UNIT CORP

FORM 10-Q
(Quarterly Report)

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	TULSA, OK, 74132
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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

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

For the quarterly period ended September 30, 2017

OR

**[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

[Commission File Number 1-9260]

UNIT CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**73-1283193**
(State or other jurisdiction of incorporation)	(I.R.S. Employer Identification No.)
8200 South Unit Drive, Tulsa, Oklahoma	**74132**
(Address of principal executive offices)	(Zip Code)

(918) 493-7700
(Registrant’s telephone number, including area code)

None
(Former name, former address and former fiscal year,
if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes [x] No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes [x] No [ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a 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 [ ] Accelerated filer [x] Non-accelerated filer (Do not check if a smaller reporting company) [ ]

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 [x]

As of October 20, 2017 , 52,879,660 shares of the issuer's common stock were outstanding.

TABLE OF CONTENTS

Forward-Looking Statements

This report contains "forward-looking statements" – meaning, statements related to future events within the meaning of Section 27A of the Securities Act of 1933, as amended and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included or incorporated by reference in this document that addresses activities, events or developments we expect or anticipate will or may occur, are forward-looking statements. The words "believes," "intends," "expects," "anticipates," "projects," "estimates," "predicts," and similar expressions are used to identify forward-looking statements. This report modifies and supersedes documents filed by us before this report. In addition, certain information we file with the SEC will automatically update and supersede information in this report.

These forward-looking statements include, among others, things as:

- the amount and nature of our future capital expenditures and how we expect to fund our capital expenditures;
- prices for oil, natural gas liquids (NGLs), and natural gas;
- demand for oil, NGLs, and natural gas;
- our exploration and drilling prospects;
- the estimates of our proved oil, NGLs, and natural gas reserves;
- oil, NGLs, and natural gas reserve potential;
- development and infill drilling potential;
- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- our plans to maintain or increase production of oil, NGLs, and natural gas;
- the number of gathering systems and processing plants we plan to construct or acquire;
- volumes and prices for natural gas gathered and processed;
- expansion and growth of our business and operations;
- demand for our drilling rigs and drilling rig rates;
- our belief that the final outcome of legal proceedings involving us will not materially affect our financial results;
- our ability to timely secure third-party services used in completing our wells;
- our ability to transport or convey our oil or natural gas production to established pipeline systems;
- impact of federal and state legislative and regulatory actions affecting our costs and increasing operating restrictions or delays and other adverse impacts on our business;
- our projected production guidelines for the year;
- our anticipated capital budgets;
- our financial condition and liquidity;
- the number of wells our oil and natural gas segment plans to drill or rework during the year; and
- our estimates of the amounts of any ceiling test write-downs or other potential asset impairments we may have to record in future periods.

These statements are based on assumptions and analyses made by us based on our experience and our perception of historical trends, current conditions, and expected future developments, and other factors we believe are appropriate in the circumstances. Whether actual results and developments will conform to our expectations and predictions is subject to several risks and uncertainties, any one or combination of which could cause our actual results to differ materially from our expectations and predictions, including:

- the risk factors discussed in this document and in the documents (if any) we incorporate by reference;
- general economic, market, or business conditions;
- the availability of and nature of (or lack of) business opportunities we pursue;
- demand for our land drilling services;
- changes in laws or regulations;
- changes in the current geopolitical situation;
- risks relating to financing, including restrictions in our debt agreements and availability and cost of credit;
- risks associated with future weather conditions;
- decreases or increases in commodity prices;
- putative class action lawsuits that may result in substantial expenditures and divert management's attention; and
- other factors, most of which are beyond our control.

You should not place undue reliance on these forward-looking statements. Except as required by law, we disclaim any intention to update forward-looking information and to release publicly the results of any future revisions we may make to forward-looking statements to reflect events or circumstances after the date of this document to reflect unanticipated events.

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	September 30, 2017	December 31, 2016
	(In thousands except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 822	$ 893
Accounts receivable, net of allowance for doubtful accounts of $2,393 and $3,773 at September 30, 2017 and December 31, 2016, respectively	116,292	83,954
Materials and supplies	3,323	3,340
Current derivative asset (Note 10)	1,064	—
Current income tax receivable	114	99
Current deferred tax asset (Note 8)	—	25,211
Prepaid expenses and other	7,351	7,699
Total current assets	128,966	121,196
Property and equipment:		
Oil and natural gas properties on the full cost method:		
Proved properties	5,605,974	5,446,305
Unproved properties not being amortized	337,064	314,867
Drilling equipment	1,593,835	1,565,268
Gas gathering and processing equipment	715,864	705,859
Saltwater disposal systems	62,387	60,638
Corporate land and building	59,079	59,066
Transportation equipment	29,731	32,842
Other	53,308	48,590
	8,457,242	8,233,435
Less accumulated depreciation, depletion, amortization, and impairment	6,099,229	5,952,330
Net property and equipment	2,358,013	2,281,105
Goodwill	62,808	62,808
Non-current derivative asset (Note 10)	—	377
Other assets	16,085	13,817
Total assets	$ 2,565,872	$ 2,479,303

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

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED) - CONTINUED

	September 30, 2017	December 31, 2016
	(In thousands except share amounts)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 116,152	$ 88,793
Accrued liabilities (Note 5)	60,132	39,651
Current derivative liability (Note 10)	636	21,564
Current portion of other long-term liabilities (Note 6)	14,227	14,907
Total current liabilities	191,147	164,915
Long-term debt less debt issuance costs (Note 6)	803,833	800,917
Non-current derivative liability (Note 10)	282	415
Other long-term liabilities (Note 6)	105,468	103,064
Deferred income taxes (Note 8)	213,237	215,922
Commitments and contingencies (Note 12)	—	—
Shareholders' equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	—	—
Common stock, $.20 par value, 175,000,000 shares authorized, 52,879,660 and 51,494,318 shares issued as of September 30, 2017 and December 31, 2016, respectively	10,277	10,016
Capital in excess of par value	531,328	502,500
Accumulated other comprehensive income (Note 13)	53	—
Retained earnings	710,247	681,554
Total shareholders' equity	1,251,905	1,194,070
Total liabilities and shareholders' equity	$ 2,565,872	$ 2,479,303

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

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In thousands except per share amounts)			
Revenues:				
Oil and natural gas	$ 85,470	$ 78,854	$ 256,241	$ 206,318
Contract drilling	51,619	25,819	128,059	88,786
Gas gathering and processing	51,399	48,735	150,493	132,793
Total revenues	188,488	153,408	534,793	427,897
Expenses:				
Operating costs:				
Oil and natural gas	33,911	26,014	95,873	92,691
Contract drilling	34,747	19,137	91,213	66,489
Gas gathering and processing	38,116	35,738	111,862	99,185
Total operating costs	106,774	80,889	298,948	258,365
Depreciation, depletion, and amortization	54,533	49,969	151,545	158,437
Impairments (Note 2)	—	49,443	—	161,563
General and administrative	9,235	8,852	26,902	25,811
Gain on disposition of assets	(81)	(154)	(1,153)	(823)
Total operating expenses	170,461	188,999	476,242	603,353
Income (loss) from operations	18,027	(35,591)	58,551	(175,456)
Other income (expense):				
Interest, net	(9,944)	(10,002)	(28,807)	(30,225)
Gain (loss) on derivatives	(2,614)	6,969	21,019	(4,774)
Other, net	5	3	14	(11)
Total other income (expense)	(12,553)	(3,030)	(7,774)	(35,010)
Income (loss) before income taxes	5,474	(38,621)	50,777	(210,466)
Income tax expense (benefit):				
Deferred	1,769	(14,599)	22,084	(73,159)
Total income taxes	1,769	(14,599)	22,084	(73,159)
Net income (loss)	$ 3,705	$ (24,022)	$ 28,693	$ (137,307)
Net income (loss) per common share:				
Basic	$ 0.07	$ (0.48)	$ 0.56	$ (2.75)
Diluted	$ 0.07	$ (0.48)	$ 0.56	$ (2.75)

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

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS) (UNAUDITED)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In thousands)			
Net income (loss)	$ 3,705	$ (24,022)	$ 28,693	$ (137,307)
Other comprehensive income, net of taxes:				
Unrealized appreciation on securities, net of tax of $20, $0, $32, and $0	33	—	53	—
Comprehensive income (loss)	$ 3,738	$ (24,022)	$ 28,746	$ (137,307)

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

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
	(In thousands)	
OPERATING ACTIVITIES:		
Net income (loss)	$ 28,693	$ (137,307)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, and amortization	151,545	158,437
Impairments (Note 2)	—	161,563
Amortization of debt issuance costs and debt discount (Note 6)	1,616	1,586
(Gain) loss on derivatives	(21,019)	4,774
Cash (payments) receipts on derivatives settled, net	(729)	11,735
Deferred tax expense (benefit)	22,084	(73,159)
Gain on disposition of assets	(1,153)	(1,100)
Stock compensation plans	12,478	10,664
Other, net	1,397	(3,055)
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	(36,381)	759
Accounts payable	4,873	26,940
Material and supplies	17	231
Accrued liabilities	20,280	14,073
Income taxes	(15)	20,636
Other, net	1,106	985
Net cash provided by operating activities	184,792	197,762
INVESTING ACTIVITIES:		
Capital expenditures	(167,392)	(154,558)
Producing properties and other acquisitions (Note 3)	(55,429)	—
Proceeds from disposition of assets	20,137	46,880
Other	(1,500)	169
Net cash used in investing activities	(204,184)	(107,509)
FINANCING ACTIVITIES:		
Borrowings under credit agreement	251,401	195,700
Payments under credit agreement	(250,100)	(261,700)
Payments on capitalized leases	(2,967)	(2,756)
Proceeds from common stock issued, net of issue costs (Note 13)	18,623	—
Tax benefit from stock compensation	—	(376)
Book overdrafts	2,364	(21,043)
Net cash provided by (used in) financing activities	19,321	(90,175)
Net increase (decrease) in cash and cash equivalents	(71)	78
Cash and cash equivalents, beginning of period	893	835
Cash and cash equivalents, end of period	$ 822	$ 913

Supplemental disclosure of cash flow information:		
Cash paid during the year for:		
Interest paid (net of capitalized)	14,601	16,650
Income taxes	—	—
Changes in accounts payable and accrued liabilities related to purchases of property, plant, and equipment	(20,122)	36,934
Non-cash (addition) reduction to oil and natural gas properties related to asset retirement obligations	(3,203)	29,423

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

UNIT CORPORATION AND SUBSIDIARIES
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 – BASIS OF PREPARATION AND PRESENTATION

The unaudited condensed consolidated financial statements in this report include the accounts of Unit Corporation and all its subsidiaries and affiliates and have been prepared under the rules and regulations of the SEC. The terms "company," "Unit," "we," "our," "us," or like terms refer to Unit Corporation, a Delaware corporation, and one or more of its subsidiaries and affiliates, except as otherwise indicated or as the context otherwise requires.

The condensed consolidated financial statements are unaudited and do not include all the notes in our annual financial statements. This report should be read with the audited consolidated financial statements and notes in our Form 10-K, filed February 28, 2017, for the year ended December 31, 2016 .

In the opinion of our management, the unaudited condensed consolidated financial statements contain all normal recurring adjustments (including the elimination of all intercompany transactions) necessary to fairly state the following:

- Balance Sheets at September 30, 2017 and December 31, 2016 ;
- Statements of Operations for the three and nine months ended September 30, 2017 and 2016 ;
- Statements of Comprehensive Income (Loss) for the three and nine months ended September 30, 2017 and 2016 ; and
- Statements of Cash Flows for the nine months ended September 30, 2017 and 2016 .

Our financial statements are prepared in conformity with generally accepted accounting principles in the United States (GAAP). GAAP requires us to make certain estimates and assumptions that may affect the amounts reported in our unaudited condensed consolidated financial statements and notes. Actual results may differ from those estimates. Results for the nine months ended September 30, 2017 and 2016 are not necessarily indicative of the results to be realized for the full year of 2017 , or that we realized for the full year of 2016 .

Certain amounts in the unaudited condensed consolidated financial statements for prior periods have been reclassified to conform to current year presentation. There was no impact to consolidated net income (loss) or shareholders' equity.

NOTE 2 – OIL AND NATURAL GAS PROPERTIES

Full cost accounting rules require us to review the carrying value of our oil and natural gas properties at the end of each quarter. Under those rules, the maximum amount allowed as the carrying value is referred to as the ceiling. The ceiling is the sum of the present value (using a 10% discount rate) of the estimated future net revenues from our proved reserves (using the unescalated 12-month average price of our oil, NGLs, and natural gas), plus the cost of properties not being amortized, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, less related income taxes. If the net book value of the oil, NGLs, and natural gas properties being amortized exceeds the full cost ceiling, the excess amount is charged to expense in the period during which the excess occurs, even if prices are depressed for only a short while. Once incurred, a write-down of oil and natural gas properties is not reversible.

We incurred non-cash ceiling test write-downs in the first nine months of 2016 of $161.6 million ($100.6 million net of tax). We did no t have a write-down in the first nine months of 2017.

NOTE 3 – ACQUISITIONS AND DIVESTITURES

Acquisitions

On April 3, 2017, we closed on an acquisition of certain oil and natural gas assets located primarily in Grady and Caddo Counties in western Oklahoma. The final adjusted value of consideration given was $54.3 million .

As of January 1, 2017 , the effective date of the acquisition, the estimated proved oil and gas reserves of the acquired properties were 3.2 million barrels of oil equivalent (MMBoe). The acquisition added approximately 8,300 net oil and gas leasehold acres to our core Hoxbar area in southwestern Oklahoma including approximately 47 proved developed producing wells. Of the acreage acquired, approximately 71% was held by production. We also received one gathering system as part of the transaction.

We accounted for this acquisition using the acquisition method under ASC 805, *Business Combinations* , which requires that the acquired assets and liabilities be recorded at their fair values as of the acquisition date. The following table summarizes the adjusted purchase price and the estimated values of assets acquired and liabilities assumed. It is based on information available to us at the time these unaudited condensed consolidated financial statements were prepared. We believe these estimates are reasonable; however, the estimates are subject to change as additional information becomes available and is assessed by us (in thousands):

Adjusted Purchase Price		
Total consideration given	$	54,332

Adjusted Allocation of Purchase Price		
Oil and natural gas properties included in the full cost pool:		
Proved oil and natural gas properties	$	43,745
Undeveloped oil and natural gas properties		8,650
Total oil and natural gas properties included in the full cost pool (1)		52,395
Gas gathering equipment and other		2,340
Asset retirement obligation		(403)
Fair value of net assets acquired	$	54,332

(1) We used a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates, and risk adjusted discount rates.

The pro forma effects of this acquired business is immaterial to the results of operations.

During the third quarter of 2017, we had approximately $2.1 million in other acquisitions.

Divestitures

We sold non-core oil and natural gas assets, net of related expenses, for $18.0 million during the first nine months of 2017, compared to $43.6 million during the first nine months of 2016. Proceeds from those sales reduced the net book value of our full cost pool with no gain or loss recognized.

NOTE 4 – EARNINGS (LOSS) PER SHARE

Information related to the calculation of earnings (loss) per share follows:

	Earnings (Loss) (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the three months ended September 30, 2017			
Basic earnings per common share	$ 3,705	51,386	$ 0.07
Effect of dilutive stock options, restricted stock, and stock appreciation rights (SARs)	—	586	—
Diluted earnings per common share	$ 3,705	51,972	$ 0.07
For the three months ended September 30, 2016			
Basic loss per common share	$ (24,022)	50,081	$ (0.48)
Effect of dilutive stock options, restricted stock, and SARs	—	—	—
Diluted loss per common share	$ (24,022)	50,081	$ (0.48)

Due to the net loss for the three months ended September 30, 2016, approximately 546,000 weighted average shares related to stock options, restricted stock, and SARs were antidilutive and excluded from the calculation above.

The following table shows the number of stock options and SARs (and their average exercise price) excluded because their option exercise prices were greater than the average market price of our common stock:

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016
Stock options and SARs	178,755	240,270
Average exercise price	$ 47.75	$ 49.29

	Earnings (Loss) (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the nine months ended September 30, 2017			
Basic earnings per common share	$ 28,693	51,019	$ 0.56
Effect of dilutive stock options, restricted stock, and SARs	—	550	—
Diluted earnings per common share	$ 28,693	51,569	$ 0.56
For the nine months ended September 30, 2016			
Basic loss per common share	$ (137,307)	50,012	$ (2.75)
Effect of dilutive stock options, restricted stock, and SARs	—	—	—
Diluted loss per common share	$ (137,307)	50,012	$ (2.75)

Because of the net loss for the nine months ended September 30, 2016, approximately 424,000 weighted average shares related to stock options, restricted stock, and SARs were antidilutive and excluded from the calculation above.

The following table shows the number of stock options and SARs (and their average exercise price) excluded because their option exercise prices were greater than the average market price of our common stock:

	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
Stock options and SARs	178,755	240,270
Average exercise price	$ 47.75	$ 49.29

NOTE 5 – ACCRUED LIABILITIES

Accrued liabilities consisted of:

	September 30, 2017	December 31, 2016
	(In thousands)	
Interest payable	$ 17,480	$ 6,524
Employee costs	14,526	15,394
Lease operating expenses	12,686	10,075
Taxes	9,982	2,219
Third-party credits	2,184	2,998
Other	3,274	2,441
Total accrued liabilities	$ 60,132	$ 39,651

NOTE 6 – LONG-TERM DEBT AND OTHER LONG-TERM LIABILITIES

Long-Term Debt

Our long-term debt as of the dates indicated consisted of the following:

	September 30, 2017	December 31, 2016
	(In thousands)	
Credit agreement with an average interest rate of 3.3% and 2.8% at September 30, 2017 and December 31, 2016, respectively	$ 162,100	$ 160,800
6.625% senior subordinated notes due 2021	650,000	650,000
Total principal amount	812,100	810,800
Less: unamortized discount	(2,380)	(2,804)
Less: debt issuance costs, net	(5,887)	(7,079)
Total long-term debt	$ 803,833	$ 800,917

Credit Agreement. Our Senior Credit Agreement (credit agreement) is scheduled to mature on April 10, 2020 . Under the credit agreement, the amount we can borrow is the lesser of the amount we elect as the commitment amount or the value of the borrowing base as determined by the lenders, but in either event not to exceed $875.0 million . Our borrowing base and elected commitment is $475.0 million . We are charged a commitment fee of 0.50% on the amount available but not borrowed. That fee varies based on the amount borrowed as a percentage of the total borrowing base. We paid $1.0 million in origination, agency, syndication, and other related fees. We are amortizing these fees over the life of the credit agreement. Under the credit agreement, we pledged the following collateral: (a) 85% of the proved developed producing (discounted as present worth at 8%) total value of our oil and gas properties and (b) 100% of our ownership interest in our mid-stream affiliate, Superior Pipeline Company, L.L.C.

The borrowing base amount–which is subject to redetermination by the lenders on April 1st and October 1st of each year–is based primarily on a percentage of the discounted future value of our oil and natural gas reserves. The October 2017 redetermination did not result in any changes. We or the lenders may request a onetime special redetermination of the borrowing base between each scheduled redetermination. In addition, we may request a redetermination following the completion of an acquisition that meets the requirements in the credit agreement.

At our election, any part of the outstanding debt under the credit agreement may be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest is computed as the LIBOR base for the term plus 2.00% to 3.00% depending on the level of debt as a percentage of the borrowing base and is payable at the end of each term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the prime rate specified in the credit agreement that cannot be less than LIBOR plus 1.00% . Interest is payable at the end of each month and the principal may be repaid in whole or in part at any time, without a premium or penalty. At September 30, 2017 , we had $162.1 million of outstanding borrowings under our credit agreement.

We can use borrowings for financing general working capital requirements for (a) exploration, development, production, and acquisition of oil and gas properties, (b) acquisitions and operation of mid-stream assets, (c) issuance of standby letters of credit, (d) contract drilling services and acquisition of contract drilling equipment, and (e) general corporate purposes.

The credit agreement prohibits, among other things:

- the payment of dividends (other than stock dividends) during any fiscal year over 30% of our consolidated net income for the preceding fiscal year;
- the incurrence of additional debt with certain limited exceptions; and
- the creation or existence of mortgages or liens, other than those in the ordinary course of business and with certain limited exceptions, on any of our properties, except in favor of our lenders.

The credit agreement also requires that we have at the end of each quarter:

- a current ratio (as defined in the credit agreement) of not less than 1 to 1 .

Through the quarter ending March 31, 2019, the credit agreement also requires that we have at the end of each quarter:

- a senior indebtedness ratio of senior indebtedness to consolidated EBITDA (as defined in the credit agreement) for the most recently ended rolling four quarters of no greater than 2.75 to 1 .

Beginning with the quarter ending June 30, 2019, and for each following quarter, the credit agreement requires:

- a leverage ratio of funded debt to consolidated EBITDA (as defined in the credit agreement) for the most recently ended rolling four fiscal quarters of no greater than 4 to 1 .

As of September 30, 2017 , we were in compliance with the credit agreement covenants.

6.625% Senior Subordinated Notes. We have an aggregate principal amount of $650.0 million , 6.625% senior subordinated notes (the Notes) outstanding. Interest on the Notes is payable semi-annually (in arrears) on May 15 and November 15 of each year. The Notes mature on May 15, 2021 . In issuing the Notes, we incurred fees of $14.7 million that are being amortized as debt issuance cost over the life of the Notes.

The Notes are subject to an Indenture dated as of May 18, 2011, between us and Wilmington Trust, National Association (successor to Wilmington Trust FSB), as Trustee (the Trustee), as supplemented by the First Supplemental Indenture dated as of May 18, 2011, between us, the Guarantors, and the Trustee, and as further supplemented by the Second Supplemental Indenture dated as of January 7, 2013, between us, the Guarantors, and the Trustee (as supplemented, the 2011 Indenture), establishing the terms of and providing for issuing the Notes. The Guarantors are most of our direct and indirect subsidiaries. The discussion of the Notes in this report is qualified by and subject to the actual terms of the 2011 Indenture.

Unit, as the parent company, has no independent assets or operations. The guarantees by the Guarantors of the Notes (registered under registration statements) are full and unconditional, joint and several, subject to certain automatic customary releases, are subject to certain restrictions on the sale, disposition, or transfer of the capital stock or substantially all of the assets of a subsidiary guarantor, and other conditions and terms set out in the 2011 Indenture. Any of our subsidiaries that are not Guarantors are minor. There are no significant restrictions on our ability to receive funds from any of our subsidiaries through dividends, loans, advances, or otherwise.

We may redeem all or, occasionally, a part of the Notes at certain redemption prices, plus accrued and unpaid interest. If a “change of control” occurs, subject to certain conditions, we must offer to repurchase from each holder all or any part of that holder’s Notes at a purchase price in cash equal to 101% of the principal amount of the Notes plus accrued and unpaid interest to the date of purchase. The 2011 Indenture contains customary events of default. The 2011 Indenture also contains covenants including those that limit our ability and the ability of certain of our subsidiaries to incur or guarantee additional indebtedness; pay dividends on our capital stock or redeem capital stock or subordinated indebtedness; transfer or sell assets; make investments; incur liens; enter into transactions with our affiliates; and merge or consolidate with other companies. We were in compliance with all covenants of the Notes as of September 30, 2017 .

Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	September 30, 2017	December 31, 2016
	(In thousands)	
Asset retirement obligation (ARO) liability	$ 75,485	$ 70,170
Capital lease obligations	16,161	18,918
Workers’ compensation	13,420	15,163
Separation benefit plans	6,020	4,943
Deferred compensation plan	5,287	4,578
Gas balancing liability	3,322	3,789
Other	—	410
	119,695	117,971
Less current portion	14,227	14,907
Total other long-term liabilities	$ 105,468	$ 103,064

Estimated annual principal payments under the terms of debt and other long-term liabilities during the five successive twelve month periods beginning October 1, 2017 (and through 2022) are $14.2 million , $48.3 million , $172.4 million , $657.0 million , and $2.5 million , respectively.

Capital Leases

In 2014, our mid-stream segment entered into capital lease agreements for 20 compressors with initial terms of seven years. The underlying assets are included in gas gathering and processing equipment. The $3.8 million current portion of our capital lease obligations is included in current portion of other long-term liabilities and the non-current portion of $12.4 million is included in other long-term liabilities in the accompanying Unaudited Condensed Consolidated Balance Sheets as of September 30, 2017 . These capital leases are discounted using annual rates of 4.00% . Total maintenance and interest remaining related to these leases are $6.3 million and $1.3 million , respectively, at September 30, 2017 . Annual payments, net of maintenance and interest, average $4.1 million annually through 2021 . At the end of the term, our mid-stream segment has the option to purchase the assets at 10% of their then fair market value.

Future payments required under the capital leases at September 30, 2017 :

	Amount
Beginning October 1,	(In thousands)
2017	$ 6,168
2018	6,168
2019	6,168
2020	5,310
Total future payments	23,814
Less payments related to:	
Maintenance	6,320
Interest	1,333
Present value of future minimum payments	$ 16,161

NOTE 7 – ASSET RETIREMENT OBLIGATIONS

We are required to record the estimated fair value of the liabilities relating to the future retirement of our long-lived assets. Our oil and natural gas wells are plugged and abandoned when the oil and natural gas reserves in those wells are depleted or the wells are no longer able to produce. The plugging and abandonment liability for a well is recorded in the period in which the obligation is incurred (at the time the well is drilled or acquired). None of our assets are restricted for purposes of settling these AROs. All our AROs relate to the plugging costs associated with our oil and gas wells.

The following table shows certain information about our AROs for the periods indicated:

	Nine Months Ended September 30,	
	2017	**2016**
	(In thousands)	
ARO liability, January 1:	$ 70,170	$ 98,297
Accretion of discount	2,112	2,147
Liability incurred	1,123	311
Liability settled	(1,350)	(874)
Liability sold [(1)]	(1,563)	(10,758)
Revision of estimates [(2)]	4,993	(18,102)
ARO liability, September 30:	75,485	71,021
Less current portion	2,947	3,498
Total long-term ARO	$ 72,538	$ 67,523

(1) We sold our interest in a number of non-core wells to unaffiliated third-parties during the first nine months of 2017 and 2016, respectively.
(2) Plugging liability estimates were revised in both 2017 and 2016 for updates in the cost of services used to plug wells over the preceding year. We had various upward and downward adjustments.

NOTE 8 – NEW ACCOUNTING PRONOUNCEMENTS

Compensation—Stock Compensation. The FASB issued ASU 2017-09, to clarify and reduce both (i) diversity in practice and (ii) cost and complexity when applying its guidance to changes in the terms and conditions of a share-based payment award. The amendments are effective for reporting periods beginning after December 15, 2017. We do not believe these amendments will have a material impact on our financial statements.

Intangibles—Goodwill and Other: Simplifying the Test for Goodwill Impairment. The FASB issued ASU 2017-04, to simplify the subsequent measurement of goodwill. The amendments eliminate Step 2 from the goodwill impairment test. The amendments will be effective prospectively for reporting periods beginning after December 31, 2019, and early adoption is permitted. We do not believe these amendments will have a material impact on our financial statements.

Business Combinations; Clarifying the Definition of a Business. The FASB issued ASU 2017-01, clarifying the definition of a business. The amendments are intended to help companies and other organizations evaluate whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. For public companies, the amendments are effective for annual periods beginning after December 15, 2017. We do not believe these amendments will have a material impact on our financial statements.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments. The FASB issued ASU 2016-15, to address diversity in how certain transactions are presented and classified in the statement of cash flows. The amendments will be effective retrospectively for reporting periods beginning after December 31, 2017, and early adoption is permitted. We do not believe these amendments will have a material impact on our financial statements.

Leases. The FASB has issued ASU 2016-02. The amendments will require lessees to recognize at the commencement date a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and a right-of-use asset, which is an asset that represents the lessee's right to use a specified asset for the lease term. Lessor accounting is largely unchanged. For public companies, the amendments are effective for annual periods beginning after

December 15, 2018, and interim periods within those annual periods. The standard will not apply to leases of mineral rights. We are in the process of evaluating the impact these amendments will have on our financial statements.

Revenue from Contracts with Customers. The FASB has issued ASU 2014-09. These amendments affect any entity using U.S. GAAP that either enters into contracts with customers to transfer goods or services or enters into contracts for the transfer of nonfinancial assets unless those contracts are within the scope of other standards (e.g., insurance contracts or lease contracts). The core principle of the amendments is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 has been amended several times pre-issuance, which will be codified in the new Topic 606, and it is effective January 1. 2018. The guidance in this update supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance throughout the Industry Topics of the Codification. We will adopt these amendments January 1, 2018.

The new revenue standard provides a five-step analysis of transactions to determine the amount and timing of revenue recognition. Entities can choose to apply Topic 606 using either the full retrospective approach or a modified retrospective approach. We plan to adopt using the modified retrospective approach, which will result in a cumulative effect adjustment upon adoption.

Currently, management believes the effect of adoption will not have a material effect on our statement of operations or our balance sheet, as the timing of revenue recognized will not be materially modified, but the adoption will result in more robust footnote disclosures in regards to revenue. We anticipate a cumulative effect of applying the new revenue standard as an adjustment to the opening balance of retained earnings at the beginning of 2018 in relation to certain mid-stream segment and contract drilling segment contracts that include adjustments to the timing of revenue recognition of certain demand fee and mobilization/demobilization expenses and revenue, respectively. We believe this adjustment will not be material due to the short-term nature of the majority of our current contract drilling segment contracts and the limited number of mid-stream segment contracts with demand fees that we anticipate to be in place at the adoption date. Part of our review included evaluation of the following issues:

- Based on an analysis of whether the transportation of gas is a performance obligation that occurs at a point in time or over time, the timing of when we recognize certain revenue elements will change. Specifically related to our mid-stream segment, certain fees that are collectible in the early stages of a contract will be recognized over the life of the contract because these fees are part of the single performance obligation associated with the contract.

- Certain of our contracts include promises to deliver a minimum volume of commodity to the customer over a defined period of time. If we do not meet this commitment, a deficiency fee is payable to the customer. Topic 606 requires that these types of arrangements represent variable consideration related to the sale of the commodity, and requires that we include an estimate of any deficiency fees expected within revenue, rather than as operating costs. In addition, we will also be required to analyze fees that are billable for deficiencies in minimum volume commitments from customers for our mid-stream segment. In these instances, we will assess the likelihood of earning these fees each reporting period based on the customer’s performance and recognize variable revenue at the time it is not expected to be subject to a significant reversal.

Adopted Standards

Income Taxes: Balance Sheet Classification of Deferred Taxes. The FASB has issued ASU 2015-17. This changes how deferred taxes are classified on organizations' balance sheets. Organizations are required to classify all deferred tax assets and liabilities as noncurrent. The amendments apply to all organizations that present a classified balance sheet. For public companies, the amendments were effective for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. The amendments require current deferred tax assets to be combined with noncurrent deferred tax assets. We have adopted this ASU during the first quarter of 2017 on a prospective basis. Previously, we had a net current deferred tax asset which is now netted with our noncurrent deferred tax liability. P rior periods were not retrospectively adjusted.

Compensation—Stock Compensation: Improvements to Employee Share-Based Payment Accounting. The FASB has issued ASU 2016-09. The amendments are intended to improve the accounting for employee share-based payments and affect all organizations that issue share-based payment awards to their employees. Several aspects of the accounting for share-based payment award transactions are simplified, including: (a) income tax consequences; (b) classification of awards as either equity or liabilities; and (c) classification on the statement of cash flows. For public companies, the amendments were effective for annual periods beginning after December 15, 2016, and interim periods within those annual periods. The amendments primarily impact classification within the statement of cash flows between financial and operating activities. This did not have a material impact on our financial statements.

NOTE 9 –STOCK-BASED COMPENSATION

For restricted stock awards and stock options, we had:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In millions)			
Recognized stock compensation expense	$ 3.2	$ 1.9	$ 9.0	$ 7.2
Capitalized stock compensation cost for our oil and natural gas properties	0.5	0.4	1.3	1.6
Tax benefit on stock based compensation	1.2	0.7	3.4	2.7

The remaining unrecognized compensation cost related to unvested awards at September 30, 2017 is approximately $14.2 million , of which $1.7 million is anticipated to be capitalized. The weighted average period over which this cost will be recognized is one year .

Our Second Amended and Restated Unit Corporation Stock and Incentive Compensation Plan effective May 6, 2015 (the amended plan) allows us to grant stock-based and cash-based compensation to our employees (including employees of subsidiaries) as well as to non-employee directors. A total of 7,000,000 shares of the company's common stock is authorized for issuance to eligible participants under the amended plan with 2,000,000 shares being the maximum number of shares that can be issued as "incentive stock options."

We did not grant any SARs or stock options during either of the three or nine month periods ending September 30, 2017 or 2016 . We did not grant any restricted stock awards during either of the three month periods ending September 30, 2017 or 2016 . The following table shows the fair value of restricted stock awards granted to employees and non-employee directors during the periods indicated:

	Nine Months Ended September 30, 2017		Nine Months Ended September 30, 2016	
	Time Vested	Performance Vested	Time Vested	Performance Vested
Shares granted:				
Employees	475,799	173,373	486,578	152,373
Non-employee directors	49,104	—	90,000	—
	524,903	173,373	576,578	152,373
Estimated fair value (in millions): (1)				
Employees	$ 11.8	$ 4.5	$ 2.6	$ 0.8
Non-employee directors	0.9	—	0.9	—
	$ 12.7	$ 4.5	$ 3.5	$ 0.8
Percentage of shares granted expected to be distributed:				
Employees	95%	91%	94%	89%
Non-employee directors	100%	N/A	100%	N/A

(1) Represents 100% of the grant date fair value. (We recognize the grant date fair value minus estimated forfeitures.)

The time vested restricted stock awards granted during the first nine months of 2017 and 2016 are being recognized over a three -year vesting period. During the first two quarters of 2017 and the first quarter of 2016, there were two different performance vested restricted stock awards granted to certain executive officers. The first will cliff vest three years from the grant date based on the company's achievement of certain stock performance measures at the end of the term and will range from 0% to 200% of the restricted shares granted as performance shares. The second will vest, one-third each year, over a three -year vesting period subject to the company's achievement of cash flow to total assets (CFTA) performance measurement each year and will range from 0% to 200% . Based on a probability assessment of the selected performance criteria at September 30, 2017, the participants are estimated to receive 81% of the 2017, 153% of the 2016, and 40% of the 2015 performance based shares. The CFTA performance measurement at September 30, 2017 was assessed to vest at target or 100% . The total aggregate stock compensation expense and capitalized cost related to oil and natural gas properties for 2017 awards for the first nine months of 2017 was $5.8 million .

NOTE 10 – DERIVATIVES

Commodity Derivatives

We have entered into various types of derivative transactions covering some of our projected natural gas and oil production. These transactions are intended to reduce our exposure to market price volatility by setting the price(s) we will receive for that production. Our decisions on the price(s), type, and quantity of our production subject to a derivative contract are based, in part, on our view of current and future market conditions. As of September 30, 2017 , our derivative transactions were comprised of the following hedges:

- *Swaps.* We receive or pay a fixed price for the commodity and pay or receive a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

- *Basis Swaps.* We receive or pay the NYMEX settlement value plus or minus a fixed delivery point price for the commodity and pay or receive the published index price at the specified delivery point. We use basis swaps to hedge the price risk between NYMEX and its physical delivery points.

- *Collars.* A collar contains a fixed floor price (put) and a ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, we receive the fixed price and pay the market price. If the market price is between the call and the put strike price, no payments are due from either party.

- *Three-way collars.* A three-way collar contains a fixed floor price (long put), fixed subfloor price (short put), and a fixed ceiling price (short call). If the market price exceeds the ceiling strike price, we receive the ceiling strike price and pay the market price. If the market price is between the ceiling and the floor strike price, no payments are due from either party. If the market price is below the floor price but above the subfloor price, we receive the floor strike price and pay the market price. If the market price is below the subfloor price, we receive the market price plus the difference between the floor and subfloor strike prices and pay the market price.

We have documented policies and procedures to monitor and control the use of derivative transactions. We do not engage in derivative transactions for speculative purposes. Any changes in the fair value of our derivative transactions occurring before maturity (i.e., temporary fluctuations in value) are reported in gain (loss) on derivatives in our Unaudited Condensed Consolidated Statements of Operations.

At September 30, 2017 , the following derivatives were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Oct'17	Natural gas – swap	70,000 MMBtu/day	$3.038	IF – NYMEX (HH)
Nov’17 – Dec'17	Natural gas – swap	60,000 MMBtu/day	$2.960	IF – NYMEX (HH)
Jan’18 – Dec'18	Natural gas – swap	20,000 MMBtu/day	$3.013	IF – NYMEX (HH)
Nov’17 – Dec'17	Natural gas – basis swap	20,000 MMBtu/day	$(0.215)	IF – NYMEX (HH)
Jan’18 – Mar'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.208)	IF – NYMEX (HH)
Nov’18 – Dec'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.208)	IF – NYMEX (HH)
Oct'17	Natural gas – collar	20,000 MMBtu/day	$2.88 - $3.10	IF – NYMEX (HH)
Oct'17	Natural gas – three-way collar	15,000 MMBtu/day	$2.50 - $2.00 - $3.32	IF – NYMEX (HH)
Nov’17 – Dec'17	Natural gas – three-way collar	25,000 MMBtu/day	$2.90 - $2.30 - $3.59	IF – NYMEX (HH)
Jan'18 – Mar'18	Natural gas – three-way collar	60,000 MMBtu/day	$3.29 - $2.63 - $4.07	IF – NYMEX (HH)
Apr'18 – Dec'18	Natural gas – three-way collar	20,000 MMBtu/day	$3.00 - $2.50 - $3.51	IF – NYMEX (HH)
Oct’17 – Dec'17	Crude oil – three-way collar	3,750 Bbl/day	$49.79 - $39.58 - $60.98	WTI – NYMEX
Jan'18 – Dec'18	Crude oil – three-way collar	2,000 Bbl/day	$47.50 - $37.50 - $56.08	WTI – NYMEX
Jan'18 – Dec'18	Crude oil – swap	2,000 Bbl/day	$50.140	WTI – NYMEX

After September 30, 2017 , the following derivative was entered into:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Apr'18 – Oct'18	Natural gas – swap	10,000 MMBtu/day	$2.990	IF – NYMEX (HH)
Apr'18 – Sep'18	Liquids – swap [(1)]	1,000 Bbl/day	$31.164	OPIS – Mont Belvieu

(1) Type of liquid involved is propane.

The following tables present the fair values and locations of the derivative transactions recorded in our Unaudited Condensed Consolidated Balance Sheets:

	Balance Sheet Location	Derivative Assets Fair Value September 30, 2017	December 31, 2016
		(In thousands)	
Commodity derivatives:			
Current	Current derivative asset	$ 1,064	$ —
Long-term	Non-current derivative asset	—	377
Total derivative assets		$ 1,064	$ 377

	Balance Sheet Location	Derivative Liabilities Fair Value September 30, 2017	December 31, 2016
		(In thousands)	
Commodity derivatives:			
Current	Current derivative liability	$ 636	$ 21,564
Long-term	Non-current derivative liability	282	415
Total derivative liabilities		$ 918	$ 21,979

All of our counterparties are subject to master netting arrangements. If a legal right of set-off exists, we net the value of the derivative transactions we have with the same counterparty in our Unaudited Condensed Consolidated Balance Sheets.

Following is the effect of derivative instruments on the Unaudited Condensed Consolidated Statements of Operations for the three months ended September 30 :

Derivatives Instruments	Location of Gain (Loss) Recognized in Income on Derivative	Amount of Gain (Loss) Recognized in Income on Derivative	
		2017	2016
		(In thousands)	
Commodity derivatives	Gain (loss) on derivatives [1]	$ (2,614)	$ 6,969
Total		$ (2,614)	$ 6,969

(1) Amounts settled during the 2017 and 2016 periods include net proceeds of $0.8 million and net payments of $0.5 million , respectively.

Following is the effect of derivative instruments on the Unaudited Condensed Consolidated Statements of Operations for the nine months ended September 30 :

Derivatives Instruments	Location of Gain (Loss) Recognized in Income on Derivative	Amount of Gain (Loss) Recognized in Income on Derivative	
		2017	2016
		(In thousands)	
Commodity derivatives	Gain (loss) on derivatives [1]	$ 21,019	$ (4,774)
Total		$ 21,019	$ (4,774)

(1) Amounts settled during the 2017 and 2016 periods include net payments of $0.7 million and net proceeds of $11.7 million , respectively.

NOTE 11 – FAIR VALUE MEASUREMENTS

The estimated fair value of our available-for-sale securities, reflected on our Unaudited Condensed Consolidated Balance Sheets as Non-current other assets, is based on market quotes. The following is a summary of available-for-sale securities:

	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(In thousands)			
Equity Securities:				
September 30, 2017	$ 830	$ 85	$ —	$ 915
December 31, 2016	$ —	$ —	$ —	$ —

During the second quarter of 2017, we received available-for-sale securities for early termination fees associated with a long-term drilling contract. We will evaluate the marketable equity securities to determine if any decline in fair value below cost is other-than-temporary. If a decline in fair value below cost is determined to be other-than-temporary, an impairment charge will be recorded and a new cost basis established. We will review several factors to determine whether a loss is other-than-temporary. These factors include, but are not limited to, (i) the length of time a security is in an unrealized loss position, (ii) the extent to which fair value is less than cost, (iii) the financial condition and near-term prospects of the issuer, and (iv) our intent and ability to hold the security for a period of time sufficient to allow for any anticipated recovery in fair value.

Fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants (in either case, an exit price). To estimate an exit price, a three-level hierarchy is used prioritizing the valuation techniques used to measure fair value into three levels with the highest priority given to Level 1 and the lowest priority given to Level 3. The levels are summarized as follows:

- Level 1—unadjusted quoted prices in active markets for identical assets and liabilities.
- Level 2—significant observable pricing inputs other than quoted prices included within level 1 either directly or indirectly observable as of the reporting date. Essentially, inputs (variables used in the pricing models) that are derived principally from or corroborated by observable market data.
- Level 3—generally unobservable inputs which are developed based on the best information available and may include our own internal data.

The inputs available to us determine the valuation technique we use to measure the fair values of our financial instruments.

The following tables set forth our recurring fair value measurements:

	September 30, 2017				
	Level 1	Level 2	Level 3	Effect of Netting	Net Amounts Presented
	(In thousands)				
Financial assets (liabilities):					
Commodity derivatives:					
Assets	$ —	$ 662	$ 1,964	$ (1,562)	$ 1,064
Liabilities	—	(2,002)	(478)	1,562	(918)
Total commodity derivatives	—	(1,340)	1,486	—	146
Equity securities	915	—	—	—	915
	$ 915	$ (1,340)	$ 1,486	$ —	$ 1,061

	December 31, 2016				
	Level 1	Level 2	Level 3	Effect of Netting	Net Amounts Presented
	(In thousands)				
Financial assets (liabilities):					
Commodity derivatives:					
Assets	$ —	$ 878	$ 43	$ (544)	$ 377
Liabilities	—	(15,358)	(7,165)	544	(21,979)
	$ —	$ (14,480)	$ (7,122)	$ —	$ (21,602)

All our counterparties are subject to master netting arrangements. If a legal right of set-off exists, we net the value of the derivative transactions we have with the same counterparty. We are not required to post cash collateral with our counterparties and no collateral has been posted as of September 30, 2017 .

We used the following methods and assumptions to estimate the fair values of the assets and liabilities in the table above. There were no transfers between Level 2 and Level 3 financial assets (liabilities).

Level 1 Fair Value Measurements

Equity Securities. We measure the fair values of our available for sale securities based on market quotes.

Level 2 Fair Value Measurements

Commodity Derivatives . We measure the fair values of our crude oil and natural gas swaps using estimated internal discounted cash flow calculations based on the NYMEX futures index.

Level 3 Fair Value Measurements

Commodity Derivatives . The fair values of our natural gas and crude oil collars and three-way collars are estimated using internal discounted cash flow calculations based on forward price curves, quotes obtained from brokers for contracts with similar terms, or quotes obtained from counterparties to the agreements.

The following table is a reconciliation of our level 3 fair value measurements:

	Net Derivatives			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In thousands)			
Beginning of period	$ 4,093	$ (4,761)	$ (7,122)	$ 9,094
Total gains or losses (realized and unrealized):				
Included in earnings [(1)]	(2,015)	3,077	9,102	(3,257)
Settlements	(592)	(443)	(494)	(7,964)
End of period	$ 1,486	$ (2,127)	$ 1,486	$ (2,127)
Total gains (losses) for the period included in earnings attributable to the change in unrealized gain relating to assets still held at end of period	$ (2,607)	$ 2,634	$ 8,608	$ (11,221)

(1) Commodity derivatives are reported in the Unaudited Condensed Consolidated Statements of Operations in gain (loss) on derivatives.

The following table provides quantitative information about our Level 3 unobservable inputs at September 30, 2017 :

Commodity [(1)]	Fair Value	Valuation Technique	Unobservable Input	Range
	(In thousands)			
Oil three-way collars	$ (9)	Discounted cash flow	Forward commodity price curve	($3.65) - $5.02
Natural gas collar	$ 25	Discounted cash flow	Forward commodity price curve	($0.11) - $0.06
Natural gas three-way collars	$ 1,470	Discounted cash flow	Forward commodity price curve	($0.34) - $0.54

(1) The commodity contracts detailed in this category include non-exchange-traded crude oil and natural gas collars and three-way collars that are valued based on NYMEX. The forward pricing range represents the low and high price expected to be paid or received within the settlement period.

Our valuation at September 30, 2017 reflected that the risk of non-performance by our counterparties was immaterial.

Fair Value of Other Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with accounting guidance for financial instruments. We have determined the estimated fair values by using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

At September 30, 2017 , the carrying values on the Unaudited Condensed Consolidated Balance Sheets for cash and cash equivalents (classified as Level 1), accounts receivable, accounts payable, other current assets, and current liabilities approximate their fair value because of their short-term nature.

Based on the borrowing rates currently available to us for credit agreement debt with similar terms and maturities and considering the risk of our non-performance, long-term debt under our credit agreement approximates its fair value and at September 30, 2017 and December 31, 2016 was $162.1 million and $160.8 million , respectively. This debt would be classified as Level 2.

The carrying amounts of long-term debt associated with the Notes, net of unamortized discount and debt issuance costs, reported in the Unaudited Condensed Consolidated Balance Sheets as of September 30, 2017 and December 31, 2016 were $641.7 million and $640.1 million , respectively. We estimate the fair value of the Notes using quoted marked prices at September 30, 2017 and December 31, 2016 was $654.6 million and $649.9 million , respectively. The Notes would be classified as Level 2.

Fair Value of Non-Financial Instruments

The initial measurement of AROs at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with property, plant, and equipment. Significant Level 3 inputs used in the calculation of AROs include plugging costs and remaining reserve lives. A reconciliation of the Company's AROs is presented in Note 7 – Asset Retirement Obligations.

NOTE 12 – COMMITMENTS AND CONTINGENCIES

We lease office space or yards in Edmond and Oklahoma City, Oklahoma; Houston, Texas; Englewood, Colorado; Pinedale, Wyoming; and Canonsburg, Pennsylvania under the terms of operating leases expiring through December 2021. We also have several compressor rentals, equipment leases, and lease space on short-term commitments to stack excess drilling rig equipment and production inventory. Future minimum rental payments under the terms of the leases are approximately $3.2 million , $0.8 million , $0.4 million , $0.3 million , and less than $0.1 million in twelve month periods beginning October 1, 2017 (and through the end of 2021), respectively. Total rent expense incurred was $6.4 million and $8.7 million for the first nine months of 2017 and 2016, respectively.

In 2014, our mid-stream segment entered into capital lease agreements for 20 compressors with initial terms of seven years. Estimated annual capital lease payments under the terms during the four successive twelve month periods beginning October 1, 2017 (and through the end of 2021) are $6.2 million , $6.2 million , $6.2 million , and $5.3 million . Total maintenance and interest remaining related to these leases are $6.3 million and $1.3 million , respectively at September 30, 2017 . Annual payments, net of maintenance and interest, average $4.1 million annually through 2021 . At the end of the term, our mid-stream segment has the option to purchase the assets at 10% of their then fair market value.

The employee oil and gas limited partnerships require, on the election of a limited partner, that we repurchase the limited partner's interest at amounts to be determined by appraisal. In any one year, these repurchases are limited to 20% of the units outstanding. We had no repurchases in the first nine months of 2016. We made repurchases of $2,900 during the first nine months of 2017.

We manage our exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. We also conduct periodic reviews, on a company-wide basis, to identify changes in our environmental risk profile. These reviews evaluate whether there is a probable liability, its amount, and the likelihood that the liability will be incurred. Any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees expected to devote significant time directly to any possible remediation effort. As it relates to evaluations of purchased properties, depending on the extent of an identified environmental problem, we may exclude a property from the acquisition, require the seller to remediate the property to our satisfaction, or agree to assume liability for the remediation of the property.

We have not historically experienced any environmental liability while being a contract driller since the greatest portion of risk is borne by the operator. Any liabilities we have incurred have been small and have been resolved while the drilling rig is on the location and the cost has been included in the direct cost of drilling the well.

For the next twelve months, we have committed to purchase approximately $3.9 million of new drilling rig components.

NOTE 13 – EQUITY

At-the-Market (ATM) Common Stock Program

On April 4, 2017, we entered into a Distribution Agreement (the Agreement) with a sales agent, under which we may offer and sell, from time to time, through the sales agent shares of our common stock, par value $.20 per share (the Shares), up to an aggregate offering price of $100.0 million . We intend to use the net proceeds from these sales to fund (or offset costs of) acquisitions, future capital expenditures, repay amounts outstanding under our revolving credit facility, and general corporate purposes.

Under the Agreement, the sales agent may sell the Shares by methods deemed to be an “at-the-market” offering as defined in Rule 415 promulgated under the Securities Act of 1933, as amended, including sales made directly on the NYSE, on any other existing trading market for the Shares or to or through a market maker. In addition, under the Agreement, the sales agent may sell the Shares by any other method permitted by law, including in privately negotiated transactions. Subject to the terms and conditions of the Agreement, the sales agent will use commercially reasonable efforts, consistent with its normal trading and sales practices and applicable state and federal law, rules and regulations and the rules of the NYSE, to sell the Shares from time to time, based on our instructions (including any price, time or size limits or other customary parameters or conditions that we may impose).

We are not obligated to make any sales of the Shares under the Agreement. The offering of Shares under the Agreement will terminate on the earlier of (1) the sale of all of the Shares subject to the Agreement or (2) the termination of the Agreement by the sales agent or us. We will pay the sales agent a commission of 2.0% of the gross sales price per share sold and have agreed to provide the sales agent with customary indemnification and contribution rights.

As of September 30, 2017 , we sold 787,547 shares of our common stock resulting in net proceeds of approximately $18.6 million .

Accumulated Other Comprehensive Income

Components of accumulated other comprehensive income were as follows for the three months ended September 30 :

	2017	2016
	(In thousands)	
Unrealized appreciation on securities, before tax	$ 53	$ —
Tax expense	(20)	—
Unrealized appreciation on securities, net of tax	$ 33	$ —

Changes in accumulated other comprehensive income by component, net of tax, for the three months ended September 30 are as follows:

	Net Gains on Equity Securities	
	2017	2016
	(In thousands)	
Balance at July 1:	$ 20	$ —
Unrealized appreciation before reclassifications	33	—
Amounts reclassified from accumulated other comprehensive income	—	—
Net current-period other comprehensive income	33	—
Balance at September 30:	$ 53	$ —

Components of accumulated other comprehensive income were as follows for the nine months ended September 30 :

	2017	2016
	(In thousands)	
Unrealized appreciation on securities, before tax	$ 85	$ —
Tax expense	(32)	—
Unrealized appreciation on securities, net of tax	$ 53	$ —

Changes in accumulated other comprehensive income by component, net of tax, for the nine months ended September 30 are as follows:

	Net Gains on Equity Securities	
	2017	2016
	(In thousands)	
Balance at January 1:	$ —	$ —
Unrealized appreciation before reclassifications	53	—
Amounts reclassified from accumulated other comprehensive income	—	—
Net current-period other comprehensive income	53	—
Balance at September 30:	$ 53	$ —

NOTE 14 – INDUSTRY SEGMENT INFORMATION

We have three main business segments offering different products and services within the energy industry:

- Oil and natural gas,
- Contract drilling, and
- Mid-stream

Our oil and natural gas segment is engaged in the acquisition, development, and production of oil, NGLs, and natural gas properties. The contract drilling segment is engaged in the land contract drilling of oil and natural gas wells and the mid-stream segment is engaged in the buying, selling, gathering, processing, and treating of natural gas and NGLs.

We evaluate each segment’s performance based on its operating income, which is defined as operating revenues less operating expenses and depreciation, depletion, amortization, and impairment. We have no oil and natural gas production outside the United States.

The following tables provide certain information about the operations of each of our segments:

	Three Months Ended September 30, 2017					
	Oil and Natural Gas	Contract Drilling	Mid-stream	Other	Eliminations	Total Consolidated
	(In thousands)					
Revenues:						
Oil and natural gas	$ 85,470	$ —	$ —	$ —	$ —	$ 85,470
Contract drilling	—	55,588	—	—	(3,969)	51,619
Gas gathering and processing	—	—	69,057	—	(17,658)	51,399
Total revenues	85,470	55,588	69,057	—	(21,627)	188,488
Expenses:						
Operating costs:						
Oil and natural gas	35,082	—	—	—	(1,171)	33,911
Contract drilling	—	38,115	—	—	(3,368)	34,747
Gas gathering and processing	—	—	54,602	—	(16,486)	38,116
Total operating costs	35,082	38,115	54,602	—	(21,025)	106,774
Depreciation, depletion, and amortization	26,460	15,280	10,880	1,913	—	54,533
Total expenses	61,542	53,395	65,482	1,913	(21,025)	161,307
Total operating income (loss) (1)	23,928	2,193	3,575	(1,913)	(602)	
General and administrative expense	—	—	—	(9,235)	—	(9,235)
Gain (loss) on disposition of assets	(1)	68	14	—	—	81
Loss on derivatives	—	—	—	(2,614)	—	(2,614)
Interest expense, net	—	—	—	(9,944)	—	(9,944)
Other	—	—	—	5	—	5
Income (loss) before income taxes	$ 23,927	$ 2,261	$ 3,589	$ (23,701)	$ (602)	$ 5,474

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(1) Operating income (loss) is total operating revenues less operating expenses, depreciation, depletion, and amortization and does not include general corporate expenses, gain (loss) on disposition of assets, loss on derivatives, interest expense, other income (loss), or income taxes.

	Three Months Ended September 30, 2016					
	Oil and Natural Gas	Contract Drilling	Mid-stream	Other	Eliminations	Total Consolidated
	(In thousands)					
Revenues:						
Oil and natural gas	$ 78,854	$ —	$ —	$ —	$ —	$ 78,854
Contract drilling	—	25,819	—	—	—	25,819
Gas gathering and processing	—	—	63,090	—	(14,355)	48,735
Total revenues	78,854	25,819	63,090	—	(14,355)	153,408
Expenses:						
Operating costs:						
Oil and natural gas	27,710	—	—	—	(1,696)	26,014
Contract drilling	—	19,137	—	—	—	19,137
Gas gathering and processing	—	—	48,397	—	(12,659)	35,738
Total operating costs	27,710	19,137	48,397	—	(14,355)	80,889
Depreciation, depletion, and amortization	27,135	11,318	11,436	80	—	49,969
Impairments	49,443	—	—	—	—	49,443
Total expenses	104,288	30,455	59,833	80	(14,355)	180,301
Total operating income (loss) (1)	(25,434)	(4,636)	3,257	(80)	—	
General and administrative expense	—	—	—	(8,852)	—	(8,852)
Gain on disposition of assets	—	151	—	3	—	154
Gain on derivatives	—	—	—	6,969	—	6,969
Interest expense, net	—	—	—	(10,002)	—	(10,002)
Other	—	—	—	3	—	3
Income (loss) before income taxes	$ (25,434)	$ (4,485)	$ 3,257	$ (11,959)	$ —	$ (38,621)

(1) Operating income (loss) is total operating revenues less operating expenses, depreciation, depletion, amortization, and impairment and does not include general corporate expenses, gain on disposition of assets, gain on derivatives, interest expense, other income (loss), or income taxes.

	Nine Months Ended September 30, 2017					
	Oil and Natural Gas	Contract Drilling	Mid-stream	Other	Eliminations	Total Consolidated
	(In thousands)					
Revenues:						
Oil and natural gas	$ 256,241	$ —	$ —	$ —	$ —	$ 256,241
Contract drilling	—	137,617	—	—	(9,558)	128,059
Gas gathering and processing	—	—	198,632	—	(48,139)	150,493
Total revenues	256,241	137,617	198,632	—	(57,697)	534,793
Expenses:						
Operating costs:						
Oil and natural gas	99,349	—	—	—	(3,476)	95,873
Contract drilling	—	99,794	—	—	(8,581)	91,213
Gas gathering and processing	—	—	156,525	—	(44,663)	111,862
Total operating costs	99,349	99,794	156,525	—	(56,720)	298,948
Depreciation, depletion, and amortization	71,544	41,896	32,547	5,558	—	151,545
Total expenses	170,893	141,690	189,072	5,558	(56,720)	450,493
Total operating income (loss) (1)	85,348	(4,073)	9,560	(5,558)	(977)	
General and administrative expense	—	—	—	(26,902)	—	(26,902)
Gain on disposition of assets	176	106	58	813	—	1,153
Gain on derivatives	—	—	—	21,019	—	21,019
Interest expense, net	—	—	—	(28,807)	—	(28,807)
Other	—	—	—	14	—	14
Income (loss) before income taxes	$ 85,524	$ (3,967)	$ 9,618	$ (39,421)	$ (977)	$ 50,777

(1) Operating income (loss) is total operating revenues less operating expenses, depreciation, depletion, and amortization and does not include general corporate expenses, gain on disposition of assets, gain on derivatives, interest expense, other income (loss), or income taxes.

	Nine Months Ended September 30, 2016					
	Oil and Natural Gas	Contract Drilling	Mid-stream	Other	Eliminations	Total Consolidated
	(In thousands)					
Revenues:						
Oil and natural gas	$ 206,318	$ —	$ —	$ —	$ —	$ 206,318
Contract drilling	—	88,786	—	—	—	88,786
Gas gathering and processing	—	—	168,668	—	(35,875)	132,793
Total revenues	206,318	88,786	168,668	—	(35,875)	427,897
Expenses:						
Operating costs:						
Oil and natural gas	98,070	—	—	—	(5,379)	92,691
Contract drilling	—	66,489	—	—	—	66,489
Gas gathering and processing	—	—	129,681	—	(30,496)	99,185
Total operating costs	98,070	66,489	129,681	—	(35,875)	258,365
Depreciation, depletion, and amortization	89,378	34,431	34,410	218	—	158,437
Impairments	161,563	—	—	—	—	161,563
Total expenses	349,011	100,920	164,091	218	(35,875)	578,365
Total operating income (loss) (1)	(142,693)	(12,134)	4,577	(218)	—	
General and administrative expense	—	—	—	(25,811)	—	(25,811)
Gain (loss) on disposition of assets	(324)	1,467	(302) —	(18)	—	823
Loss on derivatives	—	—	—	(4,774)	—	(4,774)
Interest expense, net	—	—	—	(30,225)	—	(30,225)
Other	—	—	—	(11)	—	(11)
Income (loss) before income taxes	$ (143,017)	$ (10,667)	$ 4,275	$ (61,057)	$ —	$ (210,466)

(1) Operating income (loss) is total operating revenues less operating expenses, depreciation, depletion, amortization, and impairment and does not include general corporate expenses, gain (loss) on disposition of assets, loss on derivatives, interest expense, other income (loss), or income taxes.

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

Management's Discussion and Analysis (MD&A) provides you with an understanding of our operating results and financial condition by focusing on changes in certain key measures from year to year or period to period. MD&A is organized into the following sections:

- General;
- Business Outlook;
- Executive Summary;
- Financial Condition and Liquidity;
- New Accounting Pronouncements; and
- Results of Operations.

Please read the information in our most recent Annual Report on Form 10-K with your review of the information below as well as our unaudited condensed consolidated financial statements and related notes.

Unless otherwise indicated or required by the content, when used in this report the terms "company," "Unit," "us," "our," "we," and "its" refer to Unit Corporation or, as appropriate, one or more of its subsidiaries.

General

We operate, manage, and analyze the results of our operations through our three principal business segments:

- *Oil and Natural Gas* – carried out by our subsidiary Unit Petroleum Company. This segment explores, develops, acquires, and produces oil and natural gas properties for our own account.
- *Contract Drilling* – carried out by our subsidiary Unit Drilling Company. This segment contracts to drill onshore oil and natural gas wells for others and for our oil and natural gas segment.
- *Mid-Stream* – carried out by our subsidiary Superior Pipeline Company, L.L.C. and its subsidiaries. This segment buys, sells, gathers, processes, and treats natural gas for third parties and for our oil and natural gas segment.

Business Outlook

As discussed in other parts of this report, our success depends, to a large degree, on the prices we receive for our oil and natural gas production, the demand for oil, natural gas, and NGLs, as well as, the demand for our drilling rigs which, in turn, influences the amounts we can charge for those drilling rigs. While our operations are located within the United States, events outside the United States affect us and our industry.

Deteriorating commodity prices worldwide during the past several years brought about significant and adverse changes to our industry and us. As a result we reduced or stopped, for a period of time, our oil and natural gas segment's drilling activity. Industry wide reductions in drilling activity and spending for extended periods also tends to reduce the rates for and the number of our drilling rigs that we can work. In addition, sustained lower commodity prices impact the liquidity condition of some of our industry partners and customers, which, in turn, could limit their ability to meet their financial obligations to us.

During 2016, commodity prices began to improve. In the fourth quarter of 2016, our oil and natural gas segment began using two of our drilling rigs and has been using two to three of them during the first nine months of 2017. Our contract drilling segment completed the construction and contracted the ninth and tenth BOSS drilling rigs in the fourth quarter of 2016 and the second quarter of 2017, respectively. Our drilling rig segment's rig utilization increased from 16 drilling rigs working as of June 30, 2016, to 33 drilling rigs working as of September 30, 2017. The extent and duration of this improvement remains uncertain.

The reduction in oil, NGLs, and natural gas prices had a number of consequences for us (although, as noted, we are starting to see some improvements). Below are some of those consequences:

- We incurred non-cash ceiling test write-downs in the first nine months of 2016 of $161.6 million ($100.6 million net of tax). We did not have a write-down in the fourth quarter of 2016 or the first three quarters of 2017. It is hard to predict with any reasonable certainty the need for or amount of any future impairments given the many factors that go into the ceiling test calculation including, future pricing, operating costs, drilling and completion costs, upward or downward oil and gas reserve revisions, oil and gas reserve additions, and tax attributes. Subject to these inherent uncertainties, if we hold these same factors constant as they existed at September 30, 2017, and only adjust the 12-month average price to an estimated fourth quarter ending average (holding October 2017 prices constant for the remaining two months of the fourth quarter of 2017), our forward looking expectation is that we will not recognize an impairment in the fourth quarter of 2017. But commodity prices (and other factors) remain volatile and they could negatively impact the 12-month average price resulting in the potential for an impairment in the future.
- We reduced the number of gross wells our oil and natural gas segment drilled in 2016 by approximately 64% from the number drilled in 2015 due to our reduced cash flow. For 2017, we plan to increase the number of gross wells drilled to 60 - 65 wells (depending on future commodity prices).
- The decline in drilling by our customers reduced the average utilization of our drilling rig fleet. At December 31, 2015, we had 26 drilling rigs operating. In 2016, utilization continued downward bottoming out in May 2016 at 13 operating drilling rigs. After May commodity prices began improving for the remainder of the year and we exited 2016 with 21 active rigs. As of September 30, 2017, we had 33 drilling rigs operating (an improvement of 57% over the end of the year). Operators have been increasing drilling, but the extent of further increases remain uncertain. During the second quarter of 2017, we completed the construction of our tenth BOSS drilling rig and all of our BOSS drilling rigs are under contract.
- Due to low ethane price, we continue to operate some of our mid-stream processing facilities in ethane rejection mode which reduces the amount of liquids sold. As long as ethane price relative to natural gas price remains depressed, we expect to continue operating in ethane rejection mode at some of our processing facilities.

Also, as noted elsewhere, beginning on April 4, 2017, we began an at-the-market offering for the sale of shares of our common stock. The offering allows us to sell shares, from time to time, up to an aggregate of $100 million in gross proceeds. As of September 30, 2017, we sold 787,547 shares for $18.6 million , net of offering costs of $0.4 million. Approximately $81.0 million remain available for sale under the program. Net proceeds from the offering will be used to fund (or offset costs of) acquisitions, future capital expenditures, repay amounts outstanding under our revolving credit facility, and general corporate purposes.

On April 3, 2017, we closed an acquisition of certain oil and natural gas assets from an unrelated third party. The acquisition includes approximately 47 proved developed producing wells and 8,300 net acres primarily in Grady and Caddo Counties in western Oklahoma. The final adjusted value of consideration given was $54.3 million . The effective date of this acquisition was January 1, 2017.

Executive Summary

Oil and Natural Gas

Third quarter 2017 production from our oil and natural gas segment was 4,057,000 barrels of oil equivalent (Boe), an increase of 5% over the second quarter of 2017 and a decrease of 3% from the third quarter of 2016 , respectively. The increase over the second quarter of 2017 was from acquired wells and new wells drilled in the first nine months of 2017. The decrease from the third quarter of 2016 was primarily due to the continued production decline of existing wells and reduced drilling activity between the periods. During the quarter, plant outages and delays attributable to hurricane Harvey reduced quarterly production by approximately 100 MBoe. The effects of Harvey were principally due to NGL bottlenecks from fractionation plant partial shut-downs and operational delays on new wells and recompletions. After the end of the quarter, the third-party processing plant for the majority of Unit’s natural gas production in the Gulf Coast area went down due to an equipment failure. The plant was down seven days before operations resumed. Cumulatively, hurricane Harvey, the Texas Panhandle ice storm in the first quarter, and third party plant downtimes will reduce production for the year by approximately 460 MBoe.

Third quarter 2017 oil and natural gas revenues increased 3% over the second quarter of 2017 and increase d 8% over the third quarter of 2016 . The increase over the second quarter of 2017 was due primarily to higher oil and NGL prices and higher production volumes partially offset by lower natural gas prices. The increase over the third quarter of 2016 was due primarily to higher commodity prices partially offset by lower production volumes.

Our oil prices for the third quarter of 2017 increase d 1% over the second quarter of 2017 and increased 11% over the third quarter of 2016 . Our NGLs prices increase d 23% over the second quarter of 2017 and increased 45% over the third quarter of 2016 . Our natural gas prices decrease d 4% from the second quarter of 2017 and increased 3% over the third quarter of 2016 .

Operating cost per Boe produced for the third quarter of 2017 decrease d 2% from the second quarter of 2017 and increase d 35% over the third quarter of 2016 . The decrease from the second quarter of 2017 was primarily due to higher production volumes partially offset by higher lease operating expenses and higher production taxes. The increase over the third quarter of 2016 was primarily due to lower production volumes, increased lease operating expenses, and higher production taxes partially offset by lower salt water disposal expense.

At September 30, 2017 , we had these derivatives outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Oct'17	Natural gas – swap	70,000 MMBtu/day	$3.038	IF – NYMEX (HH)
Nov’17 – Dec'17	Natural gas – swap	60,000 MMBtu/day	$2.960	IF – NYMEX (HH)
Jan’18 – Dec'18	Natural gas – swap	20,000 MMBtu/day	$3.013	IF – NYMEX (HH)
Nov’17 – Dec'17	Natural gas – basis swap	20,000 MMBtu/day	$(0.215)	IF – NYMEX (HH)
Jan’18 – Mar'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.208)	IF – NYMEX (HH)
Nov’18 – Dec'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.208)	IF – NYMEX (HH)
Oct'17	Natural gas – collar	20,000 MMBtu/day	$2.88 - $3.10	IF – NYMEX (HH)
Oct'17	Natural gas – three-way collar	15,000 MMBtu/day	$2.50 - $2.00 - $3.32	IF – NYMEX (HH)
Nov’17 – Dec'17	Natural gas – three-way collar	25,000 MMBtu/day	$2.90 - $2.30 - $3.59	IF – NYMEX (HH)
Jan'18 – Mar'18	Natural gas – three-way collar	60,000 MMBtu/day	$3.29 - $2.63 - $4.07	IF – NYMEX (HH)
Apr'18 – Dec'18	Natural gas – three-way collar	20,000 MMBtu/day	$3.00 - $2.50 - $3.51	IF – NYMEX (HH)
Oct’17 – Dec'17	Crude oil – three-way collar	3,750 Bbl/day	$49.79 - $39.58 - $60.98	WTI – NYMEX
Jan'18 – Dec'18	Crude oil – three-way collar	2,000 Bbl/day	$47.50 - $37.50 - $56.08	WTI – NYMEX
Jan'18 – Dec'18	Crude oil – swap	2,000 Bbl/day	$50.140	WTI – NYMEX

After September 30, 2017 , the following derivative was entered into:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Apr'18 – Oct'18	Natural gas – swap	10,000 MMBtu/day	$2.990	IF – NYMEX (HH)
Apr'18 – Sep'18	Liquids – swap (1)	1,000 Bbl/day	$31.164	OPIS – Mont Belvieu

(1) Type of liquid involved is propane.

For the nine months ended September 30, 2017 , we completed drilling 43 gross wells (15.10 net wells). For all of 2017, we plan to participate in the drilling of approximately 60 to 65 gross wells. Excluding acquisitions and ARO liability, our estimated 2017 capital expenditures for this segment are approximately $216.0 million. Our current 2017 production guidance is approximately 16.0 MMBoe, a decrease of 7% from 2016, although actual results continue to be subject to many factors.

Contract Drilling

The average number of drilling rigs we operated in the third quarter of 2017 was 34.6 compared to 28.8 and 16.0 in the second quarter of 2017 and the third quarter of 2016 , respectively. As of September 30, 2017 , 33 of our drilling rigs were operating.

Revenue for the third quarter of 2017 increased 31% and 100% over the second quarter of 2017 and the third quarter of 2016 , respectively. The increase over the second quarter of 2017 was primarily due to an increase in drilling rigs operating and dayrates. The increase over the third quarter of 2016 was primarily due to increased utilization partially offset by lower dayrates.

Dayrates for the third quarter of 2017 averaged $16,454 , a 3% increase over the second quarter of 2017 and a 6% decrease from the third quarter of 2016 . The increase over the second quarter of 2017 was primarily due to a labor increase that was passed through to contracted rigs. The decrease from the third quarter of 2016 was primarily due to downward pressure on dayrates due to lower demand as higher rate contracts were expiring.

Operating costs for the third quarter of 2017 increased 28% over the second quarter of 2017 and increased 82% over the third quarter of 2016 . The increases were due primarily to more drilling rigs operating.

Almost all of our working drilling rigs were drilling horizontal or directional wells for oil and NGLs. The improved commodity pricing for oil and natural gas that began during the second half of 2016 has increased demand for drilling rigs. Our drilling rig count bottomed out at 13 drilling rigs operating during the second quarter of 2016, but increased to 21 drilling rigs operating at the end of 2016. Our drilling rig count continued to increase during the first three quarters of 2017 to 36 drilling rigs during the third quarter but we ended the third quarter with 33 operating drilling rigs. The future demand for and the availability of drilling rigs to meet that demand will affect our future dayrates.

We have nine term drilling contracts with original terms ranging from six months to two years. Four are up for renewal in the fourth quarter of 2017, three in the first quarter of 2018, one in the second quarter of 2018, and one in 2019. Term contracts may contain a fixed rate during the contract or provide for rate adjustments within a specific range from the existing rate. Some operators with signed term contracts opted to release the drilling rig and pay an early termination penalty for the remaining term of the contract. During the first nine months of 2017, we recorded $0.8 million of early termination fees compared to $3.1 million in the first nine months of 2016.

All ten of our existing BOSS drilling rigs are under contract. Three stacked Mid-Continent SCR drilling rigs were returned to service in the third quarter. One was relocated from our Rocky Mountain division. Three SCR rigs also completed their contracts during the quarter. Our estimated 2017 capital expenditures for this segment are approximately $38.0 million.

Competition to keep qualified labor continues to be an issue we face in this segment. We do not believe this shortage of qualified labor will keep us from working additional drilling rigs, but it could cause some delays in the time to crew new drilling rigs. Beginning in third quarter 2017, we increased compensation for certain drilling rig personnel.

Mid-Stream

Third quarter 2017 liquids sold per day increase d 1% over the second quarter of 2017 and decreased 5% from the third quarter of 2016 , respectively. The increase over the second quarter of 2017 was due to increased volumes available to our processing facilities. The decrease from the third quarter of 2016 was primarily due to less volume available to process at our plants. For the third quarter of 2017 , gas processed per day increase d 4% over the second quarter of 2017 and decrease d 8% from the third quarter of 2016 . The increase over the second quarter of 2017 was primarily due to higher processed volumes from new wells at our Cashion facility and our Hemphill facility. The decrease from the third quarter of 2016 was primarily due to declines in existing volumes, fewer new wells connected, and no offload volume at our Hemphill facility in 2017. For the third quarter of 2017 , gas gathered per day was essentially unchanged and decreased 11% from the second quarter of 2017 and the third quarter of 2016 , respectively. The decrease from the third quarter of 2016 was primarily due to declining gathered volume on our Appalachian gathering systems.

NGLs prices in the third quarter of 2017 increase d 27% over the prices received in the second quarter of 2017 and increased 53% over the prices received in the third quarter of 2016 . Because certain of the contracts used by our mid-stream segment for NGLs transactions are commodity-based contracts–under which we receive a share of the proceeds from the sale of the NGLs–our revenues from those commodity-based contracts fluctuate based on the price of NGLs.

Total operating cost for our mid-stream segment for the third quarter of 2017 increase d 6% over the second quarter of 2017 and increase d 7% over the third quarter of 2016 . Third quarter of 2017 costs were higher than the second quarter of 2017 primarily due to both increased purchase volumes and prices and increased field direct operating expenses. The increase over the third quarter of 2016 was primarily due to higher gas purchase prices and higher field direct operating expenses partialy offset by lower purchase volumes.

In the Appalachian region, our Pittsburgh Mills gathering system, in Allegheny and Butler counties, continues to produce consistent financial results. Our average gathered volume for the third quarter of 2017 is approximately 128.5 MMcf per day.

We connected the new Allen well pad in May and it included five new wells. We did not connect any new wells in the third quarter. We are constructing a pipeline to connect the Miller well pad, which will be the next pad connected to our system. The Miller pad will include seven new wells and we anticipate it will be ready to flow in the third quarter of 2018. Also, we anticipate several in-fill wells to be drilled and connected to our system in the second half of 2018.

At our Hemphill Texas system, our total throughput volume averaged 60.8 MMcf per day for the third quarter of 2017 and our total production of natural gas liquids was approximately 164,000 gallons per day. During the third quarter, we connected two new wells and since the beginning of 2017, we connected four new wells to this processing facility. Our oil and gas segment continues to operate a rig and we anticipate connecting two more wells in the fourth quarter.

At our Cashion processing facility in central Oklahoma, our total throughput volume for the third quarter of 2017 averaged approximately 38.4 MMcf per day and our total production of natural gas liquids was approximately 196,000 gallons per day. Total processing capacity for this facility remains at approximately 45 MMcf per day. We connected four new wells to this system in the third quarter for a total of six new wells connected in 2017. We completed a construction project that allows us to bring additional gas to this processing plant from a third party producer. This new producer will deliver fee-based volume to us for five years or will pay a shortfall fee settled annually. We are in the process of constructing a new pipeline extension which will allow us to connect a new producer to our system. We have connected one well from this producer and plan to connect two more wells in the fourth quarter.

At our Bellmon processing facility in the Mississippian play in north central Oklahoma, we connected two new wells in the third quarter of 2017 and since the beginning of 2017, we connected nine new wells to this processing facility. Our total throughput volume averaged approximately 27.5 MMcf per day. Total natural gas liquids averaged approximately 131,000 gallons per day while operating in ethane recovery mode at this facility. Total processing capacity at this system is approximately 90 MMcf per day.

At our Segno gathering facility in Southeast Texas, gathered volume for the third quarter of 2017 averaged approximately 81.5 MMcf per day. At this facility, we have increased our gathering and dehydration capacity to approximately 120 MMcf per day. We have connected two new wells to this system in 2017.

Our estimated 2017 capital expenditures for this segment are approximately $18.9 million.

Financial Condition and Liquidity

Summary

Our financial condition and liquidity depends on the cash flow from our operations and borrowings under our credit agreement. Our cash flow is based primarily on:

- the amount of natural gas, oil, and NGLs we produce;
- the prices we receive for our natural gas, oil, and NGLs production;
- the demand for and the dayrates we receive for our drilling rigs; and
- the fees and margins we obtain from our natural gas gathering and processing contracts.

We believe we will have enough cash flow and liquidity to meet our obligations and remain in compliance with our debt covenants for the next twelve months. Our ability to meet our debt covenants (under our credit agreement and our 2011 Indenture) and our capacity to incur additional indebtedness will depend on our future performance, which will be affected by financial, business, economic, regulatory, and other factors. For example, if we experience lower oil, natural gas, and NGLs prices since the last borrowing base determination under our credit agreement, it could cause a reduction of the borrowing base and therefore reduce or limit our ability to incur indebtedness. We monitor our liquidity and capital resources, endeavor to anticipate potential covenant compliance issues, and work, where possible, with our lenders to address those issues ahead of time.

	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016	% Change
	(In thousands except percentages)		
Net cash provided by operating activities	$ 184,792	$ 197,762	(7)%
Net cash used in investing activities	(204,184)	(107,509)	90 %
Net cash provided by (used in) financing activities	19,321	(90,175)	121 %
Net increase (decrease) in cash and cash equivalents	$ (71)	$ 78	

Cash Flows from Operating Activities

Our operating cash flow is primarily influenced by the prices we receive for our oil, NGLs, and natural gas production, the quantity of oil, NGLs, and natural gas we produce, settlements of derivative contracts, and third-party demand for our drilling rigs and mid-stream services and the rates we obtain for those services. Our cash flows from operating activities are also impacted by changes in working capital.

Net cash provided by operating activities in the first nine months of 2017 decrease d by $13.0 million as compared to the first nine months of 2016 . The decrease was the result of changes in operating assets and liabilities related to the timing of cash receipts and disbursements partially offset by higher profit margins in all three segments.

Cash Flows from Investing Activities

We dedicate and expect to continue to dedicate a substantial portion of our capital budget to the exploration for and production of oil, NGLs, and natural gas. These expenditures are necessary to off-set the inherent production declines typically experienced in oil and gas wells.

Cash flows used in investing activities increase d by $96.7 million for the first nine months of 2017 compared to the first nine months of 2016 . The change was due primarily to an increase in capital expenditures due to an oil and gas property acquisition, the restarting of our drilling program in 2017, the construction of two new BOSS drilling rigs, and a decrease in the proceeds received from the disposition of assets. See additional information on capital expenditures below under Capital Requirements.

Cash Flows from Financing Activities

Cash flows provided by financing activities increased by $109.5 million for the first nine months of 2017 compared to the first nine months of 2016 . The increase was primarily due to proceeds from the ATM common stock program and an increase in book overdrafts in 2017 coupled with almost no change in net borrowing after paying down long-term debt in 2016.

At September 30, 2017 , we had unrestricted cash totaling $0.8 million and had borrowed $162.1 million of the $475.0 million we had elected to then have available under our credit agreement. Our credit agreement is used primarily for working capital and capital expenditures.

The following is a summary of certain financial information as of September 30, 2017 and 2016 and for the nine months ended September 30, 2017 and 2016 :

	September 30, 2017	September 30, 2016	% Change
	(In thousands except percentages)		
Working capital	$ (62,181)	$ (42,342)	(47)%
Long-term debt less debt issuance costs	$ 803,833	$ 854,583	(6)%
Shareholders’ equity	$ 1,251,905	$ 1,189,576	5 %
Net income (loss)	$ 28,693	$ (137,307)	121 %

Working Capital

Typically, our working capital balance fluctuates, in part, because of the timing of our trade accounts receivable and accounts payable and the fluctuation in current assets and liabilities associated with the mark to market value of our derivative activity. We had negative working capital of $62.2 million and $42.3 million as of September 30, 2017 and 2016 , respectively. The increase in negative working capital is primarily due to increased accounts payable due to increased activity in our drilling program and increased drilling rig utilization and the reclassification of current deferred tax asset to long-term asset per ASU 2015-17 partially offset by increased accounts receivable from increased revenues and the change in the value of outstanding derivatives. Our credit agreement is used primarily for working capital and capital expenditures. At September 30, 2017 , we had borrowed $162.1 million of the $475.0 million available under our credit agreement. The effect of our derivative contracts increased working capital by $0.4 million as of September 30, 2017 and decreased working capital by $5.6 million as of September 30, 2016 .

The following table summarizes certain operating information:

	Nine Months Ended September 30,		% Change
	2017	2016	
Oil and Natural Gas:			
Oil production (MBbls)	1,990	2,260	(12)%
NGLs production (MBbls)	3,476	3,745	(7)%
Natural gas production (MMcf)	37,317	42,376	(12)%
Average oil price per barrel received	$ 47.62	$ 38.71	23 %
Average oil price per barrel received excluding derivatives	$ 46.99	$ 36.88	27 %
Average NGLs price per barrel received	$ 17.05	$ 10.16	68 %
Average NGLs price per barrel received excluding derivatives	$ 17.05	$ 10.16	68 %
Average natural gas price per Mcf received	$ 2.50	$ 1.98	26 %
Average natural gas price per Mcf received excluding derivatives	$ 2.55	$ 1.80	42 %
Contract Drilling:			
Average number of our drilling rigs in use during the period	29.7	16.7	78 %
Total number of drilling rigs owned at the end of the period	95	94	1 %
Average dayrate	$ 16,120	$ 18,147	(11)%
Mid-Stream:			
Gas gathered—Mcf/day	385,846	417,722	(8)%
Gas processed—Mcf/day	133,986	160,411	(16)%
Gas liquids sold—gallons/day	518,054	536,911	(4)%
Number of natural gas gathering systems	25	26	(4)%
Number of processing plants	13	14	(7)%

Oil and Natural Gas Operations

Any significant change in oil, NGLs, or natural gas prices has a material effect on our revenues, cash flow, and the value of our oil, NGLs, and natural gas reserves. Generally, prices and demand for domestic natural gas are influenced by weather conditions, supply imbalances, and by worldwide oil price levels. Global oil market developments primarily influence domestic oil prices. These factors are beyond our control and we cannot predict nor measure their future influence on the prices we will receive.

Based on our first nine months of 2017 production, a $0.10 per Mcf change in what we are paid for our natural gas production, without the effect of derivatives, would cause a corresponding $398,000 per month ($4.8 million annualized) change in our pre-tax operating cash flow. The average price we received for our natural gas production, including the effect of derivatives, during the first nine months of 2017 was $2.50 compared to $1.98 for the first nine months of 2016 . Based on our first nine months of 2017 production, a $1.00 per barrel change in our oil price, without the effect of derivatives, would have a $212,000 per month ($2.5 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGLs prices, without the effect of derivatives, would have a $372,000 per month ($4.5 million annualized) change in our pre-tax operating cash flow. In the first nine months of 2017 , our average oil price per barrel received, including the effect of derivatives, was $47.62 compared with an average oil price, including the effect of derivatives, of $38.71 in the first nine months of 2016 and our first nine months of 2017 average NGLs price per barrel received was $17.05 compared with an average NGLs price per barrel of $10.16 in the first nine months of 2016 .

Because commodity prices affect the value of our oil, NGLs, and natural gas reserves, declines in those prices can cause a decline in the carrying value of our oil and natural gas properties. At September 30, 2017 , the 12-month average unescalated prices were $49.81 per barrel of oil, $27.70 per barrel of NGLs, and $3.00 per Mcf of natural gas, and then are adjusted for price differentials. We did not have to take a write down in the first nine months of 2017.

It is hard to predict with any reasonable certainty the need for or amount of any future impairments given the many factors that go into the ceiling test calculation including, but not limited to, future pricing, operating costs, drilling and completion costs, upward or downward oil and gas reserve revisions, oil and gas reserve additions, and tax attributes. Subject to these inherent uncertainties, if we hold these same factors constant as they existed at September 30, 2017, and only adjust the 12-month average price to an estimated fourth quarter ending average (holding October 2017 prices constant for the remaining two months of the fourth quarter of 2017), our forward looking expectation is that we will not recognize an impairment in the fourth quarter of 2017. But commodity prices (and other factors) remain volatile and they could negatively affect the 12-month average price resulting in the potential for an impairment in the future.

Our natural gas production is sold to intrastate and interstate pipelines and to independent marketing firms and gatherers under contracts with terms ranging from one month to five years. Our oil production is sold to independent marketing firms generally under six month contracts.

Contract Drilling Operations

Many factors influence the number of drilling rigs we are working and the costs and revenues associated with that work. These factors include the demand for drilling rigs in our areas of operation, competition from other drilling contractors, the prevailing prices for oil, NGLs, and natural gas, availability and cost of labor to run our drilling rigs, and our ability to supply the equipment needed.

Most of our working drilling rigs were drilling horizontal or directional wells for oil and NGLs. The improved commodity pricing for oil and natural gas that began during the second half of 2016 has increased demand for drilling rigs. These factors ultimately affect the demand and mix of the type of drilling rigs used by our customers. The future demand for and the availability of drilling rigs to meet that demand affect our future dayrates. For the first nine months of 2017 , our average dayrate was $16,120 per day compared to $18,147 per day for the first nine months of 2016 . The average number of our drilling rigs used in the first nine months of 2017 was 29.7 drilling rigs compared with 16.7 drilling rigs in the first nine months of 2016 . Based on the average utilization of our drilling rigs during the first nine months of 2017 , a $100 per day change in dayrates has a $2,970 per day ($1.1 million annualized) change in our pre-tax operating cash flow.

Our contract drilling segment provides drilling services for our exploration and production segment. Some of the drilling services we perform on our properties are, depending on the timing of those services, deemed to be associated with acquiring an ownership interest in the property. In those cases, revenues and expenses for those services are eliminated in our statement of operations, with any profit recognized as a reduction in our investment in our oil and natural gas properties. The contracts for these services are issued under the same conditions and rates as the contracts entered into with unrelated third parties. We eliminated revenue of $9.6 million for the first nine months of 2017 from our contract drilling segment and eliminated the associated operating expense of $8.6 million yielding $1.0 million as a reduction to the carrying value of our oil and natural gas properties. We eliminated no revenue in our contract drilling segment for the first nine months of 2016.

Mid-Stream Operations

Our mid-stream segment is engaged primarily in the buying, selling, gathering, processing, and treating of natural gas. It operates three natural gas treatment plants, 13 processing plants, 25 gathering systems, and approximately 1,480 miles of pipeline. It operates in Oklahoma, Texas, Kansas, Pennsylvania, and West Virginia. Besides serving third parties, this segment also enhances our ability to gather and market our own natural gas and NGLs and serving as a mechanism through which we can construct or acquire existing natural gas gathering and processing facilities. During the first nine months of 2017 and 2016 , our mid-stream operations purchased $43.2 million and $28.5 million , respectively, of our natural gas production and NGLs, and provided gathering and transportation services of $4.9 million and $7.4 million , respectively. Intercompany revenue from services and purchases of production between this business segment and our oil and natural gas segment has been eliminated in our unaudited condensed consolidated financial statements.

This segment gathered an average of 385,846 Mcf per day in the first nine months of 2017 compared to 417,722 Mcf per day in the first nine months of 2016 . It processed an average of 133,986 Mcf per day in the first nine months of 2017 compared to 160,411 Mcf per day in the first nine months of 2016 . The amount of NGLs sold was 518,054 gallons per day in the first nine months of 2017 compared to 536,911 gallons per day in the first nine months of 2016 . Gas gathered volumes per day in the first nine months of 2017 decrease d 8% compared to the first nine months of 2016 primarily due to declines in existing volumes, fewer new wells connected, and no offload volume at our Hemphill facility in 2017. Gas processed volumes for the first nine months of 2017 decrease d 16% from the first nine months of 2016 due to declines in existing volumes, fewer new wells connected to our processing systems, and no offload volume at our Hemphill facility in 2017. NGLs sold decrease d 4% from the comparative period due to less volume available to process at our plants.

At-the-Market (ATM) Common Stock Program

On April 4, 2017, we entered into a Distribution Agreement (the Agreement) with a sales agent, under which we may offer and sell, from time to time, through the sales agent shares of our common stock, par value $0.20 per share (the Shares), up to an aggregate offering price of $100.0 million. We intend to use the net proceeds from these sales to fund (or offset costs of) acquisitions, future capital expenditures, repay amounts outstanding under our revolving credit facility, and general corporate purposes.

Under the Agreement, the sales agent may sell the Shares by methods deemed to be an “at-the-market” offering as defined in Rule 415 promulgated under the Securities Act of 1933, as amended, including sales made directly on the NYSE, on any other existing trading market for the Shares or to or through a market maker. In addition, under the Agreement, the sales agent may sell the Shares by any other method permitted by law, including in privately negotiated transactions. Subject to the terms of the Agreement, the sales agent will use commercially reasonable efforts, consistent with its normal trading and sales practices and applicable state and federal law, rules and regulations and the rules of the NYSE, to sell the Shares from time to time, based on our instructions (including any price, time or size limits or other customary parameters or conditions we may impose).

We do not have to make any sales of the Shares under the Agreement. The offering of Shares under the Agreement will terminate on the earlier of (1) the sale of all of the Shares subject to the Agreement or (2) the termination of the Agreement by the sales agent or us. We will pay the sales agent a commission of 2.0% of the gross sales price per share sold and have agreed to provide the sales agent with customary indemnification and contribution rights.

As of October 20, 2017, we sold 787,547 shares of our common stock resulting in net proceeds of approximately $18.6 million.

Our Credit Agreement and Senior Subordinated Notes

Credit Agreement. Our Senior Credit Agreement (credit agreement) is scheduled to mature on April 10, 2020 . Under the credit agreement, the amount we can borrow is the lesser of the amount we elect as the commitment amount or the value of the borrowing base as determined by the lenders, but in either event not to exceed $875.0 million . Our borrowing base and elected commitment is $475.0 million . We are charged a commitment fee of 0.50% on the amount available but not borrowed. That fee varies based on the amount borrowed as a percentage of the total borrowing base. We paid $1.0 million in origination, agency, syndication, and other related fees. We are amortizing these fees over the life of the credit agreement. Under the credit agreement, we pledged the following collateral: (a) 85% of the proved developed producing (discounted as present worth at 8%) total value of our oil and gas properties and (b) 100% of our ownership interest in our mid-stream affiliate, Superior Pipeline Company, L.L.C.

The current lenders under our credit agreement and their respective participation interests are:

Lender	Participation Interest
BOK (BOKF, NA, dba Bank of Oklahoma)	17%
Compass Bank	17%
BMO Harris Financing, Inc.	15%
Bank of America, N.A.	15%
Comerica Bank	8%
Wells Fargo Bank, N.A.	8%
Canadian Imperial Bank of Commerce	8%
Toronto Dominion (New York), LLC	8%
The Bank of Nova Scotia	4%
	100%

The borrowing base amount–which is subject to redetermination by the lenders on April 1st and October 1st of each year–is based primarily on a percentage of the discounted future value of our oil and natural gas reserves. The October 2017 redetermination did not result in any changes. We or the lenders may request a onetime special redetermination of the borrowing base between each scheduled redetermination. In addition, we may request a redetermination following the completion of an acquisition that meets the requirements in the credit agreement.

At our election, any part of the outstanding debt under the credit agreement may be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest is computed as the LIBOR base for the term plus 2.00% to 3.00% depending on the level of debt as a percentage of the borrowing base and is payable at the end of each term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the prime rate specified in the credit agreement that cannot be less than LIBOR plus 1.00% . Interest is payable at the end of each month and the principal may be repaid in whole or in part at any time, without a premium or penalty. At September 30, 2017 and October 20, 2017, borrowings were $162.1 million and $162.7 million, respectively.

We can use borrowings for financing general working capital requirements for (a) exploration, development, production, and acquisition of oil and gas properties, (b) acquisitions and operation of mid-stream assets, (c) issuance of standby letters of credit, (d) contract drilling services and acquisition of contract drilling equipment, and (e) general corporate purposes.

The credit agreement prohibits, among other things:

- the payment of dividends (other than stock dividends) during any fiscal year over 30% of our consolidated net income for the preceding fiscal year;
- the incurrence of additional debt with certain limited exceptions; and
- the creation or existence of mortgages or liens, other than those in the ordinary course of business and with certain limited exceptions, on any of our properties, except in favor of our lenders.

The credit agreement also requires that we have at the end of each quarter:

- a current ratio (as defined in the credit agreement) of not less than 1 to 1 .

Through the quarter ending March 31, 2019, the credit agreement also requires that we have at the end of each quarter:

- a senior indebtedness ratio of senior indebtedness to consolidated EBITDA (as defined in the credit agreement) for the most recently ended rolling four quarters of no greater than 2.75 to 1.

Beginning with the quarter ending June 30, 2019, and for each following quarter, the credit agreement requires:

- a leverage ratio of funded debt to consolidated EBITDA (as defined in the credit agreement) for the most recently ended rolling four fiscal quarters of no greater than 4 to 1 .

As of September 30, 2017 , we were in compliance with the credit agreement covenants.

6.625% Senior Subordinated Notes. We have an aggregate principal amount of $650.0 million , 6.625% senior subordinated notes (the Notes) outstanding. Interest on the Notes is payable semi-annually (in arrears) on May 15 and November 15 of each year. The Notes mature on May 15, 2021 . In issuing the Notes, we incurred fees of $14.7 million that are being amortized as debt issuance cost over the life of the Notes.

The Notes are subject to an Indenture dated as of May 18, 2011, between us and Wilmington Trust, National Association (successor to Wilmington Trust FSB), as Trustee (the Trustee), as supplemented by the First Supplemental Indenture dated as of May 18, 2011, between us, the Guarantors, and the Trustee, and as further supplemented by the Second Supplemental Indenture dated as of January 7, 2013, between us, the Guarantors, and the Trustee (as supplemented, the 2011 Indenture), establishing the terms of and providing for issuing the Notes. The Guarantors are most of our direct and indirect subsidiaries. The discussion of the Notes in this report is qualified by and subject to the actual terms of the 2011 Indenture.

Unit, as the parent company, has no independent assets or operations. The guarantees by the Guarantors of the Notes (registered under registration statements) are full and unconditional, joint and several, subject to certain automatic customary releases, are subject to certain restrictions on the sale, disposition, or transfer of the capital stock or substantially all of the assets of a subsidiary guarantor, and other conditions and terms set out in the 2011 Indenture. Any of our subsidiaries that are not Guarantors are minor. There are no significant restrictions on our ability to receive funds from any of our subsidiaries through dividends, loans, advances, or otherwise.

We may redeem all or, occasionally, a part of the Notes at certain redemption prices, plus accrued and unpaid interest. If a “change of control” occurs, subject to certain conditions, we must offer to repurchase from each holder all or any part of that holder’s Notes at a purchase price in cash equal to 101% of the principal amount of the Notes plus accrued and unpaid interest to the date of purchase. The 2011 Indenture contains customary events of default. The 2011 Indenture also contains covenants including those that limit our ability and the ability of certain of our subsidiaries to incur or guarantee additional indebtedness; pay dividends on our capital stock or redeem capital stock or subordinated indebtedness; transfer or sell assets; make investments; incur liens; enter into transactions with our affiliates; and merge or consolidate with other companies. We were in compliance with all covenants of the Notes as of September 30, 2017 .

Capital Requirements

Oil and Natural Gas Segment Dispositions, Acquisitions, and Capital Expenditures. Most of our capital expenditures for this segment are discretionary and directed toward future growth. Our decisions to increase our oil, NGLs, and natural gas reserves through acquisitions or through drilling depends on the prevailing or expected market conditions, potential return on investment, future drilling potential, and opportunities to obtain financing under the circumstances which provide us with flexibility in deciding when and if to incur these costs. We completed drilling 43 gross wells (15.10 net wells) in the first nine months of 2017 compared to 15 gross wells (7.77 net wells) in the first nine months of 2016 .

On April 3, 2017, we closed an acquisition of certain oil and natural gas assets located primarily in Grady and Caddo Counties in western Oklahoma. The final adjusted value of consideration given was $54.3 million . As of January 1, 2017, the effective date of the acquisition, the estimated proved oil and gas reserves of the acquired properties were 3.2 million barrels of oil equivalent (MMBoe). The acquisition added approximately 8,300 net oil and gas leasehold acres to our core Hoxbar area in southwestern Oklahoma including approximately 47 proved developed producing wells. This acquisition included 13 potential horizontal drilling locations not otherwise included in our existing acreage. Of the acreage acquired, approximately 71% was held by production. We also received one gathering system as part of the transaction.

Capital expenditures for oil and gas properties on the full cost method for the first nine months of 2017 by this segment, excluding $56.4 million for acquisitions and a $2.8 million in the ARO liability, totaled $143.7 million. Capital expenditures for the first nine months of 2016 , excluding a $29.4 million reduction in the ARO liability, totaled $91.9 million.

We plan to participate in drilling approximately 60 to 65 gross wells in 2017 and our total estimated capital expenditures (excluding any possible acquisitions) for this segment are approximately $216.0 million. Whether we can drill the full number of wells planned depends on several factors, many of which are beyond our control, including the availability of drilling rigs, availability of pressure pumping services, prices for oil, NGLs, and natural gas, demand for oil, NGLs, and natural gas, the cost to drill wells, the weather, and the efforts of outside industry partners.

Contract Drilling Segment Dispositions, Acquisitions, and Capital Expenditures. During the first quarter of 2017, we were awarded a term contract to build our tenth BOSS rig. Construction was completed and the drilling rig was placed into service late in the second quarter.

Our estimated 2017 capital expenditures for this segment are approximately $38.0 million. At September 30, 2017, we had commitments to purchase approximately $3.9 million for drilling equipment over the next year. We have spent $30.0 million for capital expenditures during the first nine months of 2017 , compared to $7.2 million for capital expenditures during the first nine months of 2016 .

Mid-Stream Acquisitions and Capital Expenditures . In the Appalachian region, our Pittsburgh Mills gathering system, in Allegheny and Butler counties, continues to produce consistent financial results. Our average gathered volume for the third quarter of 2017 is approximately 128.5 MMcf per day. We connected the new Allen well pad in May and it included five new wells. We did not connect any new wells in the third quarter. We are constructing a pipeline to connect the Miller well pad, which will be the next pad connected to our system. The Miller pad will include seven new wells and we anticipate it will be ready to flow in the third quarter of 2018. Also, we anticipate several in-fill wells to be drilled and connected to our system in the second half of 2018.

At our Hemphill Texas system, our total throughput volume averaged 60.8 MMcf per day for the third quarter of 2017 and our total production of natural gas liquids was approximately 164,000 gallons per day. During the third quarter, we connected two new wells and since the beginning of 2017, we connected four new wells to this processing facility. Our oil and gas segment continues to operate a rig and we anticipate connecting two more wells in the fourth quarter.

At our Cashion processing facility in central Oklahoma, our total throughput volume for the third quarter of 2017 averaged approximately 38.4 MMcf per day and our total production of natural gas liquids was approximately 196,000 gallons per day. Total processing capacity for this facility remains at approximately 45 MMcf per day. We connected four new wells to this system in the third quarter for a total of six new wells connected in 2017. We completed a construction project that allows us to bring additional gas to this processing plant from a third party producer. This new producer will deliver fee-based volume to us for five years or will pay a shortfall fee settled annually. We are in the process of constructing a new pipeline extension which will allow us to connect a new producer to our system. We have connected one well from this producer and plan to connect two more wells in the fourth quarter.

At our Bellmon processing facility in the Mississippian play in north central Oklahoma, we connected two new wells in the third quarter of 2017 and since the beginning of 2017, we connected nine new wells to this processing facility. Our total throughput volume averaged approximately 27.5 MMcf per day. Total natural gas liquids averaged approximately 131,000 gallons per day while operating in ethane recovery mode at this facility. Total processing capacity at this system is approximately 90 MMcf per day.

At our Segno gathering facility in Southeast Texas, gathered volume for the third quarter of 2017 averaged approximately 81.5 MMcf per day. At this facility, we have increased our gathering and dehydration capacity to approximately 120 MMcf per day. We have connected two new wells to this system in 2017.

During the first nine months of 2017, our mid-stream segment incurred $10.1 million in capital expenditures as compared to $11.1 million in the first nine months of 2016. For 2017, our estimated capital expenditures are approximately $18.9 million.

Contractual Commitments

At September 30, 2017 , we had certain contractual obligations including:

	Payments Due by Period				
	Total	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Long-term debt [1]	$ 981,786	$ 48,443	$ 256,444	$ 676,899	$ —
Operating leases [2]	4,698	3,209	1,200	289	—
Capital lease interest and maintenance [3]	7,653	2,362	4,254	1,037	—
Drill pipe, drilling components, and equipment purchases [4]	3,887	3,887	—	—	—
Total contractual obligations	$ 998,024	$ 57,901	$ 261,898	$ 678,225	$ —

(1) See previous discussion in MD&A regarding our long-term debt. This obligation is presented in accordance with the terms of the Notes and credit agreement and includes interest calculated using our September 30, 2017 interest rates of 6.625% for the Notes and 3.3% for the credit agreement. Our credit agreement has a maturity date of April 10, 2020 .

(2) We lease office space or yards in Edmond and Oklahoma City, Oklahoma; Houston, Texas; Englewood, Colorado; Pinedale, Wyoming; and Canonsburg, Pennsylvania under the terms of operating leases expiring through December 2021. Additionally, we have several equipment leases and lease space on short-term commitments to stack excess drilling rig equipment and production inventory.

(3) Maintenance and interest payments are included in our capital lease agreements. The capital leases are discounted using annual rates of 4.00%. Total maintenance and interest remaining are $6.3 million and $1.3 million , respectively.

(4) We have committed to pay $3.9 million for drilling rig components, drill pipe, and related equipment over the year.

At September 30, 2017 , we also had the following commitments and contingencies that could create, increase, or accelerate our liabilities:

	Estimated Amount of Commitment Expiration Per Period				
Other Commitments	**Total Accrued**	**Less Than 1 Year**	**2-3 Years**	**4-5 Years**	**After 5 Years**
			(In thousands)		
Deferred compensation plan [1]	$ 5,287	Unknown	Unknown	Unknown	Unknown
Separation benefit plans [2]	$ 6,020	$ 775	Unknown	Unknown	Unknown
Asset retirement liability [3]	$ 75,485	$ 2,947	$ 48,778	$ 4,247	$ 19,513
Gas balancing liability [4]	$ 3,322	Unknown	Unknown	Unknown	Unknown
Repurchase obligations [5]	$ —	Unknown	Unknown	Unknown	Unknown
Workers' compensation liability [6]	$ 13,420	$ 6,699	$ 1,699	$ 937	$ 4,085
Capital leases obligations [7]	$ 16,161	$ 3,806	$ 8,083	$ 4,272	$ —
Other	$ —	Unknown	$ —	Unknown	Unknown

(1) We provide a salary deferral plan which allows participants to defer the recognition of salary for income tax purposes until actual distribution of benefits, which occurs at either termination of employment, death, or certain defined unforeseeable emergency hardships. We recognize payroll expense and record a liability, included in other long-term liabilities in our Unaudited Condensed Consolidated Balance Sheets, at the time of deferral.

(2) Effective January 1, 1997, we adopted a separation benefit plan ("Separation Plan"). The Separation Plan allows eligible employees whose employment is involuntarily terminated or, in the case of an employee who has completed 20 years of service, voluntarily or involuntarily terminated, to receive benefits equivalent to four weeks salary for every whole year of service completed with the company up to a maximum of 104 weeks. To receive payments the recipient must waive certain claims against us in exchange for receiving the separation benefits. On October 28, 1997, we adopted a Separation Benefit Plan for Senior Management ("Senior Plan"). The Senior Plan provides certain officers and key executives of the company with benefits generally equivalent to the Separation Plan. The Compensation Committee of the Board of Directors has absolute discretion in the selection of the individuals covered in this plan. Currently there are no participants in the Senior Plan. On May 5, 2004 we also adopted the Special Separation Benefit Plan ("Special Plan"). This plan is identical to the Separation Benefit Plan with the exception that the benefits under the plan vest on the earliest of a participant's reaching the age of 65 or serving 20 years with the company.

(3) When a well is drilled or acquired, under ASC 410 "Accounting for Asset Retirement Obligations," we record the discounted fair value of liabilities associated with the retirement of long-lived assets (mainly plugging and abandonment costs for our depleted wells).

(4) We have recorded a liability for those properties we believe do not have sufficient oil, NGLs, and natural gas reserves to allow the under-produced owners to recover their under-production from future production volumes.

(5) We formed The Unit 1984 Oil and Gas Limited Partnership and the 1986 Energy Income Limited Partnership along with private limited partnerships (the "Partnerships") with certain qualified employees, officers and directors from 1984 through 2011. One of our subsidiaries serves as the general partner of each of these programs. Effective December 31, 2014, The Unit 1984 Oil and Gas Limited Partnership dissolved and effective December 31, 2016, the two 1986 partnerships were dissolved. The Partnerships were formed for the purpose of conducting oil and natural gas acquisition, drilling and development operations and serving as co-general partner with us in any additional limited partnerships formed during that year. The Partnerships participated on a proportionate basis with us in most drilling operations and most producing property acquisitions commenced by us for our own account during the period from the formation of the Partnership through December 31 of that year. These partnership agreements require, on the election of a limited partner, that we repurchase the limited partner's interest at amounts to be determined by appraisal in the future. Repurchases in any one year are limited to 20% of the units outstanding. We had no repurchases in the first nine months of 2016. We made repurchases of approximately $2,900 during the first nine months of 2017.

(6) We have recorded a liability for future estimated payments related to workers' compensation claims primarily associated with our contract drilling segment.

(7) The amount includes commitments under capital lease arrangements for compressors in our mid-stream segment.

Derivative Activities

Periodically we enter into derivative transactions locking in the prices to be received for a portion of our oil, NGLs, and natural gas production.

Commodity Derivatives . Our commodity derivatives are intended to reduce our exposure to price volatility and manage price risks. Our decision on the type and quantity of our production and the price(s) of our derivative(s) is based, in part, on our view of current and future market conditions. At September 30, 2017 , based on our third quarter 2017 average daily production, the approximated percentages of our production under derivative contracts are as follows:

	Q3	Q4	Q1	Q2	Q3	Q4
	2017		2018			
Daily oil production	54%	54%	58%	58%	58%	58%
Daily natural gas production	74%	64%	56%	28%	28%	28%

With respect to the commodities subject to derivative contracts, those contracts serve to limit the risk of adverse downward price movements. However, they also limit increases in future revenues that would otherwise result from price movements above the contracted prices.

The use of derivative transactions carries with it the risk that the counterparties may not be able to meet their financial obligations under the transactions. Based on our September 30, 2017 evaluation, we believe the risk of non-performance by our counterparties is not material. At September 30, 2017 , the fair values of the net assets (liabilities) we had with each of the counterparties to our commodity derivative transactions are as follows:

	September 30, 2017
	(In millions)
Bank of Montreal	$ 0.9
Scotiabank	(0.1)
Canadian Imperial Bank of Commerce	(0.3)
Bank of America	(0.4)
Total assets	$ 0.1

If a legal right of set-off exists, we net the value of the derivative transactions we have with the same counterparty in our Unaudited Condensed Consolidated Balance Sheets. At September 30, 2017 , we recorded the fair value of our commodity derivatives on our balance sheet as current derivative assets of $1.0 million, and current and non-current derivative liabilities of $0.6 million and $0.3 million, respectively. At December 31, 2016, we recorded the fair value of our commodity derivatives on our balance sheet as non-current derivative assets of $0.4 million , and current and non-current derivative liabilities of $21.6 million and $0.4 million , respectively.

For our economic hedges any changes in their fair value occurring before their maturity (i.e., temporary fluctuations in value) are reported in gain (loss) on derivatives in our Unaudited Condensed Consolidated Statements of Operations. These gains (losses) at September 30 are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In thousands)			
Gain (loss) on derivatives:				
Gain (loss) on derivatives, included are amounts settled during the period of $840, ($457), ($729) and $11,735, respectively	$ (2,614)	$ 6,969	$ 21,019	$ (4,774)
	$ (2,614)	$ 6,969	$ 21,019	$ (4,774)

Stock and Incentive Compensation

During the first nine months of 2017 , we granted awards covering 698,276 shares of restricted stock. These awards had an estimated fair value as of their grant date of $17.2 million . Compensation expense will be recognized over the three year vesting periods, and during the nine months of 2017 , we recognized $5.0 million in compensation expense and capitalized $0.8 million for these awards. During the first nine months of 2017 , we recognized compensation expense of $9.0 million for all of our restricted stock, stock options, and SAR grants and capitalized $1.3 million of compensation cost for oil and natural gas properties.

During the first nine months of 2016, we granted awards covering 728,951 shares of restricted stock. These awards had an estimated fair value as of their grant date of $4.3 million. Compensation expense will be recognized over the three year vesting periods, and during the nine months of 2016, we recognized $1.1 million in compensation expense and capitalized $0.2 million for these awards. During the first nine months of 2016, we recognized compensation expense of $7.2 million for all of our restricted stock, stock options, and SAR grants and capitalized $1.6 million of compensation cost for oil and natural gas properties.

Insurance

We are self-insured for certain losses relating to workers' compensation, general liability, control of well, and employee medical benefits. Insured policies for other coverage contain deductibles or retentions per occurrence that range from zero to $1.0 million. We have purchased stop-loss coverage in order to limit, to the extent feasible, per occurrence and aggregate exposure to certain types of claims. There is no assurance that the insurance coverage we have will protect us against liability from all potential consequences. If insurance coverage becomes more expensive, we may choose to self-insure, decrease our limits, raise our deductibles, or any combination of these rather than pay higher premiums.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships

We are the general partner of 13 oil and natural gas partnerships which were formed privately or publicly. Each partnership's revenues and costs are shared under formulas set out in that partnership's agreement. The partnerships repay us for contract drilling, well supervision, and general and administrative expense. Related party transactions for contract drilling and well supervision fees are the related party's share of such costs. These costs are billed on the same basis as billings to unrelated third parties for similar services. General and administrative reimbursements consist of direct general and administrative expense incurred on the related party's behalf as well as indirect expenses assigned to the related parties. Allocations are based on the related party's level of activity and are considered by us to be reasonable. For the first nine months of 2017 and 2016 , the total we received for all of these fees was $0.1 million and $0.2 million, respectively. Our proportionate share of assets, liabilities, and net income (loss) relating to the oil and natural gas partnerships is included in our unaudited condensed consolidated financial statements.

New Accounting Pronouncements

Compensation—Stock Compensation. The FASB issued ASU 2017-09, to clarify and reduce both (i) diversity in practice and (ii) cost and complexity when applying its guidance to changes in the terms and conditions of a share-based payment award. The amendments are effective for reporting periods beginning after December 15, 2017. We do not believe these amendments will have a material impact on our financial statements.

Intangibles—Goodwill and Other: Simplifying the Test for Goodwill Impairment. The FASB issued ASU 2017-04, to simplify the subsequent measurement of goodwill. The amendments eliminate Step 2 from the goodwill impairment test. The amendments will be effective prospectively for reporting periods beginning after December 31, 2019, and early adoption is permitted. We do not believe these amendments will have a material impact on our financial statements.

Business Combinations; Clarifying the Definition of a Business. The FASB issued ASU 2017-01, clarifying the definition of a business. The amendments are intended to help companies and other organizations evaluate whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. For public companies, the amendments are effective for annual periods beginning after December 15, 2017. We do not believe these amendments will have a material impact on our financial statements.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments. The FASB issued ASU 2016-15, to address diversity in how certain transactions are presented and classified in the statement of cash flows. The amendments will be effective retrospectively for reporting periods beginning after December 31, 2017, and early adoption is permitted. We do not believe these amendments will have a material impact on our financial statements.

Leases. The FASB has issued ASU 2016-02. The amendments will require lessees to recognize at the commencement date a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and a right-of-use asset, which is an asset that represents the lessee's right to use a specified asset for the lease term. Lessor accounting is largely unchanged. For public companies, the amendments are effective for annual periods beginning after December 15, 2018, and interim periods within those annual periods. The standard will not apply to leases of mineral rights. We are in the process of evaluating the impact these amendments will have on our financial statements.

Revenue from Contracts with Customers. The FASB has issued ASU 2014-09. These amendments affect any entity using U.S. GAAP that either enters into contracts with customers to transfer goods or services or enters into contracts for the transfer of nonfinancial assets unless those contracts are within the scope of other standards (e.g., insurance contracts or lease contracts). The core principle of the amendments is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 has been amended several times pre-issuance, which will be codified in the new Topic 606, and it is effective January 1. 2018. The guidance in this update supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance throughout the Industry Topics of the Codification. We will adopt these amendments January 1, 2018.

The new revenue standard provides a five-step analysis of transactions to determine the amount and timing of revenue recognition. Entities can choose to apply Topic 606 using either the full retrospective approach or a modified retrospective approach. We plan to adopt using the modified retrospective approach, which will result in a cumulative effect adjustment upon adoption.

Currently, management believes the effect of adoption will not have a material effect on our statement of operations or our balance sheet, as the timing of revenue recognized will not be materially modified, but the adoption will result in more robust footnote disclosures in regards to revenue. We anticipate a cumulative effect of applying the new revenue standard as an adjustment to the opening balance of retained earnings at the beginning of 2018 in relation to certain mid-stream segment and contract drilling segment contracts that include adjustments to the timing of revenue recognition of certain demand fee and mobilization/demobilization expenses and revenue, respectively. We believe this adjustment will not be material due to the short-term nature of the majority of our current contract drilling segment contracts and the limited number of mid-stream segment contracts with demand fees that we anticipate to be in place at the adoption date. Part of our review included evaluation of the following issues:

- Based on an analysis of whether the transportation of gas is a performance obligation that occurs at a point in time or over time, the timing of when we recognize certain revenue elements will change. Specifically related to our mid-stream segment, certain fees that are collectible in the early stages of a contract will be recognized over the life of the contract because these fees are part of the single performance obligation associated with the contract.

- Certain of our contracts include promises to deliver a minimum volume of commodity to the customer over a defined period of time. If we do not meet this commitment, a deficiency fee is payable to the customer. Topic 606 requires that these types of arrangements represent variable consideration related to the sale of the commodity, and requires that we include an estimate of any deficiency fees expected within revenue, rather than as operating costs. In addition, we will also be required to analyze fees that are billable for deficiencies in minimum volume commitments from customers for our mid-stream segment. In these instances, we will assess the likelihood of earning these fees each reporting period based on the customer’s performance and recognize variable revenue at the time it is not expected to be subject to a significant reversal.

Adopted Standards

Income Taxes: Balance Sheet Classification of Deferred Taxes. The FASB has issued ASU 2015-17. This changes how deferred taxes are classified on organizations' balance sheets. Organizations are required to classify all deferred tax assets and liabilities as noncurrent. The amendments apply to all organizations that present a classified balance sheet. For public companies, the amendments were effective for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. The amendments require current deferred tax assets to be combined with noncurrent deferred tax assets. We have adopted this ASU during the first quarter of 2017 on a prospective basis. Previously, we had a net current deferred tax asset which is now netted with our noncurrent deferred tax liability. P rior periods were not retrospectively adjusted.

Compensation—Stock Compensation: Improvements to Employee Share-Based Payment Accounting. The FASB has issued ASU 2016-09. The amendments are intended to improve the accounting for employee share-based payments and affect all organizations that issue share-based payment awards to their employees. Several aspects of the accounting for share-based payment award transactions are simplified, including: (a) income tax consequences; (b) classification of awards as either equity or liabilities; and (c) classification on the statement of cash flows. For public companies, the amendments were effective for annual periods beginning after December 15, 2016, and interim periods within those annual periods. The amendments primarily impact classification within the statement of cash flows between financial and operating activities. This did not have a material impact on our financial statements.

Table of Contents

Results of Operations

Quarter Ended September 30, 2017 versus Quarter Ended September 30, 2016

Provided below is a comparison of selected operating and financial data:

	Quarter Ended September 30,		Percent Change [1]
	2017	2016	
	(In thousands unless otherwise specified)		
Total revenue	$ 188,488	$ 153,408	23 %
Net income (loss)	$ 3,705	$ (24,022)	115 %
Oil and Natural Gas:			
Revenue	$ 85,470	$ 78,854	8 %
Operating costs excluding depreciation, depletion, amortization, and impairment	$ 33,911	$ 26,014	30 %
Depreciation, depletion, and amortization	$ 26,460	$ 27,135	(2)%
Impairment of oil and natural gas properties	$ —	$ 49,443	(100)%
Average oil price received (Bbl)	$ 47.29	$ 42.79	11 %
Average NGLs price received (Bbl)	$ 18.35	$ 12.68	45 %
Average natural gas price received (Mcf)	$ 2.36	$ 2.29	3 %
Oil production (Bbl)	633,000	701,000	(10)%
NGLs production (Bbl)	1,243,000	1,260,000	(1)%
Natural gas production (Mcf)	13,085,000	13,399,000	(2)%
Depreciation, depletion, and amortization rate (Boe)	$ 6.18	$ 6.06	2 %
Contract Drilling:			
Revenue	$ 51,619	$ 25,819	100 %
Operating costs excluding depreciation	$ 34,747	$ 19,137	82 %
Depreciation	$ 15,280	$ 11,318	35 %
Percentage of revenue from daywork contracts	100%	100%	— %
Average number of drilling rigs in use	34.6	16.0	116 %
Average dayrate on daywork contracts	$ 16,454	$ 17,479	(6)%
Mid-Stream:			
Revenue	$ 51,399	$ 48,735	5 %
Operating costs excluding depreciation and amortization	$ 38,116	$ 35,738	7 %
Depreciation and amortization	$ 10,880	$ 11,436	(5)%
Gas gathered—Mcf/day	383,787	429,693	(11)%
Gas processed—Mcf/day	140,246	152,651	(8)%
Gas liquids sold—gallons/day	530,028	558,843	(5)%
Corporate and other:			
General and administrative expense	$ 9,235	$ 8,852	4 %
Other depreciation	$ 1,913	$ 80	NM
Gain on disposition of assets	$ 81	$ 154	(47)%
Other income (expense):			
Interest expense, net	$ (9,944)	$ (10,002)	(1)%
Gain (loss) on derivatives	$ (2,614)	$ 6,969	(138)%
Other	$ 5	$ 3	67 %
Income tax expense (benefit)	$ 1,769	$ (14,599)	112 %
Average long-term debt outstanding	$ 804,617	$ 866,249	(7)%
Average interest rate	6.0%	5.7%	5 %

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(1) NM – A percentage calculation is not meaningful due to a zero-value denominator or a percentage change greater than 200.

Oil and Natural Gas

Oil and natural gas revenues increase d $6.6 million or 8% in the third quarter of 2017 as compared to the third quarter of 2016 primarily due to higher commodity prices partially offset from reduced production volumes. In the third quarter of 2017 , as compared to the third quarter of 2016 , oil production decrease d 10% , natural gas production decrease d 2% , and NGLs production decrease d 1% . Average oil prices increase d 11% to $47.29 per barrel, average natural gas prices increase d 3% to $2.36 per Mcf, and NGLs prices increase d 45% to $18.35 per barrel.

Oil and natural gas operating costs increase d $7.9 million or 30% between the comparative third quarter s of 2017 and 2016 due to higher LOE and production taxes partially offset by lower saltwater disposal expenses.

Depreciation, depletion, and amortization ("DD&A") decrease d $0.7 million or 2% due primarily to a 3% decrease in equivalent production partially offset by a 2% increase in the DD&A rate. The increase in our DD&A rate in the third quarter of 2017 compared to the third quarter of 2016 resulted primarily from the cost of wells drilled in the first nine months of 2017.

During the third quarter of 2016, we recorded a non-cash ceiling test write-down of $49.4 million pre-tax ($30.8 million , net of tax). We did not have a write-down for the third quarter of 2017.

Contract Drilling

Drilling revenues increase d $25.8 million or 100% in the third quarter of 2017 versus the third quarter of 2016 . The increase was due primarily to a 116% increase in the average number of drilling rigs in use partially offset by a 6% decrease in the average dayrate. Average drilling rig utilization increase d from 16.0 drilling rigs in the third quarter of 2016 to 34.6 drilling rigs in the third quarter of 2017 .

Drilling operating costs increase d $15.6 million or 82% between the comparative third quarter s of 2017 and 2016 . The increase was due primarily to more drilling rigs operating. Contract drilling depreciation increase d $4.0 million or 35% also due primarily to more drilling rigs operating.

Mid-Stream

Our mid-stream revenues increase d $2.7 million or 5% in the third quarter of 2017 as compared to the third quarter of 2016 due primarily to increases in NGLs and condensate prices. Gas processed volumes per day decrease d 8% between the comparative quarters primarily due to declines in existing volumes, fewer new wells connected to our processing systems, and no offload volume at our Hemphill facility in 2017. Gas gathered volumes per day decreased 11% between the comparative quarters primarily due to declining gathered volumes on our Appalachian systems.

Operating costs increase d $2.4 million or 7% in the third quarter of 2017 compared to the third quarter of 2016 primarily due to 26% higher gas purchase prices partially offset by a 9% decrease in purchase volumes. Depreciation and amortization decrease d $0.6 million , or 5% , primarily due to certain assets being fully depreciated in 2017.

Other Depreciation

During the third quarter of 2017, we had $1.9 million of other depreciation primarily due to our new ERP accounting and reporting system that was implemented during the first quarter of 2017.

General and Administrative

Corporate general and administrative expenses increase d $0.4 million or 4% in the third quarter of 2017 compared to the third quarter of 2016 primarily due to an increase in employee costs.

Other Income (Expense)

Interest expense, net of capitalized interest, decrease d $0.1 million between the comparative third quarter s of 2017 and 2016 due primarily to a 7% decrease in average long-term debt outstanding in the third quarter of 2017 and an increase in interest capitalized partially offset by a higher average interest rate. We capitalized interest based on the net book value associated with undeveloped leasehold not being amortized, the construction of additional drilling rigs, and the construction of gas gathering systems. Capitalized interest for the third quarter of 2017 was $4.0 million compared to $3.6 million in the third quarter of 2016, and was netted against our gross interest of $14.0 million and $13.6 million for the third quarter s of 2017 and

2016, respectively. Our average interest rate increased from 5.7% in the third quarter of 2016 to 6.0% in the third quarter of 2017 and our average debt outstanding was $61.6 million lower in the third quarter of 2017 as compared to the third quarter of 2016 primarily due to the decrease in outstanding borrowings under our credit agreement over the comparative periods.

Gain (Loss) on Derivatives

Gain (loss) on derivatives increased $9.6 million primarily due to fluctuations in forward prices used to estimate the fair value in mark-to-market accounting.

Income Tax Expense (Benefit)

Income tax expense increased $16.4 million between the comparative third quarter s of 2017 and 2016 primarily due to increased pre-tax income. Our effective tax rate was 32.3% for the third quarter of 2017 compared to 37.8% for the third quarter of 2016 . The rate change was primarily due to the recognition of our Uncertain Tax Position associated with a research and development tax credit of $0.4 million. There was no current income tax expense or benefit in the third quarter of 2017 or 2016. We did not pay any income taxes in the third quarter of 2017 .

Nine Months Ended September 30, 2017 versus Nine Months Ended September 30, 2016

Provided below is a comparison of selected operating and financial data:

	Nine Months Ended September 30,		Percent Change
	2017	2016	
	(In thousands unless otherwise specified)		
Total revenue	$ 534,793	$ 427,897	25 %
Net income (loss)	$ 28,693	$ (137,307)	121 %
Oil and Natural Gas:			
Revenue	$ 256,241	$ 206,318	24 %
Operating costs excluding depreciation, depletion, amortization, and impairment	$ 95,873	$ 92,691	3 %
Depreciation, depletion, and amortization	$ 71,544	$ 89,378	(20)%
Impairment of oil and natural gas properties	$ —	$ 161,563	(100)%
Average oil price received (Bbl)	$ 47.62	$ 38.71	23 %
Average NGLs price received (Bbl)	$ 17.05	$ 10.16	68 %
Average natural gas price received (Mcf)	$ 2.50	$ 1.98	26 %
Oil production (Bbl)	1,990,000	2,260,000	(12)%
NGLs production (Bbl)	3,476,000	3,745,000	(7)%
Natural gas production (Mcf)	37,317,000	42,376,000	(12)%
Depreciation, depletion, and amortization rate (Boe)	$ 5.76	$ 6.48	(11)%
Contract Drilling:			
Revenue	$ 128,059	$ 88,786	44 %
Operating costs excluding depreciation	$ 91,213	$ 66,489	37 %
Depreciation	$ 41,896	$ 34,431	22 %
Percentage of revenue from daywork contracts	100%	100%	— %
Average number of drilling rigs in use	29.7	16.7	78 %
Average dayrate on daywork contracts	$ 16,120	$ 18,147	(11)%
Mid-Stream:			
Revenue	$ 150,493	$ 132,793	13 %
Operating costs excluding depreciation and amortization	$ 111,862	$ 99,185	13 %
Depreciation and amortization	$ 32,547	$ 34,410	(5)%
Gas gathered—Mcf/day	385,846	417,722	(8)%
Gas processed—Mcf/day	133,986	160,411	(16)%
Gas liquids sold—gallons/day	518,054	536,911	(4)%
Corporate and other:			
General and administrative expense	$ 26,902	$ 25,811	4 %
Other depreciation	$ 5,558	$ 218	NM
Gain on disposition of assets	$ 1,153	$ 823	40 %
Other income (expense):			
Interest expense, net	$ (28,807)	$ (30,225)	(5)%
Gain (loss) on derivatives	$ 21,019	$ (4,774)	NM
Other	$ 14	$ (11)	NM
Income tax expense (benefit)	$ 22,084	$ (73,159)	130 %
Average long-term debt outstanding	$ 811,159	$ 882,330	(8)%
Average interest rate	6.0%	5.6%	7 %

Oil and Natural Gas

Oil and natural gas revenues increase d $49.9 million or 24% in the first nine months 2017 as compared to the first nine months of 2016 primarily due to higher commodity prices partially offset by lower production volumes. In the first nine months of 2017 , as compared to the first nine months of 2016 , oil production decrease d 12% , natural gas production decrease d 12% , and NGLs production decrease d 7% . Average oil prices increase d 23% to $47.62 per barrel, average natural gas prices increase d 26% to $2.50 per Mcf, and NGLs prices increase d 68% to $17.05 per barrel.

Oil and natural gas operating costs increase d $3.2 million or 3% between the comparative first nine months of 2017 and 2016 due to higher LOE and gross production tax partially offset by lower saltwater disposal expense.

DD&A decrease d $17.8 million or 20% due primarily to a 11% decrease in our DD&A rate and a 11% decrease in equivalent production. The decrease in our DD&A rate in the first nine months of 2017 compared to the first nine months of 2016 resulted primarily from the effect of the ceiling test write-downs throughout 2016.

During the first nine months of 2016, we recorded non-cash ceiling test write-downs of $161.6 million pre-tax ($100.6 million , net of tax). We did not have a write-down for 2017.

Contract Drilling

Drilling revenues increase d $39.3 million or 44% in the first nine months of 2017 versus the first nine months of 2016 . The increase was due primarily to a 78% increase in the average number of drilling rigs in use partially offset by a 11% decrease in the average dayrate. Average drilling rig utilization increase d from 16.7 drilling rigs in the first nine months of 2016 to 29.7 drilling rigs in the first nine months of 2017 . We recorded $0.8 million in early termination revenue in the first nine months of 2017 compared to $3.1 million in the first nine months of 2016.

Drilling operating costs increase d $24.7 million or 37% between the comparative first nine months of 2017 and 2016 . The increase was due primarily to more drilling rigs operating. Contract drilling depreciation increase d $7.5 million or 22% also due primarily to more drilling rigs operating.

Mid-Stream

Our mid-stream revenues increase d $17.7 million or 13% in the first nine months of 2017 as compared to the first nine months of 2016 due primarily to increased gas, NGLs, and condensate prices partially offset by a decrease in gas processed volumes. Gas processed volumes per day decrease d 16% between the comparative periods primarily due to declines in existing volumes, fewer new wells connected, and no offload volume at our Hemphill facility in 2017. Gas gathered volumes per day decrease d 8% between the comparative periods primarily due declines in existing volumes, fewer new wells connected, and no offload volume at our Hemphill facility in 2017.

Operating costs increase d $12.7 million or 13% in the first nine months of 2017 compared to the first nine months of 2016 primarily due to increased purchase prices partially offset by a decrease in gas purchased volumes. Depreciation and amortization decrease d $1.9 million , or 5% , primarily due to certain assets being fully depreciated in 2017.

Other Depreciation

During the first nine months of 2017, we had $5.6 million of other depreciation primarily due to our new ERP accounting and reporting system that was implemented during the first quarter of 2017 as well as depreciation on our corporate building.

General and Administrative

Corporate general and administrative expenses increase d $1.1 million or 4% in the first nine months of 2017 compared to the first nine months of 2016 primarily due to higher employee costs.

Gain on Disposition of Assets

There was an $1.2 million gain on disposition of assets in the first nine months of 2017 primarily due to the sale of a corporate aircraft and vehicles, compared to a gain of $0.8 million for the disposition of assets in the first nine months of 2016 primarily due to the sale of various rig components (including three top drives and power units), vehicles, and a drilling yard.

Other Income (Expense)

Interest expense, net of capitalized interest, decrease d $1.4 million between the comparative first nine months of 2017 and 2016 due primarily to a 8% decrease in the average long-term debt outstanding and increase interest capitalized partially offset by a higher average interest rate. We capitalized interest based on the net book value associated with undeveloped leasehold not being amortized, the construction of additional drilling rigs, and the construction of gas gathering systems. Capitalized interest for the first nine months of 2017 was $11.9 million compared to $11.2 million in the first nine months of 2016 , and was netted against our gross interest of $40.7 million and $41.4 million for the first nine months of 2017 and 2016 , respectively. Our average interest rate increased from 5.6% to 6.0% and our average debt outstanding was $71.2 million lower in the first nine months of 2017 as compared to the first nine months of 2016 primarily due to the decrease in outstanding borrowings under our credit agreement over the comparative periods.

Gain (Loss) on Derivatives

Gain (loss) on derivatives increased $25.8 million primarily due to fluctuations in forward prices used to estimate the fair value in mark-to-market accounting.

Income Tax Expense (Benefit)

Income tax expense increased $95.2 million between the comparative first nine months of 2017 and 2016 primarily due to increased pre-tax income. Our effective tax rate was 43.5% for the first nine months of 2017 compared to 34.8% for the first nine months of 2016 . The increase was primarily due to increased deferred tax expense related to our restricted stock vestings in both comparative periods. There was no current income tax expense or benefit in the first nine months of 2017 or 2016 . We did not pay any income taxes in the first nine months of 2017 .

Safe Harbor Statement

This report, including information included in, or incorporated by reference from, future filings by us with the SEC, as well as information contained in written material, press releases, and oral statements issued by or on our behalf, contain, or may contain, certain statements that are “forward-looking statements” within the meaning of federal securities laws. All statements, other than statements of historical facts, included or incorporated by reference in this report, which address activities, events, or developments which we expect or anticipate will or may occur, are forward-looking statements. The words “believes,” “intends,” “expects,” “anticipates,” “projects,” “estimates,” “predicts,” and similar expressions are used to identify forward-looking statements.

These forward-looking statements include, among others, things as:

- the amount and nature of our future capital expenditures and how we expect to fund our capital expenditures;
- prices for oil, NGLs, and natural gas;
- demand for oil, NGLs, and natural gas;
- our exploration and drilling prospects;
- the estimates of our proved oil, NGLs, and natural gas reserves;
- oil, NGLs, and natural gas reserve potential;
- development and infill drilling potential;
- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- our plans to maintain or increase production of oil, NGLs, and natural gas;
- the number of gathering systems and processing plants we plan to construct or acquire;
- volumes and prices for natural gas gathered and processed;
- expansion and growth of our business and operations;
- demand for our drilling rigs and drilling rig rates;

- our belief that the final outcome of legal proceedings involving us will not materially affect our financial results;
- our ability to timely secure third-party services used in completing our wells;
- our ability to transport or convey our oil or natural gas production to established pipeline systems;
- impact of federal and state legislative and regulatory initiatives relating to hydrocarbon fracturing impacting our costs and increasing operating restrictions or delays as well as other adverse impacts on our business;
- our projected production guidelines for the year;
- our anticipated capital budgets;
- our financial condition and liquidity;
- the number of wells our oil and natural gas segment plans to drill or rework during the year; and
- our estimates of the amounts of any ceiling test write-downs or other potential asset impairments we may have to record in future periods.

These statements are based on certain assumptions and analyses made by us based on our experience and our perception of historical trends, current conditions, and expected future developments as well as other factors we believe are appropriate in the circumstances. However, whether actual results and developments will conform to our expectations and predictions is subject to a number of risks and uncertainties which could cause actual results to differ materially from our expectations, including:

- the risk factors discussed in this report and in the documents we incorporate by reference;
- general economic, market, or business conditions;
- the availability of and nature of (or lack of) business opportunities that we pursue;
- demand for our land drilling services;
- changes in laws or regulations;
- changes in the current geopolitical situation;
- risks relating to financing, including restrictions in our debt agreements and availability and cost of credit;
- risks associated with future weather conditions;
- decreases or increases in commodity prices;
- putative class action lawsuits that may result in substantial expenditures and divert management's attention; and
- other factors, most of which are beyond our control.

You should not place undue reliance on these forward-looking statements. Except as required by law, we disclaim any intention to update forward-looking information and to release publicly the results of any future revisions we may make to forward-looking statements to reflect events or circumstances after the date of this report to reflect the occurrence of unanticipated events.

A more thorough discussion of forward-looking statements with the possible impact of some of these risks and uncertainties is provided in our Annual Report on Form 10-K filed with the SEC. We encourage you to get and read that document.

Item 3. Quantitative and Qualitative Disclosure About Market Risk

Our operations are exposed to market risks primarily because of changes in commodity prices and interest rates.

Commodity Price Risk. Our major market risk exposure is in the prices we receive for our oil, NGLs, and natural gas production. These prices are primarily driven by the prevailing worldwide price for crude oil and market prices applicable to our NGLs and natural gas production. Historically, these prices have fluctuated and we expect this to continue. The prices for oil, NGLs, and natural gas also affect the demand for our drilling rigs and the amount we can charge for the use of our drilling rigs. Based on our first nine months 2017 production, a $0.10 per Mcf change in what we are paid for our natural gas production, without the effect of hedging, would result in a corresponding $398,000 per month ($4.8 million annualized) change in our pre-tax operating cash flow. A $1.00 per barrel change in our oil price, without the effect of hedging, would have a $212,000 per month ($2.5 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGLs prices, without the effect of hedging, would have a $372,000 per month ($4.5 million annualized) change in our pre-tax operating cash flow.

We use derivative transactions to manage the risk associated with price volatility. Our decisions regarding the amount and prices at which we choose to enter into a contract for certain of our products is based, in part, on our view of current and future market conditions. The transactions we use include financial price swaps under which we will receive a fixed price for our production and pay a variable market price to the contract counterparty. We do not hold or issue derivative instruments for speculative trading purposes.

At September 30, 2017 , the following derivatives were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Oct'17	Natural gas – swap	70,000 MMBtu/day	$3.038	IF – NYMEX (HH)
Nov’17 – Dec'17	Natural gas – swap	60,000 MMBtu/day	$2.960	IF – NYMEX (HH)
Jan’18 – Dec'18	Natural gas – swap	20,000 MMBtu/day	$3.013	IF – NYMEX (HH)
Nov’17 – Dec'17	Natural gas – basis swap	20,000 MMBtu/day	$(0.215)	IF – NYMEX (HH)
Jan’18 – Mar'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.208)	IF – NYMEX (HH)
Nov’18 – Dec'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.208)	IF – NYMEX (HH)
Oct'17	Natural gas – collar	20,000 MMBtu/day	$2.88 - $3.10	IF – NYMEX (HH)
Oct'17	Natural gas – three-way collar	15,000 MMBtu/day	$2.50 - $2.00 - $3.32	IF – NYMEX (HH)
Nov’17 – Dec'17	Natural gas – three-way collar	25,000 MMBtu/day	$2.90 - $2.30 - $3.59	IF – NYMEX (HH)
Jan'18 – Mar'18	Natural gas – three-way collar	60,000 MMBtu/day	$3.29 - $2.63 - $4.07	IF – NYMEX (HH)
Apr'18 – Dec'18	Natural gas – three-way collar	20,000 MMBtu/day	$3.00 - $2.50 - $3.51	IF – NYMEX (HH)
Oct’17 – Dec'17	Crude oil – three-way collar	3,750 Bbl/day	$49.79 - $39.58 - $60.98	WTI – NYMEX
Jan'18 – Dec'18	Crude oil – three-way collar	2,000 Bbl/day	$47.50 - $37.50 - $56.08	WTI – NYMEX
Jan'18 – Dec'18	Crude oil – swap	2,000 Bbl/day	$50.140	WTI – NYMEX

After September 30, 2017 , the following derivative was entered into:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Apr'18 – Oct'18	Natural gas – swap	10,000 MMBtu/day	$2.990	IF – NYMEX (HH)
Apr'18 – Sep'18	Liquids – swap (1)	1,000 Bbl/day	$31.164	OPIS – Mont Belvieu

(1) Type of liquid involved is propane.

Interest Rate Risk. Our interest rate exposure relates to our long-term debt under our credit agreement and the Notes. The credit agreement, at our election bears interest at variable rates based on the Prime Rate or the LIBOR Rate. At our election, borrowings under our credit agreement may be fixed at the LIBOR Rate for periods of up to 180 days. Based on our average outstanding long-term debt subject to a variable rate in the first nine months of 2017, a 1% increase in the floating rate would reduce our annual pre-tax cash flow by approximately $1.6 million. Under our Notes, we pay a fixed rate of interest of 6.625% per year (payable semi-annually in arrears on May 15 and November 15 of each year).

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures under Exchange Act Rule 13a-15. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective as of September 30, 2017 in ensuring the appropriate information is recorded, processed, summarized and reported in our periodic SEC filings relating to the company (including its consolidated subsidiaries) and is accumulated and communicated to the Chief Executive Officer, Chief Financial Officer, and management to allow timely decisions.

Changes in Internal Controls. In January 2017, we implemented a new ERP accounting and reporting system designed to upgrade our technology and improve the timeliness and quality of our financial and operational information. This new ERP system was not implemented in response to any material weakness in our internal control over financial reporting (ICFR). The implementation of the ERP system has affected the processes that constitute part of our ICFR and requires ongoing testing for effectiveness. The adoption of this new ERP system has not materially affected our ICFR. There were no changes in ICFR during the quarter ended September 30, 2017 , that materially affected our ICFR or are reasonably likely to materially affect it, as defined in Rule 13a – 15(f) under the Exchange Act.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Panola Independent School District No. 4, et al . v. Unit Petroleum Company , No. CJ-07-215, District Court of Latimer County, Oklahoma.

Panola Independent School District No. 4, Michael Kilpatrick, Gwen Grego, Carla Lessel, Thelma Christine Pate, Juanita Golightly, Melody Culberson, and Charlotte Abernathy are the Plaintiffs in this case and are royalty owners in oil and gas drilling and spacing units for which the company's exploration segment distributes royalty. The Plaintiffs' central allegation is that the company's exploration segment has underpaid royalty obligations by deducting post-production costs or marketing related fees. Plaintiffs sought to pursue the case as a class action on behalf of persons who receive royalty from us for our Oklahoma production. We have asserted several defenses including that the deductions are permitted under Oklahoma law. We have also asserted that the case should not be tried as a class action due to the materially different circumstances that determine what, if any, deductions are taken for each lease. On December 16, 2009, the trial court entered its order certifying the class. On May 11, 2012 the court of civil appeals reversed the trial court's order certifying the class. The Plaintiffs petitioned the supreme court for certiorari and on October 8, 2012, the Plaintiff's petition was denied. On January 22, 2013, the Plaintiffs filed a second request to certify a class of royalty owners that was slightly smaller than their first attempt. Since then, the Plaintiffs have further amended their proposed class to just include royalty owners entitled to royalties under certain leases located in Latimer, Le Flore, and Pittsburg Counties, Oklahoma. In July 2014, a second class certification hearing was held where, in addition to the defenses described above, we argued that the amended class definition is still deficient under the court of civil appeals opinion reversing the initial class certification. Closing arguments were held on December 2, 2014. There is no timetable for when the court will issue its ruling. The merits of Plaintiffs' claims will remain stayed while class certification issues are pending.

Cockerell Oil Properties, Ltd., v. Unit Petroleum Company , No. 16-cv-135-JHP, United States District Court for the Eastern District of Oklahoma.

On March 11, 2016, a putative class action lawsuit was filed against Unit Petroleum Company styled *Cockerell Oil Properties, Ltd., v. Unit Petroleum Company* in LeFlore County, Oklahoma. We removed the case to federal court in the Eastern District of Oklahoma. The plaintiff alleges that Unit Petroleum wrongfully failed to pay interest with respect to untimely royalty payments under Oklahoma's Production Revenue Standards Act. The lawsuit seeks actual and punitive damages, an accounting, disgorgement, injunctive relief, and attorney's fees. Plaintiff is seeking relief on behalf of royalty owners in our Oklahoma wells. We have asserted several defenses including that the case cannot be properly certified as a class action because of the wide variety of circumstances that determine whether a royalty payment was timely made or has accrued interest under Oklahoma law. At this point, the court has not taken any action on the issue of class certification.

We continue to vigorously defend against each of the pending claims. At this time we are unable to express an opinion with respect to the likelihood of an unfavorable outcome or provide an estimate of potential losses, if any.

Item 1A. Risk Factors

In addition to the other information set forth in this quarterly report, you should carefully consider the factors discussed below, if any, and in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2016, which could materially affect our business, financial condition, or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing our company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition, and/or operating results.

Except as set forth below, there have been no material changes to the risk factors disclosed in Item 1A in our Form 10-K for the year ended December 31, 2016.

We are the subject of putative class action lawsuits that may result in substantial expenditures and divert management's attention.

We are the subject of putative class action lawsuits in Oklahoma with respect to the alleged failure to pay interest with on untimely royalty payments and with respect to the alleged underpayment of royalties. These lawsuits seek various remedies, including damages, injunctive relief, and attorney's fees. For additional information on these lawsuits, see Item 1 Legal Proceedings in this Quarterly Report on Form 10-Q.

Although we believe that the allegations in these lawsuits are without merit and intend to defend such litigation vigorously, litigation is subject to inherent uncertainties, and an adverse result in one of these lawsuits or other matters that may arise from time to time could have a material adverse effect on our business, results of operations and financial condition. Defending the lawsuits may be costly and, further, could require significant involvement of our senior management and may divert management's attention from our business and operations.

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

The following table provides information relating to our repurchase of common stock for the three months ended September 30, 2017 :

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid Per Share	(c) Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
July 1, 2017 to July 31, 2017	—	$ —	—	—
August 1, 2017 to August 31, 2017	—	—	—	—
September 1, 2017 to September 30, 2017	—	—	—	—
Total	—	$ —	—	—

Item 3. Defaults Upon Senior Securities

Not applicable.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Not applicable.

Item 6. Exhibits

Exhibits:

31.1	Certification of Chief Executive Officer under Rule 13a – 14(a) of the Exchange Act.
31.2	Certification of Chief Financial Officer under Rule 13a – 14(a) of the Exchange Act.
32	Certification of Chief Executive Officer and Chief Financial Officer under Rule 13a – 14(a) of the Exchange Act and 18 U.S.C. Section 1350, as adopted under Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

SIGNATURES

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

Unit Corporation

Date:	November 2, 2017	By: /s/ Larry D. Pinkston LARRY D. PINKSTON Chief Executive Officer and Director
Date:	November 2, 2017	By: /s/ David T. Merrill DAVID T. MERRILL Chief Operating Officer, Chief Financial Officer, and Treasurer

Exhibit 31.1
302 CERTIFICATIONS

I, Larry D. Pinkston, certify that:

1. I have reviewed this quarterly report on form 10-Q of Unit Corporation;

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

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

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

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

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: November 2, 2017

/s/ Larry D. Pinkston
LARRY D. PINKSTON
Chief Executive Officer
and Director

Exhibit 31.2
302 CERTIFICATIONS

I, David T. Merrill, certify that:

1. I have reviewed this quarterly report on form 10-Q of Unit Corporation;

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

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

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

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

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: November 2, 2017

/s/ David T. Merrill
DAVID T. MERRILL
Chief Operating Officer, Chief Financial Officer,
and Treasurer

Exhibit 32

CERTIFICATION
PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
(SUBSECTIONS (A) AND (B) OF SECTION 1350, CHAPTER 63 OF TITLE 18, UNITED STATES CODE)

Pursuant to section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of section 1350, chapter 63 of title 18, United States Code), each of the undersigned officers of Unit Corporation a Delaware corporation (the “Company”), does hereby certify, to such officer’s knowledge, that:

The Quarterly Report on Form 10-Q for the quarter ended September 30, 2017 (the “Form 10-Q”) of the Company fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 and information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of the Company as of September 30, 2017 and December 31, 2016 and for the three and nine month periods ended September 30, 2017 and 2016 .

Dated: November 2, 2017

By: /s/ Larry D. Pinkston

Larry D. Pinkston
Chief Executive Officer and
Director

Dated: November 2, 2017

By: /s/ David T. Merrill

David T. Merrill
Chief Operating Officer, Chief Financial Officer, and
Treasurer

The foregoing certification is being furnished solely pursuant to section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of section 1350, chapter 63 of title 18, United States Code) and is not being filed as part of the Form 10-Q or as a separate disclosure document.

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002 has been provided to Unit Corporation and will be retained by Unit Corporation and furnished to the Securities and Exchange Commission or its staff on request.