UNIT CORP
Form 10-Q
May 03, 2018
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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 March 31, 2018
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 [x] Accelerated filer [ ] 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 April 20, 2018, 54,046,361 shares of the issuer's common stock were outstanding.

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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 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;
- our intended use of the proceeds from the sale of 50% of the interest we owned in our midstream segment; 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 cause substantial expenditures and divert management's attention; and
- other factors, most of which are beyond our control.

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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.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	March 31, 2018	December 31, 2017
	(In thousands except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 752	$ 701
Accounts receivable, net of allowance for doubtful accounts of $2,450 at both March 31, 2018 and December 31, 2017, respectively	98,506	111,512
Materials and supplies	455	505
Current derivative asset (Note 10)	537	721
Current income tax receivable	61	—
Prepaid expenses and other	7,724	6,233
Total current assets	108,035	119,672
Property and equipment:		
Oil and natural gas properties on the full cost method:		
Proved properties	5,762,069	5,712,813
Unproved properties not being amortized	305,621	296,764
Drilling equipment	1,601,777	1,593,611
Gas gathering and processing equipment	731,006	726,236
Saltwater disposal systems	63,124	62,618
Corporate land and building	59,080	59,080
Transportation equipment	29,908	29,631
Other	56,142	53,439
	8,608,727	8,534,192
Less accumulated depreciation, depletion, amortization, and impairment	6,207,449	6,151,450
Net property and equipment	2,401,278	2,382,742
Goodwill	62,808	62,808
Other assets	27,470	16,230
Total assets	$ 2,599,591	$ 2,581,452

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

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

	March 31, 2018	December 31, 2017
	(In thousands except share amounts)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 131,064	$ 112,648
Accrued liabilities (Note 5)	52,964	48,523
Current derivative liability (Note 10)	12,104	7,763
Current portion of other long-term liabilities (Note 6)	14,587	13,002
Total current liabilities	210,719	181,936
Long-term debt less debt issuance costs (Note 6)	790,522	820,276
Non-current derivative liability (Note 10)	164	—
Other long-term liabilities (Note 6)	104,286	100,203
Deferred income taxes	136,600	133,477
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, 54,046,361 and 52,880,134 shares issued as of March 31, 2018 and December 31, 2017, respectively	10,403	10,280
Capital in excess of par value	541,004	535,815
Accumulated other comprehensive income (Note 13)	(100)	63
Retained earnings	805,993	799,402
Total shareholders' equity	1,357,300	1,345,560
Total liabilities and shareholders' equity	$ 2,599,591	$ 2,581,452

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

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UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED INCOME STATEMENTS (UNAUDITED)

	Three Months Ended March 31,	
	2018	2017
	(In thousands except per share amounts)	
Revenues:		
Oil and natural gas	$103,099	$87,598
Contract drilling	45,989	37,185
Gas gathering and processing	56,044	50,941
Total revenues	205,132	175,724
Expenses:		
Operating costs:		
Oil and natural gas	35,962	29,204
Contract drilling	31,667	29,227
Gas gathering and processing	41,604	37,704
Total operating costs	109,233	96,135
Depreciation, depletion, and amortization	57,066	46,932
General and administrative	10,762	8,954
Gain on disposition of assets	(161)	(824)
Total operating expenses	176,900	151,197
Income from operations	28,232	24,527
Other income (expense):		
Interest, net	(10,004)	(9,396)
Gain (loss) on derivatives	(6,762)	14,731
Other, net	6	3
Total other income (expense)	(16,760)	5,338
Income before income taxes	11,472	29,865
Income tax expense:		
Deferred	3,607	13,936
Total income taxes	3,607	13,936
Net income	$7,865	$15,929
Net income per common share:		
Basic	$0.15	$0.32
Diluted	$0.15	$0.31

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

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

	Three Months Ended March 31,	
	2018	2017
	(In thousands)	
Net income	$7,865	$15,929
Other comprehensive income, net of taxes:		
Unrealized loss on securities, net of tax of ($58) and $0	(176)	—
Comprehensive income	$7,689	$15,929

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

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

	Three Months Ended March 31,	
	2018	2017
	(In thousands)	
OPERATING ACTIVITIES:		
Net income	$7,865	$15,929
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, and amortization	57,066	46,932
Amortization of debt issuance costs and debt discount (Note 6)	546	536
(Gain) loss on derivatives	6,762	(14,731)
Cash payments on derivatives settled, net	(2,073)	(1,159)
Deferred tax expense	3,607	13,936
Gain on disposition of assets	(161)	(824)
Stock compensation plans	6,609	3,704
Contract assets and liabilities, net (Note 2)	(1,192)	—
Other, net	937	626
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	8,005	(1,900)
Accounts payable	(55,638)	(7,735)
Material and supplies	50	73
Accrued liabilities	6,757	9,832
Other, net	(494)	433
Net cash provided by operating activities	38,646	65,652
INVESTING ACTIVITIES:		
Capital expenditures	(45,327)	(37,636)
Producing properties and other acquisitions	—	(7,508)
Proceeds from disposition of assets	22,084	16,116
Net cash used in investing activities	(23,243)	(29,028)
FINANCING ACTIVITIES:		
Borrowings under credit agreement	67,400	49,700
Payments under credit agreement	(97,700)	(60,500)
Payments on capitalized leases	(946)	(946)
Book overdrafts	15,894	(17,301)
Net cash used in financing activities	(15,352)	(29,047)
Net increase in cash and cash equivalents	51	7,577
Cash and cash equivalents, beginning of period	701	893
Cash and cash equivalents, end of period	$752	$8,470

Supplemental disclosure of cash flow information:		
Cash paid during the year for:		
Interest paid (net of capitalized)	(1,731)	(2,389)
Income taxes	—	—
Changes in accounts payable and accrued liabilities related to purchases of property, plant, and equipment	(58,160)	(11,401)
Non-cash (addition) reduction to oil and natural gas properties related to asset retirement obligations	6,340	912

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

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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 27, 2018, for the year ended December 31, 2017.

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:

- Balance Sheets at March 31, 2018 and December 31, 2017;
- Income Statements for the three months ended March 31, 2018 and 2017;
- Statements of Comprehensive Income for the three months ended March 31, 2018 and 2017; and
- Statements of Cash Flows for the three months ended March 31, 2018 and 2017.

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 three months ended March 31, 2018 and 2017 are not necessarily indicative of the results to be realized for the full year of 2018, or that we realized for the full year of 2017.

Accounting Changes - Recent Accounting Pronouncements - Adopted

As of January 1, 2018, the company adopted ASU 2018-02 Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income. This standard is explained further in Note 8 - New Accounting Pronouncements. We adopted this amendment early and it did not have a material effect to our financial statements. We previously used 37.75% to calculate the tax effect on AOCI and now we are using 24.5%. The change is reflected in our Unaudited Condensed Consolidated Statements of Comprehensive Income and in Note 13 - Equity.

Also, as of January 1, 2018, the company adopted ASU 2014-09 Revenue from Contracts with Customers - Topic 606 (ASC 606) and all later amendments that modified ASC 606. The new revenue standard is explained further in Note 8 - New Accounting Pronouncements. The company has elected to apply the standard on the modified retrospective approach method to contracts not completed as of January 1, 2018, where the cumulative effect upon adoption, which only impacted our mid-stream segment is recognized as an adjustment to opening retained earnings at January 1, 2018. This adjustment related to the timing of revenue recognition for certain demand fees. Both our oil and natural gas and contract drilling segments had no retained earnings adjustment. Comparative prior periods have not been adjusted and continue to be reported under ASC 605.

The additional disclosures required by the ASU have been included in Note 2 – Revenue from Contracts with Customers.

NOTE 2 – REVENUE FROM CONTRACTS WITH CUSTOMERS

The company's revenue streams are reported under three segments: oil and natural gas, contract drilling, and mid-stream. This is our disaggregation of revenue and how our segment revenue is reported (as reflected in Note 14 - Industry Segment Information). Revenue from the oil and natural gas segment is derived from sales of our oil and natural gas production. Revenue from the contract drilling segment is derived by contracting with upstream companies to drill an agreed-on number of wells or provide drilling rigs and services over an agreed-on period of time. Revenue from the mid-stream segment is derived from gathering, transporting, and processing natural gas production and selling those commodities. The company sells its hydrocarbons (from the oil and natural gas and mid-stream segments) to midstream and downstream oil and gas companies.

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We satisfy performance obligation for each contract as follows: for the contract drilling and mid-stream contracts, we satisfy the performance obligation over the agreed-on time period within the contracts, and for oil and natural gas contracts, we satisfy the performance obligation with each delivery of volumes. For oil and natural gas contracts, as it is more feasible, we account for these deliveries on a monthly basis. Per the contracts for all segments, customers pay for the services/goods received on a monthly basis within an agreed on number of days following the end of the month. Besides the mid-stream demand fees discussed further below, there were no other contract assets or liabilities.

Oil and Natural Gas Contracts, Revenues, Implementation Impact to Retained Earnings, and Performance Obligations

Typical types of revenue contracts signed are Oil Sales Contracts, Gas Purchase Agreements, North American Energy Standards Board (NAESB) Contracts, Gas Gathering and Processing Agreements, and revenues earned as the non-operated party with the operator serving as an agent on our behalf under our Joint Operating Agreements. Contract term can range from single month to extended term contracts spanning a decade or more; some include evergreen provisions. Revenues from sales are recognized when the customer obtains control of the company's product. For sales to other midstream and downstream oil and gas companies, this would occur at a point in time, typically on delivery to the customer. Sales generated from our non-operated interest are recorded based on the information obtained from the operator. On adoption of the standard, no adjustment to opening retained earnings was required.

Certain costs as either a deduction from revenue or an expense is determined based on when control of the commodity transfers to the customer, which would affect our total revenue recognized, but will not affect gross profit. For example, gathering, processing and transportation costs that are included as part of the contract price with the customer upon transfer of control of the commodity are included in the transaction price, while costs incurred while we are in control of the commodity represent operating costs. The following table summarizes the impact of the adoption of ASC 606 on revenue and operating costs, as the change did not impact income from operations or net income for the three months ended March 31, 2018:

	As Reported	Adjustments due to ASC 606	Amounts without the Adoption of ASC 606
	(In thousands)		
Oil and natural gas revenues	$103,099	$ (3,169)	$106,268
Oil and natural gas operating costs	35,962	(3,169)	39,131
Gross profit	$67,137	$ —	$67,137

Our performance obligation for all contracts is the delivery of oil and gas volumes to the customer. Typically the contract will establish a period of time (for example, a month or a year); however, each delivery can be considered separately identifiable as each delivery provides benefits to the customer on its own. For feasibility, as accounting for a monthly performance obligation is not materially different than identifying a more granular performance obligation, we conclude this performance obligation is satisfied monthly. We typically receive payment within a set number of days following the end of the month and includes payment for all deliveries in that month. Depending on contract circumstances, judgment could be required to determine when the transfer of control occurs. Generally, depending of the facts and circumstances, we consider the transfer of control of the asset in a commodity sale to occur at the point the commodity transfers to our final purchaser.

The majority of the consideration received for oil and gas sales is variable. Most of our contracts state the consideration is calculated by multiplying a variable quantity by an agreed-on index price less deductions related to gathering, transportation, fractionation, and related fuel charges. There are also instances where the consideration is quantity multiplied by a weighted average sales price. These different pricing tools can change the perception of when control transfers; however, when analyzed with other control factors, typically the accounting conclusion is the same for both pricing methods. In these instances, the variable consideration is partially constrained. In addition, all variable consideration is settled at the end of the month; therefore, whether the variability is constrained does not affect accounting for revenue under ASC 606 as the variability is known prior to each reporting period. An estimation and allocation of transaction price and future obligations are not required.

Contract Drilling Contracts, Revenues, Implementation impact to retained earnings, and Performance Obligations

The contract drilling contracts we use primarily are industry standard IADC contracts 2003 and 2013. Contract terms can range from six months to two or more years or can be based on terms to drill a specific number of wells. These allocation rules in ASC 606 are referred to as the series guidance which states that a contract may contain a single performance obligation

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composed of a series of distinct goods or services if 1) each distinct good or service is substantially the same and would meet the criteria to be a performance obligation satisfied over time and 2) each distinct good or service is measured using the same method as it relates to the satisfaction of the overall performance obligation. The company determined that the delivery of drilling services is within the scope of the series guidance as both criteria noted above are met. Specifically, 1) each distinct increment of service (i.e. hour available to drill) that the driller promises to transfer represents a performance obligation that would meet the criteria for recognizing revenue over time, and 2) the driller would use the same method for measuring progress toward satisfaction of the performance obligation for each distinct increment of service in the series. At inception, the total transaction price will be estimated to include any applicable fixed consideration, unconstrained variable consideration (estimated day rate mobilization and demobilization revenue, estimated operating day rate revenue to be earned over the contract term, expected bonuses (if material and can be reasonably estimated without significant reversal), and penalties (if material and can be reasonably estimated without significant reversal)). Allocation rules under the new standard will allow the company to recognize revenues associated with contract drilling contacts in materially the same manner as under the previous revenue accounting standard. A contract liability will be recorded for consideration received before the corresponding transfer of services. Such liabilities will generally only arise in relation to upfront mobilization fees which are paid in advance and are allocated/recognized over the entire performance obligation. Such balances will be amortized over the recognition period based on the same method of measure used for revenue. On adoption of the standard, no adjustment to opening retained earnings was required.

Our performance obligation for all contracts is to drill the agreed-on number of wells or drill over an agreed-on period of time as stated in the contract. Mobilization and demobilization activities associated with a drilling contract are not considered to be distinct within the context of the contract and therefore, any associated revenue is allocated to the overall performance obligation of drilling services and recognized ratably over the initial term of the related drilling contract. It typically takes from 10 to 90 days to complete drilling a well; therefore, depending on the number of wells under a contract, the contract term could be up to two years. Most of the drilling contracts are for less than one year. As the customer simultaneously received and consumes the benefits provided by the company’s performance, and the company’s performance enhances an asset that the customer controls, the performance obligation to drill the well occurs over time. We typically receive payment within a set number of days following the end of the month and includes payment for all services performed that month (calculated on an hourly basis). The company satisfies its overall performance obligation when the well included in the contract is drilled to an agreed-upon depth or by a set date.

All consideration received for contract drilling contracts is variable, excluding termination fees, which we concluded will not be applicable to our current contracts as of the reporting date. The consideration is calculated by multiplying a variable quantity (number of days/hours) by an agreed-on daily price (for the daily rate, mobilization and demobilization revenue). Other revenue items per the contract include bonus/penalty revenue, reimbursable revenue, drilling fluid rates, and early termination fees. All variable consideration is not constrained but is settled at the end of the month; therefore, whether or not the variability is constrained does not affect accounting for revenue under ASC 606 as the variability is known prior to each reporting period excluding certain bonuses/penalties which might be based on activity that occurs over the entire term of the contract. We have evaluated the mobilization and de-mobilization charges on outstanding contracts, however, the impact to the financial statements was immaterial. As of March 31, 2018, we had 32 contract drilling contracts (six long-term) for a duration of two to fourteen months.

Per the new guidance in relation to disclosures regarding remaining performance obligations, there is a practical expedient for contracts that have an original expected duration of one year or less (ASC 606-10-50-14) and for contracts where the entity can recognize revenue as invoiced (ASC 606-10-55-18). The majority of contract drilling contracts have an original term of less than one year; however, there are a few contracts with a longer duration that are not material.

Mid-stream Contracts Revenues, and Implementation impact to retained earnings, and Performance Obligations

Revenues are generated from the fees earned for gas gathering and processing services provided to a customer. Typical types of revenue contracts signed are Gas Gathering and Processing agreements. Contract terms can range from single month to extended term contracts spanning a decade or more, some include evergreen provisions. Fees for mid-stream services (gathering, transportation, processing) are performance obligations and meet the criteria of over time recognition which could be considered a series of distinct performance obligations that represents one overall performance obligation of gas gathering and processing services.

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On adoption of the standard, an adjustment to opening retained earnings was made in the amount of $1.7 million ($1.3 million, net of tax). This adjustment related to the timing of revenue recognized on certain demand fees and had the following impact to the Unaudited Condensed Consolidated Balance Sheet:

	Balance at December 31, 2017	Adjustments due to ASC 606	Balance at January 1, 2018
	(In thousands)		
Assets:			
Other assets	$16,230	$ 10,798	$27,028
Liabilities and shareholders' equity:			
Current portion of other long-term liabilities	13,002	2,748	15,750
Other long-term liabilities	100,203	9,737	109,940
Deferred income taxes	133,477	(413)	133,064
Retained earnings	799,402	(1,274)	798,128

The following impact of these demand fees to the Unaudited Condensed Consolidated Balance Sheet on at March 31, 2018:

	As Reported	Adjustments due to ASC 606	Amounts without the Adoption of ASC 606
	(In thousands)		
Assets:			
Prepaid expenses and other	$7,724	$ 50	$ 7,674
Other assets	27,470	11,397	16,073
Liabilities and shareholders' equity:			
Current portion of other long-term liabilities	14,587	2,824	11,763
Other long-term liabilities	104,286	9,118	95,168
Deferred income taxes	136,600	(121)	136,479
Retained earnings	805,993	(374)	805,619

This adjustment related to the timing of revenue recognized on certain demand fees and had the following impact to the Unaudited Condensed Consolidated Income Statement for the three months ended March 31, 2018:

	As Reported	Adjustments due to ASC 606	Amounts without the Adoption of ASC 606
	(In thousands)		
Gas gathering and processing revenues	$56,044	$ 1,192	$ 54,852

Deferred income tax expense	3,607	292	3,315
Net income	7,865	900	6,965

The only fixed consideration related to mid-stream consideration is the demand fee which is calculated by multiplying an agreed-on price by a fixed number of volumes per month over a specified term in the contract.

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Included below is the additional fixed revenue the company will earn over the remaining term of the contracts and excludes all variable consideration to be earned with the associated contract.

Contract	Remaining Term of Contract	April - December 2018	2019	2020	2021	2022	Total Remaining Impact to Revenue
		(In thousands)					
Demand fee contracts	4-5 years	$3,777	$2,632	$(3,781)	$(3,507)	$1,374	$ 495

Before the implementation of ASC 606, we recognized the entire demand fee as the fee was payable the first five years after the effective date, not the entire term of the contract. However, as the demand fee does not specifically relate to a distinct performance obligation, the amount should be recognized over the life of the contract. Therefore, the demand fee already recognized for $1.7 million ($1.3 million, net of tax) was adjusted to retained earnings as of January 1, 2018, and will be recognized over the remaining term of the contract. As this amount is fixed consideration, recognition of the remaining portion will be stable. For the first three months of March 31, 2018, $1.2 million was recognized in revenue for these demand fees.

Besides the demand fee, there were no other contract assets or liabilities (see above for the balance sheet line items where they are reported.)

	March 31, 2018	January 1, 2018	Change
	(In thousands)		
Contract assets	$11,447	$10,798	$649
Contract liabilities	11,942	12,485	(543)
Contract liabilities, net	$(495)	$(1,687)	$1,192

Our performance obligations for all contracts is to gather, transport, or process an agreed-on number of volumes as stated in the contract. Typically the contract will establish a period of time over which the company will perform the mid-stream services. Certain contracts also include an agreed-on quantity (or an agreed-on minimum quantity) of volumes that the company will deliver or service. The term under mid-stream service contracts is typically five to ten years. Under service contracts, as the customer simultaneously receives and consumes the benefits provided by the entity's performance as the entity performs, the performance obligation to gather, transport, or process occurs over time. We typically receive payment within a set number of days following the end of the month and includes payment for all services performed that month. The company satisfies its overall performance obligation at the end of the contract term.

Most of the consideration received for mid-stream service contracts is variable. The consideration is calculated by multiplying a variable quantity (number of volumes) by an agreed-on price per MCF (commodity fee and the gathering fee). One fixed component of revenue is calculated by multiplying an agreed-on price by a certain volume commitment (MCF per day). Other revenue items may include shortfall fees. All variable consideration is settled at the end of the month; therefore, whether or not the variability is constrained does not affect accounting for revenue under ASC 606 as the variability is known before each reporting period. However, this excludes the shortfall fee as this fee could be based on a set number of volumes over the course of more than one month.

Per the new guidance related to disclosures for remaining performance obligations, there is a practical expedient for contracts that have an original expected duration of one year or less (ASC 606-10-50-14). There is also a practical expedient for "variable consideration [that] is allocated entirely to a wholly unsatisfied performance obligation… that forms part of a single performance obligation… for which the criteria in paragraph 606-10-32-40 have been met" (ASC 606-10-50-14A). As stated previously, the contract term for mid-stream services is typically longer than one year. However, based on the guidance at 606-10-32-40, we determined some of the variable payment in mid-stream service agreements specifically relates to the entity's efforts to satisfy the performance obligation and that "allocating the variable amount entirely to the distinct good or service is consistent with the allocation objective in paragraph 606-10-32-28." Therefore, the practical expedient relates to this variable consideration: the commodity fee and the gathering fee. The last time we received a shortfall fee was in 2016 and the amount was immaterial to total mid-stream revenues. These terms have historically been limited in our contracts.

We calculate revenue earned from the variable consideration related to mid-stream services by multiplying the number of volumes serviced times an agreed-on price. Therefore, the variable portion of this consideration is due to the change in

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volumes. This variability is resolved at the end of each month as the company will know the number of volumes serviced under each contract and payment is received monthly. The mid-stream gathering service contracts remaining are for a duration of less than one year to 15 years.

While long term service contracts are in place as of the reporting date, due to the variable volumes an estimation and allocation of transaction price and future obligations are not required.

NOTE 3 – DIVESTITURES

Oil and Natural Gas

We sold non-core oil and natural gas assets, net of related expenses, for $21.7 million during the first three months of 2018, compared to $14.8 million during the first three months of 2017. Proceeds from those sales reduced the net book value of our full cost pool with no gain or loss recognized.

NOTE 4 – EARNINGS PER SHARE

Information related to the calculation of earnings per share follows:

	Earnings (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the three months ended March 31, 2018			
Basic earnings per common share	$7,865	51,730	$ 0.15
Effect of dilutive stock options and restricted stock	—	542	—
Diluted earnings per common share	$7,865	52,272	$ 0.15
For the three months ended March 31, 2017			
Basic earnings per common share	$15,929	50,293	$ 0.32
Effect of dilutive stock options, restricted stock, and stock appreciation rights (SARs)	—	568	(0.01)
Diluted earnings per common share	$15,929	50,861	$ 0.31

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 March 31,	
	2018	2017
Stock options and SARs	87,500	199,755
Average exercise price	$51.34	$48.79

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NOTE 5 – ACCRUED LIABILITIES

Accrued liabilities consisted of:

	March 31, 2018	December 31, 2017
	(In thousands)	
Interest payable	$17,560	$ 6,745
Lease operating expenses	11,570	11,819
Employee costs	9,754	19,521
Taxes	4,139	3,404
Third-party credits	2,051	2,240
Derivative settlements	1,527	—
Other	6,363	4,794
Total accrued liabilities	$52,964	$ 48,523

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:

	March 31, 2018	December 31, 2017
	(In thousands)	
Credit agreement with an average interest rate of 3.8% and 3.4% at March 31, 2018 and December 31, 2017, respectively	$147,700	$ 178,000
6.625% senior subordinated notes due 2021	650,000	650,000
Total principal amount	797,700	828,000
Less: unamortized discount	(2,085)	(2,234)
Less: debt issuance costs, net	(5,093)	(5,490)
Total long-term debt	$790,522	$ 820,276

Credit Agreement. On April 2, 2018, we amended our Senior Credit Agreement (credit agreement) scheduled to mature on April 10, 2020. The details of this amendment are discussed in Note 15 — Subsequent Events.

Before the amendment and through March 31, 2018, the amount we could borrow was 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 was $475.0 million. We were charged a commitment fee of 0.50% on the amount available but not borrowed. That fee varied 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 have 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. 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 could 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% plus a margin. Interest is payable at the end of each month and the principal may be repaid in whole or in part at

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any time, without a premium or penalty. At March 31, 2018, we had $147.7 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 March 31, 2018, 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 March 31, 2018.

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Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	March 31, 2018	December 31, 2017
	(In thousands)	
Asset retirement obligation (ARO) liability	$63,763	$ 69,444
Capital lease obligations	14,277	15,224
Workers' compensation	13,049	13,340
Contract liability	11,942	—
Separation benefit plans	7,087	6,524
Deferred compensation plan	5,472	5,390
Gas balancing liability	3,283	3,283
	118,873	113,205
Less current portion	14,587	13,002
Total other long-term liabilities	$104,286	$ 100,203

Estimated annual principal payments under the terms of debt and other long-term liabilities during the five successive twelve-month periods beginning April 1, 2018 (and through 2023) are $14.6 million, $41.9 million, $156.1 million, $653.2 million, and $2.0 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 $3.9 million current portion of our capital lease obligations is included in current portion of other long-term liabilities and the non-current portion of $10.4 million is included in other long-term liabilities in the accompanying Unaudited Condensed Consolidated Balance Sheets as of March 31, 2018. These capital leases are discounted using annual rates of 4.00%. Total maintenance and interest remaining related to these leases are $5.4 million and $1.0 million, respectively, at March 31, 2018. Annual payments, net of maintenance and interest, average $4.2 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 March 31, 2018:

Beginning April 1,	Amount (In thousands)
2018	$ 6,168
2019	6,168
2020	7,815
2021	579
Total future payments	20,730
Less payments related to:	
Maintenance	5,428
Interest	1,025
Present value of future minimum payments	$ 14,277

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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:

	Three Months Ended March 31,	
	2018	2017
	(In thousands)	
ARO liability, January 1:	$69,444	$70,170
Accretion of discount	659	785
Liability incurred	118	658
Liability settled	(1,626)	(630)
Liability sold	(81)	(432)
Revision of estimates [(1)]	(4,751)	(508)
ARO liability, March 31:	63,763	70,043
Less current portion	1,477	3,243
Total long-term ARO	$62,286	$66,800

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(1) Plugging liability estimates were revised in both 2018 and 2017 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

Intangibles—Goodwill and Other: Simplifying the Test for Goodwill Impairment. The FASB issued ASU 2017-04, to simplify the measurement of goodwill. The amendment eliminates Step 2 from the goodwill impairment test. The amendment will be effective prospectively for reporting periods beginning after December 15, 2019, and early adoption is permitted. This amendment will not have a material impact on our financial statements.

Leases. The FASB has issued ASU 2016-02. The amendment 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 represents the lessee's right to use a specified asset for the lease term. Lessor accounting is largely unchanged. In January 2018, the FASB issued ASU 2018-01, "Leases - Land Easement practical expedient for Transition to Topic 842", which provides clarifying guidance regarding land easements and adds practical expedients. For public companies, the amendment is 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 have begun the identification of leases and impact assessment within the scope of the guidance. Our evaluation of the impact of the new guidance on our financial statements in on-going.

Adopted Standards

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income. The FASB issued ASU 2018-02, an amendment which provides financial statement preparers with an option to reclassify stranded tax effects within AOCI to retained earnings caused by the Tax Cuts and Jobs Act of 2017. The amendment is effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted. Organizations should apply the proposed amendments either in the period of adoption or retrospectively to each period (or periods) in which the effect of the change in the U.S. federal corporate income tax rate in the Tax Cuts and Jobs Act is recognized. We adopted this amendment early and it did not have a material effect to our financial statements. We previously used 37.75% to calculate the tax effect on AOCI and now we are using 24.5%. The change is reflected in our Unaudited Condensed Consolidated Statements of Comprehensive Income and in Note 13 - Equity.

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Revenue from Contracts with Customers. Effective January 1, 2018, the company adopted ASC 606. The new revenue standard provides a five-step analysis of transactions to determine when and how revenue is recognized. The guidance in this update supersedes the revenue recognition requirements in ASC 605, Revenue Recognition, and most industry-specific guidance throughout the Industry Topics of the Codification. Under the standard, revenue is recognized when a customer obtains control of promised goods or services in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. In addition, the standard requires disclosure of the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The company applied the five step method outlined in the ASU to all revenue streams in the scope of ASC 606 and elected the modified retrospective approach method. Under that approach the cumulative effect on adoption is recognized as an adjustment to opening retained earnings at January 1, 2018. Only our mid-stream segment was affected. This adjustment related to the timing of revenue on certain demand fees. Both our oil and natural gas and contract drilling segments had no retained earnings adjustment. Comparative prior periods have not been adjusted and continue to be reported under ASC 605.

The additional disclosures required by ASC 606 have been included in Note 2 – Revenue from Contracts with Customers.

Our internal control framework did not materially change, but the existing internal controls have been modified to consider our new revenue recognition policy effective January 1, 2018. As we implement the new standard, we have added internal controls to ensure that we adequately evaluate new contracts under the five-step model under ASU 2014-09.

NOTE 9 –STOCK-BASED COMPENSATION

For restricted stock awards and stock options, we had:

	Three Months Ended March 31,	
	2018	2017
	(In millions)	
Recognized stock compensation expense	$4.6	$2.6
Capitalized stock compensation cost for our oil and natural gas properties	1.3	0.4
Tax benefit on stock based compensation	1.1	1.0

The remaining unrecognized compensation cost related to unvested awards at March 31, 2018 is approximately $27.4 million, of which $3.5 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) and to non-employee directors. 7,230,000 shares of the company's common stock are 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."

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We granted no SARs or stock options during either of the three-month periods ending March 31, 2018 or 2017. This table shows the fair value of restricted stock awards granted to employees and non-employee directors during the periods indicated:

	Three Months Ended March 31, 2018		Three Months Ended March 31, 2017	
	Time Vested	Performance Vested	Time Vested	Performance Vested
Shares granted:				
Employees	839,498	362,070	461,799	152,373
Non-employee directors	—	—	—	—
	839,498	362,070	461,799	152,373
Estimated fair value (in millions):(1)				
Employees	$16.1	$ 7.3	$11.4	$ 4.0
Non-employee directors	—	—	—	—
	$16.1	$ 7.3	$11.4	$ 4.0
Percentage of shares granted expected to be distributed:				
Employees	95 %	63 %	94 %	105 %
Non-employee directors	N/A	N/A	N/A	N/A

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(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 three months of 2018 and 2017 are being recognized over a three-year vesting period. During the the first quarter of 2018 and 2017, there were two 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 (TSR) 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 TSR performance criteria at March 31, 2018, the participants are estimated to receive 27% of the 2018, 93% of the 2017, and 164% of the 2016 performance based shares. The CFTA performance measurement at March 31, 2018 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 2018 awards for the first three months of 2018 was $1.1 million.

NOTE 10 – DERIVATIVES

Commodity Derivatives

We have signed 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 March 31, 2018, our derivative transactions comprised these 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.

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- 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 before maturity (i.e., temporary fluctuations in value) are reported in gain (loss) on derivatives in our Unaudited Condensed Consolidated Income Statements.

At March 31, 2018, these derivatives were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Apr’18 – Sep'18	Natural gas – swap	40,000 MMBtu/day	$2.985	IF – NYMEX (HH)
Oct'18	Natural gas – swap	30,000 MMBtu/day	$3.005	IF – NYMEX (HH)
Nov’18 – Dec'18	Natural gas – swap	20,000 MMBtu/day	$3.013	IF – NYMEX (HH)
Apr'18 – Oct'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.190)	NGPL TEXOK
Apr'18 – Dec'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.678)	PEPL
Apr’18 – Dec'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.568)	NGPL MIDCON
Nov’18 – Dec'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.208)	IF – NYMEX (HH)
Jan'19 – Dec'19	Natural gas – basis swap	10,000 MMBtu/day	$(0.728)	PEPL
Jan'19 – Dec'19	Natural gas – basis swap	10,000 MMBtu/day	$(0.625)	NGL MIDCON
Jan'19 – Dec'19	Natural gas – basis swap	30,000 MMBtu/day	$(0.265)	NGPL TEXOK
Jan'20 – Dec'20	Natural gas – basis swap	20,000 MMBtu/day	$(0.280)	NGPL TEXOK
Apr'18 – Sep'18	Natural gas – collar	30,000 MMBtu/day	$2.67 - $2.97	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)
Apr'18 – Dec'18	Crude oil – swap	4,000 Bbl/day	$53.52	WTI – NYMEX
Apr'18 – Dec'18	Crude oil – three-way collar	2,000 Bbl/day	$47.50 - $37.50 - $56.08	WTI – NYMEX
Apr'18 – Sep'18	NGLs – swap[1]	1,500 Bbl/day	$32.14	OPIS – Mont Belvieu

(1) Type of NGLs involved is propane.

After March 31, 2018, the following derivative was entered into:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Jan'19 – Dec'19	Crude oil – three-way collar	1,000 Bbl/day	$55.00 - $45.00 - $70.25	WTI – NYMEX
Jan'20 – Dec'20	Natural gas – basis swap	10,000 MMBtu/day	$(0.265)	NGPL TEXOK

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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 March 31, 2018	Derivative Assets Fair Value December 31, 2017
		(In thousands)	
Commodity derivatives:			
Current	Current derivative asset	$537	$ 721
Long-term	Non-current derivative asset	—	—
Total derivative assets		$537	$ 721

	Balance Sheet Location	Derivative Liabilities Fair Value March 31, 2018	Derivative Liabilities Fair Value December 31, 2017
		(In thousands)	
Commodity derivatives:			
Current	Current derivative liability	$12,104	$ 7,763
Long-term	Non-current derivative liability	164	—
Total derivative liabilities		$12,268	$ 7,763

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 in our Unaudited Condensed Consolidated Balance Sheets.

Following is the effect of derivative instruments on the Unaudited Condensed Consolidated Income Statements for the three months ended March 31:

Derivatives Instruments	Location of Gain (Loss) Recognized in Income on Derivative	Amount of Gain (Loss) Recognized in Income on Derivative 2018	2017
		(In thousands)	
Commodity derivatives	Gain (loss) on derivatives (1)	$(6,762)	$14,731
Total		$(6,762)	$14,731

(1) Amounts settled during the 2018 and 2017 periods include net payments of $2.1 million and $1.2 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	Gross Unrealized	Estimated Fair

		Gains	Losses	Value
	(In thousands)			
Equity Securities:				
March 31, 2018	$830	$ —	$ 132	$ 698
December 31, 2017	$830	$ 102	$ —	$ 932

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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 of those 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 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 transferring 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 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:

	March 31, 2018				
	Level 1	Level 2	Level 3	Effect of Netting	Net Amounts Presented
	(In thousands)				
Financial assets (liabilities):					
Commodity derivatives:					
Assets	$—	$2,897	$1,294	$(3,654)	$537
Liabilities	—	(11,422)	(4,500)	3,654	(12,268)
Total commodity derivatives	—	(8,525)	(3,206)	—	(11,731)
Equity securities	698	—	—	—	698
	$698	$(8,525)	$(3,206)	$—	$(11,033)

	December 31, 2017				
	Level 1	Level 2	Level 3	Effect of Netting	Net Amounts Presented
	(In thousands)				
Financial assets (liabilities):					
Commodity derivatives:					
Assets	$—	$2,137	$3,344	$(4,760)	$721
Liabilities	—	(8,973)	(3,550)	4,760	(7,763)
Total commodity derivatives	$—	$(6,836)	$(206)	$—	$(7,042)

Equity securities	932	—	—	—	932
	$932	$(6,836)	$(206)	$—	$(6,110)

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 March 31, 2018.

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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 March 31,	
	2018	2017
	(In thousands)	
Beginning of period	$(206)	$(7,122)
Total gains or losses (realized and unrealized):		
Included in earnings [1]	(3,919)	5,903
Settlements	919	617
End of period	$(3,206)	$(602)
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	$(3,000)	$6,520

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

The following table provides quantitative information about our Level 3 unobservable inputs at March 31, 2018:

Commodity [1]	Fair Value (In thousands)	Valuation Technique	Unobservable Input	Range
Oil three-way collars	$ (4,457)	Discounted cash flow	Forward commodity price curve	$0 - $9.41
Natural gas collar	$ (1)	Discounted cash flow	Forward commodity price curve	$0.01 - $0.12
Natural gas three-way collars	$ 1,252	Discounted cash flow	Forward commodity price curve	$0 - $0.28

(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 March 31, 2018 reflected that the risk of non-performance by our counterparties was immaterial.

Fair Value of Other Financial Instruments

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

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At March 31, 2018, 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 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 March 31, 2018 and December 31, 2017 was $147.7 million and $178.0 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 March 31, 2018 and December 31, 2017 were $642.8 million and $642.3 million, respectively. We estimate the fair value of the Notes using quoted marked prices at March 31, 2018 and December 31, 2017 was $632.9 million and $649.7 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 $2.7 million, $0.9 million, $0.4 million, and less than $0.1 million in twelve-month periods beginning April 1, 2018 (and through 2021), respectively. Total rent expense incurred was $2.3 million and $2.1 million for the first three months of 2018 and 2017, respectively.

In 2014, our mid-stream segment signed 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 April 1, 2018 (and through the end of 2021) are $6.2 million, $6.2 million, $7.8 million, and $0.6 million. Total maintenance and interest remaining related to these leases are $5.4 million and $1.0 million, respectively at March 31, 2018. Annual payments, net of maintenance and interest, average $4.2 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 quarter of 2018 or 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 $3.4 million of new drilling rig components.

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NOTE 13 – EQUITY

At-the-Market (ATM) Common Stock Program

On April 4, 2017, we signed 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 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 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 March 31, 2018, we have sold 787,547 shares of our common stock resulting in net proceeds of approximately $18.6 million. No shares were sold in the first quarter of 2018. On May 2, 2018, we terminated this Agreement, the details are discussed in Note 15 — Subsequent Events.

Accumulated Other Comprehensive Income

Components of accumulated other comprehensive income were as follows for the three months ended March 31:

	2018	2017
	(In thousands)	
Unrealized loss on securities, before tax	$ (234)	$ —
Tax expense	58 (1)	—
Unrealized loss on securities, net of tax	$ (176)	$ —

(1) Due to the implementation of ASU 2018-02, the tax rate changed from 37.75% to 24.5%.

Changes in accumulated other comprehensive income by component, net of tax, for the three months ended March 31 are as follows:

Net Gains on Equity

	Securities	
	2018	2017
	(In thousands)	
Balance at December 31, 2017	$63	$ —
Adjustment due to ASU 2018-02	13 [1]	—
Balance at January 1:	76	—
Unrealized loss before reclassifications	(176)[1]	—
Amounts reclassified from accumulated other comprehensive income	—	—
Net current-period other comprehensive income	(176)	—
Balance at March 31:	$(100)	$ —

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(1) Due to the implementation of ASU 2018-02, the tax rate changed from 37.75% to 24.5%.

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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 March 31, 2018					
	Oil and Natural Gas	Contract Drilling	Mid-stream	Other	Eliminations	Total Consolidated
	(In thousands)					
Revenues: [1]						
Oil and natural gas	$103,099	$—	$ —	$—	$ —	$ 103,099
Contract drilling	—	50,710	—	—	(4,721)	45,989
Gas gathering and processing	—	—	74,650	—	(18,606)	56,044
Total revenues	103,099	50,710	74,650	—	(23,327)	205,132
Expenses:						
Operating costs:						
Oil and natural gas	37,152	—	—	—	(1,190)	35,962
Contract drilling	—	35,954	—	—	(4,287)	31,667
Gas gathering and processing	—	—	59,020	—	(17,416)	41,604
Total operating costs	37,152	35,954	59,020	—	(22,893)	109,233
Depreciation, depletion, and amortization	30,783	13,312	11,053	1,918	—	57,066
Total expenses	67,935	49,266	70,073	1,918	(22,893)	166,299
Total operating income (loss) [2]	35,164	1,444	4,577	(1,918)	(434)	
General and administrative expense	—	—	—	(10,762)	—	(10,762)
Gain on disposition of assets	71	26	34	30	—	161
Loss on derivatives	—	—	—	(6,762)	—	(6,762)
Interest expense, net	—	—	—	(10,004)	—	(10,004)
Other	—	—	—	6	—	6
Income (loss) before income taxes	$35,235	$ 1,470	$ 4,611	$(29,410)	$ (434)	$ 11,472

(1) The revenues for oil and natural gas occur at a point in time. The revenues for contract drilling and gas gathering and processing occur over time.

(2) 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, loss on derivatives, interest expense, other income, or income taxes.

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	Three Months Ended March 31, 2017					
	Oil and Natural Gas	Contract Drilling	Mid-stream	Other	Eliminations	Total Consolidated
	(In thousands)					
Revenues:						
Oil and natural gas	$87,598	$—	$ —	$—	$ —	$ 87,598
Contract drilling	—	37,185	—	—	—	37,185
Gas gathering and processing	—	—	66,464	—	(15,523)	50,941
Total revenues	87,598	37,185	66,464	—	(15,523)	175,724
Expenses:						
Operating costs:						
Oil and natural gas	30,326	—	—	—	(1,122)	29,204
Contract drilling	—	29,227	—	—	—	29,227
Gas gathering and processing	—	—	52,105	—	(14,401)	37,704
Total operating costs	30,326	29,227	52,105	—	(15,523)	96,135
Depreciation, depletion, and amortization	21,526	12,847	10,818	1,741	—	46,932
Total expenses	51,852	42,074	62,923	1,741	(15,523)	143,067
Total operating income (loss)(1)	35,746	(4,889)	3,541	(1,741)	—	
General and administrative expense	—	—	—	(8,954)	—	(8,954)
Gain on disposition of assets	9	7	—	808	—	824
Gain on derivatives	—	—	—	14,731	—	14,731
Interest expense, net	—	—	—	(9,396)	—	(9,396)
Other	—	—	—	3	—	3
Income (loss) before income taxes	$35,755	$(4,882)	$ 3,541	$(4,549)	$ —	$ 29,865

(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, or income taxes.

NOTE 15 – SUBSEQUENT EVENTS

On April 2, 2018, the company, including certain of its subsidiaries signed a Fourth Amendment to our Senior Credit Agreement (Fourth Amendment) with these lenders: BOKF, NA (dba Bank of Oklahoma); Compass Bank; BMO Harris Financing, Inc.; Bank of America, N.A.; Wells Fargo Bank, N.A.; Comerica Bank; Canadian Imperial Bank of Commerce, New York Branch; and Toronto Dominion (New York), LLC. BOKF, NA is serving as administrative agent for the other lenders under the Fourth Amendment.

The Fourth Amendment was signed in connection with our sale of 50% of our ownership interest in our midstream segment, Superior Pipeline Company, L.L.C. One of the conditions of that sale was the release of Superior from the terms of the credit agreement. Since the Fourth Amendment needed to be signed before the closing of the Superior sale it was designed to account for the possibility the Superior sale might not close as anticipated. The Fourth Amendment provides, among other things, for a reduction of the maximum credit amount from $875.0 million to $475.0 million, and an increase in the borrowing base from $475.0 million to $525.0 million; provide that part of the proceeds from the sale be used to pay down the existing outstanding principal balance under the credit agreement. Once that payment was made on April 3, 2018-(i) the total commitment amount was reduced from $475.0 million to $425.0 million; (ii) the maximum credit amount was reduced from $475.0 million to $425.0 million and set as the amount that would otherwise be subject to redetermination in April; (iii) the borrowing base was reduced from $525.0 million to $425.0 million; and (iv) Superior and its subsidiaries (Superior), were fully released as a borrower and co-obligor under the credit agreement. The Superior sale closed on April 3, 2018 and the paydown under the credit agreement was made that same day.

The 50% interest in Superior we sold was acquired by SP Investor Holdings, LLC, a holding company jointly owned by OPTrust and funds managed and/or advised by Partners Group, a global private markets investment manager (Purchaser), for

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cash consideration of $300.0 million. The sale closed under the purchase and sale agreement (the Purchase Agreement) dated March 28, 2018 and closed on April 3, 2018. Part of the proceeds from the sale were used to pay down our bank debt and the remainder will be used to accelerate the drilling program of our upstream subsidiary, Unit Petroleum Company, make additional capital investments in the jointly owned Superior, and for general working capital purposes. In connection with the sale of the interest in Superior, the company and its board of directors took the necessary actions under the Indenture governing the company's outstanding senior subordinated notes to secure the ability to close the sale and to have Superior released from the Indenture.

Superior will be governed and managed by the Amended and Restated Limited Liability Company Agreement and Master Services and Operating Agreement, respectively, both of which are included as exhibits to the Purchase and Sale Agreement filed with this report.

On May 2, 2018, we terminated the Distribution Agreement dated April 4, 2017, as amended (the Distribution Agreement), between the company and Raymond James & Associates, Inc. (the Sales Agent). The Distribution Agreement was terminable at will on written notification by the company with no penalty. Under the Distribution Agreement, the company was entitled to issue and sell, from time to time, through or to the Sales Agent shares of its common stock, having an aggregate offering price of up to $100.0 million in an “at-the-market” offering program. As of the date of termination, the company sold 787,547 shares of its Common Stock under the Distribution Agreement. As a result of the termination, there will be no more sales of the our common stock under the Distribution Agreement.

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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 these 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 and 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, and the demand for our drilling rigs which influences the amounts we can charge for those drilling rigs. While our operations are within the United States, events outside the United States affect us and our industry.

Fluctuating commodity prices worldwide during the past several years brought about significant and adverse changes to our industry and us. Industry wide reductions in drilling activity and spending for extended periods reduces the rates for and the number of our drilling rigs we can work. In addition, sustained lower commodity prices impact the liquidity condition of some of our industry partners and customers, which could limit their ability to meet their financial obligations to us.

Recently, commodity prices have improved. During the first quarter of 2018, our oil and natural gas segment used four of our drilling rigs and used three to four during 2017. Our contract drilling segment completed the construction and contracted our tenth BOSS drilling rig in the second quarter of 2017, and is constructing the eleventh. Our drilling rig segment's rig utilization increased from an average of 25.5 drilling rigs working during the first quarter of 2017 to 31.7 average drilling rigs working during the first quarter of 2018. Rig utilization fluctuated over the past year due to commodity prices changing and budget constraints on operators in the fourth quarter of 2017. We expect this same trend to continue in 2018.

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Other recent improvements:

- We have not incurred a non-cash ceiling test write-down since 2016. We had no write-down in the first quarter of 2018 nor the first quarter 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 March 31, 2018, and only adjust the 12-month average price to an estimated second quarter ending average (holding April 2018 prices constant for the remaining two months of the second quarter of 2018), our forward looking expectation is that we will not recognize an impairment in the second quarter of 2018. But commodity prices (and other factors) remain volatile and they could negatively affect the 12-month average price resulting in the potential for a future impairment.

- We increased the number of gross wells our oil and natural gas segment plan to drill in 2018 to 75-85 wells (depending on future commodity prices). In 2017, we increased the number of gross wells drilled to 70 from 21 in 2016 due to increased cash flow.

On April 3, 2018, the company completed the sale of 50% of the ownership interests in Superior to SP Investor Holdings, LLC, a holding company jointly owned by OPTrust and funds managed and/or advised by Partners Group, a global private markets investment manager, for cash consideration of $300 million. Part of the proceeds from the sale were used to pay down our bank debt and the balance will be used to accelerate the drilling program of our upstream subsidiary, Unit Petroleum Company, make additional capital investments in the jointly owned Superior, and for general working capital purposes.

The unaudited pro forma consolidated income statement for the quarter ended March 31, 2018, if presented, would contain an adjustment to increase net income for $2.2 million resulting from the reduction in interest due to the payment of bank debt and the benefit from lower effective tax rate due to non-controlling interest. There is also an adjustment of $1.6 million of net income attributable to the non-controlling interest.

The following unaudited pro forma consolidated balance sheet totals at March 31, 2018 set forth below gives effect to the Superior sale and the reduction of our bank debt as if it had occurred on that date. The unaudited pro forma balance sheet is provided for illustrative purposes only and does not purport to represent what our actual financial position would have been if the sale had occurred on the dates indicated, nor is it necessarily indicative of our future operating results or financial position.

	March 31, 2018		
	As Reported	Adjustment	Pro Forma
	(In thousands except share and par value amounts)		
Total assets	$2,599,591	$149,692 (1)	$2,749,283
Total liabilities	1,242,291	(122,475) (2)	1,119,816
Total shareholders' equity	1,357,300	272,167 (3)	1,629,467

(1) Represents $300.0 million cash consideration from SP Investor Holdings, LLC for 50% ownership interests in Superior less $2.6 million of transaction costs and $147.7 million of bank debt reduction.

(2) Represents$147.7 million of bank debt reduction and all tax related effects of the transaction for $25.2 million based on the statutory rate of 24.5%.

(3) Represents the $300.0 million cash consideration less $2.6 million of transaction costs, and $25.2 million of taxes.

Executive Summary

Oil and Natural Gas

First quarter 2018 production from our oil and natural gas segment was 4,181,000 barrels of oil equivalent (Boe), a decrease of 3% from the fourth quarter of 2017 and an increase of 11% over the first quarter of 2017, respectively. The decrease from the fourth quarter of 2017 was due to delays in completing newer wells drilled. The increase over the first quarter of 2017 was primarily from acquired wells and new wells drilled during 2017.

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First quarter 2018 oil and natural gas revenues increased 2% over the fourth quarter of 2017 and increased 18% over the first quarter of 2017. The increase over the fourth quarter of 2017 was due primarily to higher oil and natural gas prices and increased oil volumes partially offset by lower NGLs and natural gas production volumes and lower NGLs prices. The increase over the first quarter of 2017 was due primarily to higher oil and NGLs prices and higher production volumes.

Our oil prices for the first quarter of 2018 increased 1% over the fourth quarter of 2017 and increased 13% over the first quarter of 2017. Our NGLs prices decreased 4% from the fourth quarter of 2017 and increased 18% over the first quarter of 2017. Our natural gas prices increased 10% over the fourth quarter of 2017 and decreased 2% from the first quarter of 2017.

Operating cost per Boe produced for the first quarter of 2018 increased 6% over the fourth quarter of 2017 and increased 11% over the first quarter of 2017. The increase over the fourth quarter of 2017 was primarily due to higher lease operating expenses, saltwater disposal, and gross production tax expense, partially offset by lower production volumes. The increase over the first quarter of 2017 was primarily due to higher lease operating expenses, production taxes, saltwater disposal expense, and general and administrative expense partially offset by higher production volumes.

At March 31, 2018, these derivatives were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Apr’18 – Sep'18	Natural gas – swap	40,000 MMBtu/day	$2.985	IF – NYMEX (HH)
Oct'18	Natural gas – swap	30,000 MMBtu/day	$3.005	IF – NYMEX (HH)
Nov’18 – Dec'18	Natural gas – swap	20,000 MMBtu/day	$3.013	IF – NYMEX (HH)
Apr'18 – Oct'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.190)	NGPL TEXOK
Apr'18 – Dec'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.678)	PEPL
Apr’18 – Dec'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.568)	NGPL MIDCON
Nov’18 – Dec'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.208)	IF – NYMEX (HH)
Jan'19 – Dec'19	Natural gas – basis swap	10,000 MMBtu/day	$(0.728)	PEPL
Jan'19 – Dec'19	Natural gas – basis swap	10,000 MMBtu/day	$(0.625)	NGL MIDCON
Jan'19 – Dec'19	Natural gas – basis swap	30,000 MMBtu/day	$(0.265)	NGPL TEXOK
Jan'20 – Dec'20	Natural gas – basis swap	20,000 MMBtu/day	$(0.280)	NGPL TEXOK
Apr'18 – Sep'18	Natural gas – collar	30,000 MMBtu/day	$2.67 - $2.97	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)
Apr'18 – Dec'18	Crude oil – swap	4,000 Bbl/day	$53.52	WTI – NYMEX
Apr'18 – Dec'18	Crude oil – three-way collar	2,000 Bbl/day	$47.50 - $37.50 - $56.08	WTI – NYMEX
Apr'18 – Sep'18	NGLs – swap[(1)]	1,500 Bbl/day	$32.14	OPIS – Mont Belvieu

(1) Type of NGLs involved is propane.

After March 31, 2018, the following derivative was entered into:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Jan'19 – Dec'19	Crude oil – three-way collar	1,000 Bbl/day	$55.00 - $45.00 - $70.25	WTI – NYMEX
Jan'20 – Dec'20	Natural gas – basis swap	10,000 MMBtu/day	$(0.265)	NGPL TEXOK

For the three months ended March 31, 2018, we completed drilling 15 gross wells (5.40 net wells). For all of 2018, we anticipate participating in the drilling of approximately 75 to 85 gross wells. Excluding acquisitions and ARO liability, our estimated 2018 capital expenditures for this segment are approximately $272.0 million. Our current 2018 production guidance is approximately 17.1 to 17.4 MMBoe, an increase of 7-9% from 2017, although actual results continue to be subject to many factors.

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Contract Drilling

The average number of drilling rigs we operated in the first quarter of 2018 was 31.7 compared to 31.2 and 25.5 in the fourth quarter of 2017 and the first quarter of 2017, respectively. As of March 31, 2018, 32 of our drilling rigs were operating.

Revenue for the first quarter of 2018 decreased 1% from the fourth quarter of 2017 and increased 24% over the first quarter of 2017, respectively. The decrease from the fourth quarter of 2017 was primarily due to a decrease in mobilization and other revenues partially offset by an increase in drilling rigs operating and dayrates. The increase over the first quarter of 2017 was primarily due to increased utilization and an increase in dayrates.

Dayrates for the first quarter of 2018 averaged $17,038, a 2% increase over the fourth quarter of 2017 and an 8% increase over the first quarter of 2017. The increase over the fourth quarter of 2017 was primarily due to a labor increase in the first quarter of 2018 passed through to contracted rigs. The increase over the first quarter of 2017 was due to two labor increases passed through to contracted rigs and improving market dayrates.

Operating costs for the first quarter of 2018 increased 1% over the fourth quarter of 2017 and increased 8% over the first quarter of 2017. The increases were due primarily to more drilling rigs operating.

We have six term drilling contracts with original terms ranging from six months to two years. One is up for renewal in the second quarter of 2018, two in the third quarter of 2018, two in the fourth 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.

All ten of our existing BOSS drilling rigs are under contract. Our estimated 2018 capital expenditures for this segment are approximately $47.0 million.

Competition to keep qualified labor continues to be an issue we face in this segment and in response, we implemented pay rate increases in certain areas in the first quarter of 2018. 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.

Mid-Stream

First quarter 2018 liquids sold per day decreased 1% from the fourth quarter of 2017 and increased 16% over the first quarter of 2017, respectively. The decrease from the fourth quarter of 2017 was due to lower recoveries at our processing facilities. The increase over the first quarter of 2017 was primarily due to increased volume available to process at our plants due to additional well connects. For the first quarter of 2018, gas processed per day increased 2% over the fourth quarter of 2017 and increased 19% over the first quarter of 2017. The increase over the fourth quarter of 2017 was primarily due to higher processed volumes from new wells at our Cashion facility and our Hemphill facility. The increase over the first quarter of 2017 was primarily due to higher volume from new wells connected at our processing facilities. For the first quarter of 2018, gas gathered per day decreased 3% and 4% from the fourth quarter of 2017 and the first quarter of 2017, respectively. The decrease from the fourth quarter of 2017 and the first quarter of 2017 was primarily due to declining gathered volume on our Appalachian gathering systems.

NGLs prices in the first quarter of 2018 decreased 9% from the prices received in the fourth quarter of 2017 and increased 19% over the prices received in the first quarter of 2017. 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 first quarter of 2018 decreased 5% from the fourth quarter of 2017 and increased 10% over the first quarter of 2017. First quarter of 2018 costs were lower than the fourth quarter of 2017 primarily due to lower gas and NGLs prices. The increase over the first quarter of 2017 was primarily due to higher purchased volumes and higher NGLs prices.

At our Hemphill Texas system, our total throughput volume averaged 67.5 MMcf per day for the first quarter of 2018 and our total production of natural gas liquids was approximately 171,000 gallons per day. During the first quarter, we constructed pipelines to connect several wells in the Buffalo Wallow area and expect these will begin flowing in the second quarter. Our oil and gas segment continues to operate a rig in the Buffalo Wallow area and we are completing a construction project that will expand our compression capacity at our Buffalo Wallow compressor station to accommodate additional volumes.

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At our Cashion processing facility in central Oklahoma, our total throughput volume for the first quarter of 2018 averaged approximately 42.6 MMcf per day and our total production of natural gas liquids increased to approximately 224,700 gallons per day. Total processing capacity for this facility remains at approximately 45 MMcf per day. We connected three new wells to this system in the first quarter of 2018. We completed a pipe line extension project that allows us to gather and process gas from a third-party producer who is actively drilling in the area. We are continuing to lay laterals from this trunkline in order to connect additional wells from this producer. In the first quarter, we continued to receive gas from the producer that is committed to deliver fee-based volumes to us for five years. If they fail to deliver the required volumes they will pay a shortfall fee which will be settled annually.

At our Minco processing facility, we completed an offload connection to a new producer in the first quarter of 2018. With this offload connection our total throughput volume averaged approximately 9.1 MMcf per day while natural gas liquids averaged approximately 24,200 gallons per day. Total processing capacity is approximately 12 MMcf per day at this facility.

At our Segno gathering facility in Southeast Texas, gathered volume for the first quarter of 2018 averaged approximately 84.9 MMcf per day. At this facility, our gathering and dehydration capacity will allow us gather up to 120 MMcf per day. We connected one new well to this system in the first quarter of 2018 and the producer in this area is actively reworking and recompleting wells that are connected to our system which will continue to increase gathered volumes.

In the Appalachian region at our Pittsburgh Mills gathering system, our average gathered volume for the first quarter of 2018 is approximately 106.5 MMcf per day. We are currently constructing a new pipeline to connect the next well pad to our system. This pad will include seven new wells and we anticipate construction to be completed in the third quarter. Production from this new pad is expected to begin in the fourth quarter of 2018. Additionally, we are preparing to receive production from several infill wells that are currently being drilled on existing pads. These infill wells are expected to begin flow in the second quarter of this year.

Our estimated 2018 capital expenditures for this segment are approximately $32.0 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 reduce 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.

	Three Months Ended March 31, 2018	2017	% Change
	(In thousands except percentages)		
Net cash provided by operating activities	$ 38,646	$ 65,652	(41)%
Net cash used in investing activities	(23,243)	(29,028)	(20)%
Net cash used in financing activities	(15,352)	(29,047)	(47)%
Net increase in cash and cash equivalents	$ 51	$ 7,577	

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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 affected by changes in working capital.

Net cash provided by operating activities in the first three months of 2018 decreased by $27.0 million as compared to the first three months of 2017. The decrease resulted from changes in operating assets and liabilities related to the timing of cash receipts and disbursements and partially offset by the change in the value of outstanding derivatives.

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 decreased by $5.8 million for the first three months of 2018 compared to the first three months of 2017. The change was due primarily to an increase 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 used by financing activities decreased by $13.7 million for the first three months of 2018 compared to the first three months of 2017. The decrease was primarily due to a decrease in net borrowing after paying down long-term debt in 2018 partially offset by an increase in book overdrafts.

At March 31, 2018, we had unrestricted cash totaling $0.8 million and had borrowed $147.7 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. On April 3, 2018, we paid down the outstanding debt under our credit agreement.

Below, we summarize certain financial information as of March 31, 2018 and 2017 and for the three months ended March 31, 2018 and 2017:

	March 31, 2018	March 31, 2017	% Change
	(In thousands except percentages)		
Working capital	$(102,684)	$(41,296)	(149)%
Long-term debt less debt issuance costs	$790,522	$790,653	—%
Shareholders' equity	$1,357,300	$1,213,046	12%
Net income	$7,865	$15,929	(51)%

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 $102.7 million and $41.3 million as of March 31, 2018 and 2017, 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 change in the value of outstanding derivatives partially offset by increased accounts receivable from increased revenues. Our credit agreement is used primarily for working capital and capital expenditures. At March 31, 2018, we had borrowed \$147.7 million of the \$475.0 million available under our credit agreement. The effect of our derivative contracts decreased working capital by \$11.6 million as of March 31, 2018 and decreased working capital by \$5.6 million as of March 31, 2017.

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This table summarizes certain operating information:

	Three Months Ended March 31, 2018	2017	% Change
Oil and Natural Gas:			
Oil production (MBbls)	736	643	14 %
NGLs production (MBbls)	1,195	1,097	9 %
Natural gas production (MMcf)	13,499	12,225	10 %
Average oil price per barrel received	$55.10	$48.68	13 %
Average oil price per barrel received excluding derivatives	$61.21	$48.64	26 %
Average NGLs price per barrel received	$21.08	$17.81	18 %
Average NGLs price per barrel received excluding derivatives	$21.08	$17.81	18 %
Average natural gas price per Mcf received	$2.62	$2.68	(2)%
Average natural gas price per Mcf received excluding derivatives	$2.44	$2.78	(12)%
Contract Drilling:			
Average number of our drilling rigs in use during the period	31.7	25.5	24 %
Total number of drilling rigs owned at the end of the period	95	94	1 %
Average dayrate	$17,038	$15,835	8 %
Mid-Stream:			
Gas gathered—Mcf/day	372,862	390,384	(4)%
Gas processed—Mcf/day	151,039	126,559	19 %
Gas liquids sold—gallons/day	577,560	497,862	16 %
Number of natural gas gathering systems	22 (1)	25	(12)%
Number of processing plants	13	13	— %

(1) In the first quarter of 2018, our mid-stream segment transferred two natural gas gathering systems to our oil and natural gas segment.

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 three months of 2018 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 $436,000 per month ($5.2 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 three months of 2018 was $2.62 compared to $2.68 for the first three months of 2017. Based on our first three months of 2018 production, a $1.00 per barrel change in our oil price, without the effect of derivatives, would have a $237,000 per month ($2.8 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 $388,000 per month ($4.7 million annualized) change in our pre-tax operating cash flow. In the first three months of 2018, our average oil price per barrel received, including the effect of derivatives, was $55.10 compared with an average oil price, including the effect of derivatives, of $48.68 in the first three months of 2017 and our first three months of 2018 average NGLs price per barrel received was $21.08 compared with an average NGLs price per barrel of $17.81 in the first three months of 2017.

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 March 31, 2018, the 12-month average unescalated prices were $53.49 per barrel of oil, $33.18 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 three months of 2018.

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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 March 31, 2018, and only adjust the 12-month average price to an estimated fourth quarter ending average (holding April 2018 prices constant for the remaining two months of the second quarter of 2018), our forward looking expectation is that we will not recognize an impairment in the second quarter of 2018. But commodity prices (and other factors) remain volatile and they could negatively affect the 12-month average price resulting in the potential for a future impairment.

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 continuous fluctuations in commodity prices for oil and natural gas changes the 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 will affect our future dayrates. For the first three months of 2018, our average dayrate was $17,038 per day compared to $15,835 per day for the first three months of 2017. The average number of our drilling rigs used in the first three months of 2018 was 31.7 drilling rigs compared with 25.5 drilling rigs in the first three months of 2017. Based on the average utilization of our drilling rigs during the first three months of 2018, a $100 per day change in dayrates has a $3,170 per day ($1.2 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 income statements, 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 $4.7 million for the first three months of 2018 from our contract drilling segment and eliminated the associated operating expense of $4.3 million yielding $0.4 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 three months of 2017.

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, 22 gathering systems, and approximately 1,450 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 three months of 2018 and 2017, our mid-stream operations purchased $16.9 million and $13.9 million, respectively, of our natural gas production and NGLs, and provided gathering and transportation services of $1.7

million and $1.6 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 372,862 Mcf per day in the first three months of 2018 compared to 390,384 Mcf per day in the first three months of 2017. It processed an average of 151,039 Mcf per day in the first three months of 2018 compared to 126,559 Mcf per day in the first three months of 2017. The NGLs sold was 577,560 gallons per day in the first three months of 2018 compared to 497,862 gallons per day in the first three months of 2017. Gas gathered volumes per day in the first three months of 2018 decreased 4% compared to the first three months of 2017 primarily due to declining volumes on our Appalachian systems. Gas processed volumes for the first three months of 2018 increased 19% over the first three months of 2017 due to additional wells connected to our processing systems and higher offload volumes. NGLs sold increased 16% over the comparative period due to higher volume available to process at our plants.

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At-the-Market (ATM) Common Stock Program

On May 2, 2018, we terminated the Distribution Agreement dated April 4, 2017, as amended (the Distribution Agreement), between the company and Raymond James & Associates, Inc. (the Sales Agent). The Distribution Agreement was terminable at will on written notification by the company with no penalty. Under the Distribution Agreement, the company was entitled to issue and sell, from time to time, through or to the Sales Agent shares of its common stock, having an aggregate offering price of up to $100.0 million in an “at-the-market” offering program. As of the date of termination, the company sold 787,547 shares of its Common Stock under the Distribution Agreement. As a result of the termination, there will be no more sales of the our common stock under the Distribution Agreement.

Our Credit Agreement and Senior Subordinated Notes

Credit Agreement. On April 2, 2018, we amended our Senior Credit Agreement (credit agreement) 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 the maximum credit agreement. 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. Previous amendment fees of $1.0 million in origination, agency, syndication, and other related fees are being amortized over the life of the credit agreement. No new fees were incurred for the Fourth Amendment. Under the credit agreement, we have 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 Fourth Amendment was signed in connection with our sale of 50% of our ownership interest in our midstream segment, Superior. One of the conditions of that sale was the release of Superior from the terms of the credit agreement. Under the Fourth Amendment 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 $425.0 million. Our borrowing base and elected commitment is $425.0 million. The Superior sale closed on April 3, 2018 and the paydown under the credit agreement was made that same day.

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

Lender	Participation Interest	
BOK (BOKF, NA, dba Bank of Oklahoma)	18	%
Compass Bank	18	%
BMO Harris Financing, Inc.	16	%
Bank of America, N.A.	16	%
Comerica Bank	8	%
Wells Fargo Bank, N.A.	8	%
Canadian Imperial Bank of Commerce	8	%
Toronto Dominion (New York), LLC	8	%
	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. 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 could 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% plus a margin. 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 March 31, 2018, borrowings were $147.7 million. The outstanding balance was paid down on April 3, 2018.

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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 March 31, 2018, 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, but excluding Superior. 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 with the exception of Superior. 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 March 31, 2018.

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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 15 gross wells (5.40 net wells) in the first three months of 2018 compared to eight gross wells (3.96 net wells) in the first three months of 2017.

Capital expenditures for oil and gas properties on the full cost method for the first three months of 2018 by this segment, excluding less than $0.1 million for acquisitions and a $6.3 million in the ARO liability, totaled $86.6 million. Capital expenditures for the first three months of 2017, excluding $6.0 million for acquisition and a $0.9 million reduction in the ARO liability, totaled $37.9 million.

We anticipate participating in drilling approximately 75 to 85 gross wells in 2018 and our total estimated capital expenditures (excluding any possible acquisitions) for this segment are approximately $272.0 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 drilling rig. Construction was completed and the drilling rig was placed into service late in the second quarter.

During the first quarter of 2018, we were awarded a term contract to build our eleventh BOSS drilling rig. Construction is in progress and the drilling rig will be placed into service early in the third quarter.

Our estimated 2018 capital expenditures for this segment are approximately $47.0 million. At March 31, 2018, we had commitments to purchase approximately $3.4 million for drilling equipment over the next year. We have spent $8.9 million for capital expenditures during the first three months of 2018, compared to $7.3 million for capital expenditures during the first three months of 2017.

Mid-Stream Dispositions, Acquisitions, and Capital Expenditures. At our Hemphill Texas system, our total throughput volume averaged 67.5 MMcf per day for the first quarter of 2018 and our total production of natural gas liquids was approximately 171,000 gallons per day. During the first quarter, we constructed pipelines to connect several wells in the Buffalo Wallow area and expect these will begin flowing in the second quarter. Our oil and gas segment continues to operate a rig in the Buffalo Wallow area and we are completing a construction project that will expand our compression capacity at our Buffalo Wallow compressor station to accommodate additional volumes.

At our Cashion processing facility in central Oklahoma, our total throughput volume for the first quarter of 2018 averaged approximately 42.6 MMcf per day and our total production of natural gas liquids increased to approximately 224,700 gallons per day. Total processing capacity for this facility remains at approximately 45 MMcf per day. We connected three new wells to this system in the first quarter of 2018. We completed a pipe line extension project that allows us to gather and process gas from a third-party producer who is actively drilling in the area. We are continuing to lay laterals from this trunkline in order to connect additional wells from this producer. In the first quarter, we continued to receive gas from the producer that is committed to deliver fee-based volumes to us for five years. If they fail to deliver the required volumes they will pay a shortfall fee which will be settled annually.

At our Minco processing facility, we completed an offload connection to a new producer in the first quarter of 2018. With this offload connection our total throughput volume averaged approximately 9.1 MMcf per day while natural gas liquids averaged approximately 24,200 gallons per day. Total processing capacity is approximately 12 MMcf per day at this facility.

At our Segno gathering facility in Southeast Texas, gathered volume for the first quarter of 2018 averaged approximately 84.9 MMcf per day. At this facility, our gathering and dehydration capacity will allow us gather up to 120 MMcf per day. We connected one new well to this system in the first quarter of 2018 and the producer in this area is actively reworking and recompleting wells that are connected to our system which will continue to increase gathered volumes.

In the Appalachian region at our Pittsburgh Mills gathering system, our average gathered volume for the first quarter of 2018 is approximately 106.5 MMcf per day. We are currently constructing a new pipeline to connect the next well pad to our

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system. This pad will include seven new wells and we anticipate construction to be completed in the third quarter. Production from this new pad is expected to begin in the fourth quarter of 2018. Additionally, we are preparing to receive production from several infill wells that are currently being drilled on existing pads. These infill wells are expected to begin flow in the second quarter of this year.

On April 3, 2018, the company completed the sale of 50% of the ownership interests in Superior to SP Investor Holdings, LLC, a holding company jointly owned by OPTrust and funds managed and/or advised by Partners Group, a global private markets investment manager, for cash consideration of $300 million. Part of the proceeds from the sale were used to pay down our bank debt and the remainder will be used to accelerate the drilling program of our upstream subsidiary, Unit Petroleum Company, make additional capital investments in the jointly owned Superior, and for general working capital purposes.

During the first three months of 2018, our mid-stream segment incurred $7.3 million in capital expenditures as compared to $2.1 million in the first three months of 2017. For 2018, our estimated capital expenditures are approximately $32.0 million.

Contractual Commitments

At March 31, 2018, 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)]	$943,526	$48,643	$239,574	$655,309	$ —
Operating leases [(2)]	4,027	2,656	1,296	75	—
Capital lease interest and maintenance[(3)]	6,453	2,286	4,090	77	—
Drill pipe, drilling components, and equipment purchases [(4)]	3,429	3,429	—	—	—
Total contractual obligations	$957,435	$57,014	$244,960	$655,461	$ —

(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 March 31, 2018 interest rates of 6.625% for the Notes and 3.8% for the credit agreement. Our credit agreement has a maturity date of April 10, 2020. The outstanding credit facility balance was paid down on April 3, 2018.

(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 $5.4 million and $1.0 million, respectively.

(4) We have committed to pay $3.4 million for drilling rig components, drill pipe, and related equipment over the next year.

After March 31, 2018, we entered into a contractual obligation that commits us to spend $150.0 million for drilling wells in the Granite Wash/Buffalo Wallow area over the next three years starting January 1, 2019. This amount is already included in our drilling plan. For each dollar of the $150.0 million that we do not spend (over the three year period), we would forgo receiving $0.58 of future distributions from our 50% ownership interest in our consolidated mid-stream subsidiary. If we elected not to drill or spend any money in the designated area over the three year period, the maximum amount we could forgo from distributions would be $87.0 million.

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At March 31, 2018, we also had the following commitments and contingencies that could create, increase, or accelerate our liabilities:

Other Commitments	Estimated Amount of Commitment Expiration Per Period				
	Total Accrued	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Deferred compensation plan (1)	$5,472	Unknown	Unknown	Unknown	Unknown
Separation benefit plans (2)	$7,087	$ 772	Unknown	Unknown	Unknown
Asset retirement liability (3)	$63,763	$ 1,477	$ 37,843	$ 3,648	$ 20,795
Gas balancing liability (4)	$3,283	Unknown	Unknown	Unknown	Unknown
Repurchase obligations (5)	$—	Unknown	Unknown	Unknown	Unknown
Workers' compensation liability (6)	$13,049	$ 5,632	$ 2,519	$ 1,056	$ 3,842
Capital leases obligations (7)	$14,277	$ 3,882	$ 9,892	$ 503	$ —
Contract liability (8)	$11,942	$ 2,824	Unknown	Unknown	Unknown

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(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 three months of 2018 or 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.

(8) We have recorded a liability related to the timing of revenue recognized on certain demand fees for our midstream 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.

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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 March 31, 2018, based on our first quarter 2018 average daily production, the approximated percentages of our production under derivative contracts are as follows:

	Q2 2018	Q3	Q4
Daily oil production	60%	60%	29%
Daily natural gas production	73%	73%	73%
Daily NGLs production	11%	11%	—%

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 March 31, 2018 evaluation, we believe the risk of non-performance by our counterparties is not material. At March 31, 2018, the fair values of the net assets (liabilities) we had with each of the counterparties to our commodity derivative transactions are as follows:

	March 31, 2018 (In millions)
Canadian Imperial Bank of Commerce	$ 0.5
Bank of America	(2.4)
Bank of Montreal	(9.8)
Total liabilities	$ (11.7)

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 March 31, 2018, we recorded the fair value of our commodity derivatives on our balance sheet as current derivative assets of $0.5 million, and current and non-current derivative liabilities of $12.1 million and $0.1 million, respectively. At December 31, 2017, we recorded the fair value of our commodity derivatives on our balance sheet as current derivative assets of $0.7 million and current derivative liabilities of $7.8 million.

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 Income Statements. These gains (losses) at March 31 are as follows:

	Three Months Ended March 31, 2018	2017
	(In thousands)	
Gain (loss) on derivatives:		
Gain (loss) on derivatives, included are amounts settled during the period of ($2,073) and ($1,159), respectively	$(6,762)	$14,731
	$(6,762)	$14,731

Stock and Incentive Compensation

During the first three months of 2018, we granted awards covering 1,201,568 shares of restricted stock. These awards had an estimated fair value as of their grant date of $23.4 million. Compensation expense will be recognized over the three year vesting periods, and during the three months of 2018, we recognized $1.0 million in compensation expense and capitalized $0.1 million for these awards. During the first three months of 2018, we recognized compensation expense of $4.6 million for all of our restricted stock and capitalized $1.3 million of compensation cost for oil and natural gas properties.

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During the first three months of 2017, we granted awards covering 614,172 shares of restricted stock. These awards had an estimated fair value as of their grant date of $15.4 million. Compensation expense will be recognized over the three year vesting periods, and during the three months of 2017, we recognized $0.8 million in compensation expense and capitalized $0.2 million for these awards. During the first three months of 2017, we recognized compensation expense of $2.6 million for all of our restricted stock, stock options, and SAR grants and capitalized $0.4 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 three months of 2018 and 2017, the total we received for all of these fees was less than $0.1 million and $0.1 million, respectively. Our proportionate share of assets, liabilities, and net income relating to the oil and natural gas partnerships is included in our unaudited condensed consolidated financial statements.

New Accounting Pronouncements

Intangibles—Goodwill and Other: Simplifying the Test for Goodwill Impairment. The FASB issued ASU 2017-04, to simplify the measurement of goodwill. The amendment eliminates Step 2 from the goodwill impairment test. The amendment will be effective prospectively for reporting periods beginning after December 15, 2019, and early adoption is permitted. This amendment will not have a material impact on our financial statements.

Leases. The FASB has issued ASU 2016-02. The amendment 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 represents the lessee's right to use a specified asset for the lease term. Lessor accounting is largely unchanged. In January 2018, the FASB issued ASU 2018-01, "Leases - Land Easement practical expedient for Transition to Topic 842", which provides clarifying guidance regarding land easements and adds practical expedients. For public companies, the amendment is 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 have begun the identification of leases and impact assessment within the scope of the guidance. Our evaluation of the impact of the new guidance on our financial statements in on-going.

Adopted Standards

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income. The FASB issued ASU 2018-02, an amendment which provides financial statement preparers with an option to reclassify stranded tax effects within AOCI to retained earnings caused by the Tax Cuts and Jobs Act of 2017. The amendment is effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted. Organizations should apply the proposed amendments either in the period of adoption or retrospectively to each period (or periods) in which the effect of the change in the U.S. federal corporate income tax rate in the Tax Cuts and Jobs Act is recognized. We adopted this amendment early and it did not have a material effect to our financial statements. We previously used 37.75% to calculate the tax effect on AOCI and now we are using 24.5%. The change is reflected in our Unaudited Condensed Consolidated Statements of Comprehensive Income and in Note 13 - Equity.

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Revenue from Contracts with Customers. Effective January 1, 2018, the company adopted ASC 606. The new revenue standard provides a five-step analysis of transactions to determine when and how revenue is recognized. The guidance in this update supersedes the revenue recognition requirements in ASC 605, Revenue Recognition, and most industry-specific guidance throughout the Industry Topics of the Codification. Under the standard, revenue is recognized when a customer obtains control of promised goods or services in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. In addition, the standard requires disclosure of the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The company applied the five step method outlined in the ASU to all revenue streams in the scope of ASC 606 and elected the modified retrospective approach method. Under that approach the cumulative effect on adoption is recognized as an adjustment to opening retained earnings at January 1, 2018. Only our mid-stream segment was affected. This adjustment related to the timing of revenue on certain demand fees. Both our oil and natural gas and contract drilling segments had no retained earnings adjustment. Comparative prior periods have not been adjusted and continue to be reported under ASC 605.

The additional disclosures required by ASC 606 have been included in Note 2 – Revenue from Contracts with Customers.

Our internal control framework did not materially change, but the existing internal controls have been modified to consider our new revenue recognition policy effective January 1, 2018. As we implement the new standard, we have added internal controls to ensure that we adequately evaluate new contracts under the five-step model under ASU 2014-09.

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Results of Operations

Quarter Ended March 31, 2018 versus Quarter Ended March 31, 2017

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

	Quarter Ended March 31, 2018	2017	Percent Change
	(In thousands unless otherwise specified)		
Total revenue	$205,132	$175,724	17 %
Net income	$7,865	$15,929	(51)%
Oil and Natural Gas:			
Revenue	$103,099	$87,598	18 %
Operating costs excluding depreciation, depletion, and amortization	$35,962	$29,204	23 %
Depreciation, depletion, and amortization	$30,783	$21,526	43 %
Average oil price received (Bbl)	$55.10	$48.68	13 %
Average NGLs price received (Bbl)	$21.08	$17.81	18 %
Average natural gas price received (Mcf)	$2.62	$2.68	(2)%
Oil production (Bbl)	736,000	643,000	14 %
NGLs production (Bbl)	1,195,000	1,097,000	9 %
Natural gas production (Mcf)	13,499,000	12,225,000	10 %
Depreciation, depletion, and amortization rate (Boe)	$7.02	$5.34	31 %
Contract Drilling:			
Revenue	$45,989	$37,185	24 %
Operating costs excluding depreciation	$31,667	$29,227	8 %
Depreciation	$13,312	$12,847	4 %
Percentage of revenue from daywork contracts	100 %	100 %	— %
Average number of drilling rigs in use	31.7	25.5	24 %
Average dayrate on daywork contracts	$17,038	$15,835	8 %
Mid-Stream:			
Revenue	$56,044	$50,941	10 %
Operating costs excluding depreciation and amortization	$41,604	$37,704	10 %
Depreciation and amortization	$11,053	$10,818	2 %
Gas gathered—Mcf/day	372,862	390,384	(4)%
Gas processed—Mcf/day	151,039	126,559	19 %
Gas liquids sold—gallons/day	577,560	497,862	16 %
Corporate and other:			
General and administrative expense	$10,762	$8,954	20 %
Other depreciation	$1,918	$1,741	10 %
Gain on disposition of assets	$161	$824	(80)%
Other income (expense):			
Interest expense, net	$(10,004)	$(9,396)	6 %
Gain (loss) on derivatives	$(6,762)	$14,731	(146)%

Other	$6	$3	100 %
Income tax expense	$3,607	$13,936	(74)%
Average long-term debt outstanding	$821,178	$812,296	1 %
Average interest rate	6.1 %	6.0 %	2 %

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Oil and Natural Gas

Oil and natural gas revenues increased $15.5 million or 18% in the first quarter of 2018 as compared to the first quarter of 2017 primarily due to higher oil and NGLs prices and higher production volumes. In the first quarter of 2018, as compared to the first quarter of 2017, oil production increased 14%, natural gas production increased 10%, and NGLs production increased 9%. Average oil prices increased 13% to $55.10 per barrel, average natural gas prices decreased 2% to $2.62 per Mcf, and NGLs prices increased 18% to $21.08 per barrel.

Oil and natural gas operating costs increased $6.8 million or 23% between the comparative first quarters of 2018 and 2017 due to higher LOE, production taxes, and saltwater disposal expenses.

Depreciation, depletion, and amortization (“DD&A”) increased $9.3 million or 43% due primarily to a 31% increase in the DD&A rate and an 11% increase in equivalent production. The increase in our DD&A rate in the first quarter of 2018 compared to the first quarter of 2017 resulted primarily from the cost of wells drilled in the last nine months of 2017 and the first quarter of 2018.

Contract Drilling

Drilling revenues increased $8.8 million or 24% in the first quarter of 2018 versus the first quarter of 2017. The increase was due primarily to a 24% increase in the average number of drilling rigs in use and an 8% increase in the average dayrate. Average drilling rig utilization increased from 25.5 drilling rigs in the first quarter of 2017 to 31.7 drilling rigs in the first quarter of 2018.

Drilling operating costs increased $2.4 million or 8% between the comparative first quarters of 2018 and 2017. The increase was due primarily to more drilling rigs operating. Contract drilling depreciation increased $0.5 million or 4% also due primarily to more drilling rigs operating.

Mid-Stream

Our mid-stream revenues increased $5.1 million or 10% in the first quarter of 2018 as compared to the first quarter of 2017 due primarily to increases in liquids sold and increases in NGLs and condensate prices partially offset by decreased transportation revenues due to lower transportation volumes and prices. Gas sales decreased 7% due to a 23% decrease in prices partially offset by a 20% increase in gas sales volumes. Gas processed volumes per day increased 19% between the comparative quarters primarily due to additional wells connected to our processing systems and increased offload volumes. Gas gathered volumes per day decreased 4% between the comparative quarters primarily due to declining gathered volumes on our Appalachian systems.

Operating costs increased $3.9 million or 10% in the first quarter of 2018 compared to the first quarter of 2017 primarily due to 18% higher gas purchase volumes partially offset by a 4% decrease in purchase prices. Depreciation and amortization increased $0.2 million, or 2%, primarily due to new capital assets placed in service.

Other Depreciation

Other depreciation increased $0.2 million or 10% in the first quarter of 2018 as compared to the first quarter of 2017 due primarily to the ERP system that was implemented halfway through the first quarter of 2017.

General and Administrative

Corporate general and administrative expenses increased $1.8 million or 20% in the first quarter of 2018 compared to the first quarter of 2017 primarily due to an increase in employee costs.

Other Income (Expense)

Interest expense, net of capitalized interest, increased $0.6 million between the comparative first quarters of 2018 and 2017 due primarily to a 1% increase in average long-term debt outstanding in the first quarter of 2018 and a higher average interest rate partially offset by decrease in interest capitalized. 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 quarter of 2018 was $3.6 million compared to $3.9 million in the first quarter of 2017, and was netted against our gross interest of $13.6 million and $13.3 million for the first quarters of 2018 and

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2017, respectively. Our average interest rate increased from 6.0% in the first quarter of 2017 to 6.1% in the first quarter of 2018 and our average debt outstanding was $8.9 million higher in the first quarter of 2018 as compared to the first quarter of 2017 primarily due to the increase in outstanding borrowings under our credit agreement over the comparative periods.

Gain (Loss) on Derivatives

Gain (loss) on derivatives decreased $21.5 million primarily due to fluctuations in forward prices used to estimate the fair value in mark-to-market accounting.

Income Tax Expense

Income tax expense decreased $10.3 million between the comparative first quarters of 2018 and 2017 primarily due to decreased pre-tax income and lower statutory tax rate due to the 2017 Tax Act. Our effective tax rate was 31.4% for the first quarter of 2018 compared to 46.7% for the first quarter of 2017. The rate change was again primarily due to the lower federal statutory tax rate due to the 2017 Tax Act and, to a lesser extent, smaller deferred income tax expense related to our restricted stock vestings in the first quarter of 2018 as compared to the first quarter of 2017. There was no current income tax expense in the first quarter of 2018 or 2017. We did not pay any income taxes in the first quarter of 2018.

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 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;

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- 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;
- our intended use of the proceeds from the sale of 50% of the interest we owned in our midstream segment; 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 three months 2018 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 $436,000 per month ($5.2 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 $237,000 per month ($2.8 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 $388,000 per month ($4.7 million annualized) change in our pre-tax operating cash flow.

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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 March 31, 2018, these derivatives were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Apr'18 – Sep'18	Natural gas – swap	40,000 MMBtu/day	$2.985	IF – NYMEX (HH)
Oct'18	Natural gas – swap	30,000 MMBtu/day	$3.005	IF – NYMEX (HH)
Nov'18 – Dec'18	Natural gas – swap	20,000 MMBtu/day	$3.013	IF – NYMEX (HH)
Apr'18 – Oct'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.190)	NGPL TEXOK
Apr'18 – Dec'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.678)	PEPL
Apr'18 – Dec'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.568)	NGPL MIDCON
Nov'18 – Dec'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.208)	IF – NYMEX (HH)
Jan'19 – Dec'19	Natural gas – basis swap	10,000 MMBtu/day	$(0.728)	PEPL
Jan'19 – Dec'19	Natural gas – basis swap	10,000 MMBtu/day	$(0.625)	NGL MIDCON
Jan'19 – Dec'19	Natural gas – basis swap	30,000 MMBtu/day	$(0.265)	NGPL TEXOK
Jan'20 – Dec'20	Natural gas – basis swap	20,000 MMBtu/day	$(0.280)	NGPL TEXOK
Apr'18 – Sep'18	Natural gas – collar	30,000 MMBtu/day	$2.67 - $2.97	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)
Apr'18 – Dec'18	Crude oil – swap	4,000 Bbl/day	$53.52	WTI – NYMEX
Apr'18 – Dec'18	Crude oil – three-way collar	2,000 Bbl/day	$47.50 - $37.50 - $56.08	WTI – NYMEX
Apr'18 – Sep'18	NGLs – swap[1]	1,500 Bbl/day	$32.14	OPIS – Mont Belvieu

(1) Type of NGLs involved is propane.

After March 31, 2018, the following derivative was entered into:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Jan'19 – Dec'19	Crude oil – three-way collar	1,000 Bbl/day	$55.00 - $45.00 - $70.25	WTI – NYMEX
Jan'20 – Dec'20	Natural gas – basis swap	10,000 MMBtu/day	$(0.265)	NGPL TEXOK

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 three months of 2018, a 1% increase in the floating rate would reduce our annual pre-tax cash flow by approximately $1.7 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 March 31, 2018 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.

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Changes in Internal Controls. Our internal control framework did not materially change, but the existing internal controls have been modified to consider our new revenue recognition policy effective January 1, 2018. We have added internal controls to ensure that we adequately evaluate new contracts under the five-step model under ASU 2014-09. There were no other changes in our internal control over financial reporting (ICFR) during the quarter ended March 31, 2018, 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 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 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 in Latimer, Le Flore, and Pittsburg Counties, Oklahoma. In July 2014, a second class certification hearing was held where, besides 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.

Chieftain Royalty Company v. Unit Petroleum Company, No. CJ-16-230, District Court of LeFlore County, Oklahoma.

On November 3, 2016, a putative class action lawsuit was filed against Unit Petroleum Company styled Chieftain Royalty Company v. Unit Petroleum Company in LeFlore County, Oklahoma. Plaintiff alleges that Unit Petroleum breached its duty to pay royalties on natural gas used for fuel off the lease premises. The lawsuit seeks actual and punitive damages, an accounting, injunctive relief, and attorney's fees. Plaintiff is seeking relief on behalf of Oklahoma citizens who are or were royalty owners in our Oklahoma wells. We filed a motion to dismiss on the basis that the claims asserted by the Plaintiff and the putative class are barred because they have already been asserted by the putative class in the Panola lawsuit and are subject to its reversal of class certification. The court denied our motion to dismiss and we have asked the court to certify its order so that it can be immediately appealed. That issue is still pending before the court. If we do not ultimately prevail on our claim of issue preclusion, we have several other 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 wrongfully withheld. At this point, the issue of class certification has not been set before the court.

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.

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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, 2017, 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.

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, 2017.

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 March 31, 2018:

Period	(a) Total Number of Shares Purchased (1)	(b) Average Price Paid Per Share (2)	(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
January 1, 2018 to January 31, 2018	—	$ —	—	—
February 1, 2018 to February 28, 2018	—	—	—	—
March 1, 2018 to March 31, 2018	243,819	20.28	243,819	—
Total	243,819	$ 20.28	243,819	—

(1) The shares were repurchased to remit withholding of taxes on the value of stock distributed with the first quarter 2018 vesting of restricted stock for grants previously made from our "Second Amended and Restated Unit Corporation Stock and Incentive Compensation Plan effective May 6, 2015."

(2) The price paid per common share represents the closing sales price of a share of our common stock as reported by the NYSE on the day that the stock was acquired by us.

Item 3. Defaults Upon Senior Securities

Not applicable.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

On May 2, 2018, we terminated the Distribution Agreement dated April 4, 2017, as amended (the Distribution Agreement), between the company and Raymond James & Associates, Inc. (the Sales Agent). The Distribution Agreement was terminable at will on written notification by the company with no penalty. Under the Distribution Agreement, the company was entitled to issue and sell, from time to time, through or to the Sales Agent shares of its common stock, having an aggregate offering price of up to $100.0 million in an “at-the-market” offering program. As of the date of termination, the company sold 787,547 shares of its Common Stock under the Distribution Agreement. As a result of the termination, there will be no more sales of the our common stock under the Distribution Agreement.

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On May 2, 2018, as contemplated under the Fourth Amendment to its credit agreement, the company entered into a Pledge Agreement with BOKF, NA (dba Bank of Oklahoma), as administrative agent for the benefit of the secured parties, under which the company granted a security interest in the company's limited liability membership interests and other equity interests in Superior Pipeline Company, L.L.C. (which as of the date of this report comprises 50% of the aggregate outstanding equity interests of that company) as additional collateral for the company's obligations under the credit agreement.

The foregoing does not purport to be complete and is qualified in its entirety by reference to the Pledge Agreement, a copy of which is attached as Exhibit 10.2 to this report and incorporated into this Item 5 by reference. The Pledge Agreement is filed as an exhibit to this report to provide investors with information regarding its terms. It is not intended to provide any other factual information about the company or the other parties to the agreement or any of their respective subsidiaries or affiliates.

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Item 6. Exhibits

Exhibits:

10.1*	Purchase and Sale Agreement dated March 28, 2018 by and between Unit Corporation and SP Investor Holdings, LLC (filed herewith).
10.2	Superior Pledge Agreement dated May 2, 2018 (filed herewith).
10.3	Amendment to Distribution Agreement, dated as of March 7, 2018, between the Company and Raymond James & Associates, Inc. (incorporated by reference to Exhibit 1.1 of Unit's Form 8-K, dated March 9, 2018).
10.4	Fourth Amendment to Senior Credit Agreement dated April 2, 2018 (incorporated by reference to Exhibit 10.1 of Unit's Form 8-K, dated April 6, 2018).
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.

*Certain schedules referenced in the agreement have been omitted in accordance with Item 601(b)(2) of Regulation S-K. A copy of any omitted schedule will be furnished supplementary to the U.S. Securities and Exchange Commission upon request.

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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:	May 3, 2018	By: /s/ Larry D. Pinkston LARRY D. PINKSTON Chief Executive Officer and Director
Date:	May 3, 2018	By: /s/ Les Austin LES AUSTIN Senior Vice President and Chief Financial Officer