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 June 30, 2019

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 every Interactive Data File required to be submitted 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 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 ☐

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 July 19, 2019, 55,536,916 shares of the issuer's common stock were outstanding.

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock	UNT	NYSE

TABLE OF CONTENTS

Forward-Looking Statements

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

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

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

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

- the risk factors discussed in this document and in the documents (if any) we incorporate by reference;
- general economic, market, or business conditions;
- the availability of and nature of (or lack of) business opportunities we pursue;
- demand for our land drilling services;
- changes in laws or regulations;
- changes in the current geopolitical situation;
- risks relating to financing, including restrictions in our debt agreements and availability and cost of credit;
- risks associated with future weather conditions;
- decreases or increases in commodity prices;
- putative class action lawsuits that may cause 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 this document to reflect unanticipated events.

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	June 30, 2019	December 31, 2018
	(In thousands except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 669	$ 6,452
Accounts receivable, net of allowance for doubtful accounts of $2,494 and $2,531 at June 30, 2019 and December 31, 2018, respectively	89,876	119,397
Materials and supplies	516	473
Current derivative asset (Note 10)	8,513	12,870
Income taxes receivable	2,405	2,054
Assets held for sale (Note 3)	19,500	22,511
Prepaid expenses and other	9,106	6,602
Total current assets	130,585	170,359
Property and equipment:		
Oil and natural gas properties on the full cost method:		
Proved properties	6,212,323	6,018,568
Unproved properties not being amortized	336,214	330,216
Drilling equipment	1,284,295	1,284,419
Gas gathering and processing equipment	798,503	767,388
Saltwater disposal systems	69,212	68,339
Corporate land and building	59,080	59,081
Transportation equipment	30,019	29,524
Other	57,900	57,507
	8,847,546	8,615,042
Less accumulated depreciation, depletion, amortization, and impairment	6,289,575	6,182,726
Net property and equipment	2,557,971	2,432,316
Goodwill	62,808	62,808
Right of use asset (Note 12)	8,302	—
Other assets	33,863	32,570
Total assets [(1)]	$ 2,793,529	$ 2,698,053

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

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

	June 30, 2019	December 31, 2018
	(In thousands except share amounts)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 131,129	$ 149,945
Accrued liabilities (Note 5)	45,175	49,664
Current operating lease liability (Note 12)	4,519	—
Current portion of other long-term liabilities (Note 6)	13,887	14,250
Total current liabilities	194,710	213,859
Long-term debt less debt issuance costs (Note 6)	756,590	644,475
Non-current derivative liability (Note 10)	256	293
Operating lease liability (Note 12)	3,556	—
Other long-term liabilities (Note 6)	102,700	101,234
Deferred income taxes	142,485	144,748
Commitments and contingencies (Note 13)	—	—
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, 55,536,916 and 54,055,600 shares issued as of June 30, 2019 and December 31, 2018, respectively	10,590	10,414
Capital in excess of par value	638,769	628,108
Accumulated other comprehensive loss (Note 15)	(487)	(481)
Retained earnings	741,001	752,840
Total shareholders' equity attributable to Unit Corporation	1,389,873	1,390,881
Non-controlling interests in consolidated subsidiaries	203,359	202,563
Total shareholders' equity	1,593,232	1,593,444
Total liabilities[1] and shareholders' equity	$ 2,793,529	$ 2,698,053

(1) Unit Corporation's consolidated total assets as of June 30, 2019 include total current and long-term assets of its variable interest entity (VIE) (Superior Pipeline Company, L.L.C.) of $23.7 million and $435.4 million, respectively, which can only be used to settle obligations of the VIE. Unit Corporation's consolidated total liabilities as of June 30, 2019 include total current and long-term liabilities of the VIE of $29.6 million and $21.4 million, respectively, for which the creditors of the VIE have no recourse to Unit Corporation. Unit Corporation's consolidated total assets as of December 31, 2018 include total current and long-term assets of the VIE of $40.1 million and $423.3 million, respectively, which can only be used to settle obligations of the VIE. Unit Corporation's consolidated total liabilities as of December 31, 2018 include total current and long-term liabilities of the VIE of $42.8 million and $14.7 million, respectively, for which the creditors of the VIE have no recourse to Unit Corporation. See Note 14 – Variable Interest Entity Arrangements.

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
	(In thousands except per share amounts)			
Revenues:				
Oil and natural gas	$ 77,815	$ 102,318	$ 163,910	$ 205,417
Contract drilling	43,037	46,926	94,192	92,915
Gas gathering and processing	44,294	54,059	96,735	110,103
Total revenues	165,146	203,303	354,837	408,435
Expenses:				
Operating costs:				
Oil and natural gas	36,242	32,418	68,956	68,380
Contract drilling	29,308	31,894	60,709	63,561
Gas gathering and processing	32,491	39,703	71,846	81,307
Total operating costs	98,041	104,015	201,511	213,248
Depreciation, depletion, and amortization	66,292	58,373	128,418	115,439
General and administrative	10,064	8,712	19,805	19,474
(Gain) loss on disposition of assets	(422)	(161)	1,193	(322)
Total operating expenses	173,975	170,939	350,927	347,839
Income (loss) from operations	(8,829)	32,364	3,910	60,596
Other income (expense):				
Interest, net	(8,995)	(7,729)	(17,533)	(17,733)
Gain (loss) on derivatives	7,927	(14,461)	995	(21,223)
Other, net	6	5	11	11
Total other income (expense)	(1,062)	(22,185)	(16,527)	(38,945)
Income (loss) before income taxes	(9,891)	10,179	(12,617)	21,651
Income tax expense (benefit):				
Deferred	(1,874)	2,029	(2,318)	5,636
Total income taxes	(1,874)	2,029	(2,318)	5,636
Net income (loss)	(8,017)	8,150	(10,299)	16,015
Net income attributable to non-controlling interest	492	2,362	1,714	2,362
Net income (loss) attributable to Unit Corporation	$ (8,509)	$ 5,788	(12,013)	13,653
Net income (loss) attributable to Unit Corporation per common share (Note 4):				
Basic	$ (0.16)	$ 0.11	$ (0.23)	$ 0.26
Diluted	$ (0.16)	$ 0.11	$ (0.23)	$ 0.26

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
	(In thousands)			
Net income (loss)	$ (8,017)	$ 8,150	$ (10,299)	$ 16,015
Other comprehensive income (loss), net of taxes:				
Unrealized gain (loss) on securities, net of tax of ($9), $11, ($2) and ($47)	(30)	35	(6)	(141)
Comprehensive income (loss)	(8,047)	8,185	(10,305)	15,874
Less: Comprehensive income attributable to non-controlling interest	492	2,362	1,714	2,362
Comprehensive income (loss) attributable to Unit Corporation	$ (8,539)	$ 5,823	$ (12,019)	$ 13,512

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

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY (UNAUDITED)

	Three Months Ended June 30, 2019					
	Shareholders' Equity Attributable to Unit Corporation					
	Common Stock	Capital In Excess of Par Value	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-controlling Interest in Consolidated Subsidiaries	Total
	(In thousands except per share amounts)					
Balances, March 31, 2019	$ 10,578	$ 633,361	$ (457)	$ 749,510	$ 202,867	$ 1,595,859
Net income (loss)	—	—	—	(8,509)	492	(8,017)
Other comprehensive loss (net of tax of ($9))	—	—	(30)	—	—	(30)
Total comprehensive loss						(8,047)
Activity in employee compensation plans (68,929 shares)	12	5,408	—	—	—	5,420
Balances, June 30, 2019	$ 10,590	$ 638,769	$ (487)	$ 741,001	$ 203,359	$ 1,593,232

	Six Months Ended June 30, 2019					
	Shareholders' Equity Attributable to Unit Corporation					
	Common Stock	Capital In Excess of Par Value	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-controlling Interest in Consolidated Subsidiaries	Total
	(In thousands except per share amounts)					
Balances, December 31, 2018	$ 10,414	$ 628,108	$ (481)	$ 752,840	$ 202,563	1,593,444
Cumulative effect adjustment for adoption of ASUs (Notes 1 and 12)	—	—	—	174	—	174
Net income (loss)	—	—	—	(12,013)	1,714	(10,299)
Other comprehensive loss (net of tax of ($2))	—	—	(6)	—	—	(6)
Total comprehensive loss						(10,305)
Distributions to non-controlling interest	—	—	—	—	(918)	(918)
Activity in employee compensation plans (1,481,316 shares)	176	10,661	—	—	—	10,837
Balances, June 30, 2019	$ 10,590	$ 638,769	$ (487)	$ 741,001	$ 203,359	$ 1,593,232

	Common Stock	Capital In Excess of Par Value	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-controlling Interest in Consolidated Subsidiaries	Total
	Three Months Ended June 30, 2018					
	Shareholders' Equity Attributable to Unit Corporation					
	(In thousands except per share amounts)					
Balances, March 31, 2018	$ 10,403	$ 541,004	$ (100)	$ 805,993	$ —	$ 1,357,300
Net income	—	—	—	5,788	2,362	8,150
Other comprehensive gain (net of tax of $11)	—	—	35	—	—	35
Total comprehensive income						8,185
Contributions	—	102,958	—	—	197,042	300,000
Transaction costs associated with sale of non-controlling interest	—	(2,254)	—	—	—	(2,254)
Tax effect of the sale of non-controlling interest	—	(24,300)	—	—	—	(24,300)
Activity in employee compensation plans (43,005 shares)	11	4,712	—	—	—	4,723
Balances, June 30, 2018	$ 10,414	$ 622,120	$ (65)	$ 811,781	$ 199,404	$ 1,643,654

	Common Stock	Capital In Excess of Par Value	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-controlling Interest in Consolidated Subsidiaries	Total
	Six Months Ended June 30, 2018					
	Shareholders' Equity Attributable to Unit Corporation					
	(In thousands except per share amounts)					
Balances, December 31, 2017	$ 10,280	$ 535,815	$ 63	$ 799,402	$ —	$ 1,345,560
Cumulative effect adjustment for adoption of ASUs	—	—	13	(1,274)	—	(1,261)
Net income	—	—	—	13,653	2,362	16,015
Other comprehensive loss (net of tax of ($47))	—	—	(141)	—	—	(141)
Total comprehensive income						15,874
Contributions	—	102,958	—	—	197,042	300,000
Transaction costs associated with sale of non-controlling interest	—	(2,254)	—	—	—	(2,254)
Tax effect of the sale of non-controlling interest	—	(24,300)	—	—	—	(24,300)
Activity in employee compensation plans (1,209,232 shares)	134	9,901	—	—	—	10,035
Balances, June 30, 2018	$ 10,414	$ 622,120	$ (65)	$ 811,781	$ 199,404	$ 1,643,654

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

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

	Six Months Ended June 30,	
	2019	2018
	(In thousands)	
OPERATING ACTIVITIES:		
Net income (loss)	$ (10,299)	$ 16,015
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, and amortization	128,418	115,439
Amortization of debt issuance costs and debt discount (Note 6)	1,115	1,095
(Gain) loss on derivatives (Note 10)	(995)	21,223
Cash proceeds (payments) on derivatives settled, net (Note 10)	5,314	(8,928)
Deferred tax (benefit) expense	(2,318)	5,636
(Gain) loss on disposition of assets	1,193	(322)
Stock compensation plans	11,187	12,073
Contract assets and liabilities, net (Note 2)	(1,283)	(2,371)
Other, net	1,117	1,998
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	26,939	(1,865)
Accounts payable	(30,374)	(403)
Material and supplies	(43)	4
Accrued liabilities	(1,245)	1,572
Other, net	(1,225)	(1,526)
Net cash provided by operating activities	127,501	159,640
INVESTING ACTIVITIES:		
Capital expenditures	(246,638)	(189,916)
Producing properties and other acquisitions	(3,313)	(962)
Proceeds from disposition of assets	7,340	23,528
Net cash used in investing activities	(242,611)	(167,350)
FINANCING ACTIVITIES:		
Borrowings under credit agreement	271,200	71,200
Payments under credit agreement	(160,200)	(249,200)
Payments on finance leases	(1,980)	(1,901)
Proceeds from investments in non-controlling interest	—	300,000
Employee taxes paid by withholding shares	(4,073)	(4,947)
Transaction costs associated with sale of non-controlling interest	—	(2,254)
Distributions to non-controlling interest	(918)	—
Book overdrafts	5,298	(1,581)
Net cash provided by financing activities	109,327	111,317
Net increase (decrease) in cash and cash equivalents	(5,783)	103,607
Cash and cash equivalents, beginning of period	6,452	701
Cash and cash equivalents, end of period	$ 669	$ 104,308

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

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

	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
	(In thousands)	
Supplemental disclosure of cash flow information:		
Cash paid during the year for:		
Interest paid (net of capitalized)	$ 15,748	$ 18,246
Income taxes	—	—
Changes in accounts payable and accrued liabilities related to purchases of property, plant, and equipment	(6,260)	(3,747)
Non-cash (addition) reduction to oil and natural gas properties related to asset retirement obligations	(2,057)	7,854

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

UNIT CORPORATION AND SUBSIDIARIES
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 – BASIS OF PREPARATION AND PRESENTATION

The unaudited condensed consolidated financial statements in this report include the accounts of Unit Corporation and all its subsidiaries and affiliates and have been prepared under the rules and regulations of the SEC. The terms "company," "Unit," "we," "our," "us," or like terms refer to Unit Corporation, a Delaware corporation, and one or more of its subsidiaries and affiliates, except as otherwise indicated or as the context otherwise requires. We consolidate the activities of Superior Pipeline Company, L.L.C. (Superior), a 50/50 joint venture between Unit Corporation and SP Investor Holdings, LLC, which qualifies as a Variable Interest Entity (VIE) under generally accepted accounting principles in the United States (GAAP). We have concluded that we are the primary beneficiary of the VIE, as defined in the accounting standards, since we have the power to direct those activities that most significantly affect the economic performance of Superior as further described in Note 14 – Variable Interest Entity Arrangements.

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 26, 2019, for the year ended December 31, 2018.

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 June 30, 2019 and December 31, 2018;
- Statements of Operations for the three and six months ended June 30, 2019 and 2018;
- Statements of Comprehensive Income (Loss) for the three and six months ended June 30, 2019 and 2018;
- Statements of Changes in Shareholders' Equity for the three and six months ended June 30, 2019 and 2018; and
- Statements of Cash Flows for the six months ended June 30, 2019 and 2018.

Our financial statements are prepared in conformity with GAAP, which 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 six months ended June 30, 2019 and 2018 are not necessarily indicative of the results we may realize for the full year of 2019, or that we realized for the full year of 2018.

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

Accounting Changes - Recent Accounting Pronouncements - Adopted

As of January 1, 2019, we adopted *Leases - Topic 842* (ASC 842) using the modified retrospective method and the optional transition method to record the adoption impact through a cumulative adjustment to equity. Results for reporting periods beginning after January 1, 2019, are presented under Topic 842, while prior periods are not adjusted and continue to be reported under the accounting standards in effect for those periods. This new lease standard is explained further in Note 8 – New Accounting Pronouncements.

The additional disclosures required by ASC 842 have been included in Note 12 – Leases.

NOTE 2 – REVENUE FROM CONTRACTS WITH CUSTOMERS

Our revenue streams are reported under three segments: oil and natural gas, contract drilling, and mid-stream. This is how we disaggregate our revenue and how we report our segment revenue (as reflected in Note 16 – Industry Segment Information). Revenue from the oil and natural gas segment is from sales of our oil and natural gas production. Revenue from the contract drilling segment comes from contracting with upstream companies to drill an agreed-on number of wells or provide drilling rigs and services over an agreed-on period. Revenue from the mid-stream segment is derived from gathering, transporting, and processing natural gas production and NGLs and selling those commodities. We sell the hydrocarbons (from our oil and natural gas and mid-stream segments) to other mid-stream and downstream oil and gas companies.

Oil and Natural Gas Revenues

Certain costs—as either a deduction from revenue or as an expense—are determined based on when control of the commodity is transferred to our customer, which would affect our total revenue recognized, but will not affect gross profit. For example, gathering, processing, and transportation costs included as part of the contract price with the customer on 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.

Contract Drilling Revenues

We have evaluated the mobilization and de-mobilization charges due under our outstanding drilling contracts. The impact of those charges to the financial statements was immaterial. As of June 30, 2019, we had 24 contract drilling contracts with terms ranging from one month to almost three years.

Most of our drilling contracts have an original term of less than one year. The remaining performance obligations under the contracts that have a longer duration are not material.

Mid-stream Contracts Revenues

Revenues are generated from fees earned for gas gathering and processing services provided to a customer. The typical revenue contracts used by this segment are gas gathering and processing agreements. The following tables show the changes in our mid-stream contract asset and contract liability balances during the six months ended June 30, 2019:

Contract Assets		**Amount**
		(In thousands)
Balance at December 31, 2018 (1)	$	13,164
Amounts invoiced in excess of revenue recognized		(86)
Balance at June 30, 2019 (1)	$	13,078

1. At December 31, 2018, total contract assets are included in prepaid expenses and other and other assets of $0.3 million and $12.9 million, respectively, in our Consolidated Balance Sheet. At June 30, 2019, total contract assets included prepaid expenses and other and other assets of $3.4 million and $9.7 million, respectively, in our Condensed Consolidated Balance Sheet.

Contract Liabilities		**Amount**
		(In thousands)
Balance at December 31, 2018 (1)	$	9,882
New contract		60
Revenue included in beginning balance		(1,429)
Balance at June 30, 2019 (1)	$	8,513

1. At December 31, 2018, total contract liabilities are included in current portion of other long-term liabilities and other long-term liabilities of $2.9 million and $7.0 million, respectively, in our Consolidated Balance Sheet. At June 30, 2019, total contract liabilities included current portion of other long-term liabilities and other long-term liabilities of $2.9 million and $5.6 million, respectively, in our Condensed Consolidated Balance Sheet.

Included below is the fixed revenue we 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**	**July - December 2019**	**2020**	**2021**	**2022**	**2023 and Beyond**	**Total Remaining Impact to Revenue**
			(In thousands)				
Demand fee contracts	3-9 years	$ 1,295	$ (3,775)	$ (3,501)	$ 1,380	$ 36	$ (4,565)

NOTE 3 – DIVESTITURES

Oil and Natural Gas

We sold $2.1 million of non-core oil and natural gas assets, net of related expenses, during the first six months of 2019, compared to $22.4 million during the first six months of 2018. These proceeds reduced the net book value of our full cost pool with no gain or loss recognized.

Contract Drilling

In December 2018, we removed 41 drilling rigs and other equipment from service. We estimated the fair value of the 41 drilling rigs based on the estimated market value from third-party assessments (Level 3 fair value measurement) less cost to sell. Based on these estimates, we recorded a pre-tax non-cash write-down of approximately $147.9 million. During the first six months of 2019, we sold three of these drilling rigs and some of the other equipment to unaffiliated third parties. The proceeds of those sales, less costs to sell, was less than the applicable $3.0 million net book value resulting in a loss of $0.2 million. The remaining drilling rigs and equipment will be marketed for sale throughout 2019 and remain classified as assets held for sale. The net book value of those assets is $19.5 million.

NOTE 4 – EARNINGS (LOSS) PER SHARE

Information related to the calculation of earnings (loss) per share attributable to Unit Corporation is as follows:

	Earnings (Loss) (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the three months ended June 30, 2019			
Basic loss attributable to Unit Corporation per common share	$ (8,509)	52,930	$ (0.16)
Effect of dilutive stock options and restricted stock	—	—	—
Diluted loss attributable to Unit Corporation per common share	$ (8,509)	52,930	$ (0.16)
For the three months ended June 30, 2018			
Basic earnings attributable to Unit Corporation per common share	$ 5,788	52,050	$ 0.11
Effect of dilutive stock options and restricted stock	—	731	—
Diluted earnings attributable to Unit Corporation per common share	$ 5,788	52,781	$ 0.11

Because of the net loss for the three months ended June 30, 2019, approximately 283,000 weighted average shares related to stock options and restricted stock were antidilutive and were excluded from the earnings per share calculation above.

The following table shows the number of stock options (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 June 30,	
	2019	2018
Stock options	42,000	66,500
Average exercise price	$ 48.56	$ 44.42

	Earnings (Loss) (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the six months ended June 30, 2019			
Basic loss attributable to Unit Corporation per common share	$ (12,013)	52,744	$ (0.23)
Effect of dilutive stock options and restricted stock	—	—	—
Diluted loss attributable to Unit Corporation per common share	$ (12,013)	52,744	$ (0.23)
For the six months ended June 30, 2018			
Basic earnings attributable to Unit Corporation per common share	$ 13,653	51,891	$ 0.26
Effect of dilutive stock options and restricted stock	—	651	—
Diluted earnings attributable to Unit Corporation per common share	$ 13,653	52,542	$ 0.26

Because of the net loss for the six months ended June 30, 2019, approximately 286,000 weighted average shares related to stock options and restricted stock were antidilutive and were excluded from the earnings per share calculation above.

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

	Six Months Ended June 30,	
	2019	2018
Stock options	42,000	66,500
Average exercise price	$ 48.56	$ 44.42

NOTE 5 – ACCRUED LIABILITIES

Accrued liabilities consisted of:

	June 30, 2019	December 31, 2018
	(In thousands)	
Employee costs	$ 13,910	$ 22,056
Lease operating expenses	10,552	12,756
Interest payable	6,741	6,635
Taxes	6,675	1,378
Third-party credits	2,824	2,129
Other	4,473	4,710
Total accrued liabilities	$ 45,175	$ 49,664

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

Long-Term Debt

As of the date indicated, our long-term debt consisted of the following:

	June 30, 2019	December 31, 2018
	(In thousands)	
Unit credit agreement with an average interest rate of 4.2% at June 30, 2019	$ 103,500	$ —
Superior credit agreement with an average interest rate of 6.5% at June 30, 2019	7,500	—
6.625% senior subordinated notes due 2021	650,000	650,000
Total principal amount	761,000	650,000
Less: unamortized discount	(1,303)	(1,623)
Less: debt issuance costs, net	(3,107)	(3,902)
Total long-term debt	$ 756,590	$ 644,475

Unit Credit Agreement. Our Senior Credit Agreement (Unit credit agreement) is scheduled to mature on October 18, 2023. Under that 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 amount of $1.0 billion. Our elected commitment amount is $425.0 million. Our borrowing base is $425.0 million. We are currently charged a commitment fee of 0.375% on the amount available but not borrowed. That fee varies based on the amount borrowed as a percentage of the total borrowing base. Total fees of $3.3 million in origination, agency, syndication, and other related fees are being amortized over the life of the agreement. Under the agreement, we have pledged as collateral 80% of the proved developed producing (discounted as present worth at 8%) total value of our oil and gas properties.

On May 2, 2018, we entered into a Pledge Agreement with BOKF, NA (dba Bank of Oklahoma), as administrative agent to benefit the secured parties, granting a security interest in the limited liability membership interests and other equity interests we own in Superior (which as of this report is 50% of the aggregate outstanding equity interests of Superior) as additional collateral for our obligations under the Unit credit agreement.

The borrowing base amount–which is subject to redetermination by the lenders on April 1st and October 1st of each year–is based 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 Unit credit agreement.

At our election, any part of the outstanding debt under the Unit credit agreement can be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest is computed as the LIBOR base for the term plus 1.50% to 2.50% 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 Unit credit agreement but in no event less than LIBOR plus 1.00% plus a margin. The credit agreement provides that if ICE Benchmark Administration no longer reports the LIBOR or Administrative Agent determines in good faith that the rate so reported no longer accurately reflects the rate available to Lender in the London Interbank Market or if such index no longer exists or accurately reflects the rate available to Administrative Agent in the London Interbank Market, Administrative Agent may select a replacement index. Interest is payable at the end of each month or at the end of each LIBOR contract and the principal may be repaid in whole or in part at any time, without a premium or penalty. At June 30, 2019, we had $103.5 million outstanding borrowings under the Unit credit agreement.

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

The Unit 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;
- 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; and
- investments in Unrestricted Subsidiaries (as defined in the Unit credit agreement) over $200.0 million.

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

As of June 30, 2019, we were in compliance with these covenants.

Superior Credit Agreement. On May 10, 2018, Superior signed a five-year, $200.0 million senior secured revolving credit facility with an option to increase the credit amount up to $250.0 million, subject to certain conditions (Superior credit agreement). The amounts borrowed under the Superior credit agreement bear annual interest at a rate, at Superior's option, equal to (a) LIBOR plus the applicable margin of 2.00% to 3.25% or (b) the alternate base rate (greater of (i) the federal funds rate plus 0.5%, (ii) the prime rate, and (iii) third day LIBOR plus 1.00%) plus the applicable margin of 1.00% to 2.25%. The obligations under the Superior credit agreement are secured by, among other things, mortgage liens on certain of Superior's processing plants and gathering systems. The credit agreement provides that if ICE Benchmark Administration no longer reports the LIBOR or Administrative Agent determines in good faith that the rate so reported no longer accurately reflects the rate available to Lender in the London Interbank Market or if such index no longer exists or accurately reflects the rate available to Administrative Agent in the London Interbank Market, Administrative Agent may select a replacement index.

Superior is currently charged a commitment fee of 0.375% on the amount available but not borrowed which varies based on the amount borrowed as a percentage of the total borrowing base. Superior paid $1.7 million in origination, agency, syndication, and other related fees. These fees are being amortized over the life of the Superior credit agreement.

The Superior credit agreement requires that Superior maintain a Consolidated EBITDA to interest expense ratio for the most-recently ended rolling four quarters of at least 2.50 to 1.00, and a funded debt to Consolidated EBITDA ratio of not greater than 4.00 to 1.00. The agreement also contains several customary covenants that restrict (subject to certain exceptions) Superior's ability to incur additional indebtedness, create additional liens on its assets, make investments, pay distributions, sign sale and leaseback transactions, engage in certain transactions with affiliates, engage in mergers or consolidations, sign hedging arrangements, and acquire or dispose of assets. As of June 30, 2019, Superior was in compliance with these covenants.

The borrowings under the Superior credit agreement will fund capital expenditures and acquisitions, provide general working capital, and for letters of credit for Superior. As of June 30, 2019, we had $7.5 million outstanding borrowings under the Superior credit agreement.

On June 27, 2018, Superior and the lenders amended the Superior credit agreement to revise certain definitions in the agreement.

Superior's credit agreement is not guaranteed by Unit.

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 significant 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. Effective April 3, 2018, Superior is no longer a Guarantor of the Notes. Excluding Superior, any of our other 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, unless the Company has exercised its right to redeem all of the Notes, 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. As of May 15, 2019, we may redeem the Notes at a redemption price equal to 100% of the principal amount of the Notes plus accrued and unpaid interest on 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 June 30, 2019.

We may from time to time seek to retire or purchase our outstanding Note debt through cash purchases and/or exchanges for equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	June 30, 2019	December 31, 2018
	(In thousands)	
Asset retirement obligation (ARO) liability	$ 67,433	$ 64,208
Workers' compensation	12,118	12,738
Finance lease obligations	9,400	11,380
Contract liability	8,513	9,881
Separation benefit plans	9,749	8,814
Deferred compensation plan	6,002	5,132
Gas balancing liability	3,372	3,331
	116,587	115,484
Less current portion	13,887	14,250
Total other long-term liabilities	$ 102,700	$ 101,234

Estimated annual principal payments under the terms of our long-term debt and other long-term liabilities during the five successive twelve-month periods beginning July 1, 2019 (and through 2024) are $13.9 million, $697.5 million, $5.6 million, $10.7 million, and $105.8 million, respectively.

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 estimated AROs for the periods indicated:

	Six Months Ended June 30,	
	2019	2018
	(In thousands)	
ARO liability, January 1:	$ 64,208	$ 69,444
Accretion of discount	1,168	1,248
Liability incurred	3,656	211
Liability settled	(2,316)	(3,142)
Liability sold	(1,632)	(94)
Revision of estimates (1)	2,349	(4,829)
ARO liability, June 30:	67,433	62,838
Less current portion	1,784	1,451
Total long-term ARO	$ 65,649	$ 61,387

1. Plugging liability estimates were revised in both 2019 and 2018 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

Measurement of Credit Losses on Financial Instruments (Topic 326). The FASB issued ASU 2016-13 which replaces current methods for evaluating impairment of financial instruments not measured at fair value, including trade accounts receivable and certain debt securities, with a current expected credit loss model. The amendment will be effective for reporting periods after December 15, 2019. We are evaluating the impact this will have on our financial statements by reviewing our accounts receivable accounts and our historic credit losses.

Fair Value Measurement (Topic 820): Disclosure Framework—Changes to the Disclosure Requirements for Fair Value Measurement. The FASB issued ASU 2018-13 to modify the disclosure requirements in Topic 820. Part of the disclosures were removed or modified and other disclosures were added. The amendment will be effective for reporting periods beginning after December 15, 2019. Early adoption is permitted. Also it is permitted to early adopt any removed or modified disclosure and delay adoption of the additional disclosures until their effective date. This amendment will not have a material impact on our financial statements.

Intangibles—Goodwill and Other: Simplifying the Test for Goodwill Impairment. The FASB issued ASU 2017-04, to simplify the 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.

Adopted Standards

Compensation—Stock Compensation: Improvements to Nonemployee Share-Based Payment Accounting. The FASB issued ASU 2018-07, to improve financial reporting for nonemployee share-based payments. The amendment expands Topic 718, *Compensation—Stock Compensation* to include share-based payments issued to nonemployees for goods or services. The amendment is effective for years beginning after December 15, 2018, and interim periods within those years. This amendment did not have an impact on our financial statements.

We adopted ASC 842 on January 1, 2019, using the modified retrospective method and the optional transition method to record the adoption impact through a cumulative adjustment to equity. Results for reporting periods beginning after January 1, 2019, are presented under Topic 842, while prior periods are not adjusted and continue to be reported under the accounting standards in effect for those periods.

The additional disclosures required by ASC 842 have been included in Note 12 – Leases.

NOTE 9 – STOCK-BASED COMPENSATION

For restricted stock awards and stock options, we had:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
	(In millions)			
Recognized stock compensation expense	$ 4.7	$ 4.0	$ 8.5	$ 9.5
Capitalized stock compensation cost for our oil and natural gas properties	0.7	0.6	1.3	1.0
Tax benefit on stock-based compensation	1.2	1.0	2.1	2.3

The remaining unrecognized compensation cost related to unvested awards at June 30, 2019 is approximately $24.8 million, of which $3.4 million is anticipated to be capitalized. The weighted average period over which this cost will be recognized is 0.8 of a 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."

We did not grant any stock options during either of the three or six month periods ending June 30, 2019 or 2018. This table shows the fair value of restricted stock awards granted to employees and non-employee directors during the periods indicated:

	Three Months Ended June 30, 2019		Three Months Ended June 30, 2018	
	Time Vested	Performance Vested	Time Vested	Performance Vested
Shares granted:				
Employees	1,500	—	5,000	—
Non-employee directors	72,784	—	44,312	—
	74,284	—	49,312	—
Estimated fair value (in millions):[1]				
Employees	$ —	$ —	$ 0.1	$ —
Non-employee directors	0.9	—	0.9	—
	$ 0.9	$ —	$ 1.0	$ —
Percentage of shares granted expected to be distributed:				
Employees	95 %	N/A	95 %	N/A
Non-employee directors	100%	N/A	100 %	N/A

1. The performance shares represent 100% of the grant date fair value. (We recognize the grant date fair value minus estimated forfeitures.)

	Six Months Ended June 30, 2019		Six Months Ended June 30, 2018	
	Time Vested	Performance Vested	Time Vested	Performance Vested
Shares granted:				
Employees	927,173	424,070	844,498	362,070
Non-employee directors	72,784	—	44,312	—
	999,957	424,070	888,810	362,070
Estimated fair value (in millions):(1)				
Employees	$ 14.6	$ 7.1	$ 16.2	$ 7.3
Non-employee directors	0.9	—	0.9	—
	$ 15.5	$ 7.1	$ 17.1	$ 7.3
Percentage of shares granted expected to be distributed:				
Employees	95 %	54 %	95 %	74 %
Non-employee directors	100 %	N/A	100 %	N/A

1. The performance shares represent 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 six months of 2019 and 2018 are being recognized over a three-year vesting period. During the first quarter of 2019 and 2018, two performance vested restricted stock awards were granted to certain executive officers. The first cliff vests 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 vests, 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 June 30, 2019, the participants are estimated to receive 7% of the 2019 and 63% of the 2018 performance-based shares. The CFTA performance measurement at June 30, 2019 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 2019 awards for the first six months of 2019 was $4.0 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 June 30, 2019, these hedges made up our derivative transactions:

- *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/Differential 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/differential swaps to hedge the price risk between NYMEX and its physical delivery points.
- *Collars.* A collar contains a fixed floor price (put) and a ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, we receive the fixed price and pay the market price. If the market price is between the call and the put strike price, no payments are due from either party.

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

We have documented policies and procedures to monitor and control the use of derivative transactions. We do not engage in derivative transactions not otherwise tied to our projected production. 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 Statements of Operations.

At June 30, 2019, these derivatives were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Jul'19 – Oct'19	Natural gas – swap	60,000 MMBtu/day	$2.900	IF – NYMEX (HH)
Nov'19 – Dec'19	Natural gas – swap	40,000 MMBtu/day	$2.900	IF – NYMEX (HH)
Jul'19 – Dec'19	Natural gas – basis swap	20,000 MMBtu/day	$(0.659)	PEPL
Jul'19 – Dec'19	Natural gas – basis swap	10,000 MMBtu/day	$(0.625)	NGL MIDCON
Jul'19 – Dec'19	Natural gas – basis swap	30,000 MMBtu/day	$(0.265)	NGPL TEXOK
Jan'20 – Dec'20	Natural gas – basis swap	30,000 MMBtu/day	$(0.275)	NGPL TEXOK
Jul'19 – Dec'19	Natural gas – collar	20,000 MMBtu/day	$2.63 - $3.03	IF – NYMEX (HH)
Jul'19 – Dec'19	Crude oil – three-way collar	4,000 Bbl/day	$61.25 - $51.25 - $72.93	WTI – NYMEX

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

		Derivative Assets Fair Value	
	Balance Sheet Location	June 30, 2019	December 31, 2018
		(In thousands)	
Commodity derivatives:			
Current	Current derivative asset	$ 8,513	$ 12,870
Long-term	Non-current derivative asset	—	—
Total derivative assets		$ 8,513	$ 12,870

		Derivative Liabilities Fair Value	
	Balance Sheet Location	June 30, 2019	December 31, 2018
		(In thousands)	
Commodity derivatives:			
Current	Current derivative liability	$ —	$ —
Long-term	Non-current derivative liability	256	293
Total derivative liabilities		$ 256	$ 293

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

Following is the effect of derivative instruments on the Unaudited Condensed Consolidated Statements of Operations at June 30:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
	(In thousands)			
Gain (loss) on derivatives:				
Gain (loss) on derivatives, included are amounts settled during the period of $2,658, ($6,855), $5,314 and ($8,928), respectively	$ 7,927	$ (14,461)	$ 995	$ (21,223)
	$ 7,927	$ (14,461)	$ 995	$ (21,223)

NOTE 11 – FAIR VALUE MEASUREMENTS

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

	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(In thousands)			
Equity Securities:				
June 30, 2019	$ 830	$ —	$ 645	$ 185
December 31, 2018	$ 830	$ —	$ 636	$ 194

During the second quarter of 2017, we received available-for-sale securities in payment of early termination fees associated with a long-term drilling contract. We evaluate the marketability 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 use 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:

	June 30, 2019				
	Level 1	Level 2	Level 3	Effect of Netting	Net Amounts Presented
	(In thousands)				
Financial assets (liabilities):					
Commodity derivatives:					
Assets	$ —	$ 5,422	$ 3,945	$ (854)	$ 8,513
Liabilities	—	(1,110)	—	854	(256)
Total commodity derivatives	—	4,312	3,945	—	8,257
Equity securities	185	—	—	—	185
	$ 185	$ 4,312	$ 3,945	$ —	$ 8,442

	December 31, 2018				
	Level 1	Level 2	Level 3	Effect of Netting	Net Amounts Presented
	(In thousands)				
Financial assets (liabilities):					
Commodity derivatives:					
Assets	$ —	$ 3,225	$ 10,964	$ (1,319)	$ 12,870
Liabilities	—	(1,278)	(334)	1,319	(293)
Total commodity derivatives	—	1,947	10,630	—	12,577
Equity securities	194	—	—	—	194
	$ 194	$ 1,947	$ 10,630	$ —	$ 12,771

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 June 30, 2019.

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 June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
	(In thousands)			
Beginning of period	$ 3,080	$ (3,206)	$ 10,630	$ (206)
Total gains or losses (realized and unrealized):				
Included in earnings (1)	2,060	(4,704)	(3,374)	(8,624)
Settlements	(1,195)	1,775	(3,311)	2,695
End of period	$ 3,945	$ (6,135)	$ 3,945	$ (6,135)
Total earnings (losses) for the period included in earnings attributable to the change in unrealized loss relating to assets still held at end of period	$ 865	$ (2,929)	$ (6,685)	$ (5,929)

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

The following table provides quantitative information about our Level 3 unobservable inputs at June 30, 2019:

Commodity (1)	Fair Value	Valuation Technique	Unobservable Input	Range
	(In thousands)			
Oil three-way collars	$ 2,828	Discounted cash flow	Forward commodity price curve	$0 - $9.00
Natural gas collars	$ 1,117	Discounted cash flow	Forward commodity price curve	$0 - $0.48

1. The commodity contracts detailed in this category include non-exchange-traded crude oil three-way collars and natural gas 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 June 30, 2019 reflected that the risk of non-performance 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 certain 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 our estimated fair value amounts.

At June 30, 2019, the carrying values on the Unaudited Condensed Consolidated Balance Sheets for cash and cash equivalents (composed of bank and money market accounts - 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 the Unit and Superior credit agreements approximate its fair value and at June 30, 2019 we had $103.5 million of outstanding borrowings under the Unit and $7.5 million under the Superior credit agreements. We had no borrowing under either the Unit or Superior Credit agreements at December 31, 2018. Borrowings under these agreements are 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 June 30, 2019 and December 31, 2018 were $645.6 million and $644.5 million, respectively. We estimate the fair value of the Notes using quoted marked prices at June 30, 2019 and December 31, 2018 was $592.4 million and $600.5 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 – LEASES

Operating Leases under ASC 840

We lease office space or yards in Edmond and Oklahoma City, Oklahoma; Houston, Texas; Englewood, Colorado; and Pinedale, Wyoming under the terms of operating leases expiring through December 2021. We own our corporate headquarters in Tulsa, Oklahoma. We also have several compressor rentals, equipment leases, and lease space on short-term commitments to stack excess drilling rig equipment and production inventory. As of December 31, 2018, future minimum rental payments under the terms of the leases under ASC 840 were approximately $4.6 million, $1.7 million, and $0.4 million in 2019 through 2021, respectively.

Operating Leases under ASC 842

Adoption of Accounting Standards Codification ("ASC") Topic 842, "Leases." We adopted Topic 842 on January 1, 2019, using the modified retrospective method and the optional transition method to record the adoption impact through a cumulative adjustment to equity. Results for reporting periods beginning after January 1, 2019, are presented under Topic 842, while prior periods are not adjusted and continue to be reported under the accounting standards in effect for those periods.

We determine whether a contract is or contains a lease at inception of the contract based on whether an identified asset exists and whether we have the right to obtain substantially all of the benefit of the assets and to control its use over the full term of the agreement. When available, we use the rate implicit in the lease to discount lease payments to present value; however, most of our leases do not provide a readily determinable implicit rate. Therefore, we must estimate our incremental borrowing rate considering both the revolving credit rates and a credit notching approach to discount the lease payments based on information available at lease commencement. There are no material residual value guarantees and no restrictions or covenants included in the our lease agreements. Certain of our leases include provisions for variable payments. These variable payments are typically determined based on a measure of throughput or actual days or another measure of usage and are not included in the calculation of lease liabilities and right-of-use assets.

Related to our oil and natural gas segment, our short-term lease costs include those that are recognized in profit or loss during the period and those that are capitalized as part of the cost of another asset in accordance with other U.S. GAAP. As the costs related to our drilling and production activities are reflected at our net ownership consistent with the principals of proportional consolidation, and lease commitments are generally considered gross as the operator, the costs may not reasonably reflect the company's short-term lease commitments. As of June 30, 2019, we had an average working interest of 94% in our operated properties.

Practical Expedients and Policies Elected. We elected the hindsight expedient, which allows us to use hindsight in assessing lease term; the package of practical expedients permitted under the guidance, which among other things, allowed us to carry forward the historical lease classification; and the land easement expedient, which allowed us to apply the guidance prospectively at adoption for land easements on existing agreements.We applied the short-term policy election, which allowed us to exclude from recognition on the balance sheet leases with an initial term of 12 months or less. We considered quantitative and qualitative factors when determining the application of the practical expedient that allowed us not to separate lease and non-lease components and are accounting for the agreements as a single lease component.

We routinely enter into related party agreements between our three segments. These agreements have been evaluated under the guidance of ASC 842. Routinely, our oil and natural gas segment contracts for the use of drilling equipment from our drilling segment.

We have determined that the contracting of our drilling segment's drilling rigs will be accounted for under ASC 606 as the service has been deemed the predominate component of the contract per the lessor practical expedient.

Adoption. Adoption of Topic 842 resulted in new operating lease assets and lease liabilities on our Unaudited Condensed Consolidated Balance Sheet of $3.7 million and $3.5 million, respectively, as of January 1, 2019, which represents noncash operating activity. The immaterial difference between the lease assets and lease liabilities was recorded as an adjustment to the beginning balance of retained earnings, which represents the cumulative impact of adopting the standard. Our accounting for finance leases remained substantially unchanged.

Leases. We lease certain office space, land and equipment, including pipeline equipment and office equipment. Our lease payments are generally straight-line and the exercise of lease renewal options, which vary in term, is at our sole discretion. We include renewal periods in our lease term if we are reasonably certain to exercise available renewal options. Our lease agreements do not include options to purchase the leased property.

The following table shows supplemental cash flow information related to leases for the six months of June 30, 2019:

	Amount
	(In thousands)
Cash paid for amounts included in the measurement of lease liabilities:	
Operating cash flows for operating leases	$ 1,616
Financing cash flows for finance leases	1,980
Lease liabilities recognized in exchange for new operating lease right of use assets	5

The following table shows information about our lease assets and liabilities included in our Unaudited Condensed Consolidated Balance Sheet as of June 30, 2019:

	Classification on the Consolidated Balance Sheet	June 30, 2019
		(In thousands)
Assets		
Operating right of use assets	Right of use assets	$ 8,302
Finance right of use assets	Property, plant, and equipment, net	18,416
Total right of use assets		$ 26,718
Liabilities		
Current liabilities:		
Operating lease liabilities	Current operating lease liabilities	$ 4,519
Finance lease liabilities	Current portion of other long-term liabilities	4,081
Non-current liabilities:		
Operating lease liabilities	Operating lease liabilities	3,556
Finance lease liabilities	Other long-term liabilities	5,319
Total lease liabilities		$ 17,475

The following table shows certain information related to the lease costs for our finance and operating leases for the three and six months ended June 30, 2019:

	Three Months Ended June 30, 2019	Six Months Ended June 30, 2019
	(In thousands)	
Components of total lease cost:		
Amortization of finance leased assets	$ 995	$ 1,980
Interest on finance lease liabilities	100	211
Operating lease cost	1,052	1,651
Short-term lease cost (1)	12,038	22,012
Variable lease cost	84	190
Total lease cost	$ 14,269	$ 26,044

1. Short-term lease cost includes amounts capitalized related to our oil and natural gas segment of $9.0 million and $14.7 million, respectively.

The following table shows certain information related to the weighted average remaining lease terms and the weighted average discount rates for our operating and finance leases:

	Weighted Average Remaining Lease Term	Weighted Average Discount Rate (1)
	(In years)	
Operating leases	2.2	6.34%
Finance leases	2.2	4.00%

1. Our weighted average discount rates represent the rate implicit in the lease or our incremental borrowing rate for a term equal to the remaining term of the lease.

The following table sets forth the maturity of our operating lease liabilities as of June 30, 2019:

	Amount
	(In thousands)
Ending July 1,	
2020	$ 4,902
2021	2,642
2022	839
2023	196
2024	12
2025 and beyond	81
Total future payments	8,672
Less: Interest	597
Present value of future minimum operating lease payments	8,075
Less: Current portion	4,519
Total long-term operating lease payments	$ 3,556

As of June 30, 2019, we had one additional lease for $0.1 million that had not started. That lease will start later in 2019 with a term of two years.

Finance Leases

In 2014, Superior entered into finance lease agreements for 20 compressors with initial terms of seven years. The underlying assets are included in gas gathering and processing equipment. The $4.1 million current portion of the finance lease obligations is included in current portion of other long-term liabilities and the non-current portion of $5.3 million is included in other long-term liabilities in the accompanying Unaudited Condensed Consolidated Balance Sheets as of June 30, 2019. These finance leases are discounted using annual rates of 4.00%. Total maintenance and interest remaining related to these leases are $3.2 million and $0.4 million, respectively, at June 30, 2019. Annual payments, net of maintenance and interest, average $4.3 million annually through 2021. At the end of the term, Superior has the option to purchase the assets at 10% of their then fair market value.

The following table sets forth the maturity of our finance lease liabilities as of June 30, 2019:

Ending July 1,	Amount (In thousands)
2020	$ 6,168
2021	6,672
2022	180
Total future payments	13,020
Less payments related to:	
Maintenance	3,196
Interest	424
Present value of future minimum finance lease payments	9,400
Less: Current portion	4,081
Total long-term finance lease payments	$ 5,319

NOTE 13 – COMMITMENTS AND CONTINGENCIES

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 six months of 2018. The partnerships were terminated in the second quarter of 2019 with an effective date of January 1, 2019 at a repurchase cost of $0.6 million net of Unit's interest.

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 that risk is borne by the operator. Any liabilities we have incurred have been small and were resolved while the drilling rig was on the location. Those costs were in the direct cost of drilling the well.

During the second quarter of 2018, as part of the Superior transaction, we entered into a contractual obligation that commits us to spend $150.0 million to drill wells in the Granite Wash/Buffalo Wallow area over three years starting January 1, 2019. This amount is included in our future drilling plans. 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. At June 30, 2019, if we elected not to drill or spend any additional money in the designated area before December 31, 2021, the maximum amount we could forgo from distributions would be $74.0 million. Total spent towards the $150.0 million as of June 30, 2019 was $22.4 million.

For the next 12 months, we have committed to purchase approximately $1.6 million of drilling rig components and casing.

NOTE 14 – VARIABLE INTEREST ENTITY ARRANGEMENTS

On April 3, 2018 we sold 50% of the ownership interest in Superior. 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. Superior will be governed and managed under the Amended and Restated Limited Liability Company Agreement and the MSA. The MSA is between our affiliate, SPC Midstream Operating, L.L.C. (the Operator) and Superior. The Operator is owned 100% by Unit Corporation. Under the guidance in ASC 810, *Consolidation,* we have determined that Superior is a VIE. The two variable interests applicable to Unit include the 50% equity investment in Superior and the MSA. The MSA houses the power to direct the activities that most significantly impact Superior's operating performance. The MSA is a separate variable interest. Unit through the MSA has the power to direct Superior's most significant activities; reciprocally the equity investors lack the power to direct the activities that most significantly impact the entity's economic performance. Because of this, Unit is considered the primary beneficiary. There have been no changes to the primary beneficiary during the quarter ended June 30, 2019.

As the primary beneficiary of this VIE, we consolidate in our financial statements the financial position, results of operations, and cash flows of this VIE, and all intercompany balances and transactions between us and the VIE are eliminated in our consolidated financial statements. Cash distributions of income, net of agreed on expenses, and estimated expenses are allocated to the equity owners as specified in the relevant agreements.

On the sale or liquidation of Superior, distributions would occur in the order and priority specified in the relevant agreements.

As the Operator, we provide services, like operations and maintenance support, accounting, legal, and human resources to Superior for a monthly service fee of $255,970. Superior's creditors have no recourse to our general credit. Superior's credit agreement is not guaranteed by Unit. The obligations under Superior's credit agreement are secured by, among other things, mortgage liens on certain of Superior's processing plants and gathering systems.

The carrying value of Superior's assets and liabilities, after eliminations of any intercompany transactions and balances, in the consolidated balance sheets were as follows:

	June 30, 2019	December 31, 2018
	(In thousands)	
Current assets:		
Cash and cash equivalents	$ 2	$ 5,841
Accounts receivable	19,500	33,207
Prepaid expenses and other	4,185	1,049
Total current assets	23,687	40,097
Property and equipment:		
Gas gathering and processing equipment	798,503	767,388
Transportation equipment	3,152	3,086
	801,655	770,474
Less accumulated depreciation, depletion, amortization, and impairment	387,845	364,740
Net property and equipment	413,810	405,734
Right of use asset	6,221	—
Other assets	15,330	17,551
Total assets	$ 459,048	$ 463,382
Current liabilities:		
Accounts payable	$ 14,807	$ 32,214
Accrued liabilities	4,296	3,688
Current operating lease liability	3,576	—
Current portion of other long-term liabilities	6,970	6,875
Total current liabilities	29,649	42,777
Long-term debt	7,500	—
Operating lease liability	2,451	—
Other long-term liabilities	11,449	14,687
Total liabilities	$ 51,049	$ 57,464

NOTE 15 – EQUITY

Accumulated Other Comprehensive Income (Loss)

Components of accumulated other comprehensive income (loss) were as follows for the three months ended June 30:

	2019	2018
	(In thousands)	
Unrealized appreciation (loss) on securities, before tax	$ (39)	$ 46
Tax benefit (expense)	9	(11) (1)
Unrealized appreciation (loss) on securities, net of tax	$ (30)	$ 35

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 (loss) by component, net of tax, for the three months ended June 30 are as follows:

	Net Gains (Loss) on Equity Securities	
	2019	2018
	(In thousands)	
Balance at March 31:	$ (457)	$ (100)
Unrealized appreciation (loss) before reclassifications	(30)	35 (1)
Amounts reclassified from accumulated other comprehensive income	—	—
Net current-period other comprehensive income (loss)	(30)	35
Balance at June 30:	$ (487)	$ (65)

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

Components of accumulated other comprehensive income (loss) were as follows for the six months ended June 30:

	2019	2018
	(In thousands)	
Unrealized loss on securities, before tax	$ (8)	$ (188)
Tax benefit	2	47 (1)
Unrealized loss on securities, net of tax	$ (6)	$ (141)

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 six months ended June 30 are as follows:

	Net Gains (Loss) on Equity Securities	
	2019	2018
	(In thousands)	
Prior year balance at December 31:	$ (481)	$ 63
Adjustment due to ASU 2018-02	—	13 (1)
Balance at January 1:	(481)	76
Unrealized loss before reclassifications	(6)	(141) (1)
Amounts reclassified from accumulated other comprehensive income	—	—
Net current-period other comprehensive loss	(6)	(141)
Balance at June 30:	$ (487)	$ (65)

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

NOTE 16 – 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 June 30, 2019					
	Oil and Natural Gas	Contract Drilling	Mid-stream	Corporate and Other	Eliminations	Total Consolidated
	(In thousands)					
Revenues: [(1)]						
Oil and natural gas	$ 77,815	$ —	$ —	$ —	$ —	$ 77,815
Contract drilling	—	50,773	—	—	(7,736)	43,037
Gas gathering and processing	—	—	54,630	—	(10,336)	44,294
Total revenues	77,815	50,773	54,630	—	(18,072)	165,146
Expenses:						
Operating costs:						
Oil and natural gas	37,519	—	—	—	(1,277)	36,242
Contract drilling	—	36,390	—	—	(7,082)	29,308
Gas gathering and processing	—	—	41,550	—	(9,059)	32,491
Total operating costs	37,519	36,390	41,550	—	(17,418)	98,041
Depreciation, depletion, and amortization	38,751	13,504	12,102	1,935	—	66,292
Total expenses	76,270	49,894	53,652	1,935	(17,418)	164,333
General and administrative	—	—	—	10,064	—	10,064
Gain on disposition of assets	(60)	(296)	(66)	—	—	(422)
Income (loss) from operations	1,605	1,175	1,044	(11,999)	(654)	(8,829)
Gain on derivatives	—	—	—	7,927	—	7,927
Interest, net	—	—	(345)	(8,650)	—	(8,995)
Other	—	—	—	6	—	6
Income (loss) before income taxes	$ 1,605	$ 1,175	$ 699	$ (12,716)	$ (654)	$ (9,891)

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.

	Three Months Ended June 30, 2018					
	Oil and Natural Gas	Contract Drilling	Mid-stream	Corporate and Other	Eliminations	Total Consolidated
	(In thousands)					
Revenues: (1)						
Oil and natural gas	$ 102,318	$ —	$ —	$ —	$ —	$ 102,318
Contract drilling	—	52,767	—	—	(5,841)	46,926
Gas gathering and processing	—	—	75,406	—	(21,347)	54,059
Total revenues	102,318	52,767	75,406	—	(27,188)	203,303
Expenses:						
Operating costs:						
Oil and natural gas	33,682	—	—	—	(1,264)	32,418
Contract drilling	—	36,921	—	—	(5,027)	31,894
Gas gathering and processing	—	—	59,786	—	(20,083)	39,703
Total operating costs	33,682	36,921	59,786	—	(26,374)	104,015
Depreciation, depletion, and amortization	31,554	13,726	11,175	1,918	—	58,373
Total expenses	65,236	50,647	70,961	1,918	(26,374)	162,388
General and administrative expense	—	—	—	8,712	—	8,712
Gain on disposition of assets	(59)	(57)	(45)	—	—	(161)
Income (loss) from operations	37,141	2,177	4,490	(10,630)	(814)	32,364
Loss on derivatives	—	—	—	(14,461)	—	(14,461)
Interest, net	—	—	(304)	(7,425)	—	(7,729)
Other	—	—	—	5	—	5
Income (loss) before income taxes	$ 37,141	$ 2,177	$ 4,186	$ (32,511)	$ (814)	$ 10,179

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.

	Six Months Ended June 30, 2019					
	Oil and Natural Gas	Contract Drilling	Mid-stream	Corporate and Other	Eliminations	Total Consolidated
			(In thousands)			
Revenues: [1]						
Oil and natural gas	$ 163,910	$ —	$ —	$ —	$ —	$ 163,910
Contract drilling	—	108,972	—	—	(14,780)	94,192
Gas gathering and processing	—	—	125,139	—	(28,404)	96,735
Total revenues	163,910	108,972	125,139	—	(43,184)	354,837
Expenses:						
Operating costs:						
Oil and natural gas	71,527	—	—	—	(2,571)	68,956
Contract drilling	—	73,775	—	—	(13,066)	60,709
Gas gathering and processing	—	—	97,679	—	(25,833)	71,846
Total operating costs	71,527	73,775	97,679	—	(41,470)	201,511
Depreciation, depletion, and amortization	74,518	26,203	23,828	3,869	—	128,418
Total expenses	146,045	99,978	121,507	3,869	(41,470)	329,929
General and administrative expense	—	—	—	19,805	—	19,805
(Gain) loss on disposition of assets	(138)	1,449	(108)	(10)	—	1,193
Income (loss) from operations	18,003	7,545	3,740	(23,664)	(1,714)	3,910
Gain on derivatives	—	—	—	995	—	995
Interest, net	—	—	(681)	(16,852)	—	(17,533)
Other	—	—	—	11	—	11
Income (loss) before income taxes	$ 18,003	$ 7,545	$ 3,059	$ (39,510)	$ (1,714)	$ (12,617)

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.

	Six Months Ended June 30, 2018					
	Oil and Natural Gas	Contract Drilling	Mid-stream	Corporate and Other	Eliminations	Total Consolidated
	(In thousands)					
Revenues: [1]						
Oil and natural gas	$ 205,417	$ —	$ —	$ —	$ —	$ 205,417
Contract drilling	—	103,477	—	—	(10,562)	92,915
Gas gathering and processing	—	—	150,056	—	(39,953)	110,103
Total revenues	205,417	103,477	150,056	—	(50,515)	408,435
Expenses:						
Operating costs:						
Oil and natural gas	70,834	—	—	—	(2,454)	68,380
Contract drilling	—	72,875	—	—	(9,314)	63,561
Gas gathering and processing	—	—	118,806	—	(37,499)	81,307
Total operating costs	70,834	72,875	118,806	—	(49,267)	213,248
Depreciation, depletion, and amortization	62,337	27,038	22,228	3,836	—	115,439
Total expenses	133,171	99,913	141,034	3,836	(49,267)	328,687
General and administrative expense	—	—	—	19,474	—	19,474
Gain on disposition of assets	(129)	(84)	(79)	(30)	—	(322)
Income (loss) from operations	72,375	3,648	9,101	(23,280)	(1,248)	60,596
Loss on derivatives	—	—	—	(21,223)	—	(21,223)
Interest, net	—	—	(453)	(17,280)	—	(17,733)
Other	—	—	—	11	—	11
Income (loss) before income taxes	$ 72,375	$ 3,648	$ 8,648	$ (61,772)	$ (1,248)	$ 21,651

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.

NOTE 17 – SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

We have no significant assets or operations other than our investments in our subsidiaries. Our wholly owned subsidiaries are the guarantors of our Notes. On April 3, 2018, we sold 50% of the ownership interest in our mid-stream segment, Superior and that company and its subsidiaries are no longer guarantors of the Notes. Instead of providing separate financial statements for each subsidiary issuer and guarantor, we have included the accompanying unaudited condensed consolidating financial statements based on Rule 3-10 of the SEC's Regulation S-X.

For purposes of the following footnote:

- we are referred to as "Parent",
- the direct subsidiaries are 100% owned by the Parent and the guarantee is full and unconditional and joint and several and referred to as "Combined Guarantor Subsidiaries", and
- Superior and its subsidiaries and the Operator are referred to as "Non-Guarantor Subsidiaries."

The following unaudited supplemental condensed consolidating financial information reflects the Parent's separate accounts, the combined accounts of the Combined Guarantor Subsidiaries', the combined accounts of the Non-Guarantor Subsidiaries', the combined consolidating adjustments and eliminations, and the Parent's consolidated amounts for the periods indicated.

Condensed Consolidating Balance Sheets (Unaudited)

	June 30, 2019				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
			(In thousands)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ 508	$ 159	$ 2	$ —	$ 669
Accounts receivable, net of allowance for doubtful accounts of $2,494 (Guarantor of $1,289 and Parent of $1,205)	1,775	71,965	22,058	(5,922)	89,876
Materials and supplies	—	516	—	—	516
Current derivative asset	8,513	—	—	—	8,513
Income taxes receivable	2,405	—	—	—	2,405
Assets held for sale	—	19,500	—	—	19,500
Prepaid expenses and other	1,990	2,931	4,185	—	9,106
Total current assets	15,191	95,071	26,245	(5,922)	130,585
Property and equipment:					
Oil and natural gas properties on the full cost method:					
Proved properties	—	6,212,323	—	—	6,212,323
Unproved properties not being amortized	—	336,214	—	—	336,214
Drilling equipment	—	1,284,295	—	—	1,284,295
Gas gathering and processing equipment	—	—	798,503	—	798,503
Saltwater disposal systems	—	69,212	—	—	69,212
Corporate land and building	—	59,080	—	—	59,080
Transportation equipment	9,731	17,136	3,152	—	30,019
Other	28,824	29,076	—	—	57,900
	38,555	8,007,336	801,655	—	8,847,546
Less accumulated depreciation, depletion, amortization, and impairment	30,652	5,871,078	387,845	—	6,289,575
Net property and equipment	7,903	2,136,258	413,810	—	2,557,971
Intercompany receivable	1,046,308	—	—	(1,046,308)	—
Goodwill	—	62,808	—	—	62,808
Investments	1,166,768	—	—	(1,166,768)	—
Right of use asset	58	2,080	6,221	(57)	8,302
Other assets	8,731	9,802	15,330	—	33,863
Total assets	$ 2,244,959	$ 2,306,019	$ 461,606	$ (2,219,055)	$ 2,793,529

	June 30, 2019				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
			(In thousands)		
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 10,892	$ 110,379	$ 15,779	$ (5,921)	$ 131,129
Accrued liabilities	22,080	17,837	5,725	(467)	45,175
Current operating lease liability	24	925	3,576	(6)	4,519
Current portion of other long-term liabilities	1,083	5,834	6,970	—	13,887
Total current liabilities	34,079	134,975	32,050	(6,394)	194,710
Intercompany debt	—	1,046,159	149	(1,046,308)	—
Long-term debt less debt issuance costs	749,090	—	7,500	—	756,590
Non-current derivative liability	256	—	—	—	256
Operating lease liability	34	1,122	2,451	(51)	3,556
Other long-term liabilities	14,669	77,088	11,449	(506)	102,700
Deferred income taxes	56,471	86,014	—	—	142,485
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, 55,536,916 shares issued	10,590	—	—	—	10,590
Capital in excess of par value	638,769	45,921	197,042	(242,963)	638,769
Contributions from Unit	—	—	1,145	(1,145)	—
Accumulated other comprehensive loss	—	(487)	—	—	(487)
Retained earnings	741,001	915,227	6,461	(921,688)	741,001
Total shareholders' equity attributable to Unit Corporation	1,390,360	960,661	204,648	(1,165,796)	1,389,873
Non-controlling interests in consolidated subsidiaries	—	—	203,359	—	203,359
Total shareholders' equity	1,390,360	960,661	408,007	(1,165,796)	1,593,232
Total liabilities and shareholders' equity	$ 2,244,959	$ 2,306,019	$ 461,606	$ (2,219,055)	$ 2,793,529

	December 31, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
ASSETS					
Current assets:					
Cash and cash equivalents	$ 403	$ 208	$ 5,841	$ —	$ 6,452
Accounts receivable, net of allowance for doubtful accounts of $2,531 (Guarantor of $1,326 and Parent of $1,205)	2,539	94,526	36,676	(14,344)	119,397
Materials and supplies	—	473	—	—	473
Current derivative asset	12,870	—	—	—	12,870
Income tax receivable	243	1,811	—	—	2,054
Assets held for sale	—	22,511	—	—	22,511
Prepaid expenses and other	1,993	3,560	1,049	—	6,602
Total current assets	18,048	123,089	43,566	(14,344)	170,359
Property and equipment:					
Oil and natural gas properties on the full cost method:					
Proved properties	—	6,018,568	—	—	6,018,568
Unproved properties not being amortized	—	330,216	—	—	330,216
Drilling equipment	—	1,284,419	—	—	1,284,419
Gas gathering and processing equipment	—	—	767,388	—	767,388
Saltwater disposal systems	—	68,339	—	—	68,339
Corporate land and building	—	59,081	—	—	59,081
Transportation equipment	9,273	17,165	3,086	—	29,524
Other	28,584	28,923	—	—	57,507
	37,857	7,806,711	770,474	—	8,615,042
Less accumulated depreciation, depletion, amortization, and impairment	27,504	5,790,481	364,741	—	6,182,726
Net property and equipment	10,353	2,016,230	405,733	—	2,432,316
Intercompany receivable	950,916	—	—	(950,916)	—
Goodwill	—	62,808	—	—	62,808
Investments	1,160,444	—	—	(1,160,444)	—
Other assets	8,225	6,793	17,552	—	32,570
Total assets	$ 2,147,986	$ 2,208,920	$ 466,851	$ (2,125,704)	$ 2,698,053

	December 31, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
			(In thousands)		
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 8,697	$ 122,610	$ 32,214	$ (13,576)	$ 149,945
Accrued liabilities	28,230	16,409	5,493	(468)	49,664
Current portion of other long-term liabilities	812	6,563	6,875	—	14,250
Total current liabilities	37,739	145,582	44,582	(14,044)	213,859
Intercompany debt	—	948,707	2,209	(950,916)	—
Long-term debt less debt issuance costs	644,475	—	—	—	644,475
Non-current derivative liability	293	—	—	—	293
Other long-term liabilities	13,134	73,713	14,687	(300)	101,234
Deferred income taxes	60,983	83,765	—	—	144,748
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, 54,055,600 shares issued	10,414	—	—	—	10,414
Capital in excess of par value	628,108	45,921	197,042	(242,963)	628,108
Contributions from Unit	—	—	792	(792)	—
Accumulated other comprehensive loss	—	(481)	—	—	(481)
Retained earnings	752,840	911,713	4,976	(916,689)	752,840
Total shareholders' equity attributable to Unit Corporation	1,391,362	957,153	202,810	(1,160,444)	1,390,881
Non-controlling interests in consolidated subsidiaries	—	—	202,563	—	202,563
Total shareholders' equity	1,391,362	957,153	405,373	(1,160,444)	1,593,444
Total liabilities and shareholders' equity	$ 2,147,986	$ 2,208,920	$ 466,851	$ (2,125,704)	$ 2,698,053

Condensed Consolidating Statements of Operations (Unaudited)

	Three Months Ended June 30, 2019				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
Revenues	$ —	$ 128,588	$ 54,630	$ (18,072)	$ 165,146
Expenses:					
Operating costs	—	73,909	41,550	(17,418)	98,041
Depreciation, depletion, and amortization	1,935	52,255	12,102	—	66,292
General and administrative	—	10,064	—	—	10,064
Gain on disposition of assets	—	(356)	(66)	—	(422)
Total operating costs	1,935	135,872	53,586	(17,418)	173,975
Income (loss) from operations	(1,935)	(7,284)	1,044	(654)	(8,829)
Interest, net	(8,650)	—	(345)	—	(8,995)
Gain on derivatives	7,927	—	—	—	7,927
Other, net	6	—	—	—	6
Income (loss) before income taxes	(2,652)	(7,284)	699	(654)	(9,891)
Income tax benefit	(848)	(1,026)	—	—	(1,874)
Equity in net earnings from investment in subsidiaries, net of taxes	(6,705)	—	—	6,705	—
Net income (loss)	(8,509)	(6,258)	699	6,051	(8,017)
Less: net income attributable to non-controlling interest	—	—	492	—	492
Net income (loss) attributable to Unit Corporation	$ (8,509)	$ (6,258)	$ 207	$ 6,051	$ (8,509)

	Three Months Ended June 30, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
Revenues	$ —	$ 155,085	$ 75,406	$ (27,188)	$ 203,303
Expenses:					
Operating costs	—	70,603	59,786	(26,374)	104,015
Depreciation, depletion, and amortization	1,918	45,280	11,175	—	58,373
General and administrative	—	8,655	57	—	8,712
Gain on disposition of assets	—	(116)	(45)	—	(161)
Total operating costs	1,918	124,422	70,973	(26,374)	170,939
Income (loss) from operations	(1,918)	30,663	4,433	(814)	32,364
Interest, net	(7,425)	—	(304)	—	(7,729)
Loss on derivatives	(14,461)	—	—	—	(14,461)
Other, net	5	—	—	—	5
Income (loss) before income taxes	(23,799)	30,663	4,129	(814)	10,179
Income tax expense (benefit)	(6,029)	7,803	255	—	2,029
Equity in net earnings from investment in subsidiaries, net of taxes	23,558	—	—	(23,558)	—
Net income	5,788	22,860	3,874	(24,372)	8,150
Less: net income attributable to non-controlling interest	—	—	2,362	—	2,362
Net income attributable to Unit Corporation	$ 5,788	$ 22,860	$ 1,512	$ (24,372)	$ 5,788

	Six Months Ended June 30, 2019				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
Revenues	$ —	$ 272,882	$ 125,139	$ (43,184)	$ 354,837
Expenses:					
Operating costs	—	145,302	97,679	(41,470)	201,511
Depreciation, depletion, and amortization	3,869	100,721	23,828	—	128,418
General and administrative	—	19,805	—	—	19,805
(Gain) loss on disposition of assets	(10)	1,311	(108)	—	1,193
Total operating costs	3,859	267,139	121,399	(41,470)	350,927
Income (loss) from operations	(3,859)	5,743	3,740	(1,714)	3,910
Interest, net	(16,852)	—	(681)	—	(17,533)
Gain on derivatives	995	—	—	—	995
Other, net	11	—	—	—	11
Income (loss) before income taxes	(19,705)	5,743	3,059	(1,714)	(12,617)
Income tax expense (benefit)	(4,547)	2,229	—	—	(2,318)
Equity in net earnings from investment in subsidiaries, net of tax	3,145	—	—	(3,145)	—
Net income (loss)	(12,013)	3,514	3,059	(4,859)	(10,299)
Less: net income attributable to non-controlling interest	—	—	1,714	—	1,714
Net income (loss) attributable to Unit Corporation	$ (12,013)	$ 3,514	$ 1,345	$ (4,859)	$ (12,013)

	Six Months Ended June 30, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
Revenues	$ —	$ 308,894	$ 150,056	$ (50,515)	$ 408,435
Expenses:					
Operating costs	—	143,709	118,806	(49,267)	213,248
Depreciation, depletion, and amortization	3,836	89,375	22,228	—	115,439
General and administrative	—	16,884	2,590	—	19,474
Gain on disposition of assets	(30)	(213)	(79)	—	(322)
Total operating costs	3,806	249,755	143,545	(49,267)	347,839
Income (loss) from operations	(3,806)	59,139	6,511	(1,248)	60,596
Interest, net	(17,280)	—	(453)	—	(17,733)
Loss on derivatives	(21,223)	—	—	—	(21,223)
Other, net	11	1	(1)	—	11
Income (loss) before income taxes	(42,298)	59,140	6,057	(1,248)	21,651
Income tax expense (benefit)	(10,668)	15,460	844	—	5,636
Equity in net earnings from investment in subsidiaries, net of tax	45,283	—	—	(45,283)	—
Net income	13,653	43,680	5,213	(46,531)	16,015
Less: net income attributable to non-controlling interest	—	—	2,362	—	2,362
Net income attributable to Unit Corporation	$ 13,653	$ 43,680	$ 2,851	$ (46,531)	$ 13,653

Condensed Consolidating Statements of Comprehensive Income (Loss) (Unaudited)

	Three Months Ended June 30, 2019				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
			(In thousands)		
Net income (loss)	$ (8,509)	$ (6,258)	$ 699	$ 6,051	$ (8,017)
Other comprehensive income (loss), net of taxes:					
Unrealized loss on securities, net of tax ($9)	—	(30)	—	—	(30)
Comprehensive income (loss)	(8,509)	(6,288)	699	6,051	(8,047)
Less: Comprehensive income attributable to non-controlling interests	—	—	492	—	492
Comprehensive income (loss) attributable to Unit Corporation	$ (8,509)	$ (6,288)	$ 207	$ 6,051	$ (8,539)

	Three Months Ended June 30, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
			(In thousands)		
Net income	$ 5,788	$ 22,860	$ 3,874	$ (24,372)	$ 8,150
Other comprehensive income, net of taxes:					
Unrealized gain on securities, net of tax of $11	—	35	—	—	35
Comprehensive income	5,788	22,895	3,874	(24,372)	8,185
Less: Comprehensive income attributable to non-controlling interests	—	—	2,362	—	2,362
Comprehensive income attributable to Unit Corporation	$ 5,788	$ 22,895	$ 1,512	$ (24,372)	$ 5,823

	Six Months Ended June 30, 2019				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
			(In thousands)		
Net income (loss)	$ (12,013)	$ 3,514	$ 3,059	$ (4,859)	$ (10,299)
Other comprehensive income (loss), net of taxes:					
Unrealized loss on securities, net of tax of ($2)	—	(6)	—	—	(6)
Comprehensive income (loss)	(12,013)	3,508	3,059	(4,859)	(10,305)
Less: Comprehensive income attributable to non-controlling interests	—	—	1,714	—	1,714
Comprehensive income (loss) attributable to Unit Corporation	$ (12,013)	$ 3,508	$ 1,345	$ (4,859)	$ (12,019)

	Six Months Ended June 30, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
			(In thousands)		
Net income	$ 13,653	$ 43,680	$ 5,213	$ (46,531)	$ 16,015
Other comprehensive income, net of taxes:					
Unrealized loss on securities, net of tax of ($47)	—	(141)	—	—	(141)
Comprehensive income	13,653	43,539	5,213	(46,531)	15,874
Less: Comprehensive income attributable to non-controlling interests	—	—	2,362	—	2,362
Comprehensive income attributable to Unit Corporation	$ 13,653	$ 43,539	$ 2,851	$ (46,531)	$ 13,512

Condensed Consolidating Statements of Cash Flows (Unaudited)

	Six Months Ended June 30, 2019				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$ (8,023)	$ 111,615	$ 23,943	$ (34)	$ 127,501
INVESTING ACTIVITIES:					
Capital expenditures	(100)	(212,982)	(33,556)	—	(246,638)
Producing properties and other acquisitions	—	(3,313)	—	—	(3,313)
Proceeds from disposition of assets	10	7,247	83	—	7,340
Net cash used in investing activities	(90)	(209,048)	(33,473)	—	(242,611)
FINANCING ACTIVITIES:					
Borrowings under credit agreement	238,800	—	32,400	—	271,200
Payments under credit agreement	(135,300)	—	(24,900)	—	(160,200)
Intercompany borrowings (advances), net	(96,311)	97,384	(1,107)	34	—
Payments on finance leases	—	—	(1,980)	—	(1,980)
Employee taxes paid by withholding shares	(4,073)	—	—	—	(4,073)
Distributions to non-controlling interest	919	—	(1,837)	—	(918)
Book overdrafts	4,183	—	1,115	—	5,298
Net cash provided by financing activities	8,218	97,384	3,691	34	109,327
Net increase (decrease) in cash and cash equivalents	105	(49)	(5,839)	—	(5,783)
Cash and cash equivalents, beginning of period	403	208	5,841	—	6,452
Cash and cash equivalents, end of period	$ 508	$ 159	$ 2	$ —	$ 669

	Six Months Ended June 30, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
OPERATING ACTIVITIES:					
Net cash provided by operating activities	$ (96,111)	$ 145,227	$ (16,469)	$ 126,993	$ 159,640
INVESTING ACTIVITIES:					
Capital expenditures	(13)	(173,097)	(16,806)	—	(189,916)
Producing properties and other acquisitions	—	(962)	—	—	(962)
Proceeds from disposition of assets	30	23,427	71	—	23,528
Net cash used in investing activities	17	(150,632)	(16,735)	—	(167,350)
FINANCING ACTIVITIES:					
Borrowings under credit agreement	69,200	—	2,000	—	71,200
Payments under credit agreement	(247,200)	—	(2,000)	—	(249,200)
Intercompany borrowings (advances), net	276,460	5,468	(154,935)	(126,993)	—
Payments on finance leases	—	—	(1,901)	—	(1,901)
Employee taxes paid by withholding shares	(4,947)	—	—	—	(4,947)
Proceeds from investments of non-controlling interest	102,958	—	197,042	—	300,000
Transaction costs associated with sale of non-controlling interest	(2,254)	—	—	—	(2,254)
Book overdrafts	(1,581)	—	—	—	(1,581)
Net cash provided by (used in) financing activities	192,636	5,468	40,206	(126,993)	111,317
Net increase (decrease) in cash and cash equivalents	96,542	63	7,002	—	103,607
Cash and cash equivalents, beginning of period	510	191	—	—	701
Cash and cash equivalents, end of period	$ 97,052	$ 254	$ 7,002	$ —	$ 104,308

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 in conjunction 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. References to our mid-stream segment refers to Superior Pipeline Company, L.L.C. of which we own 50%.

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 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 own account. We own 50% of this subsidiary.

In addition to the companies identified above, our corporate headquarters is owned by our wholly owned subsidiary "8200 Unit Drive, L.L.C.".

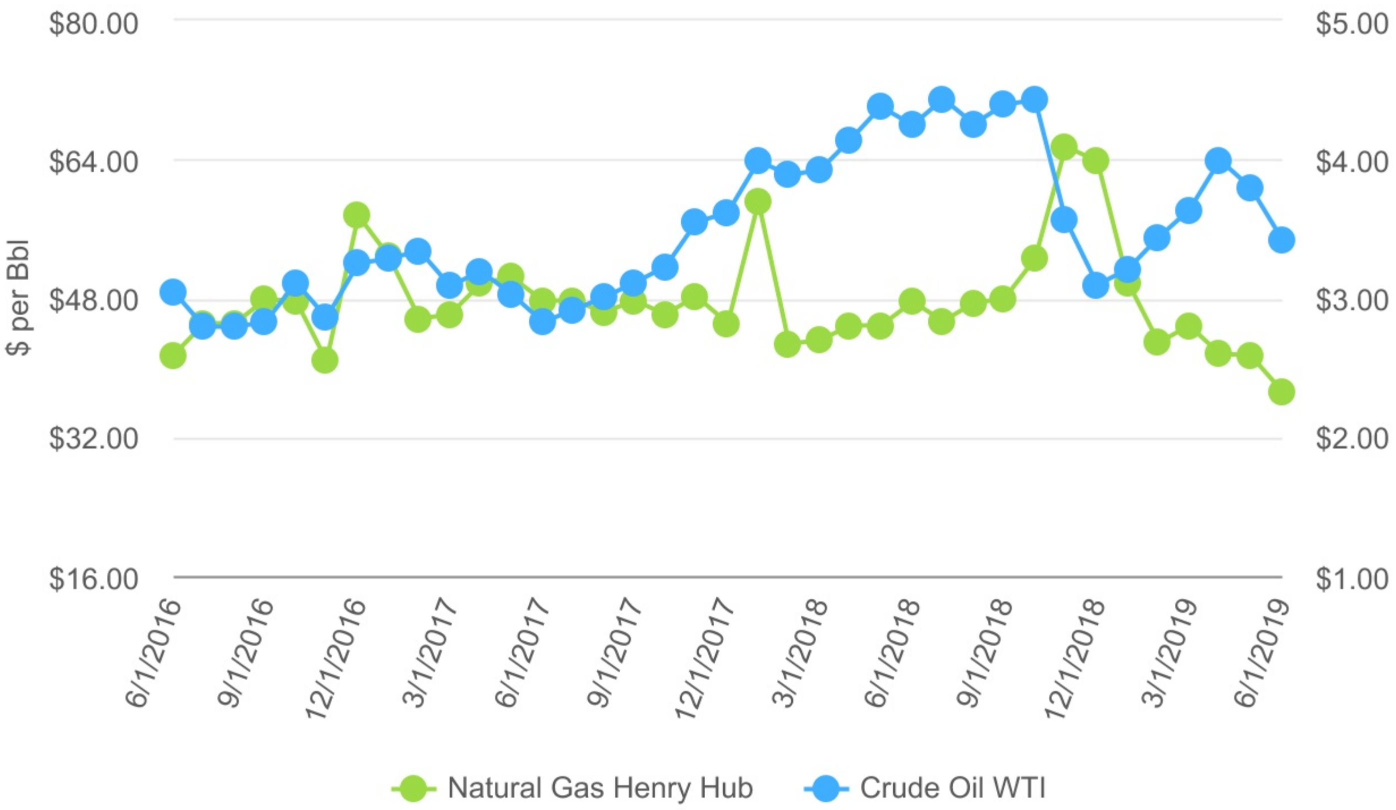
Business Outlook

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 all within the United States, events outside the United States affect us and our industry.

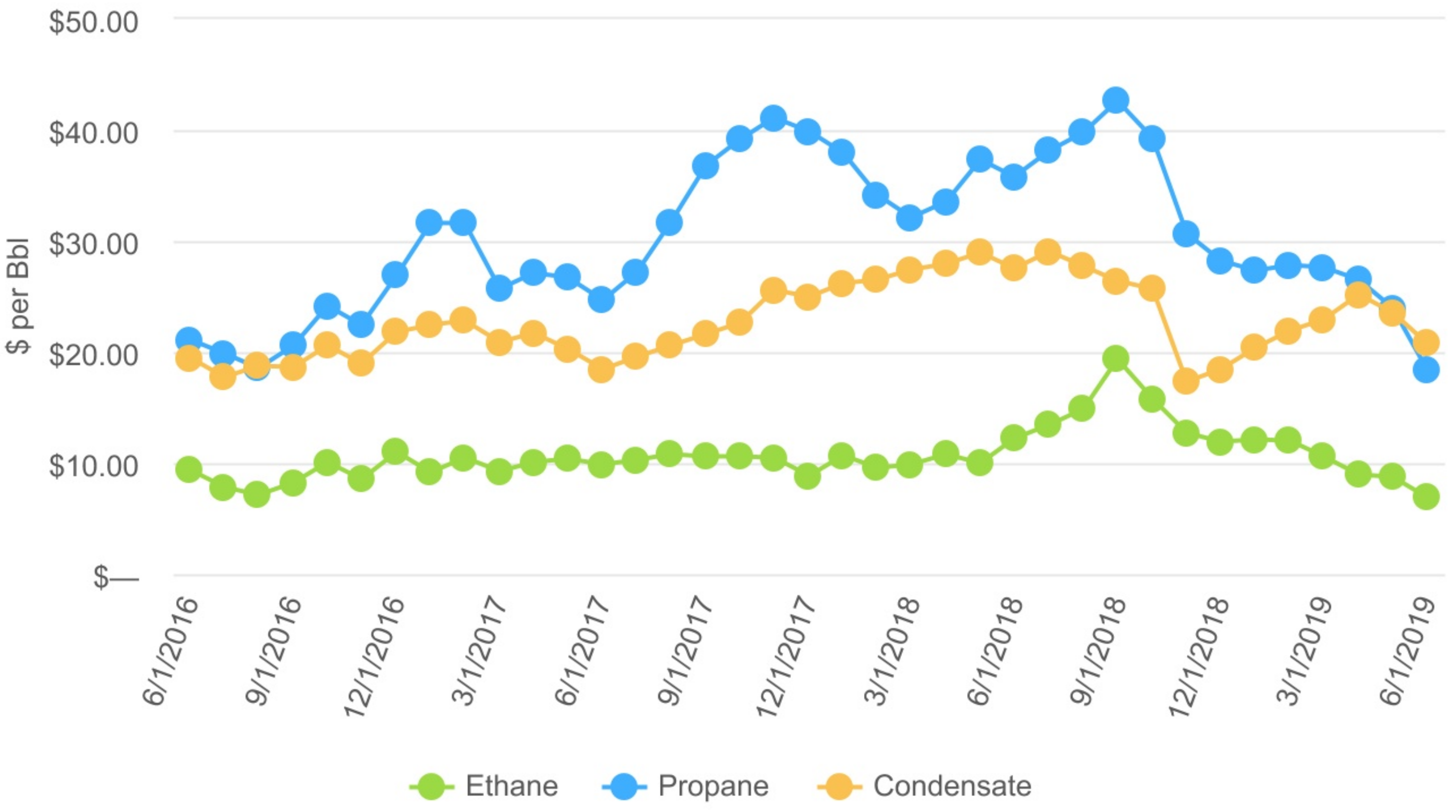
Fluctuating commodity prices can result in significant changes to our industry and us. Depressed commodity prices, particularly for the extended time, can result in industry wide reductions in drilling activity and spending which reduce the rates for and the number of our drilling rigs we were able to put to work. Such industry wide reductions in drilling activity and spending for extended periods also 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.

During the last several years, commodity prices have been volatile. Our oil and natural gas segment began using two to three drilling rigs throughout 2017. With improved commodity prices during the first quarter of 2018, our oil and natural gas segment put four of our drilling rigs to work and increased the number to six drilling rigs for a brief period during the third quarter of 2018. We started the first quarter of 2019 with four drilling rigs operating, increased to six during March and through mid-second quarter and ended the second quarter with four drilling rigs operating. Our plans are to now substantially reduce our borrowings under our credit agreement by year-end.

The following chart reflects the significant fluctuations in the prices for oil and natural gas:



The following chart reflects the significant fluctuations in the prices for NGLs:



1. NGLs prices reflect a weighted-average, based on production, of Mont Belvieu and Conway prices.

In our oil and gas segment, we had no write-downs in 2018 or in the first six months of 2019. 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 June 30, 2019, and only adjust the 12-month average price to an estimated third quarter ending average (holding July 2019 prices constant for the remaining two months of the third quarter of 2019), our forward looking expectation is that we would recognize an impairment of $107 million pre-tax in the third quarter of 2019. The actual amount of any write-down may vary significantly from this estimate depending on the final future determination.

For 2019, we believe the number of gross wells we will drill to be 85-95 wells (depending on future commodity prices).

Our contract drilling segment completed the construction of one additional BOSS drilling rigs during the third quarter of 2018. During the second quarter and third quarter of 2018, we were awarded term contracts to build our 12th and 13th BOSS drilling rigs. Construction was completed for one of these in January and it was placed into service for a third-party operator. Early in the first quarter of 2019, the other contract was terminated but we were able to find another third-party operator and it was placed into service in February. Our 14th BOSS drilling rig was contracted during the second quarter of 2019. Construction has started and the new drilling rig will be placed into service in the fourth quarter of 2019. Rig utilization fluctuated over the past year due to commodity prices changing and budget constraints on operators. We expect commodity prices and budget constraints on operators to continue to affect rig utilization throughout 2019. During 2018, utilization increased to a high of 36 drilling rigs but with a decline in commodity prices during the fourth quarter, declined to 32 drilling rigs as of December 31, 2018 and continued to decline to 24 drilling rigs as of June 30, 2019.

In December 2018, we removed from service 41 drilling rigs, some older top drives, and certain drill pipe that has been reclassed to 'Assets held for sale.' At June 30, 2019, our drilling rig fleet totaled 57 drilling rigs.

During 2018, due to low ethane and residue prices, we operated some of our mid-stream processing facilities in ethane rejection mode which reduces the liquids sold. At the end of 2018 and into the first part of 2019, as NGLs and gas prices improved, we began operating some of our mid-stream processing facilities in ethane recovery mode. We are continuing to monitor commodity prices to determine the most economical method in which to operate our processing facilities.

Executive Summary

Oil and Natural Gas

Second quarter 2019 production from our oil and natural gas segment was 4,151,000 barrels of oil equivalent (Boe), a increase of 1% over the first quarter of 2019 and a decrease of 1% from the second quarter of 2018, respectively. The increase over the first quarter of 2019 was primarily from a 14-day plant shut-down (12-days of which were in the first quarter of 2019) that resulted in a loss of slightly over 165 MBoe for the first quarter of 2019. The decrease from the second quarter of 2018 was primarily due to the 14-day plant shut-down (2-days of which were in the second quarter of 2019) and the associated delays in getting production ramped back up after the plant shutdown ended. We also had a series of weather related events in the Texas Panhandle and Oklahoma that caused well shut-ins and delays in operations.

Second quarter 2019 oil and natural gas revenues decreased 10% from the first quarter of 2019 and decreased 24% from the second quarter of 2018. The decreases were primarily from a decrease in commodity prices.

Our oil prices for the second quarter of 2019 increased 6% over the first quarter of 2019 and increased 6% over the second quarter of 2018. Our NGLs prices decreased 22% from the first quarter of 2019 and decreased 44% from the second quarter of 2018. Our natural gas prices decreased 26% from the first quarter of 2019 and decreased 15% from the second quarter of 2018.

Operating cost per Boe produced for the second quarter of 2019 increased 10% over the first quarter of 2019 and increased 13% over the second quarter of 2018. The increase over the first quarter of 2019 was primarily due to higher lease operating expenses from new wells drilled partially offset by lower general and administrative expenses and gross production taxes. The increase over the second quarter of 2018 was primarily due to higher lease operating expenses and saltwater disposal expenses and lower equivalent production.

At June 30, 2019, these derivatives were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Jul'19 – Oct'19	Natural gas – swap	60,000 MMBtu/day	$2.900	IF – NYMEX (HH)
Nov'19 – Dec'19	Natural gas – swap	40,000 MMBtu/day	$2.900	IF – NYMEX (HH)
Jul'19 – Dec'19	Natural gas – basis swap	20,000 MMBtu/day	$(0.659)	PEPL
Jul'19 – Dec'19	Natural gas – basis swap	10,000 MMBtu/day	$(0.625)	NGL MIDCON
Jul'19 – Dec'19	Natural gas – basis swap	30,000 MMBtu/day	$(0.265)	NGPL TEXOK
Jan'20 – Dec'20	Natural gas – basis swap	30,000 MMBtu/day	$(0.275)	NGPL TEXOK
Jul'19 – Dec'19	Natural gas – collar	20,000 MMBtu/day	$2.63 - $3.03	IF – NYMEX (HH)
Jul'19 – Dec'19	Crude oil – three-way collar	4,000 Bbl/day	$61.25 - $51.25 - $72.93	WTI – NYMEX

For the three months ended June 30, 2019, we completed drilling 63 gross wells (17.41 net wells). For all of 2019, we anticipate participating in the drilling of approximately 85-95 gross wells. Excluding a reduction in ARO liability and any possible acquisitions, our estimated 2019 capital expenditures for this segment is approximately $265.0 million (slightly lower than the original $271.0 million to $315.0 million range) due to lower commodity prices. Our current 2019 production guidance is approximately 17.0 to 17.2 MMBoe, although actual results continue to be subject to many factors.

Contract Drilling

The average number of drilling rigs we operated in the second quarter of 2019 was 28.6 compared to 31.4 and 32.2 in the first quarter of 2019 and the second quarter of 2018, respectively. As of June 30, 2019, 24 of our drilling rigs were operating.

Revenue for the second quarter of 2019 decreased 16% from the first quarter of 2019 and decreased 8% from the second quarter of 2018. The decreases were primarily due to less drilling rigs operating.

Dayrates for the second quarter of 2019 averaged $18,491, an 1% increase over the first quarter of 2019 and a 7% increase over the second quarter of 2018. The increase over the first quarter of 2019 was primarily due to lower dayrate drilling rigs being released and higher dayrate BOSS drilling rigs continuing to operate. The increase over the second quarter of 2018 was due to a labor increase passed through to contracted rigs rates and improving market dayrates.

Operating costs for the second quarter of 2019 decreased 7% from the first quarter of 2019 and decreased 8% from the second quarter of 2018. The decreases were both primarily due to less drilling rigs operating.

Currently, we have 14 term drilling contracts with original terms ranging from six months to three years. Two are up for renewal in the third quarter of 2019, four in the fourth quarter of 2019, five in 2020, and three after 2020. Term contracts may contain a fixed rate during the contract or provide for rate adjustments within a specific range from the existing rate. Some operators who had signed term contracts have opted to release the drilling rig early and pay an early termination penalty for the remaining term of the contract. We recorded $4.8 million in early termination fees in the first quarter of 2019. We had no early termination fees for the second quarter of 2019.
All 13 of our existing BOSS drilling rigs are under contract.

Our estimated 2019 capital expenditures for this segment is approximately $45.0 million (the midpoint of the original $30.0 million to $65.0 million range) due to the construction of our 14th BOSS drilling rig.

Our drilling rig personnel are a key component to the overall success of our drilling services. With the present conditions in the drilling industry, we do not anticipate increases in the compensation paid to those personnel in the near term.

Mid-Stream

Second quarter 2019 liquids sold per day increased 9% over the first quarter of 2019 and increased 5% over the second quarter of 2018, respectively. The increase from the first quarter of 2019 was due to higher processed volumes and better recoveries at our processing facilities. The increase over the second quarter of 2018 was primarily due to increased volume available to process at our processing facilities due to additional well connections along with operating in higher recovery mode. For the second quarter of 2019, gas processed per day increased 2% over the first quarter of 2019 and increased 3% over the second quarter of 2018. The increase over the first quarter of 2019 was primarily due to higher volumes associated with wells connected mainly to our Cashion and Bellmon processing facility. The increase over the second quarter of 2018 was mainly due to new wells connected to the Cashion facility. For the second quarter of 2019, gas gathered per day increased 4% and 19% over the first quarter of 2019 and the second quarter of 2018, respectively. These increases are both due to connecting additional wells to our gathering systems primarily in Pennsylvania and Oklahoma.

NGLs prices in the second quarter of 2019 decreased 26% from the prices received in the first quarter of 2019 and decreased 45% from the prices received in the second quarter of 2018. 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 second quarter of 2019 decreased 17% from the first quarter of 2019 and decreased 18% from the second quarter of 2018. The decreases were both primarily due to lower gas and purchase prices.

In the Appalachian region at the Pittsburgh Mills gathering system, the average gathered volume for the second quarter of 2019 was approximately 206.4 MMcf per day. In the first quarter of 2019, we added seven new wells which accounted for the significant increase in gathered volume in the first quarter. In the second quarter of 2019, the production from these wells is declining as evidenced in the lower volume as of June 2019. These wells are all long lateral wells. The Kissick compressor station facilities located on the south end of the system have been upgraded and are able to handle the increased volume from these new wells.

At the Cashion processing facility in central Oklahoma, total throughput volume for the second quarter of 2019 averaged approximately 56.7 MMcf per day and total production of natural gas liquids increased to 273,075 gallons per day. We are continuing to connect new wells to this system from several third party producers. In 2019, we have connected 16 new wells to this system from several third party producers who continue to be active in the area. During the second quarter, we completed the addition of the new 60 MMcf per day Reeding processing facility on the Cashion system. This 60 MMcf per day processing plant was relocated from our Bellmon facility to the Cashion area and is now fully operational. The addition of this new processing facility increases our total processing capacity on the Cashion system to approximately 105 MMcf per day.

At the Hemphill processing facility located in the Texas panhandle, average total throughput volume for the second quarter of 2019 was 72.9 MMcf per day and total production of natural gas liquids was 288,762 gallons per day during this same period. Since the first of this year, we have connected six new wells to the Hemphill system. The six new wells connected in 2019 are Unit Petroleum wells. There are no Unit Petroleum wells currently being drilled in this area.

Our estimated 2019 capital expenditures for this segment is approximately $45.0 million (slightly higher than the original $35.0 million to $42.0 million range) due to the purchase of previously leased assets.

Financial Condition and Liquidity

Summary

Our financial condition and liquidity depends on the cash flow from our operations and borrowings under our credit agreements. 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 12 months. Our ability to meet our debt covenants (under our credit agreements and our 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 the Unit 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.

	Six Months Ended June 30, 2019	2018	% Change
	(In thousands except percentages)		
Net cash provided by operating activities	$ 127,501	$ 159,640	(20) %
Net cash used in investing activities	(242,611)	(167,350)	45 %
Net cash provided by financing activities	109,327	111,317	(2) %
Net increase (decrease) in cash and cash equivalents	$ (5,783)	$ 103,607	

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 six months of 2019 decreased by $32.1 million as compared to the first six months of 2018. The decrease was primarily due to decreased operating profit in the oil and gas segment and a decrease in changes in operating assets and liabilities related to the timing of cash receipts and disbursements partially offset by increases in cash for derivatives settled.

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 increased by $75.3 million for the first six months of 2019 compared to the first six months of 2018. The change was due primarily to an increase in capital expenditures for development drilling and construction of BOSS drilling rigs and a reduction in cash proceeds on the sale of assets. See additional information on capital expenditures below under Capital Requirements.

Cash Flows from Financing Activities

Cash flows provided by financing activities decreased by $2.0 million for the first six months of 2019 compared to the first six months of 2018. The decrease was primarily due to an increase in the net borrowings under our credit agreements partially offset by sale of 50% interest in our mid-stream segment in 2018.

At June 30, 2019, we had unrestricted cash and cash equivalents totaling $0.7 million and had borrowed $103.5 million of the $425.0 million and $7.5 million of the $200.0 million we had elected to have available under the Unit and Superior credit agreements, respectively. The credit agreements are used primarily for working capital and capital expenditures.

Below, we summarize certain financial information as of June 30, 2019 and 2018 and for the six months ended June 30, 2019 and 2018:

	June 30, 2019	2018	% Change
	(In thousands except percentages)		
Working capital	$ (64,125)	$ 26,330	NM
Long-term debt less debt issuance costs	$ 756,590	$ 643,371	18 %
Shareholders' equity attributable to Unit Corporation	$ 1,389,873	$ 1,444,250	(4) %
Net income (loss) attributable to Unit Corporation	$ (12,013)	$ 13,653	(188) %

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

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 $64.1 million and positive working capital of $26.3 million as of June 30, 2019 and 2018, respectively. The decrease in working capital is primarily due to a decrease in accounts receivable due to lower revenues and by a decrease cash and cash equivalents from the sale of 50% interest in our mid-stream segment in 2018 partially offset by reduction in accounts payable. The Unit and Superior credit agreements are used primarily for working capital and capital expenditures. At June 30, 2019, we had borrowed $103.5 million of the $425.0 million and $7.5 million of the $200.0 million available under the Unit or Superior credit agreements, respectively. The effect of our derivative contracts increased working capital by $8.5 million as of June 30, 2019 and decreased working capital by $18.4 million as of June 30, 2018.

This table summarizes certain operating information:

	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018	% Change
Oil and Natural Gas:			
Oil production (MBbls)	1,414	1,429	(1) %
NGLs production (MBbls)	2,417	2,425	— %
Natural gas production (MMcf)	26,659	27,237	(2) %
Equivalent barrels (MBoe)	8,274	8,393	(1) %
Average oil price per barrel received	$ 58.16	$ 55.76	4 %
Average oil price per barrel received excluding derivatives	$ 55.86	$ 64.08	(13) %
Average NGLs price per barrel received	$ 14.11	$ 21.65	(35) %
Average NGLs price per barrel received excluding derivatives	$ 14.11	$ 21.91	(36) %
Average natural gas price per Mcf received	$ 2.18	$ 2.40	(9) %
Average natural gas price per Mcf received excluding derivatives	$ 2.11	$ 2.27	(7) %
Net impact of revenue recognition (ASC 606) per Boe [1]	$ (1.26)	$ (0.82)	(54) %
Average realized price per Boe received	$ 19.83	$ 22.70	(13) %
Average realized price per Boe received excluding derivatives	$ 19.19	$ 23.77	(19) %
Contract Drilling:			
Average number of our drilling rigs in use during the period	30.0	31.9	(6) %
Total number of drilling rigs owned at the end of the period	57	95	(40) %
Average dayrate	$ 18,412	$ 17,184	7 %
Mid-Stream:			
Gas gathered—Mcf/day	457,859	382,005	20 %
Gas processed—Mcf/day	163,725	155,799	5 %
Gas liquids sold—gallons/day	681,070	627,305	9 %
Number of natural gas gathering systems	21	22	(5) %
Number of processing plants	12	14	(14) %

1. Pursuant to accounting guidance on revenue recognition (ASC 606); gathering, processing, and transportation costs are reflected as a deduction from revenue instead of as an expense when we arrange for another company to provide the good or service.

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 six months of 2019 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 $427,000 per month ($5.1 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 six months of 2019 was $2.18 compared to $2.40 for the first six months of 2018. Based on our first six months of 2019 production, a $1.00 per barrel change in our oil price, without the effect of derivatives, would have a $224,000 per month ($2.7 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 $386,000 per month ($4.6 million annualized) change in our pre-tax operating cash flow. In the first six months of 2019, our average oil price per barrel received, including the effect of derivatives, was $58.16 compared with an average oil price, including the effect of derivatives, of $55.76 in the first six months of 2018 and our first six months of 2019 average NGLs price per barrel received, including the effect of derivatives was $14.11 compared with an average NGLs price per barrel of $21.65 in the first six months of 2018.

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 June 30, 2019, the 12-month average unescalated prices were $61.39 per barrel of oil, $32.38 per barrel of NGLs, and $3.02 per Mcf of natural gas, and then are adjusted for price differentials. We did not take a write down in the first six months of 2019.

We anticipate a non-cash ceiling test write-down in the third quarter of 2019. 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 June 30, 2019, and only adjust the 12-month average price to an estimated third quarter ending average (holding July 2019 prices constant for the remaining two months of the third quarter of 2019), our forward looking expectation is that we would recognize an impairment of $107 million pre-tax in the third quarter of 2019. The estimated third-quarter 2019 impairment would be partially the result of a decrease in our proved undeveloped reserves of approximately 16%. This decrease would be primarily due to certain locations no longer being economical under the adjusted 12-month average price for the third quarter. As a result, we may eliminate those locations from our future development plans. Given the uncertainty associated with the factors used in calculating our estimate of both our future period ceiling test write-down and the decrease in our undeveloped reserves, these estimates should not necessarily be construed as indicative of our future development plans or financial results and the actual amount of any write-down may vary significantly from this estimate depending on the final future determination.

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 are 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 six months of 2019, our average dayrate was $18,412 per day compared to $17,184 per day for the first six months of 2018. The average number of our drilling rigs used in the first six months of 2019 was 30.0 drilling rigs compared with 31.9 drilling rigs in the first six months of 2018. Based on the average utilization of our drilling rigs during the first six months of 2019, a $100 per day change in dayrates has a $3,000 per day ($1.1 million annualized) change in our pre-tax operating cash flow.

Our contract drilling segment provides drilling services for our exploration and production segment. Some of the drilling services we perform on our properties are, depending on the timing of those services, deemed to be associated with acquiring an ownership interest in the property. In those cases, revenues and expenses for those services are eliminated in our 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 $14.8 million and $10.6 million for the first six months of 2019 and 2018, respectively, from our contract drilling segment and eliminated the associated operating expense of $13.1 million and $9.3 million during the first six months of 2019 and 2018, respectively, yielding $1.7 million and $1.3 million during the first six months of 2019 and 2018, respectively, as a reduction to the carrying value of our oil and natural gas properties.

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, 12 processing plants, 21 gathering systems, and approximately 1,500 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 six months of 2019 and 2018, our mid-stream operations purchased $24.8 million and $36.5 million, respectively, of our natural gas production and NGLs, and provided gathering and transportation services of $3.6 million and $3.4 million, respectively. Intercompany revenue from services and purchases of production between this business segment and our oil and natural gas segment has been eliminated in our unaudited condensed consolidated financial statements.

This segment gathered an average of 457,859 Mcf per day in the first six months of 2019 compared to 382,005 Mcf per day in the first six months of 2018. It processed an average of 163,725 Mcf per day in the first six months of 2019 compared to 155,799 Mcf per day in the first six months of 2018. The NGLs sold was 681,070 gallons per day in the first six months of 2019 compared to 627,305 gallons per day in the first six months of 2018. Gas gathered volumes per day in the first six months of 2019 increased 20% compared to the first six months of 2018 primarily due to connecting additional wells to our Pennsylvania and Oklahoma facilities. Gas processed volumes for the first six months of 2019 increased 5% over the first six months of 2018 due to connecting new wells mainly at our Cashion processing facility. NGLs sold increased 9% over the comparative period due to increased volume available to process at our processing facilities from additional well connections along with operating in higher recovery mode.

Our Credit Agreements and Senior Subordinated Notes

Unit Credit Agreement. Our Senior Credit Agreement (Unit credit agreement) is scheduled to mature on October 18, 2023. Under that 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 amount of $1.0 billion. Our elected commitment amount is $425.0 million. Our borrowing base is $425.0 million. We are currently charged a commitment fee of 0.375% on the amount available but not borrowed. That fee varies based on the amount borrowed as a percentage of the total borrowing base. Total fees of $3.3 million in origination, agency, syndication, and other related fees are being amortized over the life of the Unit credit agreement. Under the agreement, we have pledged as collateral 80% of the proved developed producing (discounted as present worth at 8%) total value of our oil and gas properties.

On May 2, 2018, we entered into a Pledge Agreement with BOKF, NA (dba Bank of Oklahoma), as administrative agent to benefit the secured parties, granting a security interest in the limited liability membership interests and other equity interests we own in Superior (which as of this report is 50% of the aggregate outstanding equity interests of Superior) as additional collateral for our obligations under the Unit credit agreement.

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

Lender	Participation Interest
BOK (BOKF, NA, dba Bank of Oklahoma)	17.060 %
BBVA Compass Bank	17.060 %
BMO Harris Financing, Inc.	15.294 %
Bank of America, N.A.	15.294 %
Comerica Bank	8.235 %
Toronto Dominion Bank, New York Branch	8.235 %
Canadian Imperial Bank of Commerce	8.235 %
Arvest Bank	3.529 %
Branch Banking & Trust	3.529 %
IBERIABANK	3.529 %
	100.000 %

The borrowing base amount–which is subject to redetermination by the lenders on April 1st and October 1st of each year–is based 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 Unit credit agreement.

At our election, any part of the outstanding debt under the Unit credit agreement can be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest is computed as the LIBOR base for the term plus 1.50% to 2.50% 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 Unit credit agreement but in no event less than LIBOR plus 1.00% plus a margin. The credit agreement provides that if ICE Benchmark Administration no longer reports the LIBOR or Administrative Agent determines in good faith that the rate so reported no longer accurately reflects the rate available to Lender in the London Interbank Market or if such index no longer exists or accurately reflects the rate available to Administrative Agent in the London Interbank Market, Administrative Agent may select a replacement index. Interest is payable at the end of each month or at the end of each LIBOR contract and the principal may be repaid in whole or in part at any time, without a premium or penalty. At June 30, 2019, we had $103.5 million outstanding under the Unit credit agreement.

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

The Unit 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;
- 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; and
- investments in Unrestricted Subsidiaries (as defined in the Unit credit agreement) over $200.0 million.

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

As of June 30, 2019, we were in compliance with these covenants.

Superior Credit Agreement. On May 10, 2018, Superior, a limited liability company equally owned between the company and SP Investor Holdings, LLC, entered into a five-year, $200.0 million senior secured revolving credit facility with an option to increase the credit amount up to $250.0 million, subject to certain conditions. The amounts borrowed under the Superior credit agreement bear annual interest at a rate, at Superior's option, equal to (a) LIBOR plus the applicable margin of 2.00% to 3.25% or (b) the alternate base rate (greater of (i) the federal funds rate plus 0.5%, (ii) the prime rate, and (iii) third day LIBOR plus 1.00%) plus the applicable margin of 1.00% to 2.25%. The obligations under the Superior credit agreement are secured by, among other things, mortgage liens on certain of Superior's processing plants and gathering systems. The credit agreement provides that if ICE Benchmark Administration no longer reports the LIBOR or Administrative Agent determines in good faith that the rate so reported no longer accurately reflects the rate available to Lender in the London Interbank Market or if such index no longer exists or accurately reflects the rate available to Administrative Agent in the London Interbank Market, Administrative Agent may select a replacement index.

Superior is currently charged a commitment fee of 0.375% on the amount available but not borrowed which varies based on the amount borrowed as a percentage of the total borrowing base. Superior paid $1.7 million in origination, agency, syndication, and other related fees. These fees are being amortized over the life of the Superior credit agreement.

The Superior credit agreement requires that Superior maintain a Consolidated EBITDA to interest expense ratio for the most-recently ended rolling four quarters of at least 2.50 to 1.00, and a funded debt to Consolidated EBITDA ratio of not greater than 4.00 to 1.00. Additionally, the Superior credit agreement contains a number of customary covenants that, among other things, restrict (subject to certain exceptions) Superior's ability to incur additional indebtedness, create additional liens on its assets, make investments, pay distributions, enter into sale and leaseback transactions, engage in certain transactions with affiliates, engage in mergers or consolidations, enter into hedging arrangements, and acquire or dispose of assets. As of June 30, 2019, Superior was in compliance with the Superior credit agreement covenants.

The borrowings the Superior credit agreement will be used to fund capital expenditures and acquisitions, provide general working capital, and for letters of credit for Superior. As of June 30, 2019, we had $7.5 million outstanding borrowings under the Superior credit agreement.

On June 27, 2018, Superior and the lenders amended the Superior credit agreement to revise certain definitions in the agreement.

Superior's credit agreement is not guaranteed by Unit.

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

Lender	Participation Interest
BOK (BOKF, NA, dba Bank of Oklahoma)	17.50 %
Compass Bank	17.50 %
BMO Harris Financing, Inc.	13.75 %
Toronto Dominion (New York), LLC	13.75 %
Bank of America, N.A.	10.00 %
Branch Banking and Trust Company	10.00 %
Comerica Bank	10.00 %
Canadian Imperial Bank of Commerce	7.50 %
	100.00 %

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 significant 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. Effective April 3, 2018, Superior is no longer a Guarantor of the Notes. Excluding Superior, any of our other 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, unless the Company has exercised its right to redeem all of the Notes, 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. As of May 15, 2019, we may redeem the Notes at a redemption price equal to 100% of the principal amount of the Notes plus accrued and unpaid interest on 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 June 30, 2019.

We may from time to time seek to retire or purchase our outstanding Note debt through cash purchases and/or exchanges for securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

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 63 gross wells (17.41 net wells) in the first six months of 2019 compared to 34 gross wells (12.40 net wells) in the first six months of 2018.

At June 30, 2019 we had commitments to purchase approximately $0.5 million for casing over the next year. Capital expenditures for oil and gas properties on the full cost method for the first six months of 2019 by this segment, excluding $3.3 million for acquisitions and a $3.7 million increase in the ARO liability, totaled $195.5 million. Capital expenditures for the first six months of 2018, excluding $1.0 million for acquisitions and a $7.9 million reduction in the ARO liability, totaled $157.7 million.

We anticipate participating in drilling approximately 85 to 95 gross wells in 2019 and our total estimated capital expenditures (excluding a reduction in ARO liability and any possible acquisitions) for this segment is approximately $265.0 million (slightly lower than the original $271.0 million to $315.0 million range) due to lower commodity prices. 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 2018, we were awarded a term contract to build our 11th BOSS drilling rig which was constructed and placed into service in the second quarter of 2018. During the second quarter of 2018, we were awarded a term contract to build our 12th BOSS drilling rig.

During the first quarter of 2019, we completed construction and placed into service our 12th and 13th BOSS drilling rigs. One was delivered to an existing third party operator in Wyoming. Two additional BOSS drilling rigs under contract with the same customer were also extended. The other BOSS drilling rig was delivered to a new customer in the Permian Basin. This was following an early termination by the original third party operator prior to the drilling rig's completion.

During the second quarter of 2019, we were awarded a term contract to build our 14th BOSS drilling rig. Construction has started and the drilling rig is expected to be placed into service with a third party operator in the fourth quarter. Two existing BOSS drilling rig contracts working for the same operator were also extended at the time of the new BOSS drilling rig award.

Our estimated 2019 capital expenditures for this segment is approximately $45.0 million (the midpoint of the original $30.0 million to $65.0 million range) due to the construction of our 14th BOSS drilling rig. At June 30, 2019, we had commitments to purchase approximately $1.1 million for drilling equipment over the next year. We have spent $24.9 million for capital expenditures during the first six months of 2019, compared to $23.0 million for capital expenditures during the first six months of 2018.

Mid-Stream Dispositions, Acquisitions, and Capital Expenditures. In the Appalachian region at the Pittsburgh Mills gathering system, the average gathered volume for the second quarter of 2019 was approximately 206.4 MMcf per day. In the first quarter of 2019, we added seven new wells which accounted for the significant increase in gathered volume in the first quarter. In the second quarter of 2019, the production from these wells is declining as evidenced in the lower volume as of June 2019. These wells are all long lateral wells. The Kissick compressor station facilities located on the south end of the system have been upgraded and are able to handle the increased volume from these new wells.

At the Cashion processing facility in central Oklahoma, total throughput volume for the second quarter of 2019 averaged approximately 56.7 MMcf per day and total production of natural gas liquids increased to 273,075 gallons per day. We are continuing to connect new wells to this system from several third party producers. In 2019, we have connected 16 new wells to this system from several third party producers who continue to be active in the area. During the second quarter, we completed the addition of the new 60 MMcf per day Reeding processing facility on the Cashion system. This 60 MMcf per day processing plant was relocated from our Bellmon facility to the Cashion area and is now fully operational. The addition of this new processing facility increases our total processing capacity on the Cashion system to approximately 105 MMcf per day.

At the Hemphill processing facility located in the Texas panhandle, average total throughput volume for the second quarter of 2019 was 72.9 MMcf per day and total production of natural gas liquids was 288,762 gallons per day during this same period. Since the first of this year, we have connected six new wells to the Hemphill system. The six new wells connected in 2019 are Unit Petroleum wells. There are no Unit Petroleum wells currently being drilled in this area.

During the first six months of 2019, our mid-stream segment incurred $32.6 million in capital expenditures as compared to $13.8 million in the first six months of 2018. Our estimated 2019 capital expenditures for this segment is approximately $45.0 million (slightly higher than the original $35.0 million to $42.0 million range) due to the purchase of previously leased assets.

Contractual Commitments

At June 30, 2019, 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)]	$ 862,480	$ 47,945	$ 697,400	$ 117,135	$ —
Operating leases under ASC 840 [(2)]	507	507	—	—	—
Operating leases under ASC 842 [(3)]	8,075	4,519	3,297	195	64
Finance lease interest and maintenance [(4)]	3,620	2,087	1,533	—	—
Drilling rig components and casing [(5)]	1,584	1,584	—	—	—
Total contractual obligations	$ 876,266	$ 56,642	$ 702,230	$ 117,330	$ 64

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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 June 30, 2019 interest rates of 6.625% for the Notes and 4.2% for our Unit credit agreement and 6.5% for our Superior credit agreement. At June 30, 2019, our Unit credit agreement and our Superior credit agreement had maturity dates of October 18, 2023 and May 10, 2023, respectively. The outstanding Unit and Superior credit agreements balance were $103.5 million and $7.5 million, respectively, as of June 30, 2019.

2. We lease office space or yards in Edmond and Oklahoma City, Oklahoma; Houston, Texas; Englewood, Colorado; and Pinedale, Wyoming under the terms of operating leases expiring through March 2020. Additionally, we have several equipment leases and lease space on short-term commitments to stack excess drilling rig equipment and production inventory.

3. We lease certain office space, land and equipment, including pipeline equipment and office equipment under the terms of operating leases under ASC 842 expiring through March 2032.

4. Maintenance and interest payments are included in our finance lease agreements. The finance leases are discounted using annual rates of 4.00%. Total maintenance and interest remaining are $3.2 million and $0.4 million, respectively.

5. We have committed to pay $1.6 million for drilling rig components and casing over the next year.

During the second quarter of 2018, as part of the Superior transaction, we entered into a contractual obligation that commits us to spend $150.0 million to drill wells in the Granite Wash/Buffalo Wallow area over three years starting January 1, 2019. This amount is included in our future drilling plans. 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. At June 30, 2019, if we elected not to drill or spend any additional money in the designated area before December 31, 2021, the maximum amount we could forgo from distributions would be $74.0 million. Total spent towards the $150.0 million as of June 30, 2019 was $22.4 million.

At June 30, 2019, we also had the following commitments and contingencies that could create, increase, or accelerate our liabilities:

Other Commitments	Total Accrued	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
		Estimated Amount of Commitment Expiration Per Period			
			(In thousands)		
Deferred compensation plan (1)	$ 6,002	Unknown	Unknown	Unknown	Unknown
Separation benefit plans (2)	$ 9,749	$ 1,083	Unknown	Unknown	Unknown
Asset retirement liability (3)	$ 67,433	$ 1,784	$ 40,376	$ 3,837	$ 21,436
Gas balancing liability (4)	$ 3,372	Unknown	Unknown	Unknown	Unknown
Repurchase obligations (5)	$ —	$ —	$ —	$ —	$ —
Workers' compensation liability (6)	$ 12,118	$ 4,050	$ 2,438	$ 1,109	$ 4,521
Finance lease obligations (7)	$ 9,400	$ 4,081	$ 5,319	$ —	$ —
Contract liability (8)	$ 8,513	$ 2,889	$ 4,960	$ 638	$ 26

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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 six months of 2018. The partnerships were terminated during the second quarter of 2019 with an effective date of January 1, 2019 at a repurchase cost of $0.6 million, net of Unit's interest.

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 finance lease arrangements for compressors in Superior.

8. We have recorded a liability related to the timing of revenue recognized on certain demand fees for Superior.

Derivative Activities

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

Commodity Derivatives. Our commodity derivatives are intended to reduce our exposure to price volatility and manage price risks. Our decision on the type and quantity of our production and the price(s) of our derivative(s) is based, in part, on our view of current and future market conditions. At June 30, 2019, based on our second quarter 2019 average daily production, the approximated percentages of our production under derivative contracts are as follows:

	2019	
	Q3	Q4
Daily oil production	51 %	51 %
Daily natural gas production	55 %	46 %

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 June 30, 2019 evaluation, we believe the risk of non-performance by our counterparties is not material. At June 30, 2019, the fair values of the net assets we had with each of the counterparties to our commodity derivative transactions are as follows:

	June 30, 2019
	(In millions)
Bank of Montreal	$ 6.1
Bank of America	2.1
Total net assets	$ 8.2

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 June 30, 2019, we recorded the fair value of our commodity derivatives on our balance sheet as current derivative assets of $8.5 million and non-current derivative liabilities of $0.3 million. At December 31, 2018, we recorded the fair value of our commodity derivatives on our balance sheet as current derivative assets of $12.9 million and non-current derivative liabilities of $0.3 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 Statements of Operations. These gains (losses) at June 30 are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
	(In thousands)			
Gain (loss) on derivatives:				
Gain (loss) on derivatives, included are amounts settled during the period of $2,658, ($6,855), $5,314 and ($8,928), respectively	$ 7,927	$ (14,461)	$ 995	$ (21,223)
	$ 7,927	$ (14,461)	$ 995	$ (21,223)

Stock and Incentive Compensation

During the first six months of 2019, we granted awards covering 1,424,027 shares of restricted stock. These awards had an estimated fair value as of their grant date of $22.6 million. Compensation expense will be recognized over the three year vesting periods, and during the six months of 2019, we recognized $3.4 million in compensation expense and capitalized $0.6 million for these awards. During the first six months of 2019, we recognized compensation expense of $8.5 million for all of our restricted stock and capitalized $1.3 million of compensation cost for oil and natural gas properties.

During the first six months of 2018, we granted awards covering 1,250,880 shares of restricted stock. These awards had an estimated fair value as of their grant date of $24.4 million. Compensation expense will be recognized over the three year vesting periods, and during the six months of 2018, we recognized $3.7 million in compensation expense and capitalized $0.6

million for these awards. During the first six months of 2018, we recognized compensation expense of $9.5 million for all of our restricted stock and stock options and capitalized $1.0 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 six months 2018, the total we received for all of these fees was $0.1 million. 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. The partnerships were terminated during the second quarter of 2019 with an effective date of January 1, 2019.

New Accounting Pronouncements

Measurement of Credit Losses on Financial Instruments (Topic 326). The FASB issued ASU 2016-13 which replaces current methods for evaluating impairment of financial instruments not measured at fair value, including trade accounts receivable and certain debt securities, with a current expected credit loss model. The amendment will be effective for reporting periods after December 15, 2019. We are evaluating the impact this will have on our financial statements by reviewing our accounts receivable accounts and our historic credit losses.

Fair Value Measurement (Topic 820): Disclosure Framework—Changes to the Disclosure Requirements for Fair Value Measurement. The FASB issued ASU 2018-13 to modify the disclosure requirements in Topic 820. Part of the disclosures were removed or modified and other disclosures were added. The amendment will be effective for reporting periods beginning after December 15, 2019. Early adoption is permitted. Also it is permitted to early adopt any removed or modified disclosure and delay adoption of the additional disclosures until their effective date. This amendment will not have a material impact on our financial statements.

Intangibles—Goodwill and Other: Simplifying the Test for Goodwill Impairment. The FASB issued ASU 2017-04, to simplify the 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.

Adopted Standards

Compensation—Stock Compensation: Improvements to Nonemployee Share-Based Payment Accounting. The FASB issued ASU 2018-07, to improve financial reporting for nonemployee share-based payments. The amendment expands Topic 718, *Compensation—Stock Compensation* to include share-based payments issued to nonemployees for goods or services. The amendment is effective for years beginning after December 15, 2018, and interim periods within those years. This amendment did not have an impact on our financial statements.

We adopted ASC 842 on January 1, 2019, using the modified retrospective method and the optional transition method to record the adoption impact through a cumulative adjustment to equity. Results for reporting periods beginning after January 1, 2019, are presented under Topic 842, while prior periods are not adjusted and continue to be reported under the accounting standards in effect for those periods.

The additional disclosures required by ASC 842 have been included in Note 12 – Leases.

Results of Operations

Quarter Ended June 30, 2019 versus Quarter Ended June 30, 2018

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

	Quarter Ended June 30, 2019	Quarter Ended June 30, 2018	Percent Change [1]
	(In thousands unless otherwise specified)		
Total revenue	$ 165,146	$ 203,303	(19) %
Net income (loss)	$ (8,017)	$ 8,150	(198) %
Net income attributable to non-controlling interest	$ 492	$ 2,362	(79) %
Net income (loss) attributable to Unit Corporation	$ (8,509)	$ 5,788	NM
Oil and Natural Gas:			
Revenue	$ 77,815	$ 102,318	(24) %
Operating costs excluding depreciation, depletion, and amortization	$ 36,242	$ 32,418	12 %
Depreciation, depletion, and amortization	$ 38,751	$ 31,554	23 %
Average oil price received (Bbl)	$ 59.94	$ 56.46	6 %
Average NGLs price received (Bbl)	$ 12.52	$ 22.18	(44) %
Average natural gas price received (Mcf)	$ 1.86	$ 2.18	(15) %
Oil production (Bbl)	726,000	693,000	5 %
NGLs production (Bbl)	1,210,000	1,230,000	(2) %
Natural gas production (Mcf)	13,288,000	13,738,000	(3) %
Depreciation, depletion, and amortization rate (Boe)	$ 8.94	$ 7.14	25 %
Contract Drilling:			
Revenue	$ 43,037	$ 46,926	(8) %
Operating costs excluding depreciation	$ 29,308	$ 31,894	(8) %
Depreciation	$ 13,504	$ 13,726	(2) %
Percentage of revenue from daywork contracts	100 %	100 %	— %
Average number of drilling rigs in use	28.6	32.2	(11) %
Average dayrate on daywork contracts	$ 18,491	$ 17,330	7 %
Mid-Stream:			
Revenue	$ 44,294	$ 54,059	(18) %
Operating costs excluding depreciation and amortization	$ 32,491	$ 39,703	(18) %
Depreciation and amortization	$ 12,102	$ 11,175	8 %
Gas gathered—Mcf/day	465,714	391,047	19 %
Gas processed—Mcf/day	165,682	160,506	3 %
Gas liquids sold—gallons/day	711,192	676,503	5 %
Corporate and Other:			
General and administrative expense	$ 10,064	$ 8,712	16 %
Other depreciation	$ 1,935	$ 1,918	1 %
Gain on disposition of assets	$ 422	$ 161	162 %
Other income (expense):			
Interest income	$ 3	$ 411	(99) %
Interest expense, net	$ (8,998)	$ (8,140)	11 %
Gain (loss) on derivatives	$ 7,927	$ (14,461)	155 %
Other	$ 6	$ 5	20 %
Income tax (benefit) expense	$ (1,874)	$ 2,029	(192) %
Average long-term debt outstanding	$ 731,037	$ 646,760	13 %
Average interest rate	6.5 %	6.7 %	(3) %

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

Oil and Natural Gas

Oil and natural gas revenues decreased $24.5 million or 24% in the second quarter of 2019 as compared to the second quarter of 2018 primarily due to lower unhedged NGLs and natural gas prices and from lower NGLs and natural gas production volumes. In the second quarter of 2019, as compared to the second quarter of 2018, oil production increased 5%, natural gas production decreased 3%, and NGLs production decreased 2%. Including derivatives settled, average oil prices increased 6% to $59.94 per barrel, average natural gas prices decreased 15% to $1.86 per Mcf, and NGLs prices decreased 44% to $12.52 per barrel.

Oil and natural gas operating costs increased $3.8 million or 12% between the comparative second quarters of 2019 and 2018 primarily due to higher lease operating expenses (LOE) and salt water disposal expenses.

Depreciation, depletion, and amortization (DD&A) increased $7.2 million or 23% due primarily to a 25% increase in the DD&A rate partially offset by an 1% decrease in equivalent production. The increase in our DD&A rate in the second quarter of 2019 compared to the second quarter of 2018 resulted primarily from the cost of wells drilled in the last six months of 2018 and the first six months of 2019.

Contract Drilling

Drilling revenues decreased $3.9 million or 8% in the second quarter of 2019 versus the second quarter of 2018. The decrease was due primarily to an 11% decrease in the average number of drilling rigs in use partially offset by a 7% increase in the average dayrate. Average drilling rig utilization decreased from 32.2 drilling rigs in the second quarter of 2018 to 28.6 drilling rigs in the second quarter of 2019.

Drilling operating costs decreased $2.6 million or 8% between the comparative second quarters of 2019 and 2018. The decrease was due primarily to less drilling rigs operating. Contract drilling depreciation decreased $0.2 million or 2% in the second quarter of 2019 versus the second quarter of 2018 also due to less drilling rigs operating and the transfer of 41 drilling rigs to assets held for sale partially offset by accelerated depreciation on drilling rigs stacked more than 49 months.

Mid-Stream

Our mid-stream revenues decreased $9.8 million or 18% in the second quarter of 2019 as compared to the second quarter of 2018 due primarily to lower gas, NGLs, and condensate prices. Gas processed volumes per day increased 3% between the comparative quarters primarily due to additional wells connected mainly to our Cashion gathering system. Gas gathered volumes per day increased 19% between the comparative quarters due to connecting additional wells to our gathering and processing facilities primarily in Pennsylvania and Oklahoma.

Operating costs decreased $7.2 million or 18% in the second quarter of 2019 compared to the second quarter of 2018 primarily due to lower gas and purchase prices. Depreciation and amortization increased $0.9 million, or 8%, primarily due to new capital assets placed in service.

Gain on Disposition of Assets

There was a $0.4 million gain on disposition of assets in the second quarter of 2019 which was primarily related to assets held for sale that were sold which consisted of miscellaneous drilling rig components. For the second quarter of 2018, we had a gain of $0.2 million for the disposition of assets primarily due to the sale of drilling rig components and vehicles.

Other Income (Expense)

Interest expense, net of capitalized interest, increased $0.9 million between the comparative second quarters of 2019 and 2018 due primarily to a 13% increase in average long-term debt outstanding in the second quarter of 2019 partially offset by a lower average interest rate. We capitalized interest based on the net book value associated with undeveloped leasehold not being amortized, the construction of additional drilling rigs, and the construction of gas gathering systems. Capitalized interest for the second quarter of 2019 was $4.2 million compared to $4.3 million in the second quarter of 2018, and was netted against our gross interest of $13.2 million and $12.4 million for the second quarters of 2019 and 2018, respectively. Our average interest rate decreased from 6.7% in the second quarter of 2018 to 6.5% in the second quarter of 2019 and our average debt outstanding was $84.3 million higher in the second quarter of 2019 as compared to the second quarter of 2018 primarily due to additional capital expenditures over the last 12 months.

Gain (Loss) on Derivatives

Gain (loss) on derivatives increased by $22.4 million primarily due to fluctuations in forward prices used to estimate the fair value in mark-to-market accounting.

Income Tax (Benefit) Expense

Income tax expense went from an expense of $2.0 million to a benefit of $1.9 million between the comparative second quarters of 2019 and 2018 primarily due to decreased pre-tax income. Our effective tax rate was 18.9% for the second quarter of 2019 compared to 19.9% for the second quarter of 2018. The rate change was primarily due to decreased pre-tax income in relation to permanent tax differences. There was no current income tax expense or benefit in the second quarter of 2019 or 2018. We paid no income taxes in the second quarter of 2019.

Six Months Ended June 30, 2019 versus Six Months Ended June 30, 2018

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

	Six Months Ended June 30,		Percent Change [1]
	2019	2018	
	(In thousands unless otherwise specified)		
Total revenue	$ 354,837	$ 408,435	(13) %
Net income (loss)	$ (10,299)	$ 16,015	(164) %
Net income attributable to non-controlling interest	$ 1,714	$ 2,362	(27) %
Net income (loss) attributable to Unit Corporation	$ (12,013)	$ 13,653	(188) %
Oil and Natural Gas:			
Revenue	$ 163,910	$ 205,417	(20) %
Operating costs excluding depreciation, depletion, and amortization	$ 68,956	$ 68,380	1 %
Depreciation, depletion, and amortization	$ 74,518	$ 62,337	20 %
Average oil price received (Bbl)	$ 58.16	$ 55.76	4 %
Average NGLs price received (Bbl)	$ 14.11	$ 21.65	(35) %
Average natural gas price received (Mcf)	$ 2.18	$ 2.40	(9) %
Oil production (Bbl)	1,414,000	1,429,000	(1) %
NGLs production (Bbl)	2,417,000	2,425,000	— %
Natural gas production (Mcf)	26,659,000	27,237,000	(2) %
Depreciation, depletion, and amortization rate (Boe)	$ 8.64	$ 7.08	22 %
Contract Drilling:			
Revenue	$ 94,192	$ 92,915	1 %
Operating costs excluding depreciation	$ 60,709	$ 63,561	(4) %
Depreciation	$ 26,203	$ 27,038	(3) %
Percentage of revenue from daywork contracts	100 %	100 %	— %
Average number of drilling rigs in use	30.0	31.9	(6) %
Average dayrate on daywork contracts	$ 18,412	$ 17,184	7 %
Mid-Stream:			
Revenue	$ 96,735	$ 110,103	(12) %
Operating costs excluding depreciation and amortization	$ 71,846	$ 81,307	(12) %
Depreciation and amortization	$ 23,828	$ 22,228	7 %
Gas gathered—Mcf/day	457,859	382,005	20 %
Gas processed—Mcf/day	163,725	155,799	5 %
Gas liquids sold—gallons/day	681,070	627,305	9 %
Corporate and Other:			
General and administrative expense	$ 19,805	$ 19,474	2 %
Other depreciation	$ 3,869	$ 3,836	1 %
Gain (loss) on disposition of assets	$ (1,193)	$ 322	NM
Other income (expense):			
Interest income	$ 44	$ 411	(89) %
Interest expense, net	$ (17,577)	(18,144)	(3) %
Gain (loss) on derivatives	$ 995	$ (21,223)	NM
Other	$ 11	$ 11	— %
Income tax (benefit) expense	$ (2,318)	$ 5,636	(141) %
Average long-term debt outstanding	$ 710,494	$ 733,487	(3) %
Average interest rate	6.5 %	6.4 %	2 %

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

Oil and Natural Gas

Oil and natural gas revenues decreased $41.5 million or 20% in the first six months 2019 as compared to the first six months of 2018 primarily due to lower commodity prices and production volumes. In the first six months of 2019, as compared to the first six months of 2018, oil production decreased 1%, natural gas production decreased 2%, and NGLs production was essentially unchanged. Average oil prices increased 4% to $58.16 per barrel, average natural gas prices decreased 9% to $2.18 per Mcf, and NGLs prices decreased 35% to $14.11 per barrel.

Oil and natural gas operating costs increased $0.6 million or 1% between the comparative first six months of 2019 and 2018 due to higher saltwater disposal, general and administrative expenses, and gross production tax partially offset by lower LOE.

DD&A increased $12.2 million or 20% due primarily to a 22% increase in our DD&A rate partially offset by an 1% decrease in equivalent production. The increase in our DD&A rate in the first six months of 2019 compared to the first six months of 2018 resulted primarily from the cost of wells drilled in the last six months of 2018 and the first six months of 2019.

Contract Drilling

Drilling revenues increased $1.3 million or 1% in the first six months of 2019 versus the first six months of 2018. The increase was due primarily to a 7% increase in the average dayrate partially offset by a 6% decrease in the average number of drilling rigs in use. We also received $4.8 million in contract early termination fees during the first six months of 2019. Average drilling rig utilization decreased from 31.9 drilling rigs in the first six months of 2018 to 30.0 drilling rigs in the first six months of 2019.

Drilling operating costs decreased $2.9 million or 4% between the comparative first six months of 2019 and 2018. The decrease was due primarily to less drilling rigs operating. Contract drilling depreciation decreased $0.8 million or 3% between the comparative first six months of 2019 and 2018. The decrease was also due to less drilling rigs operating and the transfer of 41 drilling rigs to assets held for sale partially offset by accelerated depreciation on drilling rigs stacked more than 49 months.

Mid-Stream

Our mid-stream revenues decreased $13.4 million or 12% in the first six months of 2019 as compared to the first six months of 2018 due due primarily to lower gas, NGLs, and condensate prices. Gas processed volumes per day increased 5% between the comparative periods primarily due to connecting new wells at the Cashion processing facilities. Gas gathered volumes per day increased 20% between the comparative periods primarily due to connecting new wells at our Cashion and Pittsburgh Mills facilities.

Operating costs decreased $9.5 million or 12% in the first six months of 2019 compared to the first six months of 2018 primarily due lower purchase prices. Depreciation and amortization increased $1.6 million, or 7%, primarily due to new capital assets placed into service.

General and Administrative

Corporate general and administrative expenses increased $0.3 million or 2% in the first six months of 2019 compared to the first six months of 2018 primarily due to higher employee costs and computer network costs.

Gain (Loss) on Disposition of Assets

There was an $1.2 million loss on disposition of assets in the first six months of 2019. Of this amount, $0.2 million was related to assets held for sale that were sold which consisted of three drilling rigs and other drilling components. The other $1.0 million was related to the sales of other drilling rig components and vehicles. For the first six months of 2018, we had a gain of $0.3 million for the disposition of assets primarily due to the sale of drilling rig components and vehicles.

Other Income (Expense)

Interest expense, net of capitalized interest, decreased $0.6 million between the comparative first six months of 2019 and 2018 due primarily to a 3% decrease in the average long-term debt outstanding and an increase in interest capitalized partially offset by a higher average interest rate. We capitalized interest based on the net book value associated with undeveloped leasehold not being amortized, the construction of additional drilling rigs, and the construction of gas gathering systems.

Capitalized interest for the first six months of 2019 was $8.4 million compared to $7.9 million in the first six months of 2018, and was netted against our gross interest of $26.0 million and $26.1 million for the first six months of 2019 and 2018, respectively. Our average interest rate increased from 6.4% to 6.5% and our average debt outstanding was $23.0 million lower in the first six months of 2019 as compared to the first six months of 2018 primarily due to the pay down of our Unit credit agreement in the second quarter of 2018.

Gain (Loss) on Derivatives

Gain (loss) on derivatives increased $22.2 million primarily due to fluctuations in forward prices used to estimate the fair value in mark-to-market accounting.

Income Tax (Benefit) Expense

Income tax expense went from an expense of $5.6 million to a benefit of $2.3 million between the comparative first six months of 2019 and 2018 primarily due to decreased pre-tax income. Our effective tax rate was 18.4% for the first six months of 2019 compared to 26.0% for the first six months of 2018. The decrease was again primarily due to decreased pre-tax income in relation to permanent tax differences. There was no current income tax expense or benefit in the first six months of 2019 or 2018. We paid no income taxes in the first six months of 2019.

Safe Harbor Statement

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

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

- the amount and nature of our future capital expenditures and how we expect to fund our capital expenditures;
- prices for oil, NGLs, and natural gas;
- demand for oil, NGLs, and natural gas;
- our exploration and drilling prospects;
- the estimates of our proved oil, NGLs, and natural gas reserves;
- oil, NGLs, and natural gas reserve potential;
- development and infill drilling potential;
- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- our plans to maintain or increase production of oil, NGLs, and natural gas;
- the number of gathering systems and processing plants we plan to construct or acquire;
- volumes and prices for natural gas gathered and processed;
- expansion and growth of our business and operations;
- demand for our drilling rigs and drilling rig rates;
- our belief that the final outcome of legal proceedings involving us will not materially affect our financial results;
- our ability to timely secure third-party services used in completing our wells;
- our ability to transport or convey our oil or natural gas production to established pipeline systems;
- impact of federal and state legislative and regulatory initiatives relating to hydrocarbon fracturing impacting our costs and increasing operating restrictions or delays as well as other adverse impacts on our business;

- our projected production guidelines for the year;
- our anticipated capital budgets;
- our financial condition and liquidity (including our ability to refinance our senior subordinated notes);
- the number of wells our oil and natural gas segment plans to drill or rework during the year; and
- our estimates of the amounts of any ceiling test write-downs or other potential asset impairments we may have to record in future periods.

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

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

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

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

Item 3. Quantitative and Qualitative Disclosure About Market Risk

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

Commodity Price Risk. Our major market risk exposure is in the prices we receive for our oil, NGLs, and natural gas production. These prices are primarily driven by the prevailing worldwide price for crude oil and market prices applicable to our NGLs and natural gas production. Historically, these prices have fluctuated and we expect this to continue. The prices for oil, NGLs, and natural gas also affect the demand for our drilling rigs and the amount we can charge for the use of our drilling rigs. Based on our first six months 2019 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 $427,000 per month ($5.1 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 $224,000 per month ($2.7 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 $386,000 per month ($4.6 million annualized) change in our pre-tax operating cash flow.

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

At June 30, 2019, these derivatives were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Jul'19 – Oct'19	Natural gas – swap	60,000 MMBtu/day	$2.900	IF – NYMEX (HH)
Nov'19 – Dec'19	Natural gas – swap	40,000 MMBtu/day	$2.900	IF – NYMEX (HH)
Jul'19 – Dec'19	Natural gas – basis swap	20,000 MMBtu/day	$(0.659)	PEPL
Jul'19 – Dec'19	Natural gas – basis swap	10,000 MMBtu/day	$(0.625)	NGL MIDCON
Jul'19 – Dec'19	Natural gas – basis swap	30,000 MMBtu/day	$(0.265)	NGPL TEXOK
Jan'20 – Dec'20	Natural gas – basis swap	30,000 MMBtu/day	$(0.275)	NGPL TEXOK
Jul'19 – Dec'19	Natural gas – collar	20,000 MMBtu/day	$2.63 - $3.03	IF – NYMEX (HH)
Jul'19 – Dec'19	Crude oil – three-way collar	4,000 Bbl/day	$61.25 - $51.25 - $72.93	WTI – NYMEX

Interest Rate Risk. Our interest rate exposure relates to our long-term debt under our credit agreements 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 agreements 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 six months of 2019, a 1% increase in the floating rate would reduce our annual pre-tax cash flow by approximately $0.6 million. Under our Notes, we pay a fixed rate of interest of 6.625% per year (payable semi-annually in arrears on May 15 and November 15 of each year).

Item 4. Controls and Procedures

Our management, including our Chief Executive Officer (CEO) and Chief Financial Officer (CFO), does not expect that our disclosure controls and procedures (as defined in Rules 13a - 15(e) and 15d - 15(e) of the Securities Exchange Act of 1934, as amended (the Exchange Act)) (Disclosure Controls) will prevent or detect all errors and all fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of a simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls also is based in part on certain assumptions about the likelihood of future events, and there is no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to an error or fraud may occur and not be detected. We monitor our Disclosure Controls and ICFR and make modifications as necessary; our intent in this regard is that the Disclosure Controls and ICFR will be modified as systems change, and conditions warrant.

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 CEO and CFO, 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 CEO and CFO concluded that our disclosure controls and procedures are effective as of June 30, 2019 at a reasonable assurance level.

Changes in Internal Controls. There were no changes in our ICFR during the quarter ended June 30, 2019, 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. On July 29, 2019, the trial court entered its order denying the Plaintiffs' amended motion for class certification. Once the trial court's order is appealable, the Plaintiffs' will have 30 days to appeal the decision.

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.

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, 2018, which could materially affect our business, financial condition, or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing our company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition, and/or operating results.

Except as set forth below, there have been no material changes to the risk factors disclosed in Item 1A in our Form 10-K for the year ended December 31, 2018.

Changes in the method of determining LIBOR, or the replacement of LIBOR with an alternative reference rate, may adversely affect our indebtedness.

Our variable rate debt under both the Unit credit agreement and the Superior credit agreement is tied to LIBOR. On July 27, 2017, the Financial Conduct Authority announced that it would phase out LIBOR as a benchmark by the end of 2021. It is unclear whether new methods of calculating LIBOR will be established such that it continues to exist after 2021. There is no guarantee that a transition from LIBOR to an alternative will not result in financial market disruptions, significant increases in benchmark rates or borrowing costs to borrowers, any of which could have an adverse effect on our business, financial condition and results of operations.

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

The following table provides information relating to our repurchase of common stock for the three months ended June 30, 2019:

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
April 1, 2019 to April 30, 2019	—	$ —	—	—
May 1, 2019 to May 31, 2019	577	11.76	577	—
June 1, 2019 to June 30, 2019	—	—	—	—
Total	577	$ 11.76	577	—

1. The shares were repurchased to remit withholding of taxes on the value of stock distributed with the second quarter 2019 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

Not applicable.

Item 6. Exhibits

Exhibits:

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

*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.

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:	August 6, 2019	By: /s/ Larry D. Pinkston LARRY D. PINKSTON Chief Executive Officer and Director
Date:	August 6, 2019	By: /s/ Les Austin LES AUSTIN Senior Vice President and Chief Financial Officer

Exhibit 31.1
302 CERTIFICATIONS

I, Larry D. Pinkston, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: August 6, 2019

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

<u>Exhibit 31.2</u>
302 CERTIFICATIONS

I, Les Austin, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: August 6, 2019

<u>/s/ Les Austin</u>
LES AUSTIN
Senior Vice President and Chief Financial Officer

Exhibit 32

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

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

The Quarterly Report on Form 10-Q for the quarter ended June 30, 2019 (the "Form 10-Q") of the Company fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 and information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of the Company as of June 30, 2019 and December 31, 2018 and for the three and six month periods ended June 30, 2019 and 2018.

Dated: August 6, 2019

By: /s/ Larry D. Pinkston
Larry D. Pinkston
Chief Executive Officer and Director

Dated: August 6, 2019

By: /s/ Les Austin
Les Austin
Senior Vice President and Chief Financial Officer

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

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