CARRIZO OIL & GAS INC
Form 10-Q
November 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 September 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 November 2, 2018 was 91,625,532.

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

	September 30, 2018	December 31, 2017
Assets		
Current assets		
Cash and cash equivalents	$2,415	$9,540
Accounts receivable, net	128,780	107,441
Derivative assets	10,258	—
Other current assets	9,636	5,897
Total current assets	151,089	122,878
Property and equipment		
Oil and gas properties, full cost method		
Proved properties, net	2,124,767	1,965,347
Unproved properties, not being amortized	579,275	660,287
Other property and equipment, net	10,885	10,176
Total property and equipment, net	2,714,927	2,635,810
Deposit for pending acquisition of oil and gas properties	21,500	—
Other assets	23,482	19,616
Total Assets	$2,910,998	$2,778,304
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable	$147,670	$74,558
Revenues and royalties payable	52,975	52,154
Accrued capital expenditures	117,556	119,452
Accrued interest	23,748	28,362
Derivative liabilities	162,895	57,121
Other current liabilities	50,918	41,175
Total current liabilities	555,762	372,822
Long-term debt	1,327,689	1,629,209
Asset retirement obligations	17,071	23,497
Derivative liabilities	102,103	112,332
Deferred income taxes	4,699	3,635
Other liabilities	8,703	51,650
Total liabilities	2,016,027	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 September 30, 2018 and 250,000 issued and outstanding as of December 31, 2017	173,629	214,262
Shareholders' equity		
Common stock, $0.01 par value, 180,000,000 shares authorized; 91,619,733 issued and outstanding as of September 30, 2018 and 81,454,621 issued and outstanding as of December 31, 2017	916	815
Additional paid-in capital	2,132,253	1,926,056

Accumulated deficit	(1,411,827)	(1,555,974)
Total shareholders' equity	721,342	370,897
Total Liabilities and Shareholders' Equity	$2,910,998	$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 September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Revenues				
Crude oil	$254,525	$152,101	$679,242	$422,999
Natural gas liquids	33,798	12,467	71,969	27,678
Natural gas	15,052	16,711	41,417	48,440
Total revenues	303,375	181,279	792,628	499,117
Costs and Expenses				
Lease operating	41,022	34,874	115,446	100,767
Production taxes	14,516	7,741	37,578	21,092
Ad valorem taxes	2,588	1,736	8,201	5,776
Depreciation, depletion and amortization	80,108	67,564	217,005	181,018
General and administrative, net	12,811	16,029	58,368	49,328
(Gain) loss on derivatives, net	55,388	24,377	152,698	(27,004)
Interest expense, net	15,406	20,673	46,522	62,350
Loss on extinguishment of debt	—	—	8,676	—
Other (income) expense, net	(690)	462	2,305	1,640
Total costs and expenses	221,149	173,456	646,799	394,967
Income Before Income Taxes	82,226	7,823	145,829	104,150
Income tax expense	(880)	—	(1,682)	—
Net Income	$81,346	$7,823	$144,147	$104,150
Dividends on preferred stock	(4,457)	(2,249)	(13,794)	(2,249)
Accretion on preferred stock	(771)	—	(2,264)	—
Loss on redemption of preferred stock	—	—	(7,133)	—
Net Income Attributable to Common Shareholders	$76,118	$5,574	$120,956	$101,901
Net Income Attributable to Common Shareholders Per Common Share				
Basic	$0.88	$0.07	$1.45	$1.44
Diluted	$0.85	$0.07	$1.42	$1.43
Weighted Average Common Shares Outstanding				
Basic	86,727	81,053	83,461	70,728
Diluted	89,039	81,138	85,221	71,147

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	—	—	15,701	—	15,701
Issuance of common stock upon grants of restricted stock awards and vestings of restricted stock units and performance shares, net of forfeitures	665,112	6	(75)	—	(69)
Sale of common stock, net of offering costs	9,500,000	95	213,762	—	213,857
Dividends on preferred stock	—	—	(13,794)	—	(13,794)
Accretion on preferred stock	—	—	(2,264)	—	(2,264)
Loss on redemption of preferred stock	—	—	(7,133)	—	(7,133)
Net income	—	—	—	144,147	144,147
Balance as of September 30, 2018	91,619,733	$916	$2,132,253	($1,411,827)	$721,342

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

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

	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Cash Flows From Operating Activities		
Net income	$144,147	$104,150
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation, depletion and amortization	217,005	181,018
(Gain) loss on derivatives, net	152,698	(27,004)
Cash received (paid) for derivative settlements, net	(64,710)	7,714
Loss on extinguishment of debt	8,676	—
Stock-based compensation expense, net	13,786	8,462
Deferred income taxes	1,063	—
Non-cash interest expense, net	1,878	2,961
Other, net	4,100	4,249
Changes in components of working capital and other assets and liabilities-		
Accounts receivable	(12,763)	(25,885)
Accounts payable	10,863	14,748
Accrued liabilities	(9,336)	11,970
Other assets and liabilities, net	(2,115)	(1,786)
Net cash provided by operating activities	465,292	280,597
Cash Flows From Investing Activities		
Capital expenditures	(662,459)	(433,561)
Acquisitions of oil and gas properties	—	(692,006)
Deposit (paid for pending acquisition) received for pending divestiture of oil and gas properties	(21,500)	6,200
Proceeds from divestitures of oil and gas properties	377,693	18,212
Other, net	(2,687)	(3,804)
Net cash used in investing activities	(308,953)	(1,104,959)
Cash Flows From Financing Activities		
Issuance of senior notes	—	250,000
Redemptions of senior notes and other long-term debt	(330,435)	—
Redemption of preferred stock	(50,030)	—
Borrowings under credit agreement	2,415,208	1,311,875
Repayments of borrowings under credit agreement	(2,396,671)	(1,183,275)
Payments of debt issuance costs and credit facility amendment fees	(627)	(8,964)
Sale of common stock, net of offering costs	213,857	222,378
Sale of preferred stock, net of issuance costs	—	236,404
Payments of dividends on preferred stock	(13,794)	(2,249)
Other, net	(972)	(909)
Net cash provided by (used in) financing activities	(163,464)	825,260
Net Increase (Decrease) in Cash and Cash Equivalents	(7,125)	898
Cash and Cash Equivalents, Beginning of Period	9,540	4,194
Cash and Cash Equivalents, End of Period	$2,415	$5,092

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").

2. Summary of Significant Accounting Policies

Recently Adopted Accounting Standards

Revenue From Contracts with Customers. 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 nine months ended September 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 summarize the impact of adoption for the three and nine months ended September 30, 2018:

	Three Months Ended September 30, 2018			
	Under ASC 606	Under ASC 605	Increase	% Increase
	(In thousands)			
Revenues				
Crude oil	$254,525	$254,382	$143	0.1 %
Natural gas liquids	33,798	32,018	1,780	5.6 %
Natural gas	15,052	14,280	772	5.4 %
Total revenues	303,375	300,680	2,695	0.9 %
Costs and Expenses				
Lease operating	41,022	38,327	2,695	7.0 %
Income Before Income Taxes	$82,226	$82,226	$—	— %

	Nine Months Ended September 30, 2018			
	Under ASC 606	Under ASC 605	Increase	% Increase
	(In thousands)			
Revenues				
Crude oil	$679,242	$678,834	$408	0.1 %
Natural gas liquids	71,969	68,253	3,716	5.4 %
Natural gas	41,417	39,439	1,978	5.0 %
Total revenues	792,628	786,526	6,102	0.8 %
Costs and Expenses				
Lease operating	115,446	109,344	6,102	5.6 %
Income Before Income Taxes	$145,829	$145,829	$—	— %

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.

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 acquisitions 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 ("ROU") 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 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.

Revenue Recognition

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 its 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 September 30, 2018 and December 31, 2017, receivables from contracts with customers were $100.2 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 purchasers of the NGLs and residue gas are the customers. Revenue is recognized on a gross basis, with gathering, processing and transportation fees recognized as 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.

Net Income Attributable to Common Shareholders Per Common Share

The following table summarizes the calculation of net income attributable to common shareholders per common share:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands, except per share amounts)			
Net Income	$81,346	$7,823	$144,147	$104,150
Dividends on preferred stock	(4,457)	(2,249)	(13,794)	(2,249)
Accretion on preferred stock	(771)	—	(2,264)	—
Loss on redemption of preferred stock	—	—	(7,133)	—
Net Income Attributable to Common Shareholders	$76,118	$5,574	$120,956	$101,901
Basic weighted average common shares outstanding	86,727	81,053	83,461	70,728
Dilutive effect of restricted stock and performance shares	1,272	85	967	253
Dilutive effect of common stock warrants	1,040	—	793	166
Diluted weighted average common shares outstanding	89,039	81,138	85,221	71,147
Net Income Attributable to Common Shareholders Per Common Share				
Basic	$0.88	$0.07	$1.45	$1.44
Diluted	$0.85	$0.07	$1.42	$1.43

The computation of diluted net income attributable to common shareholders per common share excluded restricted stock, performance shares and common stock warrants that were anti-dilutive. The following table presents the weighted average anti-dilutive securities for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands)			
Anti-dilutive restricted stock and performance shares	—	730	5	120
Anti-dilutive common stock warrants	—	152	—	—
Total weighted average anti-dilutive securities	—	882	5	120

3. Acquisitions and Divestitures of Oil and Gas Properties

2018 Acquisitions and Divestitures

Devon Acquisition. On August 13, 2018, the Company entered into a purchase and sale agreement with Devon Energy Production Company, L.P. (“Devon”), a subsidiary of Devon Energy Corporation, to acquire oil and gas properties in the Delaware Basin in Reeves and Ward counties, Texas (the “Devon Properties”) for an agreed upon price of $215.0 million, with an effective date of April 1, 2018, subject to customary purchase price adjustments (the “Devon Acquisition”). The Company paid $21.5 million as a deposit on August 13, 2018 and $183.4 million upon initial closing on October 17, 2018, which included purchase price adjustments primarily related to the net cash flows from the effective date to the closing date, for an estimated aggregate purchase price of $204.9 million. The final purchase price remains subject to post-closing adjustments.

Under one of the Company’s existing joint operating agreements covering acreage in the vicinity of the Devon Properties, the other party to the joint operating agreement has a right to purchase a 20% interest in certain of the acres within the Devon Properties acquired by the Company at a price based on the Company’s cost to acquire the Devon Properties. This right is exercisable for a 30-day period after the Company delivers a specified notice following the closing of the Devon Acquisition and, if not exercised, will expire in the fourth quarter of 2018. To the extent that the other party exercises its right to make such purchase, the Company's interests in the Devon Properties will be reduced and the proceeds received will be recognized as a reduction of proved oil and gas properties.

The Company funded the Devon Acquisition with net proceeds from the common stock offering completed on August 17, 2018, which, pending the closing of the Devon Acquisition, were used to temporarily repay a portion of the borrowings outstanding under the revolving credit facility. See "Note 9. Shareholders' Equity and Stock-Based Compensation" for details regarding the common stock offering.

The Devon Acquisition will be accounted for as a business combination. The Company has not completed its initial allocation of the purchase price to the assets acquired and liabilities assumed based on their estimated acquisition date fair values. The Company will disclose the allocation of the purchase price as well as other related disclosures in its Annual Report on Form 10-K for the year ended December 31, 2018.

Delaware Basin Divestiture. On July 11, 2018, the Company closed on the divestiture of certain non-operated assets in the Delaware Basin for an agreed upon price of $30.0 million, with an effective date of May 1, 2018, subject to customary purchase price adjustments. The Company received $31.4 million upon closing on July 11, 2018 and paid $0.5 million upon post-closing on October 22, 2018, for aggregate net proceeds of $30.9 million.

Eagle Ford Divestiture. On December 11, 2017, the Company entered into a purchase and sale agreement with EP Energy E&P Company, L.P. to sell a portion of its assets in the Eagle Ford Shale for an agreed upon price of $245.0 million, with an effective date of October 1, 2017, subject to adjustment and customary terms and conditions. The Company received $24.5 million as a deposit on December 11, 2017, $211.7 million upon closing on January 31, 2018, $10.0 million for leases that were not conveyed at closing on February 16, 2018, and paid $0.5 million upon post-closing on July 19, 2018, for aggregate net proceeds of $245.7 million.

Niobrara Divestiture. On November 20, 2017, the Company entered into a purchase and sale agreement to sell substantially all of its assets in the Niobrara Formation for an agreed upon price of $140.0 million, with an effective date of October 1, 2017, subject to customary purchase price adjustments. The Company received $14.0 million as a deposit on November 20, 2017, $122.6 million upon closing on January 19, 2018, and paid $1.0 million upon post-closing on August 14, 2018, for aggregate net proceeds of $135.6 million. As part of this divestiture, the Company agreed to a contingent consideration arrangement (the “Contingent Niobrara Consideration”), which was determined to be an embedded derivative. As a result, the asset is recorded at fair value in the consolidated balance sheets with all gains and losses as a result of changes in the fair value between periods recognized in the consolidated statements of income in the period in which the changes occur. See “Note 10. Derivative Instruments” and “Note 11. Fair Value Measurements” for further details.

The aggregate net proceeds for each of the 2018 divestitures discussed above were recognized as a reduction of proved oil and gas properties with no gain or loss recognized.

2017 Acquisitions and Divestitures

ExL Acquisition. On June 28, 2017, the Company entered into a purchase and sale agreement with ExL Petroleum Management, LLC and ExL Petroleum Operating Inc. to acquire oil and gas properties located in the Delaware Basin in Reeves and Ward counties, Texas for an agreed upon price of $648.0 million, with an effective date of May 1, 2017, subject to customary purchase price adjustments (the “ExL Acquisition”). The Company paid $75.0 million as a deposit on June 28, 2017, $601.0 million upon closing on August 10, 2017, and $3.8 million upon post-closing on December 8, 2017 for aggregate cash consideration of $679.8 million, which included purchase price adjustments primarily related to the net cash flows from the effective date to the closing date. As part of the ExL Acquisition, the Company agreed to a contingent consideration arrangement (the “Contingent ExL Consideration”), which was determined to be an embedded derivative. As a result, the liability is recorded at fair value in the consolidated balance sheets with all gains and losses as a result of changes in the fair value between periods recognized in the consolidated statements of income in the period in which the changes occur. See “Note 10. Derivative Instruments” and “Note 11. Fair Value Measurements” for further details.

The ExL Acquisition was accounted for as a business combination, therefore, the purchase price was allocated to the assets acquired and the liabilities assumed based on their estimated acquisition date fair values based on then currently available information. A combination of a discounted cash flow model and market data was used by a third-party valuation specialist in determining the fair value of the oil and gas properties. Significant inputs into the calculation included forward oil and gas price curves, estimated volumes of oil and gas reserves, expectations for timing and amount of future development and operating costs, future plugging and abandonment costs and a risk adjusted discount rate. The fair value of the Contingent ExL Consideration was determined by a third-party valuation specialist using a Monte Carlo simulation. Significant inputs into the calculation included forward oil and gas price curves, volatility factors, and a risk adjusted discount rate. See “Note 11. Fair Value Measurements” for further details.

The following table presents the final allocation of the purchase price to the assets acquired and liabilities assumed as of the acquisition date.

	Purchase Price Allocation (In thousands)
Assets	
Other current assets	$106
Oil and gas properties	
Proved properties	294,754
Unproved properties	443,194
Total oil and gas properties	$737,948
Total assets acquired	$738,054
Liabilities	
Revenues and royalties payable	$5,785
Asset retirement obligations	153
Contingent ExL Consideration	52,300
Total liabilities assumed	$58,238
Net Assets Acquired	$679,816

The results of operations for the ExL Acquisition have been included in the Company's consolidated statements of income since the August 10, 2017 closing date, including total revenues and net income attributable to common shareholders for the three and nine months ended September 30, 2018 and 2017 as shown in the table below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands)			
Total revenues	$71,525	$14,016	$167,764	$14,016
Net Income Attributable to Common Shareholders	$57,466	$11,393	$134,317	$11,393

Pro Forma Operating Results (Unaudited). The following unaudited pro forma financial information presents a summary of the Company's consolidated results of operations for the three and nine months ended September 30, 2017, assuming the ExL Acquisition had been completed as of January 1, 2016, including adjustments to reflect the fair values assigned to the assets acquired and liabilities assumed. The pro forma financial information does not purport to represent what the actual results of operations would have been had the transactions been completed as of the date assumed, nor is this information necessarily indicative of future consolidated results of operations. The Company believes the assumptions used provide a reasonable basis for reflecting the significant pro forma effects directly attributable to the ExL Acquisition.

	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2017
	(In thousands, except per share amounts)	
Total revenues	$189,499	$534,607
Net Income Attributable to Common Shareholders	$14,654	$115,053

Net Income Attributable to Common Shareholders Per Common Share		
Basic	$0.18	$1.63
Diluted	$0.18	$1.62

Marcellus Divestiture. On October 5, 2017, the Company entered into a purchase and sale agreement with BKV Chelsea, LLC, a subsidiary of Kalnin Ventures LLC, to sell substantially all of its assets in the Marcellus Shale for an agreed upon price of $84.0 million. The Company received $6.3 million into escrow as a deposit on October 5, 2017 and $67.6 million upon closing on November 21, 2017, for aggregate net proceeds of $73.9 million. As part of this divestiture, the Company agreed to a contingent consideration arrangement (the “Contingent Marcellus Consideration”), which was determined to be an embedded derivative. As a result, the asset is recorded at fair value in the consolidated balance sheets with all gains and losses as a result of changes in the fair value between periods recognized in the consolidated statements of income in the period in which the changes occur. See “Note 10. Derivative Instruments” and “Note 11. Fair Value Measurements” for further details.

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”). 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 nine months ended September 30, 2018. The Avista Marcellus joint venture agreements terminated during the third quarter of 2018 in connection with the sale of the remaining immaterial assets.

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.

Utica Divestiture. On August 31, 2017, the Company entered into a purchase and sale agreement to sell substantially all of its assets in the Utica Shale for an agreed upon price of $62.0 million. The Company received $6.2 million as a deposit on August 31, 2017, $54.4 million upon closing on November 15, 2017, and $2.5 million upon post-closing on December 28, 2017, for aggregate net proceeds of $63.1 million. As part of this divestiture, the Company agreed to a contingent consideration arrangement (the “Contingent Utica Consideration”), which was determined to be an embedded derivative. As a result, the asset is recorded at fair value in the consolidated balance sheets with all gains and losses as a result of changes in the fair value between periods recognized in the consolidated statements of income in the period in which the changes occur. See “Note 10. Derivative Instruments” and “Note 11. Fair Value Measurements” for further details.

Delaware Basin Divestiture. During the first quarter of 2017, the Company sold a small undeveloped acreage position in the Delaware Basin for aggregate net proceeds of $15.3 million.

The aggregate net proceeds for each of the 2017 divestitures discussed above were recognized as a reduction of proved oil and gas properties with no gain or loss recognized.

2016 Acquisitions and Divestitures

Sanchez Acquisition. On October 24, 2016, the Company entered into a purchase and sale agreement with Sanchez Energy Corporation and SN Cotulla Assets, LLC, a subsidiary of Sanchez Energy Corporation to acquire oil and gas properties located in the Eagle Ford Shale for an agreed upon price of $181.0 million, with an effective date of June 1, 2016, subject to customary purchase price adjustments. The Company paid $10.0 million as a deposit on October 24, 2016, $143.5 million upon initial closing on December 14, 2016, and $7.0 million and $9.8 million on January 9, 2017 and April 13, 2017, respectively, for leases that were not conveyed to the Company at the time of initial closing, for aggregate cash consideration of $170.3 million, which included purchase price adjustments primarily related to the net cash flows from the effect date to the closing date.

The Company did not have any material divestitures in 2016.

4. Property and Equipment, Net

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

	September 30, 2018	December 31, 2017
	(In thousands)	
Oil and gas properties, full cost method		
Proved properties	$5,988,301	$5,615,153
Accumulated depreciation, depletion and amortization and impairments	(3,863,534)	(3,649,806)
Proved properties, net	2,124,767	1,965,347
Unproved properties, not being amortized		
Unevaluated leasehold and seismic costs	516,537	612,589
Capitalized interest	62,738	47,698
Total unproved properties, not being amortized	579,275	660,287
Other property and equipment	28,134	25,625

Accumulated depreciation	(17,249)	(15,449)
Other property and equipment, net	10,885	10,176
Total property and equipment, net	$2,714,927	$2,635,810

Average depreciation, depletion and amortization ("DD&A") per Boe of proved properties was $13.29 and $13.04 for the three months ended September 30, 2018 and 2017, respectively, and $13.57 and $12.73 for the nine months ended September 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 $2.9 million and $3.3 million for the three months ended September 30, 2018 and 2017, respectively, and $15.6 million and $10.6 million for the nine months ended September 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 $8.5 million for the three months ended September 30, 2018 and 2017 and $27.6 million and $16.2 million for the nine months ended September 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, excluding significant unusual or infrequent items, the tax effects of statutory rate changes, certain changes in the assessment of the realizability of deferred tax assets, and excess tax benefits or deficiencies related to the vesting of stock-based compensation awards, which are recognized as discrete items in the interim period in which they occur.

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 nine months ended September 30, 2018 and 35% for the three and nine months ended September 30, 2017, to income before income taxes as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands)			
Income before income taxes	$82,226	$7,823	$145,829	$104,150
Income tax expense at the U.S. federal statutory rate	(17,267)	(2,738)	(30,624)	(36,452)
State income tax expense, net of U.S. federal income tax benefit	(881)	(247)	(1,687)	(1,974)
Tax deficiencies related to stock-based compensation	(10)	(273)	(2,552)	(3,029)
Decrease in valuation allowance due to current period activity	17,400	3,253	33,849	41,570
Other	(122)	5	(668)	(115)
Income tax expense	($880)	$—	($1,682)	$—

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. In August 2018, the Internal Revenue Service issued Notice 2018-68, Guidance on the Application of Section 162(m) ("Notice 2018-68"), which provides initial guidance on the application of Section 162(m), as amended. Notice 2018-68 provided guidance regarding the group of covered employees subject to Section 162(m)'s deduction limit under the Act and the scope of transition relief available under the Act. The Company is currently evaluating the impact of Notice 2018-68, but as of September 30, 2018, 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 and additional guidance provided within the one year measurement period.

Deferred Tax Asset Valuation Allowance

The deferred tax asset valuation allowance was $299.1 million and $333.0 million as of September 30, 2018 and December 31, 2017, respectively. Decreases in the valuation allowance for the three months and nine months ended September 30, 2018 and 2017 were based primarily on the pre-tax income recorded during those periods. Throughout 2017 and the first nine months of 2018, the Company maintained a full valuation allowance against its deferred tax assets based on its conclusion, considering all available evidence (both positive and negative), that it was more likely than not that the deferred tax assets would not be realized. The Company intends to maintain a full valuation allowance against its deferred tax assets until there is sufficient evidence to support the reversal of such valuation allowance.

6. Long-Term Debt

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

	September 30, 2018	December 31, 2017
	(In thousands)	
Senior Secured Revolving Credit Facility due 2022	$309,837	$291,300
7.50% Senior Notes due 2020	130,000	450,000
Unamortized premium for 7.50% Senior Notes	124	579
Unamortized debt issuance costs for 7.50% Senior Notes	(980)	(4,492)
6.25% Senior Notes due 2023	650,000	650,000
Unamortized debt issuance costs for 6.25% Senior Notes	(7,219)	(8,208)
8.25% Senior Notes due 2025	250,000	250,000
Unamortized debt issuance costs for 8.25% Senior Notes	(4,073)	(4,395)
Other long-term debt due 2028	—	4,425
Long-term debt	$1,327,689	$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 September 30, 2018, had a borrowing base of $1.0 billion, with an elected commitment amount of $900.0 million, and borrowings outstanding of $309.8 million at a weighted average interest rate of 3.87%. 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. See “Note 14. Subsequent Events” for details regarding the maturity date of the credit agreement upon redemption of the remaining $130.0 million outstanding aggregate principal amount of its 7.50% Senior Notes. 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 Eagle Ford divestiture, 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. See “Note 3. Acquisitions and Divestitures of Oil and Gas Properties” for details of the Eagle Ford divestiture.

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 margins for Eurodollar loans from 2.00%-3.00% to 1.50%-2.50% and base rate loans from 1.00%-2.00% to 0.50%-1.50%, each 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.

On October 29, 2018, the Company entered into the thirteenth amendment to its credit agreement governing the revolving credit facility. See “Note 14. Subsequent Events” for further details of the thirteenth amendment.

The obligations of the Company under the credit agreement are guaranteed by the Company’s material 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 September 30, 2018, the ratio of Total Debt to EBITDA was 1.95 to 1.00 and the Current Ratio was 1.84 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 and accrued and unpaid interest of $10.9 million. The redemptions were funded primarily from the net proceeds received from the divestitures in Eagle Ford and Niobrara in the first quarter of 2018. See "Note 3. Acquisitions and Divestitures of Oil and Gas Properties" for further details of these divestitures. 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 and the write-off of associated unamortized premiums and debt issuance costs of $2.7 million.

See "Note 14. Subsequent Events" for details of the notice of conditional redemption for the remaining $130.0 million outstanding aggregate principal amount of its 7.50% Senior Notes.

Redemption of Other Long-Term Debt

On May 3, 2018, the Company redeemed the remaining $4.4 million outstanding aggregate principal amount of its 4.375% Convertible Senior Notes due 2028 at a price equal to 100% of par. Upon the redemption, the Company paid $4.5 million, which included accrued and unpaid interest of $0.1 million.

Issuance of 8.25% Senior Notes

On July 14, 2017, the Company closed a public offering of $250.0 million aggregate principal amount of 8.25% Senior Notes due 2025 (the “8.25% Senior Notes”). The Company used the proceeds of $245.4 million, net of underwriting discounts and commissions and offering costs, to fund a portion of the ExL Acquisition and for general corporate purposes. See “Note 3. Acquisitions and Divestitures of Oil and Gas Properties” for further details of the ExL Acquisition.

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, tax changes, 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 Common Stock 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 closing of the private placement occurred on August 10, 2017, contemporaneously with the closing of the ExL Acquisition. The Company used the proceeds of approximately $236.4 million, net of issuance costs, to fund a portion of the ExL Acquisition and for general corporate purposes.

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	
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 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 initial liquidation preference using the effective interest method.

The table below presents the reconciliation of changes in the carrying amount of Preferred Stock for the nine months ended September 30, 2018:

	Carrying Amount of Preferred Stock
	(In thousands)
December 31, 2017	$214,262
Redemption of Preferred Stock	(42,897)
Accretion on Preferred Stock	2,264
September 30, 2018	$173,629

Loss on Redemption of Preferred Stock

During the first quarter of 2018, the Company redeemed 50,000 shares of Preferred Stock, representing 20% of the issued and outstanding Preferred Stock, for $50.5 million, consisting of the $50.0 million redemption price and $0.5 million accrued and unpaid dividends. The Company recognized a $7.1 million loss on the redemption due to the excess of the $50.0 million redemption price over the $42.9 million redemption date carrying value of the Preferred Stock.

9. Shareholders' Equity and Stock-Based Compensation

Sales of Common Stock

On August 17, 2018, the Company completed a public offering of 9.5 million shares of its common stock at a price per share of $22.55. The Company used the proceeds of $213.9 million, net of offering costs, to fund the Devon Acquisition and for general corporate purposes. Pending the closing of the Devon Acquisition, the Company used the net proceeds to temporarily repay a portion of the borrowings outstanding under the revolving credit facility. See "Note 3. Acquisitions and Divestitures of Oil and Gas Properties" for further details of the Devon Acquisition.

On July 3, 2017, the Company completed a public offering of 15.6 million shares of its common stock at a price per share of $14.28. The Company used the proceeds of $222.4 million, net of offering costs, to fund a portion of the ExL Acquisition and for general corporate purposes. See "Note 3. Acquisitions and Divestitures of Oil and Gas Properties" for further details of the ExL Acquisition.

Stock-Based Compensation

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 may grant restricted stock awards and units, stock appreciation rights that can be settled in cash or shares of common stock, performance shares, and stock options to employees, independent contractors, and non-employee directors. Under the Cash SAR Plan, the Company may grant stock appreciation rights that may only be settled in cash 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 granted (the "Maximum Share Limit"). Each restricted stock award and unit and 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 granted under the 2017 Incentive Plan counts as 1.00 share against the Maximum Share Limit. Stock appreciation rights to be settled in cash granted under the 2017 Incentive Plan and stock appreciation rights granted under the Cash SAR Plan (collectively, "Cash SARs") do not count against the Maximum Share Limit. Restricted stock awards and units, performance shares, and Cash SARs activity during the nine months ended September 30, 2018 is presented below. The Company has not granted stock appreciation rights to be settled in shares of common stock and has no outstanding stock options. As of September 30, 2018, there were 296,654 shares of common stock available for grant under the 2017 Incentive Plan.

Restricted Stock Awards and Units

The table below summarizes restricted stock award and unit activity for the nine months ended September 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	1,391,422	$15.07
Vested	(615,762)	$31.44
Forfeited	(23,880)	$18.51
Unvested restricted stock awards and units, end of period	2,234,435	$19.14

During the nine months ended September 30, 2018, the Company granted 1,391,422 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 vest ratably over an approximate three-year period. During the third quarter of 2018, the Company granted 33,536 restricted stock units to its non-employee directors, which had a grant date fair value of $0.9 million and will vest on the earlier of the date of the 2019 Annual Meeting of Shareholders and June 30, 2019.

As of September 30, 2018, unrecognized compensation costs related to unvested restricted stock awards and units were $26.8 million and will be recognized over a weighted average period of 2.0 years.

Cash SARs

The table below summarizes the Cash SAR activity for the nine months ended September 30, 2018:

	Cash 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	4.6	$6.5	
Vested, end of period	543,018	$27.18			
Vested and exercisable, end of period	—	$27.18	2.8	$—	

During the nine months ended September 30, 2018, the Company granted 616,686 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 Cash SARs vest ratably over an approximate three-year period and expire approximately seven years from the grant date.

The grant date fair value of the 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 Cash SARs granted during the nine months ended September 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	—	%

The liability for Cash SARs as of September 30, 2018 was $7.9 million, all of which was classified as "Other current liabilities," in the consolidated balance sheets. As of December 31, 2017, the liability for Cash SARs was $4.4 million, all of which was classified as "Other liabilities" in the consolidated balance sheets. Unrecognized compensation costs related to unvested Cash SARs were $8.7 million as of September 30, 2018, and will be recognized over a weighted average period of 2.4 years.

Performance Shares

The table below summarizes performance share activity for the nine months ended September 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 nine months ended September 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 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.

During the first quarter of 2018, 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 the vesting of 49,458 shares and 7,059 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 nine months ended September 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	—	%

As of September 30, 2018, unrecognized compensation costs related to unvested performance shares were $2.5 million and will be recognized over a weighted average period of 2.0 years.

Stock-Based Compensation Expense, Net

Stock-based compensation expense associated with restricted stock awards and units, Cash SARs and performance shares, net of amounts capitalized, is included in “General and administrative, net” in the consolidated statements of income.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands)			
Restricted stock awards and units	$4,487	$5,311	$14,291	$16,184
Cash SARs	(868)	429	3,505	(7,040)
Performance shares	411	581	1,374	1,861
	4,030	6,321	19,170	11,005
Less: amounts capitalized to oil and gas properties	(968)	(1,455)	(5,384)	(2,543)
Total stock-based compensation expense, net	$3,062	$4,866	$13,786	$8,462

10. Derivative Instruments

Commodity Derivative Instruments

The Company uses commodity derivative instruments to mitigate the effects of commodity price volatility for a portion of its forecasted sales of production and achieve a more predictable level of cash flow. Since the Company derives a significant portion of its revenues from sales of crude oil, crude oil price volatility represents the Company's most significant commodity price risk. While the use of commodity derivative instruments limits or partially reduces the downside risk of adverse commodity price movements, such use also limits the upside from favorable commodity price movements. The Company does not enter into commodity derivative instruments for speculative purposes.

The Company's commodity derivative instruments, which settle on a monthly basis over the term of the contract for contracted volumes, consist of over-the-counter price swaps, three-way collars, sold call options and basis swaps, each of which is described below.

Price swaps are settled based on differences between a fixed price and the settlement price of a referenced index. If the settlement price of the referenced index is below the fixed price, the Company receives the difference from the counterparty. If the referenced settlement price is above the fixed price, the Company pays the difference to the counterparty.

Three-way collars consist of a purchased put option (floor price), a sold call option (ceiling price) and a sold put option (sub-floor price) and are settled based on differences between the floor or ceiling prices and the settlement price of a referenced index or the difference between the floor price and sub-floor price. If the settlement price of the referenced index is below the sub-floor price, the Company receives the difference between the floor price and sub-floor price from the counterparty. If the settlement price of the referenced index is between the floor price and sub-floor price, the Company receives the difference between the floor price and the settlement price of the referenced index from the counterparty. If the settlement price of the referenced index is between the floor price and ceiling price, no payments are due to or from either party. If the settlement price of the referenced index is above the ceiling price, the Company pays the difference to the counterparty.

Sold call options are settled based on differences between the ceiling price and the settlement price of a referenced index. If the settlement price of the referenced index is above the ceiling price, the Company pays the difference to the counterparty. If the settlement price of the referenced index is below the ceiling price, no payments are due to or from either party. Premiums from the sale of call options have been used to enhance the fixed price of certain contemporaneously executed price swaps. Purchased call options executed contemporaneously with sold call options in order to increase the ceiling price of existing sold call options have been presented on a net basis in the table below.

Basis swaps are settled based on differences between a fixed price differential and the differential between the settlement prices of two referenced indexes. If the differential between the settlement prices of the two referenced indexes is greater than the fixed price differential, the Company receives the difference from the counterparty. If the differential between the settlement prices of the two referenced indexes is less than the fixed price differential, the Company pays the difference to the counterparty.

The referenced index of the Company's price swaps, three-way collars and sold call options is U.S. New York Mercantile Exchange ("NYMEX") West Texas Intermediate ("WTI") for crude oil, NYMEX Henry Hub for natural gas and OPIS Mont Belvieu Non-TET (“OPIS”) for NGL products, as applicable. The prices received by the Company for the sale of its production generally vary from these referenced index prices due to adjustments for delivery location (basis) and other factors. The referenced indexes of the Company’s basis swaps, which are used to mitigate location price risk for a portion of its production, are Argus WTI Cushing (“WTI Cushing”) and the applicable index price of the Company’s crude oil sales contracts is Argus WTI Midland (“WTI Midland”) for its Delaware Basin crude oil production and Argus Light Louisiana Sweet (“LLS”) for its Eagle Ford crude oil production.

The Company has incurred premiums on certain of its commodity derivative instruments in order to obtain a higher fixed price, higher floor price and/or higher ceiling price. Payment of these premiums are deferred until the applicable contracts settle on a monthly basis over 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.
As of September 30, 2018, the Company had the following outstanding commodity derivative instruments at weighted average contract volumes and prices:

Commodity	Period	Type of Contract	Index	Volumes (Bbls per day)	Fixed Price ($ per Bbl)	Sub-Floor Price ($ per Bbl)	Floor Price ($ per Bbl)	Ceiling Price ($ per Bbl)	Fixed Price Differential ($ per Bbl)
Crude oil	4Q18	Price Swaps	NYMEX WTI	6,000	$49.55	—	—	—	—
Crude oil	4Q18	Three-Way Collars	NYMEX WTI	24,000	—	$39.38	$49.06	$60.14	—
Crude oil	4Q18	Basis Swaps	LLS-WTI Cushing	18,000	—	—	—	—	$5.11
Crude oil	4Q18	Basis Swaps	WTI Midland-WTI Cushing	6,000	—	—	—	—	($0.10)
Crude oil	4Q18	Sold Call Options	NYMEX WTI	3,388	—	—	—	$71.33	—
Crude oil	2019	Three-Way Collars	NYMEX WTI	21,000	—	$40.71	$49.80	$67.80	—
Crude oil	2019	Basis Swaps	LLS-WTI Cushing	3,000	—	—	—	—	$4.57
Crude oil	2019	Basis Swaps	WTI Midland-WTI Cushing	7,389	—	—	—	—	($4.82)
Crude oil	2019	Sold Call Options	NYMEX WTI	3,875	—	—	—	$73.66	—
Crude oil	2020	Basis Swaps	WTI Midland-WTI Cushing	13,000	—	—	—	—	($1.27)
Crude oil	2020	Sold Call Options	NYMEX WTI	4,575	—	—	—	$75.98	—
Crude oil	2021	Basis Swaps	WTI Midland-WTI Cushing	6,000	—	—	—	—	$0.03

Commodity	Period	Type of Contract	Index	Volumes (Bbls per day)	Fixed Price ($ per Bbl)	Sub-Floor Price ($ per Bbl)	Floor Price ($ per Bbl)	Ceiling Price ($ per Bbl)	Fixed Price Differential ($ per Bbl)
NGLs	4Q18	Price Swaps	OPIS-Ethane	2,200	$12.01	—	—	—	—
NGLs	4Q18	Price Swaps	OPIS-Propane	1,500	$34.23	—	—	—	—
NGLs	4Q18	Price Swaps	OPIS-Butane	200	$38.85	—	—	—	—
NGLs	4Q18	Price Swaps	OPIS-Isobutane	600	$38.98	—	—	—	—
NGLs	4Q18	Price Swaps	OPIS-Natural Gasoline	600	$55.23	—	—	—	—

Commodity	Period	Type of Contract	Index	Volumes (MMBtu per day)	Fixed Price ($ per MMBtu)	Sub-Floor Price ($ per MMBtu)	Floor Price ($ per MMBtu)	Ceiling Price ($ per MMBtu)	Fixed Price Differential ($ per MMBtu)

Natural gas	4Q18	Price Swaps	NYMEX Henry Hub	25,000	$3.01	—	—	—	—
Natural gas	4Q18	Sold Call Options	NYMEX Henry Hub	33,000	—	—	—	$3.25	—
Natural gas	2019	Sold Call Options	NYMEX Henry Hub	33,000	—	—	—	$3.25	—
Natural gas	2020	Sold Call Options	NYMEX Henry Hub	33,000	—	—	—	$3.50	—

The Company typically has numerous commodity derivative instruments outstanding with a counterparty that were executed at various dates, for various contract types, commodities and time periods often resulting in both commodity derivative asset and liability positions with that counterparty. The Company nets its commodity derivative instrument fair values executed with the same counterparty, along with any deferred premium obligations, to a single asset or liability pursuant to International Swap Dealers Association Master Agreements (“ISDAs”), 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 to be novated to a Lender Counterparty if the Company's net liability position exceeds the Company's unsecured credit limit with the Non-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. The Company executes its derivative instruments with seventeen counterparties to minimize its credit exposure to any individual counterparty.

Contingent Consideration Arrangements

The purchase and sale agreements of the ExL Acquisition and divestitures of the Company's assets in the Niobrara, Marcellus and Utica, included contingent consideration arrangements that entitle the Company to receive or require the Company to pay specified amounts if commodity prices exceed specified thresholds, which are summarized in the table below. See "Note 3. Acquisitions and Divestitures of Oil and Gas Properties" for details of these acquisitions and divestitures.

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 specified threshold for each year has been met for the Contingent ExL Consideration, Contingent Niobrara Consideration and Contingent Utica Consideration is the average daily closing spot price per barrel of WTI crude oil as measured by the U.S. Energy Information Administration. The price used to determine whether the specified threshold for each year has been met for the Marcellus Contingent Consideration is the average monthly settlement price per 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.

Derivative Assets and Liabilities

Commodity derivative instruments and contingent consideration arrangements are recorded in the consolidated balance sheets as either an asset or liability measured at fair value. As of September 30, 2018, the Company had $9.8 million classified as current derivative assets and $49.2 million classified as current derivative liabilities, representing the first cash receipts and payments, expected to occur in January 2019, from settlement of contingent consideration assets and liabilities. 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 asset or liability fair values pursuant to the netting provisions of the ISDAs described above.

The derivative instrument asset and liability fair values recorded in the consolidated balance sheets as of September 30, 2018 and December 31, 2017 are summarized below:

	September 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	$19,408	($18,985)	$423
Contingent Niobrara Consideration	4,920	—	4,920
Contingent Utica Consideration	4,915	—	4,915
Derivative assets	$29,243	($18,985)	$10,258
Commodity derivative instruments	12,028	(12,028)	—
Contingent Niobrara Consideration	6,755	—	6,755
Contingent Marcellus Consideration	1,315	—	1,315
Contingent Utica Consideration	7,300	—	7,300
Other assets	$27,398	($12,028)	$15,370
Commodity derivative instruments	($123,611)	$9,876	($113,735)
Deferred premium obligations	(9,109)	9,109	—
Contingent ExL Consideration	(49,160)	—	(49,160)
Derivative liabilities-current	($181,880)	$18,985	($162,895)
Commodity derivative instruments	(45,532)	6,314	(39,218)
Deferred premium obligations	(5,714)	5,714	—
Contingent ExL Consideration	(62,885)	—	(62,885)
Derivative liabilities-non current	($114,131)	$12,028	($102,103)

	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 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. Deferred premium obligations associated with the Company's commodity derivative instruments are recognized as “(Gain) loss on derivatives, net” in the consolidated statements of income in the period in which the deferred premium obligations are incurred. The net (gain) loss on derivatives in the consolidated statements of income for the three and nine months ended September 30, 2018 and 2017 are summarized below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands)			
(Gain) Loss on Derivatives, Net				
Crude oil	$43,664	$8,409	$126,612	($39,754)
NGL	5,086	—	9,885	—
Natural gas	(192)	(2,183)	(3,084)	(12,902)
Deferred premium obligations	—	10,151	—	17,652
Contingent ExL Consideration	9,990	8,000	26,420	8,000
Contingent Niobrara Consideration	(1,705)	—	(3,795)	—
Contingent Marcellus Consideration	215	—	890	—
Contingent Utica Consideration	(1,670)	—	(4,230)	—
(Gain) Loss on Derivatives, Net	$55,388	$24,377	$152,698	($27,004)

Cash Received (Paid) for Derivative Settlements, Net

Cash flows are impacted to the extent that settlements of commodity derivative instruments, including deferred premium obligations, and contingent consideration arrangements result in cash received or paid during the period and are recognized as “Cash received (paid) for derivative settlements, net” in the consolidated statements of cash flows. Cash received or paid in settlement of contingent consideration assets or liabilities, respectively, 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 nine months ended September 30, 2018 and 2017, there were no settlements of contingent consideration arrangements. The net cash received (paid) for derivative settlements in the consolidated statements of cash flows for the three and nine months ended September 30, 2018 and 2017 are summarized below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Cash Flows from Operating Activities	(In thousands)			
Cash Received (Paid) for Derivative Settlements, Net				
Crude oil	($21,261)	$6,500	($54,594)	$9,941
NGL	(2,641)	—	(3,829)	—
Natural gas	245	522	785	(731)
Deferred premium obligations	(2,605)	(566)	(7,072)	(1,496)
Cash Received (Paid) for Derivative Settlements, Net	($26,262)	$6,456	($64,710)	$7,714

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 derivative instrument assets and liabilities measured at fair value on a recurring basis as of September 30, 2018 and December 31, 2017:

	September 30, 2018		
	Level 1	Level 2	Level 3
	(In thousands)		
Assets			
Commodity derivative instruments	$—	$423	$—
Contingent Niobrara Consideration	—	—	11,675
Contingent Marcellus Consideration	—	—	1,315
Contingent Utica Consideration	—	—	12,215
Liabilities			
Commodity derivative instruments	$—	($152,953)	$—
Contingent ExL Consideration	—	—	(112,045)

	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 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 had no transfers into Level 1 and no transfers into or out of Level 2 for the nine months ended September 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, volatility factors, and risk adjusted discount rates, which include adjustments for the counterparties' credit quality for contingent consideration assets and the Company's credit quality for the contingent consideration liabilities. 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 nine months ended September 30, 2018 and 2017:

	Contingent Consideration Arrangements	
	Assets	Liability
	(In thousands)	
December 31, 2017	$10,190	($85,625)
Recognition of divestiture date fair value	7,880	—
Gain (loss) on changes in fair value, net[1]	7,135	(26,420)
Transfers into (out of) Level 3	—	—
September 30, 2018	$25,205	($112,045)

	Contingent Consideration Arrangements	
	Assets	Liability
	(In thousands)	
December 31, 2016	$—	$—
Recognition of acquisition date fair value	—	(52,300)
Loss on change in fair value[1]	—	(8,000)
Transfers into (out of) Level 3	—	—
September 30, 2017	$—	($60,300)

(1) Recognized as "(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 within the valuation hierarchy. 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.

The fair value measurements of assets acquired and liabilities assumed, other than contingent consideration which is discussed above, are measured as of the acquisition date by a third-party valuation specialist using a discounted cash flow model based on inputs that are not observable in the market and are therefore designated as Level 3 inputs. Significant inputs to the valuation of acquired oil and gas properties include forward oil and gas price curves, estimated volumes of oil and gas reserves, expectations for timing and amount of future development and operating costs, future plugging and abandonment costs, and a risk adjusted discount rate. See "Note 3. Acquisitions and Divestitures of Oil and Gas Properties" for details of assets acquired and liabilities assumed as of the acquisition date for the ExL Acquisition.

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, net of unamortized premiums and debt issuance costs with the fair values measured using quoted secondary market trading prices which are designated as Level 1 within the valuation hierarchy.

	September 30, 2018		December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
7.50% Senior Notes due 2020	$129,144	$130,000	$446,087	$459,518
6.25% Senior Notes due 2023	642,781	664,625	641,792	674,375
8.25% Senior Notes due 2025	245,927	268,750	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)

	September 30, 2018				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Total current assets	$3,114,698	$133,308	$—	($3,096,917)	$151,089
Total property and equipment, net	6,570	2,709,162	3,028	(3,833)	2,714,927
Investment in subsidiaries	(576,826)	—	—	576,826	—
Other assets	29,611	15,371	—	—	44,982
Total Assets	$2,574,053	$2,857,841	$3,028	($2,523,924)	$2,910,998
Liabilities and Shareholders' Equity					
Current liabilities	$305,096	$3,347,575	$3,028	($3,099,937)	$555,762
Long-term liabilities	1,357,294	87,092	—	15,879	1,460,265
Preferred stock	173,629	—	—	—	173,629
Total shareholders' equity	738,034	(576,826)	—	560,134	721,342
Total Liabilities and Shareholders' Equity	$2,574,053	$2,857,841	$3,028	($2,523,924)	$2,910,998

	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 September 30, 2018				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$38	$303,337	$—	$—	$303,375
Total costs and expenses	85,242	135,920	—	(13)	221,149
Income (loss) before income taxes	(85,204)	167,417	—	13	82,226
Income tax expense	—	(880)	—	—	(880)
Equity in income of subsidiaries	166,537	—	—	(166,537)	—
Net income	$81,333	$166,537	$—	($166,524)	$81,346
Dividends on preferred stock	(4,457)	—	—	—	(4,457)
Accretion on preferred stock	(771)	—	—	—	(771)
Loss on redemption of preferred stock	—	—	—	—	—
Net income attributable to common shareholders	$76,105	$166,537	$—	($166,524)	$76,118

	Three Months Ended September 30, 2017				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$35	$181,244	$—	$—	$181,279
Total costs and expenses	54,061	119,366	—	29	173,456
Income (loss) before income taxes	(54,026)	61,878	—	(29)	7,823
Income tax expense	—	—	—	—	—
Equity in income of subsidiaries	61,878	—	—	(61,878)	—
Net income	$7,852	$61,878	$—	($61,907)	$7,823
Dividends on preferred stock	(2,249)	—	—	—	(2,249)
Accretion on preferred stock	—	—	—	—	—
Loss on redemption of preferred stock	—	—	—	—	—
Net income attributable to common shareholders	$5,603	$61,878	$—	($61,907)	$5,574

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

	Nine Months Ended September 30, 2018				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$77	$792,551	$—	$—	$792,628
Total costs and expenses	278,942	367,902	—	(45)	646,799
Income (loss) before income taxes	(278,865)	424,649	—	45	145,829
Income tax expense	—	(1,682)	—	—	(1,682)
Equity in income of subsidiaries	422,967	—	—	(422,967)	—
Net income	$144,102	$422,967	$—	($422,922)	$144,147
Dividends on preferred stock	(13,794)	—	—	—	(13,794)
Accretion on preferred stock	(2,264)	—	—	—	(2,264)
Loss on redemption of preferred stock	(7,133)	—	—	—	(7,133)
Net income attributable to common shareholders	$120,911	$422,967	$—	($422,922)	$120,956

	Nine Months Ended September 30, 2017				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$291	$498,826	$—	$—	$499,117
Total costs and expenses	80,660	314,237	—	70	394,967
Income (loss) before income taxes	(80,369)	184,589	—	(70)	104,150
Income tax expense	—	—	—	—	—
Equity in income of subsidiaries	184,589	—	—	(184,589)	—
Net income	$104,220	$184,589	$—	($184,659)	$104,150
Dividends on preferred stock	(2,249)	—	—	—	(2,249)
Accretion on preferred stock	—	—	—	—	—
Loss on redemption of preferred stock	—	—	—	—	—
Net income attributable to common shareholders	$101,971	$184,589	$—	($184,659)	$101,901

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

	Nine Months Ended September 30, 2018				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities	($218,926)	$684,218	$—	$—	$465,292
Net cash provided by (used in) investing activities	375,265	(284,076)	—	(400,142)	(308,953)
Net cash used in financing activities	(163,464)	(400,142)	—	400,142	(163,464)
Net decrease in cash and cash equivalents	(7,125)	—	—	—	(7,125)
Cash and cash equivalents, beginning of period	9,540	—	—	—	9,540
Cash and cash equivalents, end of period	$2,415	$—	$—	$—	$2,415

	Nine Months Ended September 30, 2017				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities	($95,529)	$376,126	$—	$—	$280,597
Net cash used in investing activities	(728,833)	(1,102,155)	—	726,029	(1,104,959)
Net cash provided by financing activities	825,260	726,029	—	(726,029)	825,260
Net increase in cash and cash equivalents	898	—	—	—	898
Cash and cash equivalents, beginning of period	4,194	—	—	—	4,194
Cash and cash equivalents, end of period	$5,092	$—	$—	$—	$5,092

13. Supplemental Cash Flow Information

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

	Nine Months Ended September 30,	
	2018	2017
	(In thousands)	
Supplemental cash flow disclosures:		
Cash paid for interest, net of amounts capitalized	$44,644	$59,389
Non-cash investing activities:		
Increase in capital expenditure payables and accruals	$61,893	$98,829
Fair value of contingent consideration (assets) liabilities on date of (divestiture) acquisition	(7,880)	52,300
Stock-based compensation expense capitalized to oil and gas properties	5,384	2,543
Asset retirement obligations capitalized to oil and gas properties	1,127	2,761

14. Subsequent Events

Commodity Derivative Instruments

In October 2018, the Company entered into the following commodity derivative instruments at weighted average contract volumes and prices:

Commodity	Period	Type of Contract	Index	Volumes (Bbls per day)	Fixed Price ($ per Bbl)	Sub-Floor Price ($ per Bbl)	Floor Price ($ per Bbl)	Ceiling Price ($ per Bbl)	Fixed Price Differential ($ per Bbl)
Crude oil	2019	Three-Way Collars	NYMEX WTI	6,000	—	$45.00	$55.00	$93.01	—
Crude oil	2019	Basis Swaps	LLS-WTI Cushing	1,000	$5.78	—	—	—	—

Redemption of 7.50% Senior Notes Due 2020

On October 18, 2018, the Company delivered a notice of conditional redemption to the trustee for its 7.50% Senior Notes to call for redemption on November 19, 2018, the remaining $130.0 million outstanding aggregate principal amount of 7.50% Senior Notes at a redemption price of 100% of par, plus accrued and unpaid interest. The Company’s redemption obligation was conditioned on and subject to there being made available to the Company under its revolving credit facility a commitment amount of at least $1.1 billion as of November 19, 2018, which was satisfied on October 29, 2018 in connection with the amendment to the credit agreement discussed below, therefore, the Company’s redemption obligation is no longer conditional. As a result of the redemption, the Company expects to record a loss on extinguishment of debt of approximately $0.8 million, which is solely attributable to the write-off of unamortized premium and debt issuance costs.

Upon redemption of the 7.50% Senior Notes, the May 4, 2022 maturity date of the credit agreement will no longer be subject to a springing maturity date of June 15, 2020.

Thirteenth Amendment to the Credit Agreement

On October 29, 2018, the Company entered into the thirteenth amendment to its credit agreement governing its revolving credit facility to, among other things, (i) establish the borrowing base at $1.3 billion, with an elected commitment amount of $1.1 billion, until the next redetermination thereof, (ii) reduce the applicable margins for Eurodollar loans from 1.50%-2.50% to 1.25%-2.25% and base rate loans from 0.50%-1.50% to 0.25%-1.25%, each depending on the level of facility usage and each subject to an increase of 0.25% for any period during which the ratio of Total Debt to EBITDA exceeds 3.00 to 1.00, (iii) amend the definition of Capital Leases, and (iv) amend certain other definitions and provisions.

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

Third Quarter 2018 Highlights

- Total production for the three months ended September 30, 2018 was 64,627 Boe/d, an increase of 17% from the three months ended September 30, 2017, primarily due to production from new wells in the Eagle Ford and Delaware Basin, partially offset by the divestitures in Utica and Marcellus in the fourth quarter of 2017 and Niobrara and Eagle Ford in the first quarter of 2018, as well as normal production declines.
- Operated drilling and completion activity for the three months ended September 30, 2018 along with our drilled but uncompleted and producing wells as of September 30, 2018 are summarized in the table below.

	Three Months Ended September 30, 2018				September 30, 2018			
	Drilled		Completed		Drilled But Uncompleted		Producing	
Region	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Eagle Ford	32	31.3	25	24.3	20	19.4	516	463.1
Delaware Basin	7	5.3	10	8.7	7	5.6	57	47.2
Total	39	36.6	35	33.0	27	25.0	573	510.3

- Drilling and completion expenditures for the third quarter of 2018 were $241.1 million, of which approximately 62% were in the Eagle Ford with the balance in the Delaware Basin. As a result of the relative outlook for crude oil prices in the Eagle Ford and Delaware Basin, we elected to shift capital expenditures to the Eagle Ford in order to take advantage of the superior returns in the current environment. As of September 30, 2018, we were operating six rigs, with four located in the Eagle Ford and two located in the Delaware Basin, and two completion crews, both of which were in the Eagle Ford. For the remainder of 2018, we currently expect to continue operating an average of six rigs between the Eagle Ford and Delaware Basin, however, completion activity is expected to decline in the fourth quarter of 2018 as we have planned for a frac holiday. Our current 2018 drilling, completion, and infrastructure capital expenditure plan remains unchanged at $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 July 2018, we closed on the divestiture of certain non-operated assets in the Delaware Basin for aggregate net proceeds of $30.9 million.
- In August 2018, we entered into a purchase and sale agreement with Devon to acquire oil and gas properties in the Delaware Basin in Reeves and Ward counties, Texas for an agreed upon price of $215.0 million, subject to customary purchase price adjustments. We paid $21.5 million as a deposit upon signing the purchase and sale agreement and $183.4 million upon closing in October for an aggregate purchase price of $204.9 million. The final purchase price remains subject to post-closing adjustments. Certain of the acreage included in the acquisition is subject to a third party's right to purchase a 20% interest in such acreage.
- In August 2018, we completed a public offering of 9.5 million shares of our common stock at a price per share of $22.55. We used the net proceeds of $213.9 million, net of offering costs, to fund the purchase price of the Devon Acquisition and for general corporate purposes. Pending the closing of the Devon Acquisition, we used the net proceeds to temporarily repay a portion of the borrowings outstanding under the revolving credit facility.
- We recorded net income attributable to common shareholders for the three months ended September 30, 2018 of $76.1 million, or $0.85 per diluted share, as compared to net income attributable to common shareholders for the three

months ended September 30, 2017 of $5.6 million, or $0.07 per diluted share. The increase in net income attributable to common shareholders for the third quarter of 2018 as compared to the net income attributable to common shareholders for the third quarter of 2017 was driven primarily by higher production volumes and commodity prices in the third quarter of 2018 compared to the third quarter of 2017, partially offset by a loss on derivatives, net of $55.4 million in the third quarter of 2018 as compared to a loss on derivatives, net of $24.4 million in the third quarter of 2017 and an increase in our depreciation, depletion and amortization ("DD&A") expense of $12.5 million to $80.1 million for the third quarter of 2018 as compared to $67.6 million for the third quarter of 2017. See "—Results of Operations" below for further details.

Recent Developments

- In October 2018, we delivered a notice of conditional redemption to the trustee for our 7.50% Senior Notes to call for redemption on November 19, 2018, the remaining $130.0 million aggregate principal amount of outstanding 7.50% Senior Notes at a redemption price of 100% of par, plus accrued and unpaid interest. Our redemption obligation was conditioned on and subject to there being made available to us under the revolving credit facility a commitment amount of at least $1.1 billion as of November 19, 2018, which was satisfied on October 29, 2018 in connection with the amendment to the credit agreement discussed below, therefore, our redemption obligation is no longer conditional. As a result of the redemption, we expect to record a loss on extinguishment of debt of approximately $0.8 million, which is solely attributable to the write-off of unamortized premium and debt issuance costs. Additionally, upon redemption of the 7.50% Senior Notes, the May 4, 2022 maturity date of the credit agreement will no longer be subject to a springing maturity date of June 15, 2020.
- In October 2018, we entered into the thirteenth amendment to our credit agreement governing the revolving credit facility to, among other things, (i) establish the borrowing base at $1.3 billion, with an elected commitment amount of $1.1 billion, until the next redetermination thereof, (ii) reduce the applicable margins for Eurodollar loans from 1.50%-2.50% to 1.25%-2.25% and base rate loans from 0.50%-1.50% to 0.25%-1.25%, each depending on the level of facility usage and each subject to an increase of 0.25% for any period during which the ratio of Total Debt to EBITDA exceeds 3.00 to 1.00, (iii) amend the definition of Capital Leases, and (iv) amend certain other definitions and provisions.

Results of Operations

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

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

	Three Months Ended September 30,		2018 Period Compared to 2017 Period	
	2018	2017	Increase (Decrease)	% Increase (Decrease)
Total production volumes -				
Crude oil (MBbls)	3,755	3,211	544	17 %
NGLs (MBbls)	1,055	623	432	69 %
Natural gas (MMcf)	6,815	7,476	(661)	(9 %)
Total barrels of oil equivalent (MBoe)	5,946	5,080	866	17 %
Daily production volumes by product -				
Crude oil (Bbls/d)	40,813	34,903	5,910	17 %
NGLs (Bbls/d)	11,469	6,777	4,692	69 %
Natural gas (Mcf/d)	74,072	81,265	(7,193)	(9 %)
Total barrels of oil equivalent (Boe/d)	64,627	55,224	9,403	17 %
Daily production volumes by region (Boe/d) -				
Eagle Ford	39,024	39,002	22	— %
Delaware Basin	25,577	6,994	18,583	266 %
Other	26	9,228	(9,202)	(100 %)
Total barrels of oil equivalent (Boe/d)	64,627	55,224	9,403	17 %
Average realized prices -				
Crude oil ($ per Bbl)	$67.78	$47.37	$20.41	43 %
NGLs ($ per Bbl)	32.04	20.01	12.03	60 %
Natural gas ($ per Mcf)	2.21	2.24	(0.03)	(1 %)
Total average realized price ($ per Boe)	$51.02	$35.68	$15.34	43 %
Revenues (In thousands) -				
Crude oil	$254,525	$152,101	$102,424	67 %
NGLs	33,798	12,467	21,331	171 %
Natural gas	15,052	16,711	(1,659)	(10 %)
Total revenues	$303,375	$181,279	$122,096	67 %

Production volumes for the three months ended September 30, 2018 were 64,627 Boe/d, an increase of 17% from 55,224 Boe/d for the same period in 2017. The increase is primarily due to production from new wells in the Delaware Basin, primarily drilled on properties from the ExL Acquisition, as well as in Eagle Ford, partially offset by the divestitures in Utica and Marcellus in the fourth quarter of 2017 and Niobrara and Eagle Ford in the first quarter of 2018. Revenues for the three months ended September 30, 2018 increased 67% to $303.4 million compared to $181.3 million for the same period in 2017 primarily due to higher crude oil prices and higher crude oil production.

Lease operating expenses for the three months ended September 30, 2018 increased to $41.0 million ($6.90 per Boe) from $34.9 million ($6.86 per Boe) for the same period in 2017. The increase in lease operating expenses is primarily due to costs associated with increased production. The increase in lease operating expense per Boe is primarily due to processing fees for certain of our natural gas and NGL processing contracts that, effective January 1, 2018, are presented in lease operating expenses as a result of the adoption of ASC in 606. This more than offset a net decrease in lease operating expense per Boe related to the change in the proportion of production from properties acquired in the ExL Acquisition, which have lower operating costs per Boe than our other Delaware Basin and Eagle Ford properties, and the increased proportion of total production from crude oil properties, as a result of the divestiture in Marcellus in the fourth quarter of 2017, which have a higher per operating cost per Boe than natural gas properties.

Production taxes increased to $14.5 million (4.8% of revenues) for the three months ended September 30, 2018 from $7.7 million (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 Marcellus in the fourth quarter of 2017, as our production in Marcellus was not subject to production taxes.

Ad valorem taxes increased to $2.6 million (0.9% of revenues) for the three months ended September 30, 2018 from $1.7 million (1.0% of revenues) for the same period in 2017. The increase in ad valorem taxes is due to new wells drilled in the Eagle Ford and Delaware Basin and higher property tax valuations as a result of the increase in crude oil prices, partially offset by a reduction in ad valorem taxes resulting from the divestitures discussed above. The decrease in ad valorem taxes as a percentage of revenues is primarily due to the timing of when wells are included in the ad valorem tax assessment as wells drilled and producing during 2018 would not be included in ad valorem tax assessment until 2019.

DD&A expense for the third quarter of 2018 increased $12.5 million to $80.1 million ($13.47 per Boe) from the DD&A expense for the third quarter of 2017 of $67.6 million ($13.30 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 costs that occurred subsequent to the third quarter of 2017 as well as an increase in proved oil and gas properties as a result of our ongoing capital expenditure program, partially offset by the reduction in proved oil and gas properties as a result of the divestitures in Utica and Marcellus in the fourth quarter of 2017 and Niobrara and Eagle Ford in the first quarter of 2018 and an increase in proved oil and gas reserves. The components of our DD&A expense were as follows:

	Three Months Ended September 30,	
	2018	2017
	(In thousands)	
DD&A of proved oil and gas properties	$79,051	$66,221
Depreciation of other property and equipment	607	584
Amortization of other assets	102	294
Accretion of asset retirement obligations	348	465
Total DD&A	$80,108	$67,564

General and administrative expense, net decreased to $12.8 million for the three months ended September 30, 2018 from $16.0 million for the corresponding period in 2017. The decrease was primarily due to stock-based compensation expense, net as a result of a larger decrease in the fair value of stock appreciation rights for the three months ended September 30, 2018 as compared to the same period in 2017.

We recorded a loss on derivatives, net of $55.4 million and $24.4 million for the three months ended September 30, 2018 and 2017, respectively. The components of our loss on derivatives, net were as follows:

	Three Months Ended September 30,	
	2018	2017
	(In thousands)	
Crude oil derivative positions:		
Loss due to upward shift in the futures curve of forecasted crude oil prices during the period on derivative positions outstanding at the beginning of the period	$34,282	$7,567
Loss due to new derivative positions executed during the period	9,382	842
Loss due to deferred premium obligations incurred	—	10,151
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	5,086	—
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	(192)	(2,183)
Contingent consideration arrangements:		
Net loss primarily due to upward shift in the futures curve of forecasted crude oil prices during the period	6,830	8,000
Loss on derivatives, net	$55,388	$24,377

Interest expense, net for the three months ended September 30, 2018 was $15.4 million as compared to $20.7 million for the same period in 2017. The decrease was primarily due to 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 increased borrowings and associated interest expense on our revolving credit facility for the three months ended September 30, 2018 as compared to the three months ended September 30, 2017. The components of our interest expense, net were as follows:

	Three Months Ended September 30,	
	2018	2017
	(In thousands)	
Interest expense on Senior Notes	$17,750	$25,750
Interest expense on revolving credit facility	5,092	1,969
Amortization of premiums and debt issuance costs	956	1,116
Other interest expense	124	293
Interest capitalized	(8,516)	(8,455)
Interest expense, net	$15,406	$20,673

The effective income tax rates for the third quarter of 2018 and 2017 were 1.1% and 0.0%, respectively, which were nominal as a result of maintaining a full valuation allowance against our net deferred tax assets. The increase in the effective rate between the periods is due to $0.9 million of Texas franchise tax recognized for the three months ended September 30, 2018 due to an increase in the apportionment of income to the state of Texas as a result of our divestitures in the fourth quarter of 2017 and first quarter of 2018.

Throughout 2017 and the first nine months of 2018, we maintained a full valuation allowance against our deferred tax assets based on our conclusion, considering all available evidence (both positive and negative), that it was more likely than not that the deferred tax assets would not be realized. A significant item of objective negative evidence considered was the cumulative pre-tax loss incurred over the three-year period ended September 30, 2018, primarily due to impairments of proved oil and gas properties recognized in the fourth quarter of 2015 and the first three quarters of 2016, which limits our ability to consider subjective positive evidence, such as its projections of future taxable income.

We currently believes it is reasonably possible for us to achieve a three-year cumulative level of profitability within the next 12 months, and considering the rebound in crude oil prices during 2018 and improved outlook for 2019, would enhance our ability to conclude that it is more likely than not that the deferred tax assets would be realized and support a release of a portion or substantially all of the valuation allowance. A release of the valuation allowance would result in the recognition of an increase in deferred tax assets and an income tax benefit in the period in which the release occurs, although the exact timing and amount of the release is subject to change based on numerous factors, including our projections of future taxable income, which we continue to assess based on available information each reporting period.

For the three months ended September 30, 2018 and 2017, we declared and paid cash dividends of $4.5 million and $2.2 million, respectively, on our Preferred Stock.

Results of Operations

Nine Months Ended September 30, 2018, Compared to the Nine Months Ended September 30, 2017

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

	Nine Months Ended September 30,		2018 Period Compared to 2017 Period	
	2018	2017	Increase (Decrease)	% Increase (Decrease)
Total production volumes -				
Crude oil (MBbls)	10,272	8,867	1,405	16 %
NGLs (MBbls)	2,648	1,482	1,166	79 %
Natural gas (MMcf)	16,996	21,279	(4,283)	(20 %)
Total barrels of oil equivalent (MBoe)	15,753	13,896	1,857	13 %
Daily production volumes by product -				
Crude oil (Bbls/d)	37,628	32,481	5,147	16 %
NGLs (Bbls/d)	9,699	5,430	4,269	79 %
Natural gas (Mcf/d)	62,258	77,946	(15,688)	(20 %)
Total barrels of oil equivalent (Boe/d)	57,703	50,902	6,801	13 %
Daily production volumes by region (Boe/d) -				
Eagle Ford	37,241	36,569	672	2 %
Delaware Basin	20,236	3,871	16,365	423 %
Other	226	10,462	(10,236)	(98 %)
Total barrels of oil equivalent (Boe/d)	57,703	50,902	6,801	13 %
Average realized prices -				
Crude oil ($ per Bbl)	$66.13	$47.70	$18.43	39 %
NGLs ($ per Bbl)	27.18	18.68	8.50	46 %
Natural gas ($ per Mcf)	2.44	2.28	0.16	7 %
Total average realized price ($ per Boe)	$50.32	$35.92	$14.40	40 %
Revenues (In thousands) -				
Crude oil	$679,242	$422,999	$256,243	61 %
NGLs	71,969	27,678	44,291	160 %
Natural gas	41,417	48,440	(7,023)	(14 %)
Total revenues	$792,628	$499,117	$293,511	59 %

Production volumes for the nine months ended September 30, 2018 were 57,703 Boe/d, an increase of 13% from 50,902 Boe/d for the same period in 2017. The increase is primarily due to production from new wells in the Delaware Basin, primarily drilled on properties from the ExL Acquisition, as well as in Eagle Ford, partially offset by the divestitures in Utica and Marcellus in the fourth quarter of 2017 and Niobrara and Eagle Ford in the first quarter of 2018. Revenues for the nine months ended September 30, 2018 increased 59% to $792.6 million from $499.1 million for the same period in 2017 primarily due to higher crude oil prices and higher crude oil production.

Lease operating expenses for the nine months ended September 30, 2018 increased to $115.4 million ($7.33 per Boe) from $100.8 million ($7.25 per Boe) for the same period in 2017. The increase in lease operating expenses is primarily due to costs associated with increased production. The increase in lease operating expense per Boe is primarily due to processing fees for certain of our natural gas and NGL processing contracts that, effective January 1, 2018, are presented in lease operating expenses as a result of the adoption of ASC in 606. Additionally, there was a net increase in lease operating expense per Boe related to the 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 Marcellus in the fourth quarter of 2017 and the increased proportion of production from properties acquired in the ExL Acquisition, which have lower operating costs per Boe than our other Delaware Basin and Eagle Ford properties. Production taxes increased to $37.6 million (or 4.7% of revenues) for the nine months ended September 30, 2018 from $21.1 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 due to the divestiture of substantially all of our assets in Marcellus in the fourth quarter of 2017, as our production in Marcellus was not subject to production taxes.
Ad valorem taxes increased to $8.2 million (1.0% of revenues) for the nine months ended September 30, 2018 from $5.8 million (1.2% of revenues) 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 and higher property tax valuations as a result of the increase in crude oil prices, partially offset by a reduction in ad valorem taxes resulting from the divestitures discussed above. The decrease in ad valorem taxes as a percentage of revenues is primarily due to the timing of when wells are included in the ad valorem tax assessment as wells drilled and producing during 2018 would not be included in ad valorem tax assessment until 2019.
DD&A expense for the nine months ended September 30, 2018 increased $36.0 million to $217.0 million ($13.78 per Boe) from $181.0 million ($13.03 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 costs that occurred subsequent to the third quarter of 2017 as well as an increase to proved oil and gas properties as a result of our ongoing capital expenditure program, partially offset by the reduction in proved oil and gas properties as a result of the divestitures in Utica and Marcellus in the fourth quarter of 2017 and Niobrara and Eagle Ford in the first quarter of 2018 and an increase in proved oil and gas reserves. The components of our DD&A expense were as follows:

	Nine Months Ended September 30,	
	2018	2017
	(In thousands)	
DD&A of proved oil and gas properties	$213,727	$176,876
Depreciation of other property and equipment	1,801	1,842
Amortization of other assets	476	966
Accretion of asset retirement obligations	1,001	1,334
Total DD&A	$217,005	$181,018

General and administrative expense, net increased to $58.4 million for the nine months ended September 30, 2018 from $49.3 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 nine months ended September 30, 2018 compared to a decrease in fair value for the nine months ended September 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 $152.7 million and a gain on derivatives, net of $27.0 million for the nine months ended September 30, 2018 and 2017, respectively. The components of our (gain) loss on derivatives, net were as follows:

	Nine Months Ended September 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	$113,282	($28,334)
(Gain) loss due to new derivative positions executed during the period	13,330	(11,420)
Loss due to deferred premium obligations incurred	—	17,652
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	9,885	—
Natural gas derivative positions:		
	(3,152)	(12,902)

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		
Loss due to new derivative positions executed during the period	68	—
Contingent consideration arrangements:		
Net loss primarily due to upward shift in the futures curve of forecasted crude oil prices during the period	19,285	8,000
(Gain) loss on derivatives, net	$152,698	($27,004)

Interest expense, net for the nine months ended September 30, 2018 was $46.5 million as compared to $62.4 million for the same period in 2017. The decrease was due primarily to 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 as well as an increase in capitalized interest as a result of higher average balances of unevaluated leasehold and seismic costs over the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017, primarily as a result of the ExL Acquisition in the third quarter of 2017. 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 increased borrowings and associated interest expense on our revolving credit facility for the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017. The components of our interest expense, net were as follows:

	Nine Months Ended September 30,	
	2018	2017
	(In thousands)	
Interest expense on Senior Notes	$57,003	$68,660
Interest expense on revolving credit facility	13,741	5,656
Amortization of debt issuance costs, premiums, and discounts	2,996	3,381
Other interest expense	394	876
Capitalized interest	(27,612)	(16,223)
Interest expense, net	$46,522	$62,350

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 nine months ended September 30, 2018, which included 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.

The effective income tax rate for the nine months ended September 30, 2018 and 2017 was 1.2% and 0.0%, respectively, which were nominal as a result of maintaining a full valuation allowance against our net deferred tax assets. The increase in the effective rate between the periods is due to $1.7 million of Texas franchise tax recognized for the nine months ended September 30, 2018 due to an increase in the apportionment of income to the state of Texas as a result of our divestitures in the fourth quarter of 2017 and first quarter of 2018.

Throughout 2017 and the first nine months of 2018, we maintained a full valuation allowance against our deferred tax assets based on our conclusion, considering all available evidence (both positive and negative), that it was more likely than not that the deferred tax assets would not be realized. A significant item of objective negative evidence considered was the cumulative pre-tax loss incurred over the three-year period ended September 30, 2018, primarily due to impairments of proved oil and gas properties recognized in the fourth quarter of 2015 and the first three quarters of 2016, which limits our ability to consider subjective positive evidence, such as its projections of future taxable income.

We currently believe it is reasonably possible for us to achieve a three-year cumulative level of profitability within the next 12 months, and considering the rebound in crude oil prices during 2018 and improved outlook for 2019, would enhance our ability to conclude that it is more likely than not that the deferred tax assets would be realized and support a release of a portion or substantially all of the valuation allowance. A release of the valuation allowance would result in the recognition of an increase in deferred tax assets and an income tax benefit in the period in which the release occurs, although the exact timing and amount of the release is subject to change based on numerous factors, including our projections of future taxable income, which we continue to assess based on available information each reporting period.

For the nine months ended September 30, 2018 and 2017, we declared and paid cash dividends of $13.8 million and $2.2 million, respectively, on our Preferred Stock.

During the first quarter of 2018, we redeemed 50,000 shares of Preferred Stock, representing 20% of the issued and outstanding Preferred Stock, for $50.5 million, consisting of the $50.0 million redemption price and $0.5 million accrued and unpaid dividends. We recognized a $7.1 million loss on the redemption due to the excess of the $50.0 million redemption price over the $42.9 million redemption date carrying value of the Preferred Stock.

Liquidity and Capital Resources

2018 Drilling, Completion, and Infrastructure Capital Expenditure Plan and Funding Strategy. Our 2018 drilling, completion, and infrastructure capital expenditure plan remains unchanged at $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 nine months ended September 30, 2018:

	Three Months Ended			Nine Months Ended
	March 31, 2018	June 30, 2018	September 30, 2018	September 30, 2018
	(In thousands)			
Drilling, completion, and infrastructure				
Eagle Ford	$135,677	$101,249	$149,386	$386,312
Delaware Basin	73,892	116,743	91,761	282,396
All other regions	284	—	—	284
Total drilling, completion, and infrastructure	209,853	217,992	241,147	668,992
Leasehold and seismic	5,520	6,129	6,668	18,317
Total capital expenditures (1)	$215,373	$224,121	$247,815	$687,309

(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 nine months ended September 30, 2018, we funded our capital expenditures primarily 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 November 2, 2018, our revolving credit facility had a borrowing base of $1.3 billion, with an elected commitment amount of $1.1 billion, with $618.0 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 14. Subsequent Events" for details of the recent thirteenth 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. See "Note 9. Shareholders' Equity and Stock-Based Compensation" for details regarding the recent common stock offering.

- 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 further details.
- 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 $465.3 million and $280.6 million for the nine months ended September 30, 2018 and 2017, respectively. The increase was driven primarily by an increase in revenues as a result of higher crude oil prices and higher crude oil production, partially offset by an increase in the net cash paid for derivative settlements and an increase in operating expenses and cash general and administrative expense.

Net cash used in investing activities decreased to $309.0 million for the nine months ended September 30, 2018, from $1,105.0 million for the corresponding period in 2017. This was due primarily to a decrease in cash payments for acquisitions of oil and gas properties, as well as cash received from the divestitures in Niobrara and Eagle Ford in early 2018, partially offset by an increase in capital expenditures as a result of our ongoing drilling, completion, and infrastructure activity in Eagle Ford and the Delaware Basin.

Net cash used in financing activities was $163.5 million for the nine months ended September 30, 2018 compared to net cash provided by financing activities for the nine months ended September 30, 2017 of $825.3 million. The change was primarily due to payments for the redemptions of our 7.50% Senior Notes and Preferred Stock, decreased borrowings, net of repayments under our revolving credit facility, decreased cash provided by the issuance of senior notes and preferred stock, and increased cash 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 and "Item 3. Quantitative and Qualitative Disclosures About Market Risk" for details of the sensitivities to commodity price for each contingent consideration arrangement.
- Commodity derivative instruments. We use commodity derivative instruments to mitigate the effects of commodity price volatility for a portion of our forecasted sales of production and achieve a more predictable level of cash flow.

As of November 2, 2018, we had the following outstanding commodity derivative instruments at weighted average contract volumes and prices:

Commodity	Period	Type of Contract	Index	Volumes (Bbls per day)	Fixed Price ($ per Bbl)	Sub-Floor Price ($ per Bbl)	Floor Price ($ per Bbl)	Ceiling Price ($ per Bbl)	Fixed Price Differential ($ per Bbl)
Crude oil	4Q18	Price Swaps	NYMEX WTI	6,000	$49.55	—	—	—	—
Crude oil	4Q18	Three-Way Collars	NYMEX WTI	24,000	—	$39.38	$49.06	$60.14	—
Crude oil	4Q18	Basis Swaps	LLS-WTI Cushing	18,000	—	—	—	—	$5.11
Crude oil	4Q18	Basis Swaps	WTI Midland-WTI Cushing	6,000	—	—	—	—	($0.10)
Crude oil	4Q18	Sold Call Options	NYMEX WTI	3,388	—	—	—	$71.33	—
Crude oil	2019	Three-Way Collars	NYMEX WTI	27,000	—	$41.67	$50.96	$73.40	—
Crude oil	2019	Basis Swaps	LLS-WTI Cushing	4,000	—	—	—	—	$4.87
Crude oil	2019	Basis Swaps	WTI Midland-WTI Cushing	7,389	—	—	—	—	($4.82)
Crude oil	2019	Sold Call Options	NYMEX WTI	3,875	—	—	—	$73.66	—
Crude oil	2020	Basis Swaps	WTI Midland-WTI Cushing	13,000	—	—	—	—	($1.27)
Crude oil	2020	Sold Call Options	NYMEX WTI	4,575	—	—	—	$75.98	—
Crude oil	2021	Basis Swaps	WTI Midland-WTI Cushing	6,000	—	—	—	—	$0.03

Commodity	Period	Type of Contract	Index	Volumes (Bbls per day)	Fixed Price ($ per Bbl)	Sub-Floor Price ($ per Bbl)	Floor Price ($ per Bbl)	Ceiling Price ($ per Bbl)	Fixed Price Differential ($ per Bbl)
NGLs	4Q18	Price Swaps	OPIS-Ethane	2,200	$12.01	—	—	—	—
NGLs	4Q18	Price Swaps	OPIS-Propane	1,500	$34.23	—	—	—	—
NGLs	4Q18	Price Swaps	OPIS-Butane	200	$38.85	—	—	—	—
NGLs	4Q18	Price Swaps	OPIS-Isobutane	600	$38.98	—	—	—	—
NGLs	4Q18	Price Swaps	OPIS-Natural Gasoline	600	$55.23	—	—	—	—

Commodity	Period	Type of Contract	Index	Volumes (MMBtu per day)	Fixed Price ($ per MMBtu)	Sub-Floor Price ($ per MMBtu)	Floor Price ($ per MMBtu)	Ceiling Price ($ per MMBtu)	Fixed Price Differential ($ per MMBtu)
Natural gas	4Q18	Price Swaps	NYMEX Henry Hub	25,000	$3.01	—	—	—	—
Natural gas	4Q18	Sold Call Options	NYMEX Henry Hub	33,000	—	—	—	$3.25	—
Natural gas	2019	Sold Call Options	NYMEX Henry Hub	33,000	—	—	—	$3.25	—
Natural gas	2020	Sold Call Options	NYMEX Henry Hub	33,000	—	—	—	$3.50	—

Based on existing market conditions and our expected liquidity needs, among other factors, we may use a portion of our cash flows from operations, proceeds from 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. See “Note 14. Subsequent Events” for details of the notice of conditional redemption for the remaining $130.0 million aggregate principal amount of outstanding 7.50% Senior Notes.

Contractual Obligations

The following table sets forth estimates of our contractual obligations as of September 30, 2018 (in thousands):

	October - December 2018	2019	2020	2021	2022	2023 and Thereafter	Total
Long-term debt [(1)]	$—	$—	$130,000	$—	$309,837	$900,000	$1,339,837
Cash interest on senior notes [(2)]	20,313	71,000	71,000	61,250	61,250	82,188	367,001
Cash interest and commitment fees on revolving credit facility [(3)]	3,637	14,233	14,233	14,233	4,903	—	51,239
Capital leases	450	1,800	1,050	—	—	—	3,300
Operating leases	1,158	4,500	4,219	3,702	3,639	24,658	41,876
Drilling rig contracts [(4)]	12,412	35,541	15,932	792	—	—	64,677
Delivery commitments [(5)]	938	3,726	2,807	2,487	30	26	10,014
Produced water disposal commitments [(6)]	3,331	21,336	21,443	21,445	21,501	17,678	106,734
Asset retirement obligations and other [(7)]	633	2,853	910	377	244	16,499	21,516
Total Contractual Obligations [(8)]	$42,872	$154,989	$261,594	$104,286	$401,404	$1,041,049	$2,006,194

(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). Subsequent to September 30, 2018, we delivered a notice of conditional redemption to the trustee for our 7.50% Senior Notes to call for redemption the remaining $130.0 million aggregate principal amount of our outstanding 7.50% Senior Notes due 2020, which was satisfied on October 29, 2018 in connection with entering into the thirteenth amendment to our credit agreement governing our revolving credit facility. See "Note 14. Subsequent Events" for further details.

(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 September 30, 2018 of 3.87%. Commitment fees on our revolving credit facility were calculated based on the unused portion of lender commitments as of September 30, 2018, at the applicable commitment fee rate of 0.375%.

(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 September 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 September 30, 2018, had a borrowing base of $1.0 billion, with an elected commitment amount of $900.0 million, and $309.8 million of borrowings outstanding at a weighted average interest rate of 3.87%. 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. Upon redemption of the 7.50% Senior Notes discussed below, the May 4, 2022 maturity date of the credit agreement will no longer be subject to a springing maturity date of June 15, 2020.

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 and base rate 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.

On October 29, 2018, we entered into the thirteenth amendment to the credit agreement governing the revolving credit facility to, among other things, increase the borrowing base and elected commitment amount and reduce the margins applied to Eurodollar and base rate loans. See “Note 14. Subsequent Events” 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 as of September 30, 2018.

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. 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.

On October 18, 2018, we delivered a notice of conditional redemption to the trustee for our 7.50% Senior Notes to call for redemption on November 19, 2018, the remaining $130.0 million aggregate principal amount of the outstanding 7.50% Senior Notes at a redemption price of 100% of par, plus accrued and unpaid interest. The redemption obligation was conditioned on and subject to there being made available to us under our revolving credit facility a commitment amount of at least $1.1 billion as of November 19, 2018, which was satisfied on October 29, 2018 in connection with the amendment to the credit agreement discussed above, therefore, our redemption obligation is no longer conditional. See “Note 14. Subsequent Events” for further details.

Redemption of Preferred Stock

During the first quarter of 2018, we redeemed 50,000 shares of Preferred Stock, representing 20% of the issued and outstanding Preferred Stock, for $50.5 million, consisting of the $50.0 million redemption price and $0.5 million accrued and unpaid dividends. We recognized a $7.1 million loss on the redemption due to the excess of the $50.0 million redemption price over the $42.9 million redemption date carrying value of the Preferred Stock.

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.

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 September 30, 2018 cost center ceiling to changes in the 12-month average benchmark crude oil and natural gas prices underlying 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 September 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 September 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)
September 30, 2018 Actual	$62.65	$2.55	$1,553	
Crude Oil and Natural Gas Price Sensitivity				
Crude Oil and Natural Gas +10%	$68.99	$2.85	$2,105	$552
Crude Oil and Natural Gas -10%	$56.32	$2.25	$1,001	($552)
Crude Oil Price Sensitivity				
Crude Oil +10%	$68.99	$2.55	$2,062	$509
Crude Oil -10%	$56.32	$2.55	$1,044	($509)
Natural Gas Price Sensitivity				
Natural Gas +10%	$62.65	$2.85	$1,596	$43
Natural Gas -10%	$62.65	$2.25	$1,510	($43)

Income Taxes

As of September 30, 2018, we have estimated U.S. federal net operating loss carryforwards of $1.1 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 offering associated with the ExL Acquisition in 2017, as well as the common stock offering in August 2018, our calculated ownership change percentage increased, however, as of September 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.

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;
- the use of commodity derivative instruments to mitigate the effects of commodity price volatility for a portion of our forecasted sales of production;
- anticipated trends in our business;
- availability of pipeline connections and water disposal on economic terms;
- effects of competition on us;
- our future results of operations;
- profitability of drilling locations;
- our liquidity and our ability to finance our exploration and development activities, including accessibility of borrowings under our revolving credit facility, our borrowing base, modification to financial covenants, and the result of any borrowing base redetermination;
- our planned expenditures, prospects and capital expenditure plan;
- future market conditions in the oil and gas industry;
- our ability to make, integrate and develop acquisitions including the Devon Acquisition and realize any expected benefits or effects of any acquisitions or the timing, final purchase price, financing or consummation of any acquisitions including the Devon Acquisition;
- results of the Devon Properties;
- 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 commodity 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 redeterminations 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 an acquisition, including the Devon Acquisition, exercise of third party purchase rights under area of mutual interest provisions under a joint operating agreement, 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, 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 nine months ended September 30, 2018 as well as the impact on the crude oil, NGL, and natural gas revenues assuming a 10% increase and decrease in our average realized crude oil, NGL, and natural gas prices, excluding the impact of derivative settlements:

	Three Months Ended September 30, 2018			
	Crude oil	NGLs	Natural gas	Total
	(In thousands)			
Revenues	$254,525	$33,798	$15,052	$303,375
Impact of a 10% fluctuation in average realized prices	$25,450	$3,381	$1,506	$30,337

	Nine Months Ended September 30, 2018			
	Crude oil	NGLs	Natural gas	Total
	(In thousands)			
Revenues	$679,242	$71,969	$41,417	$792,628
Impact of a 10% fluctuation in average realized prices	$67,931	$7,197	$4,147	$79,275

We use commodity derivative instruments to mitigate the effects of commodity price volatility for a portion of our forecasted sales of production and achieve a more predictable level of cash flow. We do not enter into commodity derivative instruments for speculative purposes. As of September 30, 2018, our commodity derivative instruments consisted of price swaps, three-way collars, basis swaps, and sold call options. See “Note 10. Derivative Instruments” for further details of our crude oil, NGL and natural gas commodity derivative instruments as of September 30, 2018 and “Note 14. Subsequent Events” for further details of our crude oil derivative instruments entered into subsequent to September 30, 2018.

The primary drivers of our commodity derivative instrument fair values are the underlying forward oil and gas price curves. The following table sets forth the fair values as of September 30, 2018, excluding deferred premium obligations, as well as the impact on the fair values assuming a 10% increase and decrease in the underlying forward oil and gas price curves:

	Crude oil	NGLs	Natural gas	Total
	(In thousands)			
Fair value liability as of September 30, 2018	$128,497	$7,378	$1,832	$137,707
Impact of a 10% increase in forward commodity prices	$75,109	$1,887	$2,266	$79,262
Impact of a 10% decrease in forward commodity prices	($56,318)	($1,845)	($1,376)	($59,539)

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, volatility factors and risk adjusted discount rates. 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 September 30, 2018, as well as the impact on the fair values assuming a 10% increase and decrease in the underlying forward oil and gas price curves:

	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 (liability) asset as of September 30, 2018	($112,045)	$11,675	$1,315	$12,215
Impact of a 10% increase in forward commodity prices	($2,685)	$835	$625	$690
Impact of a 10% decrease in forward commodity prices	$5,490	($1,270)	($530)	($1,130)

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 September 30, 2018, we had approximately $1.3 billion of long-term debt outstanding. Of this amount, approximately $1.0 billion was fixed-rate debt with a weighted average interest rate of 6.89%. 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 September 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 September 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.

The following disclosure updates the legal proceeding set forth under the heading “Barrow-Shaver Litigation” in the 2017 Annual Report to reflect developments during the three months ended September 30, 2018 and should be read together with the corresponding disclosure in the 2017 Annual Report.

Barrow-Shaver Litigation

On September 24, 2014 an unfavorable jury verdict was delivered against the Company in a case entitled Barrow-Shaver Resources Company v. Carrizo Oil & Gas, Inc. in the amount of $27.7 million. On January 5, 2015, the court entered a judgment awarding the verdict amount plus $2.9 million in attorneys’ fees plus pre-judgment interest. On January 31, 2017, the Twelfth Court of Appeals at Tyler, Texas reversed the trial court decision and rendered judgment in favor of the Company, declaring that the plaintiff take nothing on any of its claims. The plaintiff filed a motion for rehearing with the Twelfth Court of Appeals at Tyler, Texas, which was not granted, and petitioned the Texas Supreme Court for review. In August 2018, the Texas Supreme Court granted review and set oral argument for December 4, 2018. The payment of damages per the original judgment was superseded by posting a bond in the amount of $25.0 million, which will remain outstanding pending resolution of the appeals process (which could take an extended period of time) or agreement of the parties.

The case was filed September 19, 2012 in the 7th Judicial District Court of Smith County, Texas and arises from an agreement between the plaintiff and the Company whereby the plaintiff could earn an assignment of certain of the Company’s leasehold interests in Archer and Baylor counties, Texas for each commercially productive oil and gas well drilled by the plaintiff on acreage covered by the agreement. The agreement contained a provision that the plaintiff had to obtain the Company’s written consent to any assignment of rights provided by such agreement. The plaintiff subsequently entered into a purchase and sale agreement with a third-party purchaser allowing the third-party purchaser to purchase rights in approximately 62,000 leasehold acres, including the rights under the agreement with the Company, for approximately $27.7 million. The plaintiff requested the Company’s consent to make the assignment to the third-party purchaser and the Company refused. The plaintiff alleged that, as a result of the Company’s refusal, the third-party purchaser terminated such purchase and sale agreement. The plaintiff sought damages for breach of contract, tortious interference with existing contract and other grounds in an amount not to exceed $35.0 million plus exemplary damages and attorneys’ fees. As mentioned above, the Twelfth Court of Appeals at Tyler, Texas found in favor of the Company on all grounds.

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
†1.1	Underwriting Agreement, dated as of August 14, 2018, by and between Carrizo Oil & Gas, Inc. and Citigroup Global Markets Inc. and Goldman Sachs & Co. LLC, as representatives of the Underwriters (incorporated herein by reference to Exhibit 1.1 to the Company’s Current Report on Form 8-K filed on August 16, 2018).
*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: November 7, 2018 By: /s/ David L. Pitts
Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: November 7, 2018 By: /s/ Gregory F. Conaway
Vice President and Chief Accounting Officer
(Principal Accounting Officer)