, 2018 (in thousands):

	July - December 2018	2019	2020	2021	2022	2023 and Thereafter	Total
Long-term debt (1)	$—	$—	$130,000	$—	$485,000	$900,000	$1,515,000
Cash interest on senior notes (2)	35,500	71,000	71,000	61,250	61,250	82,188	382,188
Cash interest and commitment fees on revolving credit facility (3)	10,332	20,214	20,214	20,214	6,963	—	77,937
Capital leases	900	1,800	1,050	—	—	—	3,750
Operating leases	2,330	3,461	4,219	3,702	3,639	24,658	42,009
Drilling rig contracts (4)	20,200	18,677	1,196	—	—	—	40,073
Delivery commitments (5)	1,861	3,706	2,786	2,467	30	26	10,876
Produced water disposal commitments (6)	5,283	18,599	18,698	18,708	18,764	17,453	97,505
Asset retirement obligations and other (7)	1,833	2,972	657	376	239	15,745	21,822
Total Contractual Obligations (8)	$78,239	$140,429	$249,820	$106,717	$575,885	$1,040,070	$2,191,160

(1) Long-term debt consists of the principal amounts of the 7.50% Senior Notes due 2020, the 6.25% Senior Notes due 2023, the 8.25% Senior Notes due 2025, and borrowings outstanding under our revolving credit facility which matures in 2022 (subject to a springing maturity date of June 15, 2020 if the 7.50% Senior Notes have not been redeemed or refinanced on or prior to such time).

(2) Cash interest on senior notes includes cash payments for interest on the 7.50% Senior Notes due 2020, the 6.25% Senior Notes due 2023, and the 8.25% Senior Notes due 2025.

(3) Cash interest on our revolving credit facility was calculated using the weighted average interest rate of the outstanding borrowings under the revolving credit facility as of June 30, 2018 of 3.74%. Commitment fees on our revolving credit facility were calculated based on the unused portion of lender commitments as of June 30, 2018, at the applicable commitment fee rate of 0.50%.

(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) Delivery commitments represent contractual obligations we have entered into for certain gathering, processing and transportation service agreements which require minimum volumes of natural gas to be delivered. The amounts in the table above reflect the aggregate undiscounted deficiency fees assuming no delivery of any natural gas.

(6) Produced water disposal commitments represent contractual obligations we have entered into for certain service agreements which require minimum volumes of produced water to be delivered. The amounts in the table above reflect the aggregate undiscounted deficiency fees assuming no delivery of any produced water.

(7) Asset retirement obligations and other are based on estimates and assumptions that affect the reported amounts as of June 30, 2018. Certain of such estimates and assumptions are inherently unpredictable and will differ from actual results.

(8) In connection with the ExL Acquisition, we have agreed to a contingent payment of $50.0 million per year if crude oil prices exceed specified thresholds for each of the years of 2018 through 2021 with a cap of $125.0 million, which is not included in the table above.

Financing Arrangements

Senior Secured Revolving Credit Facility

We have a senior secured revolving credit facility with a syndicate of banks that, as of June 30, 2018, had a borrowing base of $1.0 billion, with an elected commitment amount of $900.0 million, and $485.0 million of borrowings outstanding at a weighted average interest rate of 3.74%. The credit agreement governing our senior secured revolving credit facility provides for interest-only payments until May 4, 2022, when the credit agreement matures (subject to a springing maturity date of June 15, 2020 if the 7.50% Senior Notes have not been redeemed or refinanced on or prior to such time) and any outstanding borrowings are due.

On January 31, 2018, as a result of the divestiture in the Eagle Ford Shale, the borrowing base under the senior secured revolving credit facility was reduced from $900.0 million to $830.0 million, however, the elected commitment amount remained unchanged at $800.0 million.

On May 4, 2018, we entered into the twelfth amendment to the credit agreement governing the revolving credit facility to, among other things, increase the borrowing base and elected commitment amount, reduce the margins applied to Eurodollar loans, and amend the covenant limiting payment of dividends and distributions on equity to increase our ability to make dividends and distributions on our equity interests. See “Note 6. Long-Term Debt” for further details.

See “Note 6. Long-Term Debt” for details of 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

During the first quarter of 2018, we redeemed $320.0 million of the outstanding aggregate principal amount of our 7.50% Senior Notes at a price equal to 101.875% of par. Upon the redemptions, we paid $336.9 million, which included redemption premiums of $6.0 million as well as accrued but unpaid interest of $10.9 million from the last interest payment date up to, but not including, the redemption date. As a result of the redemptions, we recorded a loss on extinguishment of debt of $8.7 million, which included the redemption premiums $6.0 million paid to redeem the notes and non-cash charges of $2.7 million attributable to the write-off of unamortized premium and debt issuance costs.

We have the right to redeem all or a portion of the remaining principal amount of the 7.50% Senior Notes at redemption prices of 101.875% until September 14, 2018 and 100% beginning September 15, 2018 and thereafter, in each case plus accrued and unpaid interest.

Redemption of Preferred Stock

In the first quarter of 2018, we redeemed 50,000 shares of Preferred Stock, representing 20% of the issued and outstanding Preferred Stock. Upon redemption, we paid $50.5 million, which consisted of $1,000.00 per share of Preferred Stock redeemed, plus accrued and unpaid dividends, with a portion of the proceeds from the divestitures of oil and gas properties. See “Note 3. Acquisitions and Divestitures of Oil and Gas Properties” for further details of the divestitures of oil and gas properties. As a result of the redemption, we recorded a loss on redemption of preferred stock of $7.1 million, which included $0.1 million of direct costs incurred as a result of the redemption and a non-cash charge of $7.0 million attributable to the difference between $50.0 million, which was the consideration transferred to the holders of the Preferred Stock excluding accrued and unpaid dividends, and $42.9 million, which was 20% of the carrying value of the Preferred Stock on the date of redemption.

Redemption of Other Long-Term Debt

During the second quarter of 2018, we redeemed the remaining $4.4 million outstanding principal amount of our 4.375% Convertible Senior Notes due 2028 at a price equal to 100% of par. Upon redemption, we paid $4.5 million, which included accrued and unpaid interest of $0.1 million from the last interest payment date up to, but not including, the redemption 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, contingent consideration arrangements, income taxes, commitments and contingencies and preferred stock. These policies and estimates are described in “Note 2. Summary of Significant Accounting Policies” of the Notes to Consolidated Financial Statements in our 2017 Annual Report. See “Note 8. Preferred Stock”, “Note 10. Derivative Instruments” and “Note 11. Fair Value Measurements” for details of the preferred stock and contingent consideration arrangements. We evaluate subsequent events through the date the financial statements are issued.

The table below presents various pricing scenarios to demonstrate the sensitivity of our June 30, 2018 cost center ceiling to changes in the average realized prices for sales of crude oil, NGLs, 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"). The sensitivity analysis is as of June 30, 2018 and, accordingly, does not consider drilling and completion activity, acquisitions or divestitures of oil and gas properties, production, changes in crude oil and natural gas prices, and changes in development and operating costs occurring subsequent to June 30, 2018 that may require revisions to estimates of proved reserves.

	12-Month Average Realized Prices		Excess 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)
June 30, 2018 Actual	$57.10	$2.71	$1,158	
Crude Oil and Natural Gas Price Sensitivity				
Crude Oil and Natural Gas +10%	$62.87	$3.01	$1,654	$496
Crude Oil and Natural Gas -10%	$51.31	$2.40	$595	($563)
Crude Oil Price Sensitivity				
Crude Oil +10%	$62.87	$2.71	$1,613	$455
Crude Oil -10%	$51.31	$2.71	$647	($511)
Natural Gas Price Sensitivity				
Natural Gas +10%	$57.10	$3.01	$1,198	$40
Natural Gas -10%	$57.10	$2.40	$1,117	($41)

Income Taxes

Primarily as a result of the impairments of proved oil and gas properties recognized beginning in the third quarter of 2015 and continuing through the third quarter of 2016, we had a cumulative historical three year pre-tax loss and a net deferred tax asset position at June 30, 2018. We have assessed the realizability of our deferred tax assets and, beginning in the third quarter of 2015 and continuing through the second quarter of 2018, have concluded that it was more likely than not our deferred tax assets will not be realized and a valuation allowance was required. Based on current estimates, we anticipate that during 2019, we will no longer be in a cumulative historical three year pre-tax loss, at which time, based on analysis of available evidence, we may conclude that it is more likely than not our deferred tax assets will be realized. This conclusion could result in a portion or all of the remaining valuation allowance to be recognized in earnings as an income tax benefit. See "Note 5. Income Taxes" for further details of our valuation allowance as of June 30, 2018.

As of June 30, 2018, we have estimated U.S. federal net operating loss carryforwards of $1.2 billion. Our ability to utilize these U.S. loss carryforwards to reduce future taxable income is subject to various limitations under the Internal Revenue Code of 1986, as amended (the "Code"). The utilization of such carryforwards may be limited upon the occurrence of certain ownership changes, including the purchase or sale of stock by 5% shareholders and the offering of stock by us during any three-year period resulting in an aggregate change of more than 50% in our beneficial ownership. In the event of an ownership change, Section 382 of the Code imposes an annual limitation on the amount of our taxable income that can be offset by these carryforwards. The limitation is generally equal to the product of (a) the fair market value of our equity multiplied by (b) a percentage approximately equivalent to the yield on long-term tax exempt bonds during the month in which an ownership change occurs. In addition, the limitation is increased if there are recognized built-in gains during any post-change year, but only to the extent of any net unrealized built-in gains inherent in the assets sold.

Due to the issuance of the Preferred Stock and the common stock offerings associated with the ExL Acquisition in 2017, our calculated ownership change percentage increased, however, as of June 30, 2018, we do not believe we have a Section 382 limitation on the ability to utilize our U.S. loss carryforwards. Future equity transactions involving us or 5% shareholders of us (including, potentially, relatively small transactions and transactions beyond our control) could cause further ownership changes and therefore a limitation on the annual utilization of the U.S. loss carryforwards.

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 pronouncements we recently adopted as well as the recently issued accounting pronouncements from the Financial Accounting Standards Board.

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, guidance and forecasts, including those regarding timing and levels of production;
- changes in working capital requirements, reserves, and acreage;
- commodity price risk management 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;
- possible future divestitures or other disposition transactions and the proceeds, results or benefits of any such transactions, including the timing thereof;
- the benefits, 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 divestitures;
- our ability to complete planned transactions on desirable terms; and
- the impact of governmental regulation, taxes, market changes and world events.

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,” “po “should,” “guidance” or 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 oil and gas prices, the need to replace reserves depleted by production, impairments of proved oil and gas properties, operating risks of oil and 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, waivers or amendments under our revolving credit facility in connection with acquisitions, other actions by lenders and holders of our capital stock, the potential impact of government regulations, including current and proposed

legislation and regulations related to hydraulic fracturing, 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 to realize the anticipated benefits of the any acquisition, market conditions and other factors affecting our ability to pay dividends on or redeem the Preferred Stock, 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 2017 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” in our 2017 Annual Report. Except as disclosed below, there have been no material changes from the disclosure made in our 2017 Annual Report regarding our exposure to certain market risks.

Commodity Price Risk

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, NGLs, and natural gas, which are affected by changes in market supply and demand and other factors. The markets for crude oil, NGLs, and natural gas have been volatile, especially over the last several years, and these markets will likely continue to be volatile in the future.

The following tables set forth our crude oil, NGL, and natural gas revenues for the three and six months ended June 30, 2018 as well as the impacts assuming a 10% fluctuation in our average realized crude oil, NGL, and natural gas prices, excluding the impact of derivative settlements:

	Three Months Ended June 30, 2018			
	Crude oil	NGLs	Natural gas	Total
	(In thousands)			
Revenues	$229,798	$21,269	$12,906	$263,973
Impact of a 10% fluctuation in average realized prices	$22,980	$2,127	$1,291	$26,398

	Six Months Ended June 30, 2018			
	Crude oil	NGLs	Natural gas	Total
	(In thousands)			
Revenues	$424,717	$38,171	$26,365	$489,253

Impact of a 10% fluctuation in average realized prices	$42,472	$3,817	$2,636	$48,925

We use commodity derivative instruments to reduce our exposure to commodity price volatility for a portion of our forecasted production and thereby achieve a more predictable level of cash flows to support our capital expenditure program and fixed costs. We do not enter into derivative instruments for speculative or trading purposes. As of June 30, 2018, our commodity derivative instruments consisted of price swaps, three-way collars, basis swaps, and purchased and sold call options. See “Note 10. Derivative

Instruments" for further details of our crude oil, NGL and natural gas derivative positions as of June 30, 2018 and "Note 14. Subsequent Events" for further details of our crude oil derivative positions entered into subsequent to June 30, 2018.

The fair value of our commodity derivative contracts are largely determined by estimates of the forward curves of the relevant price indices. The following table sets forth the fair values as of June 30, 2018, excluding deferred premium obligations, as well as the impact on the fair values assuming a 10% increase and decrease in the respective forward curves:

	Crude oil	NGLs	Natural gas	Total
	(In thousands)			
Fair value liability as of June 30, 2018	($106,405)	($4,934)	($1,780)	($113,119)
Fair value with a 10% increase in the forward curve	($183,728)	($7,980)	($5,144)	($196,852)
Increase in fair value liability	(77,323)	(3,046)	(3,364)	(83,733)
Fair value with a 10% decrease in the forward curve	($44,572)	($1,942)	$386	($46,128)
Decrease in fair value liability	61,833	2,992	2,166	66,991

We determined that the contingent consideration arrangements are not clearly and closely related to the purchase and sale agreement for the applicable acquisition or divestiture, and therefore bifurcated these embedded features and reflected the associated assets and liabilities at fair value in the consolidated financial statements. The fair values of the contingent consideration arrangements were determined by a third-party valuation specialist using Monte Carlo simulations including significant inputs such as future commodity prices, volatility factors for the future commodity prices and a risk adjusted discount rate. See "Note 10. Derivative Instruments" and "Note 11. Fair Value Measurements" for further details.

The following table sets forth the fair values of the contingent consideration arrangements as of June 30, 2018 as well as the impact on the fair values assuming a 10% increase and decrease in the respective future commodity prices:

	Contingent ExL Consideration	Contingent Niobrara Consideration	Contingent Marcellus Consideration	Contingent Utica Consideration
	(In thousands)			
Potential (payment) receipt per year	($50,000)	$5,000	$3,000	$5,000
Maximum potential (payment) receipt	($125,000)	$15,000	$7,500	$15,000
Fair value as of June 30, 2018	($102,055)	$9,970	$1,530	$10,545
10% increase in commodity price	(107,210)	10,960	2,580	11,465
10% decrease in commodity price	(94,155)	8,735	920	9,340

Interest Rate Risk

We are exposed to market risk due to the floating interest rate associated with any outstanding borrowings on our revolving credit facility. Changes in interest rates do not impact the amount of interest we pay on our fixed-rate 7.50% Senior Notes, 6.25% Senior Notes, and 8.25% Senior Notes, but can impact their fair values. As of June 30, 2018, we had approximately $1.5 billion of long-term debt outstanding, net of unamortized premiums and debt issuance costs. Of this amount, approximately $1.0 billion was fixed-rate debt, net of unamortized premiums and debt issuance costs, with a weighted average interest rate of 7.10%. See "Note 11. Fair Value Measurements" for further details on the fair value of our 7.50% Senior Notes, 6.25% Senior Notes, and 8.25% Senior Notes.

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 June 30, 2018 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 June 30, 2018 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

There were no material changes to the factors discussed in "Part I. Item 1A. Risk Factors" in our 2017 Annual Report.

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
†3.1	Amended and Restated Bylaws of Carrizo Oil & Gas, Inc., adopted May 23, 2018 (incorporated herein by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed on May 29, 2018 (File No. 000-29187-87)).
†10.1	Form of Indemnification Agreement for Directors and Executive Officers of the Company, adopted May 23, 2018 (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 29, 2018 (File No. 000-29187-87)).
*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

† Incorporated by reference as indicated.
* 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:	August 7, 2018	By:	/s/ David L. Pitts
			Vice President and Chief Financial Officer
			(Principal Financial Officer)
Date:	August 7, 2018	By:	/s/ Gregory F. Conaway
			Vice President and Chief Accounting Officer
			(Principal Accounting Officer)