

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2015

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

(State or other jurisdiction of incorporation)

73-1283193

(I.R.S. Employer Identification No.)

7130 South Lewis, Suite 1000, Tulsa, Oklahoma

(Address of principal executive offices)

74136

(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 ☒ No ☐

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

Yes ☒ No ☐

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

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ☐ No ☒

As of July 24, 2015, 50,414,951 shares of the issuer's common stock were outstanding.

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Forward-Looking Statements

This report contains “forward-looking statements” – meaning, statements related to future events within the meaning of Section 27A of the Securities Act of 1933, as amended and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included or incorporated by reference in this document that addresses activities, events or developments we expect or anticipate will or may occur in the future, 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 in the future will automatically update and supersede information in this report.

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

- the amount and nature of our future capital expenditures and how we expect to fund our capital expenditures;
- the amount of wells we plan to drill or rework;
- 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 our legal proceedings 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;
- the number of wells our oil and natural gas segment plans to drill during the year; and
- our estimates of the amounts of any ceiling test write-downs we may be required to record in future periods.

These statements are based on certain assumptions and analyses made by us in light of 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;
- decreases or increases in commodity prices; and
- other factors, most of which are beyond our control.

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

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	June 30, 2015	December 31, 2014
	(In thousands except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 839	\$ 1,049
Accounts receivable, net of allowance for doubtful accounts of \$4,008 and \$5,039 at June 30, 2015 and at December 31, 2014, respectively	108,109	189,812
Materials and supplies	7,956	5,590
Current derivative asset (Note 10)	14,587	31,139
Current income taxes receivable	1,364	—
Current deferred tax asset	11,527	11,527
Assets held for sale (Note 3)	12,649	—
Prepaid expenses and other	9,503	13,374
Total current assets	166,534	252,491
Property and equipment:		
Oil and natural gas properties on the full cost method:		
Proved properties	5,173,365	4,990,753
Unproved properties not being amortized	460,963	485,568
Drilling equipment	1,667,614	1,620,692
Gas gathering and processing equipment	650,679	628,689
Saltwater disposal systems	60,239	56,702
Transportation equipment	40,568	40,693
Other	75,799	57,706
	8,129,227	7,880,803
Less accumulated depreciation, depletion, amortization, and impairment	4,752,931	3,747,412
Net property and equipment	3,376,296	4,133,391
Debt issuance cost	9,461	10,255
Goodwill	62,808	62,808
Non-current derivative asset (Note 10)	137	—
Other assets	14,757	14,783
Total assets	\$ 3,629,993	\$ 4,473,728

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, 2015	December 31, 2014
	(In thousands except share amounts)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	\$ 105,309	\$ 218,500
Accrued liabilities (Note 5)	55,700	70,171
Income taxes payable	—	481
Current portion of other long-term liabilities (Note 6)	16,891	15,019
Total current liabilities	177,900	304,171
Long-term debt (Note 6)	926,908	812,163
Other long-term liabilities (Note 6)	141,153	148,785
Deferred income taxes	560,432	876,215
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, 50,423,251 and 49,593,812 shares issued as of June 30, 2015 and December 31, 2014, respectively	9,831	9,732
Capital in excess of par value	481,973	468,123
Retained earnings	1,331,796	1,854,539
Total shareholders' equity	1,823,600	2,332,394
Total liabilities and shareholders' equity	\$ 3,629,993	\$ 4,473,728

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,	
	2015	2014	2015	2014
(In thousands except per share amounts)				
Revenues:				
Oil and natural gas	\$ 107,256	\$ 198,498	\$ 213,325	\$ 386,705
Contract drilling	55,015	114,278	150,092	220,878
Gas gathering and processing	52,176	92,655	106,129	185,836
Total revenues	214,447	405,431	469,546	793,419
Expenses:				
Oil and natural gas:				
Operating costs	45,972	44,723	91,183	85,138
Depreciation, depletion, and amortization	68,101	71,245	145,219	130,925
Impairment of oil and natural gas properties (Note 2)	410,536	—	811,129	—
Contract drilling:				
Operating costs	36,485	66,494	88,231	130,298
Depreciation	13,265	20,239	28,278	38,634
Impairment of contract drilling equipment (Note 3)	8,314	—	8,314	—
Gas gathering and processing:				
Operating costs	40,592	78,648	84,767	159,608
Depreciation and amortization	10,848	10,109	21,542	19,700
General and administrative	9,624	10,600	18,994	20,237
Gain on disposition of assets	(415)	(195)	(960)	(9,621)
Total operating expenses	643,322	301,863	1,296,697	574,919
Income (loss) from operations	(428,875)	103,568	(827,151)	218,500
Other income (expense):				
Interest, net	(7,956)	(4,131)	(15,196)	(7,921)
Gain (loss) on derivatives not designated as hedges	(1,919)	(10,709)	4,667	(29,075)
Other	24	(49)	22	71
Total other expense	(9,851)	(14,889)	(10,507)	(36,925)
Income (loss) before income taxes	(438,726)	88,679	(837,658)	181,575
Income tax expense (benefit):				
Current	803	8,475	868	18,270
Deferred	(165,140)	25,844	(315,783)	52,000
Total income taxes	(164,337)	34,319	(314,915)	70,270
Net income (loss)	\$ (274,389)	\$ 54,360	\$ (522,743)	\$ 111,305
Net income (loss) per common share:				
Basic	\$ (5.58)	\$ 1.12	\$ (10.66)	\$ 2.29
Diluted	\$ (5.58)	\$ 1.11	\$ (10.66)	\$ 2.27

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,	
	2015	2014
	(In thousands)	
OPERATING ACTIVITIES:		
Net income (loss)	\$ (522,743)	\$ 111,305
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, and amortization	196,576	190,813
Impairments (Notes 2 and 3)	819,443	—
(Gain) loss on derivatives	(4,667)	29,075
Cash (payments) receipts on derivatives settled	21,082	(17,955)
Deferred tax expense (benefit)	(315,783)	52,000
Gain on disposition of assets	(960)	(9,621)
Employee stock compensation plans	12,329	11,655
Other, net	1,944	3,076
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	77,894	(45,150)
Accounts payable	(16,327)	(11,585)
Material and supplies	(2,366)	2,458
Accrued liabilities	(11,811)	7,440
Other, net	2,995	2,017
Net cash provided by operating activities	257,606	325,528
INVESTING ACTIVITIES:		
Capital expenditures	(371,572)	(420,235)
Proceeds from disposition of assets	5,130	40,825
Other	—	303
Net cash used in investing activities	(366,442)	(379,107)
FINANCING ACTIVITIES:		
Borrowings under credit agreement	396,000	129,300
Payments under credit agreement	(281,500)	(129,300)
Payments on capitalized leases	(1,757)	(711)
Proceeds from exercise of stock options	4	887
Book overdrafts	(4,121)	35,888
Net cash provided by financing activities	108,626	36,064
Net decrease in cash and cash equivalents	(210)	(17,515)
Cash and cash equivalents, beginning of period	1,049	18,593
Cash and cash equivalents, end of period	\$ 839	\$ 1,078
Supplemental disclosure of cash flow information:		
Cash paid during the year for:		
Interest paid (net of capitalized)	15,886	6,223
Income taxes	3,142	15,800
Changes in accounts payable and accrued liabilities related to purchases of property, plant, and equipment	92,743	(29,247)
Non-cash reductions to oil and natural gas properties related to asset retirement obligations	5,956	15,432
Non-cash additions to property, plant, and equipment acquired under capital leases	—	(26,510)

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

The accompanying 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 24, 2015, for the year ended December 31, 2014.

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

- Balance Sheets at June 30, 2015 and December 31, 2014;
- Statements of Operations for the three and six months ended June 30, 2015 and 2014; and
- Statements of Cash Flows for the six months ended June 30, 2015 and 2014.

Our financial statements are prepared in conformity with generally accepted accounting principles in the United States (GAAP). GAAP requires us to make certain estimates and assumptions that may affect the amounts reported in our unaudited condensed consolidated financial statements and accompanying notes. Actual results may differ from those estimates. Results for the six months ended June 30, 2015 and 2014 are not necessarily indicative of the results to be realized for the full year of 2015, or that we realized for the full year of 2014.

Certain amounts in the accompanying unaudited condensed consolidated financial statements for prior periods have been reclassified to conform to current year presentation. Certain financial statement captions were expanded or combined with no impact to consolidated net income (loss) or shareholders' equity.

Regarding the unaudited financial information for the three and six month periods ended June 30, 2015 and 2014, our auditors, PricewaterhouseCoopers LLP, reported that it applied limited procedures under professional standards in reviewing that information. Its separate report dated August 4, 2015, which is included in this report, states it did not audit and it expresses no opinion on that unaudited financial information. The reliance placed on its report should be restricted in light of the limited review procedures applied. PricewaterhouseCoopers LLP is not subject to the liability provisions of Section 11 of the Securities Act of 1933 (Act) for its report on the unaudited financial information because that report is not a “report” or a “part” of a registration statement prepared or certified by PricewaterhouseCoopers LLP within the meaning of Sections 7 and 11 of the Act.

NOTE 2 – OIL AND NATURAL GAS PROPERTIES

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

During the first quarter of 2015, the 12-month average commodity prices decreased significantly, resulting in a non-cash ceiling test write-down of \$400.6 million pre-tax (\$249.4 million, net of tax).

During the second quarter of 2015, the 12-month average commodity prices decreased further, resulting in a non-cash ceiling test write-down of \$410.5 million pre-tax (\$255.6 million, net of tax).

NOTE 3 – DIVESTITURES

We sold non-core oil and natural gas assets, net of related expenses, for less than \$0.1 million during the first six months of 2015, compared to \$11.3 million during the first six months of 2014. Proceeds from those sales reduced the net book value of our full cost pool with no gain or loss recognized.

In December 2014, we removed from service 31 drilling rigs, some older top drives, and certain drill pipe no longer marketable under the current environment and based on estimated market value from third party assessments (Level 3 fair value measurement), we recorded a write-down of approximately \$74.3 million pre-tax. During the first quarter of 2015, we sold one of these drilling rigs to an unaffiliated third party. The proceeds of this sale, less costs to sell, exceeded the \$0.3 million net book value of the drilling rig resulting in a gain of \$7,900. During the second quarter we decided to place the remaining 30 drilling rigs and most of the equipment for sale in an auction to be held during the third quarter. Any equipment not sold at the auction will be sold within the next twelve months. As a result, these assets have been classified as assets held for sale. Since December, the estimated fair value of the drilling rigs and other assets has declined based on the estimated market value from similar auctions. Based on these estimates, we recorded an additional write-down of approximately \$8.3 million pre-tax during the second quarter. The proceeds from the sale of these assets, less costs to sell, is expected to be approximately \$12.6 million.

During the first quarter of 2014, we sold four idle 3,000 horsepower drilling rigs to an unaffiliated third-party. The proceeds of this sale, less costs to sell, exceeded the \$16.3 million net book value of the drilling rigs, both in the aggregate and for each drilling rig, resulting in a gain of \$9.6 million.

NOTE 4 – EARNINGS PER SHARE

Information related to the calculation of earnings per share follows:

	Income (Loss) (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
(In thousands except per share amounts)			
For the three months ended June 30, 2015			
Basic earnings (loss) per common share	\$ (274,389)	49,148	\$ (5.58)
Effect of dilutive stock options, restricted stock, and stock appreciation rights (SARs)	—	—	—
Diluted earnings (loss) per common share	\$ (274,389)	49,148	\$ (5.58)
For the three months ended June 30, 2014			
Basic earnings per common share	\$ 54,360	48,642	\$ 1.12
Effect of dilutive stock options, restricted stock, and SARs	—	474	(0.01)
Diluted earnings per common share	\$ 54,360	49,116	\$ 1.11

Due to the net loss for the three months ended June 30, 2015, approximately 307,000 weighted average shares related to stock options, restricted stock, and SARs were antidilutive and were excluded from the earnings per share calculation above.

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

	Three Months Ended June 30,	
	2015	2014
Stock options and SARs	259,085	24,500
Average exercise price	\$ 50.50	\$ 73.26

	Income (Loss) (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
(In thousands except per share amounts)			
For the six months ended June 30, 2015			
Basic earnings (loss) per common share	\$ (522,743)	49,063	\$ (10.66)
Effect of dilutive stock options, restricted stock, and SARs	—	—	—
Diluted earnings (loss) per common share	\$ (522,743)	49,063	\$ (10.66)
For the six months ended June 30, 2014			
Basic earnings per common share	\$ 111,305	48,568	\$ 2.29
Effect of dilutive stock options, restricted stock, and SARs	—	442	(0.02)
Diluted earnings per common share	\$ 111,305	49,010	\$ 2.27

Due to the net loss for the six months ended June 30, 2015, approximately 206,000 weighted average shares related to stock options, restricted stock, and SARs were antidilutive and were excluded from the earnings per share calculation above.

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

	Six Months Ended June 30,	
	2015	2014
Stock options and SARs	261,270	49,000
Average exercise price	\$ 50.34	\$ 67.83

NOTE 5 – ACCRUED LIABILITIES

Accrued liabilities consisted of the following:

	June 30, 2015	December 31, 2014
(In thousands)		
Lease operating expenses	\$ 20,257	\$ 20,709
Employee costs	10,854	31,451
Taxes	9,134	3,284
Interest	6,560	6,654
Third-party credits	4,040	2,825
Other	4,855	5,248
Total accrued liabilities	\$ 55,700	\$ 70,171

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

Long-Term Debt

As of the dates in the table, our long-term debt consisted of the following:

	June 30, 2015	December 31, 2014
	(In thousands)	
Credit agreement with an average interest rate of 2.2% and 2.9% at June 30, 2015 and December 31, 2014, respectively	\$ 280,500	\$ 166,000
6.625% senior subordinated notes due 2021, net of unamortized discount of \$3.6 million and \$3.8 million at June 30, 2015 and December 31, 2014, respectively	646,408	646,163
Total long-term debt	\$ 926,908	\$ 812,163

Credit Agreement. On April 10, 2015, we amended our Senior Credit Agreement (credit agreement) previously scheduled to mature on September 13, 2016. The amended credit agreement has a maturity date of April 10, 2020. The amount we can borrow is the lesser of the amount we elect (from time to time) as the commitment amount or the value of the borrowing base as determined by the lenders (currently \$725.0 million), but in either event not to exceed the maximum credit agreement amount of \$900.0 million. Our current elected commitment amount is \$500.0 million. We are charged a commitment fee ranging from 0.375 to 0.50 of 1% on the amount available but not borrowed. The fee varies based on the amount borrowed as a percentage of the amount of the total borrowing base. To date, for this new amendment, we paid \$2.6 million in origination, agency, syndication, and other related fees. We are amortizing these fees over the life of the 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 primarily on a percentage of the discounted future value of our oil and natural gas reserves. We or the lenders may request a onetime special redetermination of the borrowing base between each scheduled redetermination. In addition, we may request a redetermination following the completion of an acquisition that meets the requirements in the credit agreement.

At our election, any part of the outstanding debt under the credit agreement may be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest is computed as the sum of the LIBOR base for the applicable term plus 1.75% 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 credit agreement that cannot be less than LIBOR plus 1.00%. Interest is payable at the end of each month and the principal may be repaid in whole or in part at any time, without a premium or penalty. At June 30, 2015, the outstanding borrowings under the credit agreement were \$280.5 million.

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

The credit agreement prohibits, among other things:

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

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

- a current ratio (as defined in the credit agreement) of not less than 1 to 1; and
- a leverage ratio of funded debt to consolidated EBITDA (as defined in the credit agreement) for the most recently ended rolling four fiscal quarters of no greater than 4 to 1.

As of June 30, 2015, we were in compliance with the covenants in the credit agreement.

6.625% Senior Subordinated Notes. We have an aggregate principal amount of \$650.0 million, 6.625% senior subordinated notes (the Notes). Interest on the Notes is payable semi-annually (in arrears) on May 15 and November 15 of each year. The Notes will mature on May 15, 2021. We incurred in connection with the issuance of the Notes \$14.7 million of fees 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 and providing for issuing the Notes. The Guarantors are all of our direct and indirect subsidiaries. The discussion of the Notes in this report is qualified by and subject to the actual terms of the 2011 Indenture.

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

Before May 15, 2016, we may redeem the Notes, in whole or in part, at a redemption price equal to 100% of the principal amount plus a “make whole” premium, plus accrued and unpaid interest, if any, to the redemption date. On and after May 15, 2016, we may redeem all or, from time to time, a part of the Notes at certain redemption prices, plus accrued and unpaid interest. If a “change of control” occurs, subject to certain conditions, we must offer to repurchase from each holder all or any part of that holder’s Notes at a purchase price in cash equal to 101% of the principal amount of the Notes plus accrued and unpaid interest, if any, to the date of purchase. The 2011 Indenture contains customary events of default. The 2011 Indenture also contains covenants that, among other things, 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, 2015.

Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	June 30, 2015	December 31, 2014
	(In thousands)	
Asset retirement obligation (ARO) liability	\$ 96,368	\$ 100,567
Capital lease obligations	24,188	25,876
Workers’ compensation	17,681	17,997
Separation benefit plans	11,368	11,276
Deferred compensation plan	4,406	4,055
Gas balancing liability	3,623	3,623
Other	410	410
	158,044	163,804
Less current portion	16,891	15,019
Total other long-term liabilities	\$ 141,153	\$ 148,785

Estimated annual principal payments under the terms of debt and other long-term liabilities during each of the five successive twelve month periods beginning July 1, 2015 (and through 2020) are \$16.9 million, \$39.0 million, \$9.1 million, \$8.3 million, and \$288.9 million, respectively.

Capital Leases

During 2014, our mid-stream segment entered into capital lease agreements for twenty compressors with initial terms of seven years. The underlying assets are included in gas gathering and processing equipment. The current \$3.5 million portion of our capital lease obligations is included in current portion of other long-term liabilities and the non-current portion of \$20.7 million is included in other long-term liabilities in the accompanying Unaudited Condensed Consolidated Balance Sheets as of June 30, 2015. These capital leases are discounted using annual rates of 4.00%. Total maintenance and interest remaining at June 30, 2015 related to these leases are \$10.5 million and \$3.2 million, respectively. Annual payments, net of maintenance and interest, average \$3.9 million annually through 2021. At the end of the term, our mid-stream segment has the option to purchase the assets at 10% of the fair market value of the assets at that time.

Future payments required under the capital leases at June 30, 2015:

	Amount
Ending June 30,	(In thousands)
2016	\$ 6,195
2017	6,195
2018	6,195
2019	6,195
2020	6,195
2021 and thereafter	6,869
Total future payments	37,844
Less payments related to:	
Maintenance	10,489
Interest	3,167
Present value of future minimum payments	\$ 24,188

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 of our AROs relate to the plugging costs associated with our oil and gas wells.

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

	Six Months Ended	
	June 30,	
	2015	2014
	(In thousands)	
ARO liability, January 1:	\$ 100,567	\$ 133,657
Accretion of discount	1,757	2,366
Liability incurred	5,986	1,900
Liability settled	(1,566)	(1,917)
Liability sold	(246)	(877)
Revision of estimates ⁽¹⁾	(10,130)	(14,538)
ARO liability, June 30:	96,368	120,591
Less current portion	3,277	3,118
Total long-term ARO	\$ 93,091	\$ 117,473

(1) Plugging liability estimates were revised in both 2015 and 2014 to account for changes 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

Interest—Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs. The FASB has issued ASU 2015-03. The amendments in this ASU require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. For public business entities, the amendments are effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. Early adoption of the amendments is permitted for financial statements that have not been previously issued. The amendments should be applied on a retrospective basis, wherein the balance sheet of each individual period presented should be adjusted to reflect the period-specific effects of applying the new guidance. We are in the process of evaluating the impact it will have on our financial statements.

Revenue from Contracts with Customers. The FASB has issued ASU 2014-09. This affects any entity using U.S. GAAP that either enters into contracts with customers to transfer goods or services or enters into contracts for the transfer of nonfinancial assets unless those contracts are within the scope of other standards (e.g., insurance contracts or lease contracts). The core principle of the guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The FASB has deferred the effective date by one year to December 15, 2017 for annual reporting periods beginning after that date. Early adoption is not permitted. We are in the process of evaluating the impact it will have on our financial statements.

NOTE 9 – STOCK-BASED COMPENSATION

For restricted stock awards and stock options, we had:

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2015	2014	2015	2014
	(In millions)			
Recognized stock compensation expense	\$ 4.8	\$ 4.5	\$ 9.1	\$ 8.3
Capitalized stock compensation cost for our oil and natural gas properties	1.0	1.0	1.9	1.8
Tax benefit on stock based compensation	1.7	1.7	3.4	3.2

The remaining unrecognized compensation cost related to unvested awards at June 30, 2015 is approximately \$30.4 million, of which \$4.8 million is anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 0.9 of a year.

The Second Amended and Restated Unit Corporation Stock and Incentive Compensation Plan effective May 6, 2015 (the amended plan) allows us to grant stock-based and cash-based compensation to our employees (including employees of subsidiaries) as well as to non-employee directors. As of the date of this report, a total of 4,500,000 shares of the company's common stock was authorized for issuance to eligible participants under the amended plan.

We did not grant any SARs or stock options during either of the three or six month periods ending June 30, 2015 and 2014. The following table shows the fair value of restricted stock awards granted to employees and non-employee directors during the periods indicated:

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2015	2014	2015	2014
Shares granted:				
Employees	—	—	724,442	438,342
Non employee directors	25,848	13,768	25,848	13,768
	25,848	13,768	750,290	452,110
Estimated fair value (in millions):				
Employees	\$ —	\$ —	\$ 23.6	\$ 22.4
Non employee directors	0.9	0.9	0.9	0.9
	\$ 0.9	\$ 0.9	\$ 24.5	\$ 23.3
Percentage of shares granted expected to be distributed:				
Employees	N/A	N/A	96%	95%
Non employee directors	100%	100%	100%	100%

The restricted stock awards granted during the first three and six months of 2015 and 2014 are being recognized over a three year vesting period, except for a portion of those awards made to certain executive officers. As to those executive officers, 50% of the shares granted, or 148,081 shares in 2015 and 40% of the share granted, or 71,674 shares in 2014, (the performance shares), will cliff vest in the first half of 2018 and 2017, respectively. The actual number of performance shares that vest in 2017 and 2018 will be based on the company's achievement of certain stock performance measures at the end of the term, and will range from 0% to 150% of the restricted shares granted as performance shares. Based on the selected performance criteria, the participants are estimated to receive the targeted amount (or approximately 100%) of the 2015 and 2014 performance based shares. The total aggregate stock compensation expense and capitalized cost related to oil and natural gas properties for 2015 awards for the first six months of 2015 was \$4.4 million.

NOTE 10 – DERIVATIVES

Commodity Derivatives

We have entered into various types of derivative transactions covering some of our projected natural gas and oil production. These transactions are intended to reduce our exposure to market price volatility by setting the price(s) we will receive for that production. Our decisions on the price(s), type, and quantity of our production subject to a derivative contract are based, in part, on our view of current and future market conditions. As of June 30, 2015, our derivative transactions comprised the following hedges:

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

We have documented policies and procedures to monitor and control the use of derivative transactions. We do not engage in derivative transactions for speculative purposes. The change in fair value on all commodity derivatives is reflected in the statement of operations and not in accumulated other comprehensive income (OCI).

At June 30, 2015, the following non-designated hedges were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Jul'15 – Dec'15	Crude oil – swap	1,000 Bbl/day	\$95.00	WTI – NYMEX
Jul'15 – Dec'15	Crude oil – collar	2,000 Bbl/day	\$58.00-\$64.40	WTI – NYMEX
Jul'15 – Dec'15	Natural gas – swap	40,000 MMBtu/day	\$3.98	NYMEX (HH)
Jul'15 – Sep'15	Natural gas – collar	30,000 MMBtu/day	\$2.58-\$3.04	NYMEX (HH)
Jan'16 - Dec'16	Natural gas – swap	10,000 MMBtu/day	\$3.25	NYMEX (HH)

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	
		June 30, 2015	December 31, 2014
Balance Sheet Location		(In thousands)	
Commodity derivatives:			
Current	Current derivative asset	\$ 14,587	\$ 31,139
Long-term	Non-current derivative asset	137	—
Total derivative assets		\$ 14,724	\$ 31,139

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.

For our economic hedges any changes in fair value occurring before maturity (i.e., temporary fluctuations in value) are reported in gain (loss) on derivatives not designated as hedges in our Unaudited Condensed Consolidated Statements of Operations.

Effect of derivative instruments on the Unaudited Condensed Consolidated Statements of Operations (derivatives not designated as hedging instruments) for the three months ended June 30:

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain or (Loss) Recognized in Income on Derivative	
		2015	2014
(In thousands)			
Commodity derivatives	Loss on derivatives not designated as hedges ⁽¹⁾	\$ (1,919)	\$ (10,709)
Total		\$ (1,919)	\$ (10,709)

(1) Amounts settled during the 2015 and 2014 periods include a gain of \$10.1 million and a loss of \$9.1 million, respectively.

Effect of derivative instruments on the Unaudited Condensed Consolidated Statements of Operations (derivatives not designated as hedging instruments) for the six months ended June 30:

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain or (Loss) Recognized in Income on Derivative	
		2015	2014
		(In thousands)	
Commodity derivatives	Gain (loss) on derivatives not designated as hedges ⁽¹⁾	\$ 4,667	\$ (29,075)
Total		\$ 4,667	\$ (29,075)

(1) Amounts settled during the 2015 and 2014 periods include a gain of \$21.1 million and a loss of \$18.0 million, respectively.

NOTE 11 – FAIR VALUE MEASUREMENTS

Fair value is defined as the amount 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. The highest priority is given to Level 1 and the lowest priority is 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. Inputs (variables used in the pricing models) that are derived principally from or corroborated by observable market data.
- Level 3 - 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. We corroborate these inputs based on recent transactions and broker quotes and compare the fair value with actual settlements.

The following tables set forth our recurring fair value measurements:

June 30, 2015					
	Level 2	Level 3	Gross Amounts	Effect of Netting	Net Amounts Presented
(In thousands)					
Financial assets (liabilities):					
Commodity derivatives:					
Assets	\$ 14,517	\$ 273	\$ 14,790	\$ (66)	\$ 14,724
Liabilities	—	(66)	(66)	66	—
	<u>\$ 14,517</u>	<u>\$ 207</u>	<u>\$ 14,724</u>	<u>\$ —</u>	<u>\$ 14,724</u>
December 31, 2014					
	Level 2	Level 3	Gross Amounts	Effect of Netting	Net Amounts Presented
(In thousands)					
Financial assets (liabilities):					
Commodity derivatives:					
Assets	\$ 27,784	\$ 3,355	\$ 31,139	\$ —	\$ 31,139
Liabilities	—	—	—	—	—
	<u>\$ 27,784</u>	<u>\$ 3,355</u>	<u>\$ 31,139</u>	<u>\$ —</u>	<u>\$ 31,139</u>

All of our counterparties are subject to master netting arrangements. If a legal right of set-off exists, we net the value of the derivative transactions we have with the same counterparty. We are not required to post cash collateral with our counterparties.

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above.

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 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 tables are reconciliations of our level 3 fair value measurements:

	Commodity Collars			
	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2015	2014	2015	2014
	(In thousands)			
Beginning of period	\$ 857	\$ (4,464)	\$ 3,355	\$ (2,595)
Total gains or losses (realized and unrealized):				
Included in earnings ⁽¹⁾	111	(4,401)	888	(7,829)
Settlements	(761)	2,784	(4,036)	4,343
End of period	\$ 207	\$ (6,081)	\$ 207	\$ (6,081)
Total losses for the period included in earnings attributable to the change in unrealized loss relating to assets still held at end of period	\$ (650)	\$ (1,617)	\$ (3,148)	\$ (3,486)

(1) Commodity collars are reported in the Unaudited Condensed Consolidated Statements of Operations in gain (loss) on derivatives not designated as hedges.

The following table provides quantitative information about our Level 3 unobservable inputs at June 30, 2015:

Commodity ⁽¹⁾	Fair Value	Valuation Technique	Unobservable Input	Range
	(In thousands)			
Oil collar	\$ 239	Discounted cash flow	Forward commodity price curve	\$0.37 - \$4.33
Natural gas collars	(32)	Discounted cash flow	Forward commodity price curve	\$0.00 - \$0.15

(1) The commodity contracts detailed in this category include non-exchange-traded crude oil 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.

Based on our valuation at June 30, 2015, we determined that risk of non-performance by our counterparties was immaterial.

Fair Value of Other Financial Instruments

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

At June 30, 2015, the carrying values on the Unaudited Condensed Consolidated Balance Sheets for cash and cash equivalents (classified as Level 1), accounts receivable, accounts payable, other current assets, and current liabilities approximate their fair value because of their short term nature.

Based on the borrowing rates currently available to us for credit agreement debt with similar terms and maturities and also considering the risk of our non-performance, long-term debt under our credit agreement has historically approximated its fair value and at June 30, 2015 was \$280.5 million. This debt would be classified as Level 2.

The carrying amounts of long-term debt, net of unamortized discount, associated with the Notes reported in the Unaudited Condensed Consolidated Balance Sheets as of June 30, 2015 and December 31, 2014 were \$646.4 million and \$646.2 million, respectively. We estimated the fair value of these Notes using quoted marked prices at June 30, 2015 and December 31, 2014 which were \$625.6 million and \$605.5 million, respectively. These 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 – INDUSTRY SEGMENT INFORMATION

We have three main business segments offering different products and services:

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

The oil and natural gas segment is engaged in the development, acquisition, 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. Our oil and natural gas properties outside the United States are not significant.

The following table provides certain information about the operations of each of our segments:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
(In thousands)				
Revenues:				
Oil and natural gas	\$ 107,256	\$ 198,498	\$ 213,325	\$ 386,705
Contract drilling	60,813	135,782	165,751	260,040
Elimination of inter-segment revenue	(5,798)	(21,504)	(15,659)	(39,162)
Contract drilling net of inter-segment revenue	55,015	114,278	150,092	220,878
Gas gathering and processing	69,163	116,354	142,967	236,714
Elimination of inter-segment revenue	(16,987)	(23,699)	(36,838)	(50,878)
Gas gathering and processing net of inter-segment revenue	52,176	92,655	106,129	185,836
Total revenues	\$ 214,447	\$ 405,431	\$ 469,546	\$ 793,419
Operating income (loss):				
Oil and natural gas	\$ (417,353)	\$ 82,530	\$ (834,206)	\$ 170,642
Contract drilling	(3,049)	27,545	25,269	51,946
Gas gathering and processing	736	3,898	(180)	6,528
Total operating income (loss) ⁽¹⁾	(419,666)	113,973	(809,117)	229,116
General and administrative	(9,624)	(10,600)	(18,994)	(20,237)
Gain on disposition of assets	415	195	960	9,621
Gain (loss) on derivatives not designated as hedges	(1,919)	(10,709)	4,667	(29,075)
Interest expense, net	(7,956)	(4,131)	(15,196)	(7,921)
Other	24	(49)	22	71
Income (loss) before income taxes	\$ (438,726)	\$ 88,679	\$ (837,658)	\$ 181,575

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
Unit Corporation

We have reviewed the accompanying unaudited condensed consolidated balance sheet of Unit Corporation and its subsidiaries as of June 30, 2015, and the related unaudited condensed consolidated statements of operations for the three-month and six month periods ended June 30, 2015 and 2014 and the unaudited condensed consolidated statement of cash flows for the six month periods ended June 30, 2015 and 2014. These interim financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying unaudited condensed consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2014, and the related consolidated statements of operations, shareholder's equity and of cash flows for the year then ended (not presented herein), and in our report dated February 24, 2015, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2014, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma

August 4, 2015

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

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

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

Please read the following discussion and our unaudited condensed consolidated financial statements and related notes with the information in our most recent Annual Report on Form 10-K.

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

General

We operate, manage, and analyze our results of 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 and its subsidiaries. This segment contracts to drill onshore oil and natural gas wells for others and for our own account.
- *Mid-Stream* – carried out by our subsidiary Superior Pipeline Company, L.L.C. and its subsidiaries. This segment buys, sells, gathers, processes, and treats natural gas for third parties and for our own account.

Business Outlook

As discussed in other parts of this report, the success of our consolidated business, and that of each of our three operating segments, depends, to a large extent, on: the prices we receive for and the amount of our oil, NGLs, and natural gas production; the demand for oil, NGLs, and natural gas; and, the demand for our drilling rigs which influences the amounts we can charge for those drilling rigs. Although all of our current operations are within the United States, events outside the United States can affect us and our industry.

Both within the United States and the world, deteriorating commodity prices have brought about significant and immediate changes affecting our industry and us. The decline in commodity prices has caused us (and other oil and gas companies) to reduce our level of drilling activity and spending. When drilling activity and spending decline for any sustained period of time the number of our drilling rigs working and the rates we charge for them also decline. In addition, lower commodity prices for any sustained period of time could affect the liquidity condition of some of our industry partners and customers, which might limit their ability to meet their financial obligations to us.

How long the current depressed prices for oil and natural gas products continue is uncertain. As noted elsewhere in this report, commodity prices are subject to several factors most of which are beyond our control.

The impact on our business and financial results because of the reduction in oil and NGLs (and to a lesser extent natural gas) prices is uncertain in the long term, but in the short term, it has had several consequences for us, including:

- In March 2015, we incurred a non-cash ceiling test write-down of our oil and natural gas properties of \$400.6 million pre-tax (\$249.4 million net of tax) and in June 2015, we incurred a non-cash ceiling test write-down of our oil and natural gas properties of \$410.5 million pre-tax (\$255.6 million net of tax). We will experience a non-cash

ceiling test write-down in the third quarter of 2015. It is difficult to predict with reasonable certainty the amount of expected future impairments given the many factors impacting the ceiling test calculation including, but not limited to, future pricing, operating costs, drilling and completion costs, upward or downward reserve revisions, reserve adds, and tax attributes. Subject to these numerous factors and inherent limitations, holding these factors constant and only adjusting the 12-month average price to an estimated third quarter ending average (holding July 2015 prices constant for the remaining two months), we currently anticipate that we could recognize an impairment in the third quarter of 2015 of approximately \$300 million.

- We have reduced the number of gross wells we plan to drill in 2015 by approximately 68% - 73% from the number of gross wells drilled in 2014.
- The majority of our drilling rig customers have significantly reduced their drilling budgets for 2015, resulting in a significant reduction in the average utilization of our drilling rig fleet. At December 31, 2014, we had 75 rigs operating, at June 30, 2015, this number was 32.
- Due to the decline in NGLs prices, we operated our processing facilities in full ethane rejection mode which reduced the liquids sold. As long as NGLs prices continue to be at or below second quarter levels, we expect to continue operating in full ethane rejection mode. While processed volumes increased in the first quarter of 2015, they started to decline in the second quarter. As low commodity prices continue, we expect the reductions in drilling activity around our systems will reduce the number of new wells available to connect to our systems and result in lower processed volumes as production from wells previously connected naturally decline.

We have reduced our total 2015 capital budget for all three of our business segments by approximately 52% as compared to 2014, excluding acquisitions and ARO liability. Our budget is designed to keep our capital expenditures substantially within our anticipated cash flow.

Our 2015 current capital expenditures budget is based on realized prices for the year of \$53.73 per barrel of oil, \$17.03 per barrel of NGLs, and \$3.18 per Mcf of natural gas. Our budget is subject to possible periodic adjustments for various reasons including changes in commodity prices and industry conditions. Funding for the budget will come primarily from our cash flow and borrowings under our credit agreement.

Executive Summary

Oil and Natural Gas

Second quarter 2015 production from our oil and natural gas segment was 5,054,000 barrels of oil equivalent (Boe) which was an decrease of 1% from the first quarter of 2015 and an increase of 9% over the second quarter of 2014. Production for the second quarter of 2015 was negatively impacted by approximately 125,000 Boe due to an unexpected shut-in of some of our production in East Texas due to maintenance of a third party's processing facility. The increases over the second quarter of 2014 were primarily from production associated with new wells drilled in 2014.

Second quarter 2015 oil and natural gas revenues increased 1% over the first quarter of 2015 and decreased 46% from second quarter of 2014, respectively. The increase over the first quarter of 2015 was primarily due to higher oil and NGLs prices and higher NGLs and natural gas production partially offset by lower oil production and natural gas prices. The decrease from the second quarter of 2014 was due primarily to lower oil, NGLs, and natural gas prices partially offset by higher NGLs and natural gas production.

Our oil prices for the second quarter of 2015 increased 15% compared to the first quarter of 2015 and decreased 41% from the second quarter of 2014. Our NGLs prices increased 39% over the first quarter of 2015 and decreased 60% from the second quarter of 2014. Our natural gas prices decreased 9% and 34% from the first quarter of 2015 and second quarter of 2014, respectively.

Operating cost per Boe produced for the second quarter of 2015 increased 3% over the first quarter of 2015 and decreased 6% from the second quarter of 2014. Costs increased between the second and first quarters of 2015 primarily due to higher gross production taxes due to higher sales revenue and fewer gross production tax credits somewhat offset by lower lease operating and workover expenses. The decrease from the second quarter of 2014 was primarily due to higher production volumes.

For the remainder of 2015, we have derivative contracts covering approximately 3,000 Bbls per day of oil production. We have hedged 70,000 MMBtu per day of natural gas production in the third quarter of 2015 and 40,000 MMBtu per day of natural gas production in the fourth quarter of 2015. The contracts for the oil production are a swap contract for 1,000 Bbls per day and a collar for 2,000 Bbls per day. The swap transaction was done at a comparable average NYMEX price of \$95.00. The collar contract was done at a comparable average NYMEX floor price of \$58.00 and a ceiling price of \$64.40. The natural gas production in the third quarter is hedged by swaps for 40,000 MMBtu per day and collars for 30,000 MMBtu per day. The third quarter swap transactions were done at a comparable average NYMEX price of \$3.98. The third quarter collar transactions were done at a comparable average NYMEX floor price of \$2.58 and ceiling price of \$3.04. The natural gas production in the fourth quarter is hedged by swaps for 40,000 MMBtu per day. The fourth quarter swap transactions were done at a comparable average NYMEX price of \$3.98.

For 2016, we have a derivative contract covering 10,000 MMBtu per day of natural gas production. That contract is a swap contract at a comparable average NYMEX price of \$3.25.

As of June 30, 2015, we completed drilling 33 gross wells (21.85 net wells). For all of 2015, we plan to participate in the drilling of approximately 50-60 gross wells. Excluding acquisitions and ARO liability, our estimated 2015 capital expenditures for this segment are \$308.5 million. Our current 2015 production guidance is approximately 18.6 to 19.0 MMBoe, an increase of 2% to 4% over 2014, although actual results continue to be subject to many factors.

Contract Drilling

The average number of drilling rigs we operated for the second quarter of 2015 was 30.7 compared to 50.1 and 73.5 in the first quarter of 2015 and the second quarter of 2014, respectively. Late in the fourth quarter of 2014, the number of our drilling rigs operating started to decline and has continued to decline throughout the first six months of 2015 due to lower commodity prices and operators reducing their drilling budgets. As of June 30, 2015, 32 drilling rigs are operating. We have recently been notified of a customer's intent to terminate early the contracts on two BOSS drilling rigs both of which are under term contracts that contain early termination penalties.

Revenue for the second quarter of 2015 decreased 42% and 52% from the first quarter of 2015 and the second quarter of 2014, respectively. The decreases were due primarily to fewer rigs operating. The second quarter of 2015 included early contract termination revenue of \$1.6 million compared to \$12.7 million in the first quarter of 2015. There was no early termination revenue during the second quarter of 2014.

Dayrates for the second quarter of 2015 averaged \$19,881, a 1% decrease from the first quarter of 2015 and were essentially unchanged from the second quarter of 2014. The decrease from the first quarter of 2015 was due to downward pressure on dayrates with lower demand.

Operating costs for the second quarter of 2015 decreased 29% and 45% from the first quarter of 2015 and the second quarter of 2014, respectively. The decreases were due primarily to fewer rigs operating.

Low commodity prices continue to curtail our customer drilling budgets and demand for our drilling rigs. As a result, we are experiencing reduced drilling rig utilization. Almost all of our working drilling rigs in 2015 have been drilling horizontal or directional wells. Our drilling rig fleet consists of drilling rigs capable of meeting our customers' demands whether it be for oil, natural gas, or NGLs and whether it be for shallow, deep, vertical, or horizontal type drilling. Current and future demand for drilling rigs and the availability of drilling rigs to meet that demand will affect our future dayrates.

As of June 30, 2015, we had 32 drilling rigs operating. Of those, 18 are on spot market contracts and 14 are on term drilling contracts, with original terms ranging from six months to two years. Four term contracts are up for renewal in 2015 (three in the third quarter and one in the fourth quarter), seven are up for renewal in 2016, and three are up for renewal in 2017. Term contracts may contain a fixed rate for the duration of 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 and pay an early termination penalty for the remaining term of the contract. During the first six months of 2015, we recorded \$14.3 million in early termination fees.

During the second quarter of 2015, three BOSS drilling rigs were placed into service for third-party operators. We have completed our new build program for drilling rigs contracted for 2015 delivery. Some of the long lead time components for three additional BOSS drilling rigs were ordered during 2014 and will be delivered in the next twelve months. Currently, we do not have any contracts to build new BOSS drilling rigs. Our estimated 2015 capital expenditures for this segment are \$99.7 million.

In December 2014, we removed from service 31 drilling rigs, some older top drives, and certain drill pipe no longer marketable under the current environment and based on estimated market value from third party assessments (Level 3 fair value measurement), we recorded a write-down of approximately \$74.3 million pre-tax. During the first quarter of 2015, we sold one of these drilling rigs to an unaffiliated third party. The proceeds of this sale, less costs to sell, exceeded the \$0.3 million net book value of the drilling rig resulting in a gain of \$7,900. During the second quarter we decided to place the remaining 30 drilling rigs and most of the equipment for sale in an auction to be held during the third quarter. Any equipment not sold at the auction will be sold within the next twelve months. As a result, these assets have been classified as assets held for sale. Since December, the estimated fair value of the drilling rigs and other assets has declined based on the estimated market value from similar auctions. Based on these estimates, we recorded an additional write-down of approximately \$8.3 million pre-tax during the second quarter. The proceeds from the sale of these assets, less costs to sell, is expected to be approximately \$12.6 million.

Mid-Stream

Second quarter 2015 liquids sold per day increased 5% over the first quarter of 2015 and decreased 21% from the second quarter of 2014. The increase over the first quarter of 2015 was due to additional well connects. The decrease from the second quarter of 2014 was due to operating in ethane ejection mode in 2015. For the second quarter of 2015, gas processed per day decreased 2% from the first quarter of 2015 and increased 15% over the second quarter of 2014. The decrease from the first quarter was primarily due to reductions in drilling activity around our systems which has reduced the number of new wells available to connect to our systems. The increase over the second quarter of 2014 was primarily due to connecting new wells to both existing and newly constructed systems to replace production declines from wells already connected. For the second quarter of 2015, gas gathered per day increased 9% over the first quarter of 2015 and increased 11% over the second quarter of 2014 due to additional wells added to our systems.

NGLs prices in the second quarter of 2015 decreased 8% from the prices received in the first quarter of 2015 and decreased 45% from the prices received in the second quarter of 2014. Because certain contracts used by our mid-stream segment for NGLs transactions are percent of proceeds (POP) contracts—under which we receive a share of the proceeds from the sale of the NGLs—our revenues from those POP contracts fluctuate based on the price of NGLs.

Total operating cost for our mid-stream segment for the second quarter of 2015 decreased 8% from the first quarter of 2015 and decreased 48% from the second quarter of 2014 due to lower gas purchase prices.

We completed the connection of our Buffalo Wallow gathering system to our Hemphill County, Texas facility and delivered Buffalo Wallow gathered gas to the Hemphill processing facility on January 1, 2015. Our Hemphill facility has a total processing capacity of approximately 135 MMcf per day. During the second quarter of 2015, we added three new wells to this system and had an average throughput volume of 88 MMcf per day.

At our Perkins facility, our total processing capacity is now 27 MMcf per day after completing several projects to upgrade our processing capacity and increase liquid recoveries. During the second quarter of 2015, we connected four new wells to this system.

In the Mississippian play in north central Oklahoma, we continue to connect new wells and increase volumes on our Bellmon system. During the second quarter of 2015, we connected 12 new wells to this system. Our total processing capacity at this facility is approximately 90 MMcf per day from two cryogenic processing plant skids. During the second quarter, we had an average throughput volume of 41 MMcf per day at this facility.

At our Segno gathering facility located in southeast Texas, we have several upgrade projects in process which will increase our gathering capacity up to 120 MMcf per day. We have completed the installation of additional dehydration equipment at this facility and are in the process of looping a section of pipeline. We are currently acquiring the right of way for the line looping project and expect to begin pipeline construction in the third quarter of 2015. This project is expected to be completed and operational by year end.

In the Appalachian region, we are continuing to expand the Pittsburgh Mills gathering system. We are completing the construction of an expansion project which extends our gathering system into Butler County, Pennsylvania. This project consists of a seven-mile pipeline with a related compressor station and provides us an additional outlet for our gas. The pipeline has been completed and we gathered gas from a new well pad connected to our system in the first quarter of 2015. Construction of the compressor station is underway and will be completed by the time compression services are required. This expansion project will allow us the ability to connect additional well pads scheduled to be drilled in 2015 and 2016.

Also in the Appalachian area, we recently began construction of the Snow Shoe gathering system. This is a new fee-based gathering system which will be located in Centre County, Pennsylvania and will consist of approximately seven miles of 16" and 24" pipeline and a related compressor station. The 16" pipeline is almost complete and we are continuing to work on the installation of the 24" pipeline. Construction is expected to be completed the fourth quarter of 2015.

Our estimated 2015 capital expenditures for this segment are \$68.4 million, excluding acquisitions.

Financial Condition and Liquidity

Summary

Our financial condition and liquidity depends on the cash flow from our operations and borrowings under our credit agreement. The principal factors determining our cash flow are:

- the quantity 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.

	Six Months Ended June 30,		%
	2015	2014	Change ⁽¹⁾
(In thousands except percentages)			
Net cash provided by operating activities	\$ 257,606	\$ 325,528	(21)%
Net cash used in investing activities	(366,442)	(379,107)	(3)%
Net cash provided by financing activities	108,626	36,064	NM
Net decrease in cash and cash equivalents	\$ (210)	\$ (17,515)	

(1) NM - A percentage calculation is not meaningful due to a percentage greater than 200.

Cash Flows from Operating Activities

Our operating cash flow is primarily influenced by the prices for and the quantity of our oil, NGLs, and natural gas production; settlements of derivative contracts; third-party demand for our drilling rigs and mid-stream services; and the rates we can charge 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 2015 decreased by \$67.9 million from the first six months of 2014 due primarily to lower revenues due to lower commodity prices and lower utilization partially offset by changes in operating assets and liabilities related to the timing of cash receipts and disbursements.

Cash Flows from Investing Activities

We dedicate and expect to continue to dedicate a substantial portion of our capital expenditure program toward the exploration for and production of oil, NGLs, and natural gas. These capital expenditures are necessary to limit inherent declines in production, which is typical in the capital-intensive oil and natural gas industry.

Cash flows used in investing activities decreased by \$12.7 million for the first six months of 2015 compared to the first six months of 2014. The change was due primarily to a decrease in capital expenditures partially offset by a decrease in the proceeds received from the disposition of assets. See additional information on capital expenditures below under Capital Requirements.

Cash Flows from Financing Activities

Cash flows provided by financing activities increased by \$72.6 million for the first six months of 2015 compared to the first six months of 2014. This increase was primarily due to borrowings under our credit agreement offset partially by a decrease in our book overdrafts (checks issued but not presented to our bank for payment before the end of the period).

At June 30, 2015, we had unrestricted cash totaling \$0.8 million and had borrowed \$280.5 million of the \$500.0 million we had elected to then have available under our credit agreement. On April 10, 2015, we amended our credit agreement to extend the maturity date from September 13, 2016 to April 10, 2020. Our credit agreement is used primarily for working capital and capital expenditures.

The following is a summary of certain financial information as of June 30, 2015 and 2014 and for the six months ended June 30, 2015 and 2014:

	June 30,		%
	2015	2014	Change ⁽¹⁾
(In thousands except percentages)			
Working capital	\$ (11,366)	\$ (103,284)	89 %
Long-term debt	\$ 926,908	\$ 645,925	44 %
Shareholders' equity	\$ 1,823,600	\$ 2,294,687	(21)%
Ratio of long-term debt to total capitalization	34%	22%	
Net income (loss)	\$ (522,743)	\$ 111,305	NM

(1) NM - A percentage calculation is not meaningful due to a percentage greater than 200.

The following table summarizes certain operating information:

	Six Months Ended			% Change
	June 30,			
	2015	2014		
Oil and Natural Gas:				
Oil production (MBbls)	2,046	1,760	16 %	
NGLs production (MBbls)	2,615	2,228	17 %	
Natural gas production (MMcf)	33,064	28,881	14 %	
Average oil price per barrel received	\$ 51.73	\$ 92.95	(44)%	
Average oil price per barrel received excluding derivatives	\$ 48.13	\$ 97.81	(51)%	
Average NGLs price per barrel received	\$ 10.37	\$ 34.57	(70)%	
Average NGLs price per barrel received excluding derivatives	\$ 10.37	\$ 34.57	(70)%	
Average natural gas price per Mcf received	\$ 2.80	\$ 4.14	(32)%	
Average natural gas price per Mcf received excluding derivatives	\$ 2.39	\$ 4.47	(47)%	
Contract Drilling:				
Average number of our drilling rigs in use during the period	40.4	70.7	(43)%	
Total number of drilling rigs available for use at the end of the period	94	118	(20)%	
Average dayrate	\$ 20,032	\$ 19,766	1 %	
Mid-Stream:				
Gas gathered—Mcf/day	348,666	315,116	11 %	
Gas processed—Mcf/day	187,592	155,807	20 %	
Gas liquids sold—gallons/day	584,389	737,353	(21)%	
Number of natural gas gathering systems ⁽¹⁾	27	38	(29)%	
Number of processing plants	13	14	(7)%	

(1) In January 2015, our mid-stream segment transferred nine natural gas gathering systems to our oil and natural gas segment.

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 \$11.4 million and \$103.3 million as of June 30, 2015 and 2014, respectively. This is primarily from the timing of our accounts payable associated with our capital expenditures. The effect of our derivative contracts increased working capital by \$14.6 million as of June 30, 2015 and decreased working capital by \$15.8 million as of June 30, 2014.

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. Prices and demand for domestic natural gas are influenced by weather conditions, supply imbalances, and by worldwide oil price levels. Domestic oil prices are primarily influenced by global oil market developments. All of these factors are beyond our control and we cannot predict nor measure their future impact on the prices we will receive.

Based on our first six months of 2015 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 \$528,000 per month (\$6.3 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 2015 was \$2.80 compared to \$4.14 for the first six months of 2014. Based on our first six months of 2015 production, a \$1.00 per barrel change in our oil price, without the effect of derivatives, would have a \$330,000 per month (\$4.0 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 \$419,000 per month (\$5.0 million annualized) change in our pre-tax operating cash flow. In the first six months of 2015, our average oil price per barrel received, including the effect of derivatives, was \$51.73 compared with an average oil price, including the effect of derivatives, of \$92.95 in the first six months of 2014 and our first six months of 2015 average NGLs price per barrel received was \$10.37 compared with an average NGLs price per barrel of \$34.57 in the first six months of 2014.

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. In the first two quarters of 2015, the unamortized cost of our oil and gas properties exceeded the ceiling of our proved oil, NGLs, and natural gas reserves. As a result, we recorded in March of 2015 a non-cash ceiling test write down of \$400.6 million pre-tax (\$249.4 million, net of tax) and in June of 2015, we recorded a non-cash ceiling test write-down of \$410.5 million pre-tax (\$255.6 million, net of tax). At June 30, 2015, the 12-month average unescalated prices were \$71.68 per barrel of oil, \$30.54 per barrel of NGLs, and \$3.39 per Mcf of natural gas, then adjusted for price differentials.

We will experience a non-cash ceiling test write-down in the third quarter of 2015. It is difficult to predict with reasonable certainty the amount of expected future impairments given the many factors impacting the ceiling test calculation including, but not limited to, future pricing, operating costs, drilling and completion costs, upward or downward reserve revisions, reserve adds, and tax attributes. Subject to these numerous factors and inherent limitations, holding these factors constant and only adjusting the 12-month average price to an estimated third quarter ending average (holding July 2015 prices constant for the remaining two months), we currently anticipate that we could recognize an impairment in the third quarter of 2015 of approximately \$300 million. The estimated third-quarter 2015 impairment is partially the result of a decrease in our proved undeveloped reserves of approximately 23%. This decrease was primarily due to certain locations no longer being economical under the adjusted 12-month average price for the third quarter. As a result, we have eliminated 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.

Price declines can also adversely affect future semi-annual determinations of the amount we can borrow under our credit agreement since that determination is based mainly on the value of our oil, NGLs, and natural gas reserves. Such a reduction could limit our ability to carry out our planned capital projects.

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 in six month increments.

Contract Drilling Operations

Many factors influence the number of drilling rigs we are working at any given time 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.

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

Low commodity prices continue to curtail our customer drilling budgets and demand for our drilling rigs. As a result, we are experiencing reduced drilling rig utilization. Almost all of our working drilling rigs in 2015 have been drilling horizontal or directional wells. Our drilling rig fleet consists of drilling rigs capable of meeting our customers' demands whether it be for oil, natural gas, or NGLs and whether it be for shallow, deep, vertical, or horizontal type drilling. Current and future demand for drilling rigs and the availability of drilling rigs to meet that demand will affect our future dayrates. For the first six months of 2015, our average dayrate was \$20,032 per day compared to \$19,766 per day for the first six months of 2014. The average number of our drilling rigs used in the first six months of 2015 was 40.4 drilling rigs compared with 70.7 drilling rigs in the first six months of 2014. Based on the average utilization of our drilling rigs during the first six months of 2015, a \$100 per day change in dayrates has a \$4,040 per day (\$1.5 million annualized) change in our pre-tax operating cash flow.

Our contract drilling segment also provides drilling services for our oil and natural gas 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 drilling services are eliminated in our statement of operations, with any profit recognized as a reduction in our investment in our oil and natural gas properties. The contracts for these services are issued under the same conditions and rates as the contracts entered into with unrelated third parties. We eliminated revenue of \$15.7 million and \$39.2 million for the first six months of 2015 and 2014, respectively, from our contract drilling segment and eliminated the associated operating expense of \$12.2 million and \$26.8 million during the first six months of 2015 and 2014, respectively, yielding \$3.5 million and \$12.4 million during the first six months of 2015 and 2014, 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, 13 processing plants, 27 gathering systems, and approximately 1,450 miles of pipeline. It operates in Oklahoma, Texas, Kansas, Pennsylvania, and West Virginia. Besides serving third parties, this segment also enhances our ability to gather and market our own natural gas and NGLs and serving as a mechanism through which we can construct or acquire existing natural gas gathering and processing facilities. During the first six months of 2015 and 2014, our mid-stream operations purchased \$33.0 million and \$45.8 million, respectively, of our natural gas production and NGLs, and provided gathering and transportation services of \$3.8 million and \$5.1 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 348,666 Mcf per day in the first six months of 2015 compared to 315,116 Mcf per day in the first six months of 2014. It processed an average of 187,592 Mcf per day in the first six months of 2015 compared to 155,807 Mcf per day in the first six months of 2014. The amount of NGLs sold was 584,389 gallons per day in the first six months of 2015 compared to 737,353 gallons per day in the first six months of 2014. Gas gathering volumes per day in the first six months of 2015 increased 11% compared to the first six months of 2014 primarily from an increase in the number of wells connected to our systems between the comparative periods. Processed volumes for the first six months of 2015 increased 20% over the first six months of 2014 due primarily to new wells connected. NGLs sold decreased 21% from the comparative period due to being in ethane rejection mode.

Our Credit Agreement and Senior Subordinated Notes

Credit Agreement. On April 10, 2015, we amended our Senior Credit Agreement (credit agreement) previously scheduled to mature on September 13, 2016. The amended credit agreement now has a maturity date of April 10, 2020. The amount we can borrow is the lesser of the amount we elect (from time to time) as the commitment amount or the value of the borrowing base as determined by the lenders (currently \$725.0 million), but in either event not to exceed the maximum credit agreement

amount of \$900.0 million. Our current elected commitment amount is \$500.0 million. We are charged a commitment fee ranging from 0.375 to 0.50 of 1% on the amount available but not borrowed. The fee varies based on the amount borrowed as a percentage of the amount of the total borrowing base. To date, for this new amendment, we paid \$2.6 million in origination, agency, syndication, and other related fees. We are amortizing these fees over the life of the credit agreement.

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

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

The borrowing base amount—which is subject to redetermination by the lenders on April 1st and October 1st of each year—is based primarily on a percentage of the discounted future value of our oil and natural gas reserves. We or the lenders may request a onetime special redetermination of the borrowing base between each scheduled redetermination. In addition, we may request a redetermination following the completion of an acquisition that meets the requirements in the credit agreement.

At our election, any part of the outstanding debt under the credit agreement may be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest is computed as the sum of the LIBOR base for the applicable term plus 1.75% 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 credit agreement that cannot be less than LIBOR plus 1.00%. Interest is payable at the end of each month and the principal may be repaid in whole or in part at any time, without a premium or penalty. At June 30, 2015 and July 24, 2015, borrowings were \$280.5 million and \$289.7 million, respectively.

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

The credit agreement prohibits, among other things:

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

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

- a current ratio (as defined in the credit agreement) of not less than 1 to 1; and
- a leverage ratio of funded debt to consolidated EBITDA (as defined in the credit agreement) for the most recently ended rolling four fiscal quarters of no greater than 4 to 1.

As of June 30, 2015, we were in compliance with the covenants in the credit agreement.

6.625% Senior Subordinated Notes. We have an aggregate principal amount of \$650.0 million, 6.625% senior subordinated notes (the Notes). Interest on the Notes is payable semi-annually (in arrears) on May 15 and November 15 of each

year. The Notes will mature on May 15, 2021. We incurred in connection with the issuance of the Notes \$14.7 million of fees 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 and providing for issuing the Notes. The Guarantors are all of our direct and indirect subsidiaries. The discussion of the Notes in this report is qualified by and subject to the actual terms of the 2011 Indenture.

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

Before May 15, 2016, we may redeem the Notes, in whole or in part, at a redemption price equal to 100% of the principal amount plus a “make whole” premium, plus accrued and unpaid interest, if any, to the redemption date. On and after May 15, 2016, we may redeem all or, from time to time, a part of the Notes at certain redemption prices, plus accrued and unpaid interest. If a “change of control” occurs, subject to certain conditions, we must offer to repurchase from each holder all or any part of that holder’s Notes at a purchase price in cash equal to 101% of the principal amount of the Notes plus accrued and unpaid interest, if any, to the date of purchase. The 2011 Indenture contains customary events of default. The 2011 Indenture also contains covenants that, among other things, 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, 2015.

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 involved, all of which provide us with flexibility in deciding when and if to incur these costs. We completed drilling 33 gross wells (21.85 net wells) in the first six months of 2015 compared to 85 gross wells (53.16 net wells) in the first six months of 2014. Total capital expenditures for oil and gas properties on the full cost method for the first six months of 2015, excluding a \$6.0 million reduction in the ARO liability, totaled \$167.6 million. Total capital expenditures for the first six months of 2014, excluding a \$15.4 million reduction in the ARO liability, totaled \$355.0 million.

Currently we plan to participate in drilling approximately 50-60 gross wells in 2015 and our total estimated capital expenditures (excluding any possible acquisitions) for this segment are approximately \$308.5 million. Whether we can drill the full number of wells planned depends on several factors, many of which are beyond our control, including the availability of drilling rigs, availability of pressure pumping services, prices for oil, NGLs, and natural gas, demand for oil, NGLs, and natural gas, the cost to drill wells, the weather, and the efforts of outside industry partners.

Contract Drilling Segment Dispositions, Acquisitions, and Capital Expenditures. In December 2014, we removed from service 31 drilling rigs, some older top drives, and certain drill pipe no longer marketable under the current environment and based on estimated market value from third party assessments (Level 3 fair value measurement), we recorded a write-down of approximately \$74.3 million pre-tax. During the first quarter of 2015, we sold one of these drilling rigs to an unaffiliated third party. The proceeds of this sale, less costs to sell, exceeded the \$0.3 million net book value of the drilling rig resulting in a gain of \$7,900. During the second quarter we decided to place the remaining 30 drilling rigs and most of the equipment for sale in an auction to be held during the third quarter. Any equipment not sold at the auction will be sold within the next twelve months. As a result, these assets have been classified as assets held for sale. Since December, the estimated fair value of the drilling rigs and other assets has declined based on the estimated market value from similar auctions. Based on these estimates, we recorded an additional write-down of approximately \$8.3 million pre-tax during the second quarter. The proceeds from the sale of these assets, less costs to sell, is expected to be approximately \$12.6 million.

During the first quarter of 2015, two BOSS drilling rigs were placed into service for third-party operators. During the second quarter of 2015, three BOSS drilling rigs were placed into service for third-party operators. We have completed our new build program for drilling rigs for 2015 delivery. Some of the long lead time components for three additional BOSS drilling rigs were ordered during 2014 and will be delivered in the next twelve months. Currently, we do not have any contracts to build new BOSS drilling rigs.

Our estimated 2015 capital expenditures for this segment are \$99.7 million. At June 30, 2015, we had commitments to purchase approximately \$9.1 million for drilling equipment within the next year. We have spent \$70.1 million for capital expenditures, including \$53.8 million for the BOSS drilling rigs during the first six months of 2015, compared to \$74.2 million for capital expenditures, including \$39.1 million for the BOSS drilling rigs, during the first six months of 2014.

Mid-Stream Acquisitions and Capital Expenditures. We completed the connection of our Buffalo Wallow gathering system to our Hemphill County, Texas facility and delivered Buffalo Wallow gathered gas to the Hemphill processing facility on January 1, 2015. Our Hemphill facility has a total processing capacity of approximately 135 MMcf per day. During the second quarter of 2015, we added three new wells to this system and had an average throughput volume of 88 MMcf per day.

At our Perkins facility, our total processing capacity is now 27 MMcf per day after completing several projects to upgrade our processing capacity and increase liquid recoveries. During the second quarter of 2015, we connected four new wells to this system.

In the Mississippian play in north central Oklahoma, we continue to connect new wells and increase volumes on our Bellmon system. During the second quarter of 2015, we connected 12 new wells to this system. Our total processing capacity at this facility is approximately 90 MMcf per day from two cryogenic processing plant skids. During the second quarter, we had an average throughput volume of 41 MMcf per day at this facility.

At our Segno gathering facility located in southeast Texas, we have several upgrade projects in process which will increase our gathering capacity up to 120 MMcf per day. We have completed the installation of additional dehydration equipment at this facility and are in the process of looping a section of pipeline. We are currently acquiring the right of way for the line looping project and expect to begin pipeline construction in the third quarter of 2015. This project is expected to be completed and operational by year end.

In the Appalachian region, we are continuing to expand the Pittsburgh Mills gathering system. We are completing the construction of an expansion project which extends our gathering system into Butler County, Pennsylvania. This project consists of a seven-mile pipeline with a related compressor station and provides us an additional outlet for our gas. The pipeline has been completed and we gathered gas from a new well pad connected to our system in the first quarter of 2015. Construction of the compressor station is underway and will be completed by the time compression services are required. This expansion project will allow us the ability to connect additional well pads scheduled to be drilled in 2015 and 2016.

Also in the Appalachian area, we recently began construction of the Snow Shoe gathering system. This is a new fee-based gathering system which will be located in Centre County, Pennsylvania and will consist of approximately seven miles of 16" and 24" pipeline and a related compressor station. The 16" pipeline is almost complete and we are continuing to work on the installation of the 24" pipeline. Construction is expected to be completed the fourth quarter of 2015.

During the first six months of 2015, our mid-stream segment incurred \$24.3 million in capital expenditures as compared to \$16.3 million, excluding \$26.5 million for capital leases added during the first six months of 2014. For 2015, our estimated capital expenditures are \$68.4 million, excluding acquisitions.

Contractual Commitments

At June 30, 2015, 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⁾	\$ 1,212,425	\$ 49,126	\$ 98,253	\$ 377,411	\$ 687,635
Operating leases ⁽²⁾	6,653	4,936	1,676	41	—
Capital lease interest and maintenance ⁽³⁾	13,656	2,716	5,001	4,386	1,553
Drill pipe, drilling components, and equipment purchases ⁽⁴⁾	9,134	9,134	—	—	—
Enterprise Resource Planning software obligations ⁽⁵⁾	1,911	1,425	486	—	—
Total contractual obligations	<u>\$ 1,243,779</u>	<u>\$ 67,337</u>	<u>\$ 105,416</u>	<u>\$ 381,838</u>	<u>\$ 689,188</u>

- (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, 2015 interest rates of 6.625% for the Notes and 2.2% for the credit agreement.
- (2) We lease office space or yards in Edmond, Oklahoma City, and Tulsa, Oklahoma; Houston, Texas; Englewood, Colorado; Pinedale, Wyoming; and Pittsburgh, Pennsylvania under the terms of operating leases expiring through July, 2019. Additionally, we have several equipment leases and lease space on short-term commitments to stack excess drilling rig equipment and production inventory.
- (3) Maintenance and interest payments are included in our capital lease agreements. The capital leases are discounted using annual rates of 4.00%. Total maintenance and interest remaining are \$10.5 million and \$3.2 million, respectively.
- (4) We have committed to pay \$9.1 million for drilling rig components, drill pipe, and related equipment over the next twelve months.
- (5) We have committed to pay \$1.4 million for Enterprise Resource Planning software and \$0.5 million for maintenance for one year following implementation.

At June 30, 2015, we also had the following commitments and contingencies that could create, increase, or accelerate our liabilities:

Other Commitments	Estimated Amount of Commitment Expiration Per Period				
	Total Accrued	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Deferred compensation plan ⁽¹⁾	\$ 4,406	Unknown	Unknown	Unknown	Unknown
Separation benefit plans ⁽²⁾	\$ 11,368	\$ 1,927	Unknown	Unknown	Unknown
Asset retirement liability ⁽³⁾	\$ 96,368	\$ 3,277	\$ 37,854	\$ 7,412	\$ 47,825
Gas balancing liability ⁽⁴⁾	\$ 3,623	Unknown	Unknown	Unknown	Unknown
Repurchase obligations ⁽⁵⁾	\$ —	Unknown	Unknown	Unknown	Unknown
Workers' compensation liability ⁽⁶⁾	\$ 17,681	\$ 8,208	\$ 2,481	\$ 1,214	\$ 5,778
Capital leases obligations ⁽⁷⁾	\$ 24,188	\$ 3,479	\$ 7,389	\$ 8,002	\$ 5,318
Other	\$ 410	Unknown	\$ 410	Unknown	Unknown

- (1) We provide a salary deferral plan which allows participants to defer the recognition of salary for income tax purposes until actual distribution of benefits, which occurs at either termination of employment, death, or certain defined unforeseeable emergency hardships. We recognize payroll expense and record a liability, included in other long-term liabilities in our Unaudited Condensed Consolidated Balance Sheets, at the time of deferral.
- (2) Effective January 1, 1997, we adopted a separation benefit plan ("Separation Plan"). The Separation Plan allows eligible employees whose employment is involuntarily terminated or, in the case of an employee who has completed 20 years of service, voluntarily or involuntarily terminated, to receive benefits equivalent to four weeks salary for every whole year of service completed with the company up to a maximum of 104 weeks. To receive payments the recipient must waive certain claims against us in exchange for receiving the separation benefits. On October 28, 1997, we adopted a Separation Benefit Plan for Senior Management ("Senior Plan"). The Senior Plan provides certain officers and key executives of the company with benefits generally equivalent to the Separation Plan. The Compensation Committee of the Board of Directors has absolute discretion in the selection of the individuals covered in this plan. Currently there are no participants in the Senior Plan. On May 5, 2004 we also adopted the Special Separation Benefit Plan ("Special Plan"). This plan is identical to the Separation Benefit Plan with the exception that the benefits under the plan vest on the earliest of a participant's reaching the age of 65 or serving 20 years with the company. On December 31, 2008, all these plans were amended to bring the plans into compliance with Section 409A of the Internal Revenue Code of 1986, as amended.
- (3) When a well is drilled or acquired, under "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. 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 made repurchases of \$8,000 during the first six months of 2015. We did not have any repurchases for the first six months of 2014.
- (6) We have recorded a liability for future estimated payments related to workers' compensation claims primarily associated with our contract drilling segment.
- (7) The amount includes commitments under capital lease arrangements for compressors in our mid-stream segment.

Derivative Activities

Periodically we enter into derivative transactions locking in the prices to be received for a portion of our oil, NGLs, and natural gas production. Any change in fair value on all commodity derivatives we have entered into are reflected in the statement of operations and not in accumulated other comprehensive income.

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, 2015, based on our second quarter 2015 average daily production, the approximated percentages of our production under derivative contracts are as follows:

	Q3 2015	Q4 2015	2016
Daily oil production	29%	29%	—%
Daily natural gas production	38%	22%	5%

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, 2015 evaluation, we believe the risk of non-performance by our counterparties is not material. At June 30, 2015, the fair values of the net assets (liabilities) we had with each of the counterparties to our commodity derivative transactions are as follows:

	June 30, 2015 (In millions)
Bank of Montreal	\$ 14.2
CIBC	0.3
Bank of America Merrill Lynch	0.2
Total assets	\$ 14.7

If a legal right of set-off exists, we net the value of the derivative transactions we have with the same counterparty in our Unaudited Condensed Consolidated Balance Sheets. At June 30, 2015, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative assets of \$14.6 million and \$0.1 million, respectively. At June 30, 2014, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative liabilities of \$15.8 million and \$0.3 million, respectively.

For our economic hedges any changes in their fair value occurring before their maturity (i.e., temporary fluctuations in value) are reported in gain (loss) on derivatives not designated as hedges 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,	
	2015	2014	2015	2014
(In thousands)				
Gain (loss) on derivatives not designated as hedges:				
Gain (loss) on derivatives not designated as hedges, included are amounts settled during the period of \$10,070, (\$9,084), \$21,082, and (\$17,955), respectively	\$ (1,919)	\$ (10,709)	\$ 4,667	\$ (29,075)
	\$ (1,919)	\$ (10,709)	\$ 4,667	\$ (29,075)

Stock and Incentive Compensation

During the first six months of 2015, we granted awards covering 750,290 shares of restricted stock. These awards had an estimated fair value as of their grant date of \$24.5 million. Compensation expense will be recognized over the three year vesting periods, and during the six months of 2015, we recognized \$3.6 million in compensation expense and capitalized \$0.8 million for these awards. During the first six months of 2015, we recognized compensation expense of \$9.1 million for all of our restricted stock, stock options, and SAR grants and capitalized \$1.9 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 \$1.5 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. We have elected to use an ERISA governed occupational injury benefit plan to cover our Texas based drilling operations in lieu of covering them under Texas workers' compensation. 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 15 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 each of the first six months of 2015 and 2014, the total we received for all of these fees was \$0.2 million. Our proportionate share of assets, liabilities, and net income (loss) relating to the oil and natural gas partnerships is included in our unaudited condensed consolidated financial statements.

New Accounting Pronouncements

Interest—Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs. The FASB has issued ASU 2015-03. The amendments in this ASU require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. For public business entities, the amendments are effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. Early adoption of the amendments is permitted for financial statements that have not been previously issued. The amendments should be applied on a retrospective basis, wherein the balance sheet of each individual period presented should be adjusted to reflect the period-specific effects of applying the new guidance. We are in the process of evaluating the impact it will have on our financial statements.

Revenue from Contracts with Customers. The FASB has issued ASU 2014-09. This affects any entity using U.S. GAAP that either enters into contracts with customers to transfer goods or services or enters into contracts for the transfer of nonfinancial assets unless those contracts are within the scope of other standards (e.g., insurance contracts or lease contracts). The core principle of the guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. On April 1, 2015, the FASB proposed deferring the effective date by one year to December 15, 2017 for annual reporting periods beginning after that date. The FASB also proposed permitting early adoption of the standard, but not before the original effective date of December 15, 2016. We are in the process of evaluating the impact it will have on our financial statements.

Results of Operations

Quarter Ended June 30, 2015 versus Quarter Ended June 30, 2014

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

	Quarter Ended June 30,		Percent Change ⁽¹⁾
	2015	2014	
(In thousands unless otherwise specified)			
Total revenue	\$ 214,447	\$ 405,431	(47)%
Net income (loss)	\$ (274,389)	\$ 54,360	NM
Oil and Natural Gas:			
Revenue	\$ 107,256	\$ 198,498	(46)%
Operating costs excluding depreciation, depletion, amortization, and impairment	\$ 45,972	\$ 44,723	3 %
Depreciation, depletion, and amortization	\$ 68,101	\$ 71,245	(4)%
Impairment of oil and natural gas properties	\$ 410,536	\$ —	NM
Average oil price received (Bbl)	\$ 55.52	\$ 94.17	(41)%
Average NGLs price received (Bbl)	\$ 12.05	\$ 29.99	(60)%
Average natural gas price received (Mcf)	\$ 2.67	\$ 4.05	(34)%
Oil production (Bbl)	948,000	950,000	— %
NGLs production (Bbl)	1,328,000	1,163,000	14 %
Natural gas production (Mcf)	16,665,000	15,026,000	11 %
Depreciation, depletion, and amortization rate (Boe)	\$ 13.14	\$ 15.12	(13)%
Contract Drilling:			
Revenue	\$ 55,015	\$ 114,278	(52)%
Operating costs excluding depreciation and impairment	\$ 36,485	\$ 66,494	(45)%
Depreciation	\$ 13,265	\$ 20,239	(34)%
Impairment of contract drilling equipment	\$ 8,314	\$ —	NM
Percentage of revenue from daywork contracts	100%	100%	— %
Average number of drilling rigs in use	30.7	73.5	(58)%
Average dayrate on daywork contracts	\$ 19,881	\$ 19,904	— %
Mid-Stream:			
Revenue	\$ 52,176	\$ 92,655	(44)%
Operating costs excluding depreciation and amortization	\$ 40,592	\$ 78,648	(48)%
Depreciation and amortization	\$ 10,848	\$ 10,109	7 %
Gas gathered—Mcf/day	362,896	326,028	11 %
Gas processed—Mcf/day	186,041	161,509	15 %
Gas liquids sold—gallons/day	599,732	762,205	(21)%
Corporate and other:			
General and administrative expense	\$ 9,624	\$ 10,600	(9)%
Gain on disposition of assets	\$ 415	\$ 195	113 %
Other income (expense):			
Interest expense, net	\$ (7,956)	\$ (4,131)	93 %
Loss on derivatives not designated as hedges	\$ (1,919)	\$ (10,709)	82 %
Other	\$ 24	\$ (49)	149 %
Income tax expense (benefit)	\$ (164,337)	\$ 34,319	NM
Average long-term debt outstanding	\$ 906,609	\$ 648,289	40 %
Average interest rate	5.4%	6.7%	(19)%

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

Oil and Natural Gas

Oil and natural gas revenues decreased \$91.2 million or 46% in the second quarter of 2015 as compared to the second quarter of 2014 due primarily to lower oil, natural gas, and NGLs prices. In the second quarter of 2015, as compared to the second quarter of 2014, oil production was essentially unchanged, NGLs production increased 14%, and natural gas production increased 11%. Average oil prices decreased 41% to \$55.52 per barrel, average natural gas prices decreased 34% to \$2.67 per Mcf, and NGLs prices decreased 60% to \$12.05 per barrel.

Oil and natural gas operating costs increased \$1.2 million or 3% between the comparative second quarters of 2015 and 2014 due primarily to higher saltwater disposal expenses and lease operating expenses partially offset by lower gross production taxes due to lower sales revenues.

Depreciation, depletion, and amortization ("DD&A") decreased \$3.1 million or 4% due primarily to a 13% decrease in our DD&A rate partially offset by a 9% increase in equivalent production. The decrease in our DD&A rate in the second quarter of 2015 compared to the second quarter of 2014 resulted primarily from the effect of the ceiling test write-downs in the fourth quarter of 2014 and the first quarter of 2015. Our DD&A expense on our oil and natural gas properties is calculated each quarter utilizing period end reserve quantities adjusted for current period production.

During the second quarter of 2015, we recorded a non-cash ceiling test write-down of \$410.5 million pre-tax (\$255.6 million, net of tax).

Contract Drilling

Drilling revenues decreased \$59.3 million or 52% in the second quarter of 2015 versus the second quarter of 2014. The decrease was due primarily to a 58% decrease in the average number of drilling rigs in use partially offset by \$1.6 million for fees on contracts terminated early in the second quarter of 2015. Average drilling rig utilization decreased from 73.5 drilling rigs in the second quarter of 2014 to 30.7 drilling rigs in the second quarter of 2015.

Drilling operating costs decreased \$30.0 million or 45% between the comparative second quarters of 2015 and 2014. The decrease was due primarily to fewer drilling rigs operating. Contract drilling depreciation decreased \$7.0 million or 34% also due primarily to fewer drilling rigs operating. In December 2014, 31 drilling rigs and other drilling equipment were written down to their estimated market value. During the second quarter of 2015, we recorded an additional impairment of approximately \$8.3 million on the 30 of the 31 drilling rigs and other equipment that will be sold at auction during the third quarter or within the next twelve months. The other rig was sold in the first quarter.

Mid-Stream

Our mid-stream revenues decreased \$40.5 million or 44% in the second quarter of 2015 as compared to the second quarter of 2014 due primarily from the average price for natural gas sold decreasing 43% and the average price for NGLs sold decreasing 45% and NGLs volumes sold per day decreasing 21% primarily from being in ethane ejection mode. Gas processing volumes per day increased 15% and gas gathering volumes per day increased 11% between the comparative quarters due to new well connects.

Operating costs decreased \$38.1 million or 48% in the second quarter of 2015 compared to the second quarter of 2014 primarily due to a 55% decrease in prices paid for natural gas purchased partially offset by a 14% increase in purchase volumes. Depreciation and amortization increased \$0.7 million, or 7%, primarily due to capital expenditures for upgrades and well connects.

General and Administrative

General and administrative expenses decreased \$1.0 million or 9% in the second quarter of 2015 compared to the second quarter of 2014 primarily due to lower employee costs.

Gain on Disposition of Assets

There was a \$0.4 million gain on disposition of assets in the second quarter of 2015 primarily due to the sale of one gathering system in our mid-stream segment in the second quarter of 2015, compared to a gain of \$0.2 million in the second quarter of 2014.

Other Income (Expense)

Interest expense, net of capitalized interest, increased \$3.8 million between the comparative second quarters of 2015 and 2014 due primarily to higher average bank debt outstanding. 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 2015 was \$5.5 million compared to \$8.1 million in the second quarter of 2014, and was netted against our gross interest of \$13.4 million and \$12.2 million for the second quarters of 2015 and 2014, respectively. Our average interest rate decreased from 6.7% to 5.4% and our average debt outstanding was \$258.3 million higher in the second quarter of 2015 as compared to the second quarter of 2014 primarily due to the increase in outstanding borrowings under our credit agreement over the comparative periods.

Gain (loss) on derivatives not designated as hedges increased \$8.8 million primarily due to fluctuations in forward prices used to estimate the fair value in mark-to-market accounting.

Income Tax Expense

Income tax expense (benefit) changed from an expense of \$34.3 million in the second quarter of 2014 to a benefit of \$164.3 million in the second quarter of 2015 primarily due to decreased pre-tax income primarily from the non-cash ceiling test write-down. Our effective tax rate was 37.5% for the second quarter of 2015 compared to 38.7% for the second quarter of 2014. This decrease is primarily due to our permanent tax differences having a lesser impact on our effective tax rate due to our pre-tax loss in the second quarter of 2015. Current income tax expense was \$0.8 million for the second quarter of 2015 compared to \$8.5 million for the second quarter of 2014 with the decrease primarily due to decreased anticipated alternative minimum taxes. We paid \$2.6 million of income taxes in the second quarter of 2015.

Six Months Ended June 30, 2015 versus Six Months Ended June 30, 2014

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

	Six Months Ended June 30,		Percent Change ⁽¹⁾
	2015	2014	
	(In thousands unless otherwise specified)		
Total revenue	\$ 469,546	\$ 793,419	(41)%
Net income (loss)	\$ (522,743)	\$ 111,305	NM
Oil and Natural Gas:			
Revenue	\$ 213,325	\$ 386,705	(45)%
Operating costs excluding depreciation, depletion, amortization, and impairment	\$ 91,183	\$ 85,138	7 %
Depreciation, depletion, and amortization	\$ 145,219	\$ 130,925	11 %
Impairment of oil and natural gas properties	\$ 811,129	\$ —	NM
Average oil price received (Bbl)	\$ 51.73	\$ 92.95	(44)%
Average NGLs price received (Bbl)	\$ 10.37	\$ 34.57	(70)%
Average natural gas price received (Mcf)	\$ 2.80	\$ 4.14	(32)%
Oil production (Bbl)	2,046,000	1,760,000	16 %
NGLs production (Bbl)	2,615,000	2,228,000	17 %
Natural gas production (Mcf)	33,064,000	28,881,000	14 %
Depreciation, depletion, and amortization rate (Boe)	\$ 13.98	\$ 14.58	(4)%
Contract Drilling:			
Revenue	\$ 150,092	\$ 220,878	(32)%
Operating costs excluding depreciation and impairment	\$ 88,231	\$ 130,298	(32)%
Depreciation	\$ 28,278	\$ 38,634	(27)%
Impairment of contract drilling equipment	\$ 8,314	\$ —	NM
Percentage of revenue from daywork contracts	100%	100%	— %
Average number of drilling rigs in use	40.4	70.7	(43)%
Average dayrate on daywork contracts	\$ 20,032	\$ 19,766	1 %
Mid-Stream:			
Revenue	\$ 106,129	\$ 185,836	(43)%
Operating costs excluding depreciation and amortization	\$ 84,767	\$ 159,608	(47)%
Depreciation and amortization	\$ 21,542	\$ 19,700	9 %
Gas gathered—Mcf/day	348,666	315,116	11 %
Gas processed—Mcf/day	187,592	155,807	20 %
Gas liquids sold—gallons/day	584,389	737,353	(21)%
Corporate and other:			
General and administrative expense	\$ 18,994	\$ 20,237	(6)%
Gain on disposition of assets	\$ 960	\$ 9,621	(90)%
Other income (expense):			
Interest expense, net	\$ (15,196)	\$ (7,921)	92 %
Gain (loss) on derivatives not designated as hedges	\$ 4,667	\$ (29,075)	116 %
Other	\$ 22	\$ 71	(69)%
Income tax expense (benefit)	\$ (314,915)	\$ 70,270	NM
Average long-term debt outstanding	\$ 876,510	\$ 649,179	35 %
Average interest rate	5.5%	6.7%	(18)%

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

Oil and Natural Gas

Oil and natural gas revenues decreased \$173.4 million or 45% in the first six months of 2015 as compared to the first six months of 2014 due primarily to lower oil, natural gas, and NGLs prices partially offset by an increase in production. In the first six months of 2015, as compared to the first six months of 2014, oil production increased 16%, NGLs production increased 17%, and natural gas production increased 14%. Average oil prices decreased 44% to \$51.73 per barrel, average natural gas prices decreased 32% to \$2.80 per Mcf, and NGLs prices decreased 70% to \$10.37 per barrel.

Oil and natural gas operating costs increased \$6.0 million or 7% between the comparative first six months of 2015 and 2014 due to higher saltwater disposal expenses and lease operating expenses partially offset by lower general and administrative expense and lower gross production taxes due to lower sales revenue.

DD&A increased \$14.3 million or 11% due primarily to a 16% increase in equivalent production partially offset by a 4% decrease in the DD&A rate. The decrease in our DD&A rate in the first six months of 2015 compared to the first six months of 2014 resulted primarily from the effect of the ceiling test write-downs in the fourth quarter of 2014 and the first quarter of 2015. Our DD&A expense on our oil and natural gas properties is calculated each quarter utilizing period end reserve quantities adjusted for current period production.

During the first six months, we recorded two non-cash ceiling test write-downs totaling \$811.1 million pre-tax (\$505.0 million, net of tax).

Contract Drilling

Drilling revenues decreased \$70.8 million or 32% in the first six months of 2015 versus the first six months of 2014. The decrease was due primarily to a 43% decrease in the average number of drilling rigs in use partially offset by \$14.3 million for fees on contracts terminated early in the first six months of 2015. Average drilling rig utilization decreased from 70.7 drilling rigs in the first six months of 2014 to 40.4 drilling rigs in the first six months of 2015.

Drilling operating costs decreased \$42.1 million or 32% between the comparative first six months of 2015 and 2014. The decrease was due primarily to fewer drilling rigs operating. Contract drilling depreciation decreased \$10.4 million or 27% also due primarily to fewer drilling rigs operating. In December 2014, 31 drilling rigs and other drilling equipment were written down to their estimated market value. During the second quarter of 2015, we recorded an additional impairment of approximately \$8.3 million on the 30 of the 31 drilling rigs and other equipment that will be sold at auction during the third quarter or within the next twelve months. The other rig was sold in the first quarter.

Mid-Stream

Our mid-stream revenues decreased \$79.7 million or 43% in the first six months of 2015 as compared to the first six months of 2014 due primarily from the average price for natural gas sold decreasing 41% and the average price for NGLs sold decreasing 47% and NGLs volumes sold per day decreasing 21% primarily from being in ethane ejection mode. Gas processing volumes per day increased 20% between the comparative months primarily from new well connections. Gas gathering volumes per day increased 11% between the comparative months due to new well connects.

Operating costs decreased \$74.8 million or 47% in the first six months of 2015 compared to the first six months of 2014 primarily due to a 56% decrease in prices paid for natural gas purchased partially offset by a 19% increase in purchase volumes. Depreciation and amortization increased \$1.8 million, or 9%, primarily due to capital expenditures for upgrades and well connects.

General and Administrative

General and administrative expenses decreased \$1.2 million or 6% in the first six months of 2015 compared to the first six months of 2014 primarily due to lower employee costs.

Gain on Disposition of Assets

There was a \$1.0 million gain on disposition of assets in the first six months of 2015 primarily due to the sale of one gathering system, various rig components, vehicles, and a drilling rig in the first six months of 2015, compared to a gain of \$9.6 million for the sale of four idle 3,000 horsepower drilling rigs to an unaffiliated third-party in the first six months of 2014.

Other Income (Expense)

Interest expense, net of capitalized interest, increased \$7.3 million between the comparative first six months of 2015 and 2014 due primarily to higher average bank debt outstanding. 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 2015 was \$11.4 million compared to \$16.3 million in the first six months of 2014, and was netted against our gross interest of \$26.6 million and \$24.2 million for the first six months of 2015 and 2014, respectively. Our average interest rate decreased from 6.7% to 5.5% and our average debt outstanding was \$227.3 million higher in the first six months of 2015 as compared to the first six months of 2014 primarily due to the increase in outstanding borrowings under our credit agreement over the comparative periods.

Gain (loss) on derivatives not designated as hedges increased \$33.7 million primarily due to fluctuations in forward prices used to estimate the fair value in mark-to-market accounting.

Income Tax Expense

Income tax expense (benefit) changed from an expense of \$70.3 million in the first six months of 2014 to a benefit of \$314.9 million in the first six months of 2015 primarily due to decreased pre-tax income primarily from the non-cash ceiling test write-downs. Our effective tax rate was 37.6% for the first six months of 2015 compared to 38.7% for the first six months of 2014. This decrease is primarily due to our permanent tax differences having a lesser impact on our effective tax rate due to our pre-tax losses in the first six months of 2015. Current income tax expense was \$0.9 million for the first six months of 2015 compared to \$18.3 million for the first six months of 2014 with the decrease primarily due to decreased anticipated alternative minimum taxes. We paid \$3.1 million of income taxes in the first six months of 2015.

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 in the future 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, such things as:

- the amount and nature of our future capital expenditures and how we expect to fund our capital expenditures;
- the amount of wells we plan to drill or rework;
- 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 our legal proceedings 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;
- the number of wells our oil and natural gas segment plans to drill during the year; and
- our estimates of the amounts of any ceiling test write-downs we may be required to record in future periods.

These statements are based on certain assumptions and analyses made by us in light of 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;
- decreases or increases in commodity prices; and
- other factors, most of which are beyond our control.

You should not place undue reliance on any of these forward-looking statements. Except as required by law, we disclaim any current 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 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 2015 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 \$528,000 per month (\$6.3 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 \$330,000 per month (\$4.0 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 \$419,000 per month (\$5.0 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, 2015, the following non-designated hedges were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Jul'15 – Dec'15	Crude oil – swap	1,000 Bbl/day	\$95.00	WTI – NYMEX
Jul'15 – Dec'15	Crude oil – collar	2,000 Bbl/day	\$58.00-\$64.40	WTI – NYMEX
Jul'15 – Dec'15	Natural gas – swap	40,000 MMBtu/day	\$3.98	NYMEX (HH)
Jul'15 – Sep'15	Natural gas – collar	30,000 MMBtu/day	\$2.58-\$3.04	NYMEX (HH)
Jan'16 - Dec'16	Natural gas – swap	10,000 MMBtu/day	\$3.25	NYMEX (HH)

Interest Rate Risk. Our interest rate exposure relates to our long-term debt under our credit agreement and the Notes. The credit agreement, at our election bears interest at variable rates based on the Prime Rate or the LIBOR Rate. At our election, borrowings under our credit agreement may be fixed at the LIBOR Rate for periods of up to 180 days. Based on our average outstanding long-term debt subject to a variable rate in the first six months of 2015, a 1% increase in the floating rate would reduce our annual pre-tax cash flow by approximately \$2.3 million. Under our Notes, we pay a fixed rate of interest of 6.625% per year (payable semi-annually in arrears on May 15 and November 15 of each year).

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures under Exchange Act Rule 13a-15. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective as of June 30, 2015 in ensuring the appropriate information is recorded, processed, summarized and reported in our periodic SEC filings relating to the company (including its consolidated subsidiaries) and is accumulated and communicated to the Chief Executive Officer, Chief Financial Officer, and management to allow timely decisions.

Changes in Internal Controls. There were no changes in our internal controls over financial reporting during the quarter ended June 30, 2015 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting, as defined in Rule 13a – 15(f) under the Exchange Act.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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

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

timetable for when the court will issue its ruling. The merits of Plaintiffs' claims will remain stayed while class certification issues are pending.

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, 2014, which could materially affect our business, financial condition, or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing our company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition, and/or operating results.

There have been no material changes to the risk factors disclosed in Item 1A in our Form 10-K for the year ended December 31, 2014.

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, 2015:

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 ⁽¹⁾	(d) Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
April 1, 2015 to April 30, 2015	—	\$ —	—	—
May 1, 2015 to May 31, 2015	—	—	—	—
June 1, 2015 to June 30, 2015	87	31.18	87	—
Total	87	\$ 31.18	87	—

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

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

SIGNATURES

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

Unit Corporation

Date: August 4, 2015

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

Date: August 4, 2015

By: /s/ David T. Merrill
DAVID T. MERRILL
Senior Vice President, Chief Financial Officer,
and Treasurer

Exhibit 15

August 4, 2015

Securities and Exchange Commission
100 F. Street, N.W.
Washington, D.C. 20549

Commissioners:

We are aware that our report dated August 4, 2015 on our review of interim financial information of Unit Corporation for the three and six month periods ended June 30, 2015 and 2014 and included in the Company's quarterly report on Form 10-Q for the quarter ended June 30, 2015 is incorporated by reference in its Registration Statements on Form S-3 (File No. 333-202956) and Form S-8 (File No.'s 33-19652, 33-44103, 33-49724, 33-64323, 33-53542, 333-38166, 333-39584, 333-135194, 333-137857, 333-166605, 333-181922, and 333-205033).

Very truly yours,

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Tulsa, Oklahoma

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 4, 2015

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

Exhibit 31.2
302 CERTIFICATIONS

I, David T. Merrill, certify that:

1. I have reviewed this quarterly report on form 10-Q of Unit Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 4, 2015

/s/ David T. Merrill
DAVID T. MERRILL
Senior Vice President, Chief Financial Officer,
and Treasurer

Exhibit 32

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

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

The Quarterly Report on Form 10-Q for the quarter ended June 30, 2015 (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, 2015 and December 31, 2014 and for the three and six month periods ended June 30, 2015 and 2014.

Dated: August 4, 2015

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

Dated: August 4, 2015

By: /s/ David T. Merrill
David T. Merrill
Senior Vice President, Chief Financial Officer, and
Treasurer

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

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