PATTERSON UTI ENERGY INC
Form 10-Q
August 02, 2016

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

R QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2016

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 0-22664

Patterson-UTI Energy, Inc.

(Exact name of registrant as specified in its charter)

DELAWARE	75-2504748
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
450 GEARS ROAD, SUITE 500	
HOUSTON, TEXAS	77067
(Address of principal executive offices)	(Zip Code)

(281) 765-7100

(Registrant's telephone number, including area code)

N/A

(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 R 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 (section 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 R 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:

Large accelerated filer	R	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 R

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

147,732,339 shares of common stock, $0.01 par value, as of July 28, 2016

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

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PART I — FINANCIAL INFORMATION

ITEM 1. Financial Statements

The following unaudited condensed consolidated financial statements include all adjustments which are, in the opinion of management, necessary for a fair statement of the results for the interim periods presented.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(unaudited, in thousands, except share data)

	June 30, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$209,627	$113,346
Accounts receivable, net of allowance for doubtful accounts of $3,191 and $3,545 at June 30, 2016 and December 31, 2015, respectively	128,551	219,672
Federal and state income taxes receivable	36,671	33,454
Inventory	11,532	14,716
Deferred tax assets, net	28,487	65,121
Other	40,855	40,227
Total current assets	455,723	486,536
Property and equipment, net	3,640,894	3,920,708
Goodwill and intangible assets	90,788	92,609
Deposits on equipment purchases	17,970	22,367
Other	6,096	7,264
Total assets	$4,211,471	$4,529,484
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$66,343	$82,771
Accrued expenses	139,922	161,611
Current portion of long-term debt, net of debt issuance cost of $529 and $483 at June 30, 2016 and December 31, 2015, respectively	85,721	63,267
Total current liabilities	291,986	307,649
Long-term debt, net of debt issuance cost of $2,581 and $3,350 at June 30, 2016 and December 31, 2015, respectively	741,169	787,900
Deferred tax liabilities, net	768,556	863,833
Other	7,930	8,971
Total liabilities	1,809,641	1,968,353
Commitments and contingencies (see Note 9)		

Stockholders' equity:		
Preferred stock, par value $.01; authorized 1,000,000 shares, no shares issued	—	—
Common stock, par value $.01; authorized 300,000,000 shares with 191,112,033 and 190,374,801 issued and 147,735,741 and 147,167,561 outstanding at June 30, 2016 and December 31, 2015, respectively	1,911	1,904
Additional paid-in capital	1,023,001	1,011,811
Retained earnings	2,284,520	2,458,554
Accumulated other comprehensive income (loss)	3,054	(4,093)
Treasury stock, at cost, 43,376,292 and 43,207,240 shares at June 30, 2016 and December 31, 2015, respectively	(910,656)	(907,045)
Total stockholders' equity	2,401,830	2,561,131
Total liabilities and stockholders' equity	$4,211,471	$4,529,484

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(unaudited, in thousands, except per share data)

	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Operating revenues:				
Contract drilling	$115,235	$288,321	$283,894	$689,799
Pressure pumping	73,950	176,624	170,263	426,345
Oil and natural gas	4,722	7,816	8,689	14,316
Total operating revenues	193,907	472,761	462,846	1,130,460
Operating costs and expenses:				
Contract drilling	63,803	153,848	144,701	366,658
Pressure pumping	69,546	142,756	157,359	355,481
Oil and natural gas	1,650	2,779	3,740	5,577
Depreciation, depletion, amortization and impairment	170,975	181,924	347,745	357,306
Selling, general and administrative	17,087	19,216	35,059	39,753
Other operating (income) expense, net	(4,822)	(2,998)	(6,167)	6,346
Total operating costs and expenses	318,239	497,525	682,437	1,131,121
Operating loss	(124,332)	(24,764)	(219,591)	(661)
Other income (expense):				
Interest income	100	318	210	601
Interest expense, net of amount capitalized	(10,678)	(9,249)	(21,478)	(17,790)
Other	17	-	33	-
Total other expense	(10,561)	(8,931)	(21,235)	(17,189)
Loss before income taxes	(134,893)	(33,695)	(240,826)	(17,850)
Income tax expense (benefit):				
Current	(2,000)	1,705	(25,814)	32,225
Deferred	(47,027)	(16,425)	(58,643)	(40,225)
Total income tax benefit	(49,027)	(14,720)	(84,457)	(8,000)
Net loss	$(85,866)	$(18,975)	$(156,369)	$(9,850)
Net loss per common share:				
Basic	$(0.58)	$(0.13)	$(1.06)	$(0.07)
Diluted	$(0.58)	$(0.13)	$(1.06)	$(0.07)
Weighted average number of common shares outstanding:				
Basic	145,944	145,300	145,857	145,142
Diluted	145,944	145,300	145,857	145,142
Cash dividends per common share	$0.02	$0.10	$0.12	$0.20

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

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PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(unaudited, in thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Net loss	$(85,866)	$(18,975)	$(156,369)	$(9,850)
Other comprehensive income (loss), net of taxes of $0 for all periods:				
Foreign currency translation adjustment	469	3,033	7,147	(5,545)
Total comprehensive loss	$(85,397)	$(15,942)	$(149,222)	$(15,395)

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY

(unaudited, in thousands)

	Common Stock Number of Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock	Total
Balance, December 31, 2015	190,375	$ 1,904	$ 1,011,811	$ 2,458,554	$ (4,093)	$ (907,045)	2,561,131
Net loss	—	—	—	(156,369)	—	—	(156,369)
Foreign currency translation adjustment	—	—	—	—	7,147	—	7,147
Issuance of restricted stock	749	7	(7)	—	—	—	—
Vesting of restricted stock units	15	—	—	—	—	—	—
Forfeitures of restricted stock	(27)	—	—	—	—	—	—
Stock-based compensation	—	—	14,192	—	—	—	14,192
Tax expense related to stock-based compensation	—	—	(2,995)	—	—	—	(2,995)
Payment of cash dividends	—	—	—	(17,665)	—	—	(17,665)
Purchase of treasury stock	—	—	—	—	—	(3,611)	(3,611)
Balance, June 30, 2016	191,112	$ 1,911	$ 1,023,001	$ 2,284,520	$ 3,054	$ (910,656)	$ 2,401,830

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited, in thousands)

	Six Months Ended June 30,	
	2016	2015
Cash flows from operating activities:		
Net loss	$(156,369)	$(9,850)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion, amortization and impairment	347,745	357,306
Dry holes and abandonments	—	114
Deferred income tax benefit	(58,643)	(40,225)
Stock-based compensation expense	14,192	13,831
Net gain on asset disposals	(7,267)	(5,914)
Tax expense on stock-based compensation	(2,995)	—
Amortization of debt issuance costs	723	522
Changes in operating assets and liabilities:		
Accounts receivable	91,559	330,176
Income taxes receivable/payable	(2,329)	93,527
Inventory and other assets	3,795	11,555
Accounts payable	(25,738)	(108,424)
Accrued expenses	(21,658)	(1,894)
Other liabilities	(1,088)	(63)
Net cash provided by operating activities	181,927	640,661
Cash flows from investing activities:		
Purchases of property and equipment	(51,834)	(463,633)
Proceeds from disposal of assets	12,350	10,728
Net cash used in investing activities	(39,484)	(452,905)
Cash flows from financing activities:		
Purchases of treasury stock	(3,611)	(8,010)
Dividends paid	(17,665)	(29,352)
Tax benefit related to stock-based compensation	—	1,129
Debt issuance costs	—	(1,979)
Proceeds from long-term debt	—	200,000
Repayment of long-term debt	(25,000)	(10,000)
Proceeds from borrowings under revolving credit facility	—	54,000
Repayment of borrowings under revolving credit facility	—	(357,000)
Net cash used in financing activities	(46,276)	(151,212)
Effect of foreign exchange rate changes on cash	114	(3,050)
Net increase in cash and cash equivalents	96,281	33,494
Cash and cash equivalents at beginning of period	113,346	43,012
Cash and cash equivalents at end of period	$209,627	$76,506
Supplemental disclosure of cash flow information:		
Net cash (paid) received during the period for:		
Interest, net of capitalized interest of $286 in 2016 and $3,343 in 2015	$(20,252)	$(16,506)
Income taxes	$19,603	$63,740

Non-cash investing and financing activities:		
Net increase (decrease) in payables for purchases of property and equipment	$9,283	$(50,487)
Net decrease in deposits on equipment purchases	$4,397	$64,638

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Consolidation and Presentation

The unaudited interim condensed consolidated financial statements include the accounts of Patterson-UTI Energy, Inc. (the “Company”) and its wholly-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated. Except for wholly-owned subsidiaries, the Company has no controlling financial interests in any entity which would require consolidation.

The unaudited interim condensed consolidated financial statements have been prepared by management of the Company pursuant to the rules and regulations of the Securities and Exchange Commission. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been omitted pursuant to such rules and regulations, although the Company believes the disclosures included either on the face of the financial statements or herein are sufficient to make the information presented not misleading. In the opinion of management, all adjustments which are of a normal recurring nature considered necessary for a fair statement of the information in conformity with accounting principles generally accepted in the United States of America have been included. The Unaudited Condensed Consolidated Balance Sheet as of December 31, 2015, as presented herein, was derived from the audited consolidated balance sheet of the Company, but does not include all disclosures required by accounting principles generally accepted in the United States of America. These unaudited condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and related notes included in the Company’s Annual Report on Form 10-K for the fiscal year ended December 31, 2015. The results of operations for the six months ended June 30, 2016 are not necessarily indicative of the results to be expected for the full year.

The U.S. dollar is the functional currency for all of the Company’s operations except for its Canadian operations, which uses the Canadian dollar as its functional currency. The effects of exchange rate changes are reflected in accumulated other comprehensive income, which is a separate component of stockholders’ equity.

During the first quarter of 2016, the Company determined that certain income and expense items should be classified as “other operating (income) expense, net” in the condensed consolidated statements of operations. This caption now includes gains and losses on asset disposals and expenses related to certain legal settlements. Gains and losses on asset disposals were previously presented as a separate line in the condensed consolidated statements of operations. Expenses related to legal settlements were previously included in operating costs of the respective operating segment or in selling, general and administrative expense. For comparative purposes, all such prior period amounts were reclassified to conform to the current presentation, including the Company’s previously disclosed $12.3 million legal settlement that was previously included within selling, general and administrative expense for the six months ended June 30, 2015.

The Company provides a dual presentation of its net income (loss) per common share in its unaudited condensed consolidated statements of operations: Basic net income (loss) per common share (“Basic EPS”) and diluted net income (loss) per common share (“Diluted EPS”).

Basic EPS excludes dilution and is computed by first allocating earnings between common stockholders and holders of non-vested shares of restricted stock. Basic EPS is then determined by dividing the earnings attributable to common stockholders by the weighted average number of common shares outstanding during the period, excluding non-vested shares of restricted stock.

Diluted EPS is based on the weighted average number of common shares outstanding plus the dilutive effect of potential common shares, including stock options, non-vested shares of restricted stock and restricted stock units. The dilutive effect of stock options and restricted stock units is determined using the treasury stock method. The dilutive effect of non-vested shares of restricted stock is based on the more dilutive of the treasury stock method or the two-class method, assuming a reallocation of undistributed earnings to common stockholders after considering the dilutive effect of potential common shares other than non-vested shares of restricted stock.

The following table presents information necessary to calculate net loss per share for the three and six month periods ended June 30, 2016 and 2015 as well as potentially dilutive securities excluded from the weighted average number of diluted common shares outstanding because their inclusion would have been anti-dilutive (in thousands, except per share amounts):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
BASIC EPS:				
Net loss	$(85,866)	$(18,975)	$(156,369)	$(9,850)
Adjust for loss attributed to holders of non-vested restricted stock	846	198	1,526	109
Loss attributed to other common stockholders	$(85,020)	$(18,777)	$(154,843)	$(9,741)
Weighted average number of common shares outstanding, excluding non-vested shares of restricted stock	145,944	145,300	145,857	145,142
Basic net loss per common share	$(0.58)	$(0.13)	$(1.06)	$(0.07)
DILUTED EPS:				
Loss attributed to other common stockholders	$(85,020)	$(18,777)	$(154,843)	$(9,741)
Weighted average number of common shares outstanding, excluding non-vested shares of restricted stock	145,944	145,300	145,857	145,142
Add dilutive effect of potential common shares	-	-	-	-
Weighted average number of diluted common shares outstanding	145,944	145,300	145,857	145,142
Diluted net loss per common share	$(0.58)	$(0.13)	$(1.06)	$(0.07)
Potentially dilutive securities excluded as anti-dilutive	9,370	8,208	9,370	8,208

2. Stock-based Compensation

The Company uses share-based payments to compensate employees and non-employee directors. The Company recognizes the cost of share-based payments under the fair-value-based method. Share-based awards consist of equity instruments in the form of stock options, restricted stock or restricted stock units and have included service and, in certain cases, performance conditions. The Company's share-based awards also included share-settled performance unit awards. Share-settled performance unit awards are accounted for as equity awards. The Company issues shares of common stock when vested stock options are exercised, when restricted stock is granted and when restricted stock units and share-settled performance unit awards vest.

Stock Options — The Company estimates the grant date fair values of stock options using the Black-Scholes-Merton valuation model. Volatility assumptions are based on the historic volatility of the Company's common stock over the most recent period equal to the expected term of the options as of the date the options are granted. The expected term assumptions are based on the Company's experience with respect to employee stock option activity. Dividend yield assumptions are based on the expected dividends at the time the options are granted. The risk-free interest rate assumptions are determined by reference to United States Treasury yields. Weighted-average assumptions used to estimate the grant date fair values for stock options granted for the three and six month periods ended June 30, 2016 and 2015 follow:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Volatility	34.87 %	37.91 %	35.13 %	37.95 %
Expected term (in years)	5.00	5.00	5.00	5.00
Dividend yield	2.16 %	1.97 %	2.19 %	2.00 %
Risk-free interest rate	1.40 %	1.35 %	1.42 %	1.37 %

Stock option activity from January 1, 2016 to June 30, 2016 follows:

	Underlying Shares	Weighted Average Exercise Price Per Share
Outstanding at January 1, 2016	6,307,250	$ 21.68
Granted	894,900	$ 18.35
Exercised	—	$ -
Cancelled	—	$ -
Expired	(50,000)	$ 29.24
Outstanding at June 30, 2016	7,152,150	$ 21.21
Exercisable at June 30, 2016	5,666,148	$ 21.48

Restricted Stock — For all restricted stock awards to date, shares of common stock were issued when the awards were made. Non-vested shares are subject to forfeiture for failure to fulfill service conditions and, in certain cases, performance conditions. Non-forfeitable dividends are paid on non-vested shares of restricted stock. The Company uses the straight-line method to recognize periodic compensation cost over the vesting period.

Restricted stock activity from January 1, 2016 to June 30, 2016 follows:

	Shares	Weighted Average Grant Date Fair Value Per Share
Non-vested restricted stock outstanding at January 1, 2016	1,432,250	$ 24.56
Granted	748,825	$ 20.66
Vested	(670,987)	$ 24.53
Forfeited	(26,626)	$ 24.76
Non-vested restricted stock outstanding June 30, 2016	1,483,462	$ 22.60

Restricted Stock Units — For all restricted stock unit awards made to date, shares of common stock are not issued until the units vest. Restricted stock units are subject to forfeiture for failure to fulfill service conditions. Non-forfeitable cash dividend equivalents are paid on certain non-vested restricted stock units. The Company uses the straight-line method to recognize periodic compensation cost over the vesting period.

Restricted stock unit activity from January 1, 2016 to June 30, 2016 follows:

	Shares	Weighted Average Grant Date Fair Value Per Share

Non-vested restricted stock units outstanding at January 1, 2016	41,686	$ 26.22
Granted	18,350	$ 21.71
Vested	(15,033)	$ 27.30
Forfeited	(7,668)	$ 24.83
Non-vested restricted stock units outstanding June 30, 2016	37,335	$ 23.86

Performance Unit Awards. The Company has granted stock-settled performance unit awards to certain executive officers (the “Performance Units”) on an annual basis since 2010. The Performance Units provide for the recipients to receive a grant of shares of stock upon the achievement during a specified period of certain performance goals established by the Compensation Committee. The performance period for the Performance Units is the three year period commencing on April 1 of the year of grant, except that for the Performance Units granted in 2013 the performance period has been extended pursuant to its terms, as described below.

The performance goals for the Performance Units are tied to the Company's total shareholder return for the performance period as compared to total shareholder return for a peer group determined by the Compensation Committee. These goals are considered to be market conditions under the relevant accounting standards and the market conditions were factored into the determination of the fair value of the respective performance units. Generally, the recipients will receive a target number of shares if the Company's total shareholder return during the performance period is positive and, when compared to the peer group, is at the 50th percentile. If the Company's total shareholder return during the performance period is positive and, when compared to the peer group, is at the 75th percentile or higher, then the recipients will receive two times the target number of shares. If the Company's total shareholder return during the performance period is positive, and, when compared to the peer group, is at the 25th percentile, then the recipients will only receive one-half of the target number of shares. If the Company's total shareholder return during the performance period is positive and, when compared to the peer group, achievement is between the 25th and 75th percentile, then the shares to be received by the recipients will be determined on a pro-rata basis. For the Performance Units awarded prior to 2016, there is no payout unless the Company's total shareholder return is positive and, when compared to the peer group, is at or above the 25th percentile.

For the Performance Units granted in April 2016, if the Company's total shareholder return is negative, and, when compared to the peer group is at or above the 25th percentile, then the recipients will receive one-half of the number of shares they would have received if the Company's total shareholder return had been positive.

In respect of the 2013 Performance Units, the performance period ended March 31, 2016, the Company's total shareholder return for the performance period was negative, the Company's total shareholder return for the performance period when compared to the peer group was above the 75th percentile, and there was no payout; provided, however, that pursuant to the terms of those 2013 awards, if, during the two-year period ending March 31, 2018, the Company's total shareholder return for any 30 consecutive day period equals or exceeds 18 percent on an annualized basis from April 1, 2013 through the last day of such 30 consecutive day period, and the recipient is actively employed by the Company through the last day of the extended performance period, then the Company will issue to the recipient the number of shares equal to the amount the recipient would have been entitled to receive if the Company's total shareholder return had been positive during the initial three year performance period.

The total target number of shares with respect to the Performance Units for the awards in 2012-2016 is set forth below:

	2016 Performance Unit Awards	2015 Performance Unit Awards	2014 Performance Unit Awards	2013 Performance Unit Awards	2012 Performance Unit Awards
Target number of shares	185,000	190,600	154,000	236,500	192,000

Because the performance units are stock-settled awards, they are accounted for as equity awards and measured at fair value on the date of grant using a Monte Carlo simulation model. The fair value of the Performance Units is set forth below (in thousands):

2016	2015	2014	2013	2012

	Performance Unit Awards	Performance Unit Awards	Performance Unit Awards	Performance Unit Awards	Performance Unit Awards
Fair value at date of grant	$ 3,854	$ 4,052	$ 5,388	$ 5,564	$ 3,065

These fair value amounts are charged to expense on a straight-line basis over the performance period. Compensation expense associated with the Performance Units is shown below (in thousands):

	2016 Performance Unit Awards	2015 Performance Unit Awards	2014 Performance Unit Awards	2013 Performance Unit Awards	2012 Performance Unit Awards
Three months ended June 30, 2015	NA	$ 338	$ 449	$ 464	NA
Three months ended June 30, 2016	$ 321	$ 338	$ 449	NA	NA
Six months ended June 30, 2015	NA	$ 338	$ 898	$ 928	$ 255
Six months ended June 30, 2016	$ 321	$ 675	$ 898	$ 464	NA

3. Property and Equipment

Property and equipment consisted of the following at June 30, 2016 and December 31, 2015 (in thousands):

	June 30, 2016	December 31, 2015
Equipment	$6,885,227	$6,963,148
Oil and natural gas properties	199,591	200,923
Buildings	97,054	96,470
Land	22,370	22,370
	7,204,242	7,282,911
Less accumulated depreciation, depletion and impairment	(3,563,348)	(3,362,203)
Property and equipment, net	$3,640,894	$3,920,708

The Company evaluates the recoverability of its long-lived assets whenever events or changes in circumstances indicate that their carrying amounts may not be recoverable (a "triggering event"). Based on recent commodity prices, the Company's results of operations for the three and six month periods ended June 30, 2016 and management's expectations of results of operations in future periods, the Company concluded that no triggering event occurred during the six months ended June 30, 2016 with respect to its contract drilling segment or its pressure pumping segment. Management's expectations of results of operations in future periods were based on the assumption that activity levels in both segments will begin to recover by early 2017 in response to improved future oil prices.

The Company reviews its proved oil and natural gas properties for impairment whenever a triggering event occurs, such as downward revisions in reserve estimates or decreases in expected future oil and natural gas prices. Proved properties are grouped by field and undiscounted cash flow estimates are prepared based on the Company's expectation of future pricing over the lives of the respective fields. These cash flow estimates are reviewed by an independent petroleum engineer. If the net book value of a field exceeds its undiscounted cash flow estimate, impairment expense is measured and recognized as the difference between net book value and fair value. The fair value estimates used in measuring impairment are based on internally developed unobservable inputs including reserve volumes and future production, pricing and operating costs (Level 3 inputs in the fair value hierarchy of fair value accounting). The expected future net cash flows are discounted using an annual rate of 10% to determine fair value. The Company reviews unproved oil and natural gas properties quarterly to assess potential impairment. The Company's impairment assessment is made on a lease-by-lease basis and considers factors such as the Company's intent to drill, lease terms and abandonment of an area. If an unproved property is determined to be impaired, the related property costs are expensed. Impairment expense related to proved and unproved oil and natural gas properties totaled approximately $2.2 million in the first quarter of 2016 and is included in depreciation, depletion, amortization and impairment in the condensed consolidated statements of operations. There was no impairment expense in the second quarter of 2016.

4. Business Segments

The Company's revenues, operating income (losses) and identifiable assets are primarily attributable to three business segments: (i) contract drilling of oil and natural gas wells, (ii) pressure pumping services and (iii) the investment, on a non-operating working interest basis, in oil and natural gas properties. Each of these segments represents a distinct type of business. These segments have separate management teams which report to the Company's chief operating decision maker. The results of operations in these segments are regularly reviewed by the chief operating decision maker for purposes of determining resource allocation and assessing performance.

The following tables summarize selected financial information relating to the Company's business segments (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Revenues:				
Contract drilling	$115,235	$288,588	$283,992	$690,829
Pressure pumping	73,950	176,624	170,263	426,345
Oil and natural gas	4,722	7,816	8,689	14,316
Total segment revenues	193,907	473,028	462,944	1,131,490
Elimination of intercompany revenues (a)	-	(267)	(98)	(1,030)
Total revenues	$193,907	$472,761	$462,846	$1,130,460
Operating income (loss):				
Contract drilling	$(70,449)	$9,426	$(105,545)	$77,824
Pressure pumping	(46,025)	(18,744)	(89,984)	(33,760)
Oil and natural gas	1,267	(3,631)	(1,588)	(8,193)
	(115,207)	(12,949)	(197,117)	35,871
Corporate and other	(13,947)	(14,813)	(28,641)	(30,186)
Other operating income (expense), net (b)	4,822	2,998	6,167	(6,346)
Interest income	100	318	210	601
Interest expense	(10,678)	(9,249)	(21,478)	(17,790)
Other	17	-	33	-
Loss before income taxes	$(134,893)	$(33,695)	$(240,826)	$(17,850)

	June 30, 2016	December 31, 2015
Identifiable assets:		
Contract drilling	$3,201,494	$3,457,044
Pressure pumping	703,768	813,704
Oil and natural gas	30,903	34,073
Corporate and other (c)	275,306	224,663
Total assets	$4,211,471	$4,529,484

(a) Consists of contract drilling intercompany revenues for services provided to the oil and natural gas exploration and production segment.
(b) Other operating income (expense) includes net gains or losses associated with the disposal of assets related to corporate strategy decisions of the executive management group. Accordingly, the related gains or losses have been excluded from the results of specific segments. This caption also includes expenses related to certain legal settlements.
(c) Corporate and other assets primarily include cash on hand, income tax receivables and certain deferred tax assets.

5. Goodwill and Intangible Assets

Goodwill — All of the Company's goodwill at both June 30, 2016 and December 31, 2015 related to the contract drilling operating segment. Goodwill as of June 30, 2016 and changes for the six months then ended are as follows (in thousands):

	Six Months Ended June 30, 2016
Balance at beginning of period	$86,234
Changes to goodwill	—
Balance at end of period	$86,234

There were no impairment losses related to the goodwill in the contract drilling operating segment as of June 30, 2016 or December 31, 2015.

Goodwill is evaluated at least annually as of December 31, or when circumstances require, to determine if the fair value of recorded goodwill has decreased below its carrying value. For purposes of impairment testing, goodwill is evaluated at the reporting unit level. The Company's reporting units for impairment testing have been determined to be its operating segments. The Company first determines whether it is more likely than not that the fair value of a reporting unit is less than its carrying value after considering qualitative, market and other factors, and if it is, then goodwill impairment is determined using a two-step quantitative impairment test. From time to time, the Company may perform the first step of the quantitative testing for goodwill impairment in lieu of performing the qualitative assessment. The first step of the quantitative testing is to compare the fair value of an entity's reporting units to the respective carrying value of those reporting units. If the carrying value of a reporting unit exceeds its fair value, the second step of the quantitative testing is performed whereby the fair value of the reporting unit is allocated to its identifiable tangible and intangible assets and liabilities with any remaining fair value representing the fair value of goodwill. If this resulting fair value of goodwill is less than the carrying value of goodwill, an impairment loss would be recognized in the amount of the shortfall.

Intangible Assets — Intangible assets were recorded in the pressure pumping operating segment in connection with the fourth quarter 2010 acquisition of the assets of a pressure pumping business. As a result of the purchase price allocation, the Company recorded an intangible asset related to the customer relationships acquired. The intangible asset was recorded at fair value on the date of acquisition.

The value of the customer relationships was estimated using a multi-period excess earnings model to determine the present value of the projected cash flows associated with the customers in place at the time of the acquisition and taking into account a contributory asset charge. The resulting intangible asset is being amortized on a straight-line basis over seven years. Amortization expense of approximately $911,000 was recorded in the three months ended June 30, 2016 and 2015, and amortization expense of approximately $1.8 million was recorded in the six months ended June 30, 2016 and 2015.

The following table presents the gross carrying amount and accumulated amortization of the customer relationships as of June 30, 2016 and December 31, 2015 (in thousands):

	June 30, 2016			December 31, 2015		
	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Customer relationships	$25,500	$ (20,946)	$ 4,554	$25,500	$ (19,125)	$ 6,375

6. Accrued Expenses

Accrued expenses consisted of the following at June 30, 2016 and December 31, 2015 (in thousands):

	June 30, 2016	December 31, 2015
Salaries, wages, payroll taxes and benefits	$18,132	$27,055
Workers' compensation liability	70,155	75,358
Property, sales, use and other taxes	6,416	9,061
Insurance, other than workers' compensation	10,205	12,817
Accrued interest payable	7,403	7,668
Other	27,611	29,652
Total	$139,922	$161,611

7. Asset Retirement Obligation

The Company records a liability for the estimated costs to be incurred in connection with the abandonment of oil and natural gas properties in the future. This liability is included in the caption “other” in the liabilities section of the condensed consolidated balance sheet. The following table describes the changes to the Company’s asset retirement obligations during the six months ended June 30, 2016 and 2015 (in thousands):

	Six Months Ended June 30,	
	2016	2015
Balance at beginning of year	$5,692	$5,301
Liabilities incurred	66	271
Liabilities settled	(71)	(65)
Accretion expense	84	86
Revision in estimated costs of plugging oil and natural gas wells	43	—
Asset retirement obligation at end of period	$5,814	$5,593

8. Long Term Debt

2012 Credit Agreement — On September 27, 2012, the Company entered into a Credit Agreement (“Base Credit Agreement”) with Wells Fargo Bank, N.A., as administrative agent, letter of credit issuer, swing line lender and lender, and each of the other lenders party thereto. The Base Credit Agreement (as amended, the “Credit Agreement”) is a committed senior unsecured credit facility that includes a revolving credit facility.

On July 8, 2016, the Company entered into Amendment No. 2 to the Credit Agreement (the “Amendment No. 2”), which amended the Base Credit Agreement. Amendment No. 2, among other things:

- provided that borrowings under the Credit Agreement will be subject to a borrowing base calculated by reference to the Company’s and certain of its subsidiaries’ eligible equipment, inventory, accounts receivable and unencumbered cash as described in Amendment No. 2;
- decreased the permitted amount of certain secured indebtedness of the Company and its subsidiaries and decreased the permitted amount of certain unsecured indebtedness of the Company’s subsidiaries;
- revised the limitation on the Company’s ability to make investments in foreign subsidiaries or joint ventures such that, if the book value of all such investments since September 27, 2012 is above 20% of the total book value of the assets of the Company and its subsidiaries on a pro forma basis, the Company will not be able to make such investment;
- added a restricted payments covenant that restricts the Company’s ability to pay dividends and make equity repurchases, subject to certain exceptions, including an exception allowing such restricted payments if before and immediately after giving effect to such restricted payment, the Pro Forma Debt Service Coverage Ratio (as defined in Amendment No. 2) is at least 1.50 to 1.00; and
- requires that, if the consolidated cash balance of the Company and its subsidiaries, subject to certain exclusions, is more than $100 million at the end of the day on which a borrowing is made, the Company can only use the proceeds from such borrowing to fund acquisitions, capital expenditures and the

repurchase of indebtedness, and if such proceeds are not used in such manner within three business days, the Company must repay such unused proceeds on the fourth business day following such borrowings.

As a condition precedent, Amendment No. 2 required that the Company repay the entire outstanding principal amount of its bank term loans. The Company used $160 million of cash and $70 million drawn under the revolving credit facility to repay the bank term loans.

The revolving credit facility permits aggregate borrowings of up to $500 million outstanding at any time, subject to the borrowing base described above. The revolving credit facility contains a letter of credit facility that is limited to $50 million and a swing line facility that is limited to $20 million, in each case outstanding at any time.

The term loan facility included in the Base Credit Agreement, which facility was terminated in connection with Amendment No. 2, provided for a loan of $100 million, which was drawn on December 24, 2012 and was payable in quarterly principal installments.

Subject to customary conditions, the Company may request that the lenders' aggregate commitments with respect to the revolving credit facility be increased by up to $100 million, not to exceed total commitments of $600 million. The maturity date under the Base Credit Agreement was September 27, 2017 for the revolving facility, however, Amendment No. 2 extended the maturity date of $357.9 million in revolving credit commitments of certain lenders to March 27, 2019.

Loans under the Credit Agreement bear interest by reference, at the Company's election, to the LIBOR rate or base rate, provided, that swing line loans bear interest by reference only to the base rate. Until September 27, 2017, the applicable margin on LIBOR rate loans varies from 2.75% to 3.25% and the applicable margin on base rate loans varies from 1.75% to 2.25%, in each case determined based upon the Company's debt to capitalization ratio. On or after September 27, 2017, the applicable margin on LIBOR rate loans varies from 3.25% to 3.75% and the applicable margin on base rate loans varies from 2.25% to 2.75%, in each case determined based on the Company's excess availability under the credit facility. As of June 30, 2016 the applicable margin on LIBOR rate loans was 2.75% and the applicable margin on base rate loans was 1.75%. Based on the Company's debt to capitalization ratio at March 31, 2016, the applicable margin on LIBOR loans is 2.75% and the applicable margin on base rate loans is 1.75% as of July 1, 2016. Based on the Company's debt to capitalization ratio at June 30, 2016, the applicable margin on LIBOR loans will be 2.75% and the applicable margin on base rate loans will be 1.75% as of October 1, 2016. A letter of credit fee is payable by the Company equal to the applicable margin for LIBOR rate loans times the daily amount available to be drawn under outstanding letters of credit. The commitment fee rate payable to the lenders for the unused portion of the credit facility is 0.50%.

Each domestic subsidiary of the Company unconditionally guarantees all existing and future indebtedness and liabilities of the other guarantors and the Company arising under the Credit Agreement, other than (a) Ambar Lone Star Fluid Services LLC, (b) domestic subsidiaries that directly or indirectly have no material assets other than equity interests in, or capitalization indebtedness owed by, foreign subsidiaries, and (c) any subsidiary having total assets of less than $1 million. Such guarantees also cover obligations of the Company and any subsidiary of the Company arising under any interest rate swap contract with any person while such person is a lender or an affiliate of a lender under the Credit Agreement.

The Credit Agreement requires compliance with two financial covenants. The Company must not permit its debt to capitalization ratio to exceed 40%. The Credit Agreement generally defines the debt to capitalization ratio as the ratio of (a) total borrowed money indebtedness to (b) the sum of such indebtedness plus consolidated net worth, with consolidated net worth determined as of the last day of the most recently ended fiscal quarter. The Company also must not permit the interest coverage ratio as of the last day of a fiscal quarter to be less than 3.00 to 1.00. The Credit Agreement generally defines the interest coverage ratio as the ratio of earnings before interest, taxes, depreciation and amortization ("EBITDA") of the four prior fiscal quarters to interest charges for the same period. The Company was in compliance with these covenants at June 30, 2016.

The Credit Agreement also contains customary representations, warranties and affirmative and negative covenants.

Events of default under the Credit Agreement include failure to pay principal or interest when due, failure to comply with the financial and operational covenants, as well as a cross default event, loan document enforceability event, change of control event and bankruptcy and other insolvency events. If an event of default occurs and is continuing, then a majority of the lenders have the right, among others, to (i) terminate the commitments under the Credit Agreement, (ii) accelerate and require the Company to repay all the outstanding amounts owed under any loan document (provided that in limited circumstances with respect to insolvency and bankruptcy of the Company, such acceleration is automatic), and (iii) require the Company to cash collateralize any outstanding letters of credit.

As of June 30, 2016, the Company had $60 million principal amount outstanding under the term loan facility at an interest rate of 5.25% and no amounts outstanding under the revolving credit facility. As a condition precedent to Amendment No. 2, the Company repaid the entire outstanding principal amount under the term loan facility. The borrowing base under the Credit Agreement is currently $500 million. As of August 2, 2016, the Company had $70 million drawn under the revolving credit facility, with available borrowing capacity of $430 million.

2015 Reimbursement Agreement — On March 16, 2015, the Company entered into a Reimbursement Agreement (the “Reimbursement Agreement”) with The Bank of Nova Scotia (“Scotiabank”), pursuant to which the Company may from time to time request that Scotiabank issue an unspecified amount of letters of credit. As of June 30, 2016, the Company had $38.2 million in letters of credit outstanding under the Reimbursement Agreement.

Under the terms of the Reimbursement Agreement, the Company will reimburse Scotiabank on demand for any amounts that Scotiabank has disbursed under any letters of credit. Fees, charges and other reasonable expenses for the issuance of letters of credit are payable by the Company at the time of issuance at such rates and amounts as are in accordance with Scotiabank's prevailing practice. The Company is obligated to pay to Scotiabank interest on all amounts not paid by the Company on the date of demand or when otherwise due at the LIBOR rate plus 2.25% per annum, calculated daily and payable monthly, in arrears, on the basis of a calendar year for the actual number of days elapsed, with interest on overdue interest at the same rate as on the reimbursement amounts.

The Company has also agreed that if obligations under the Credit Agreement are secured by liens on any of its or any of its subsidiaries' property, then the Company's reimbursement obligations and (to the extent similar obligations would be secured under the Credit Agreement) other obligations under the Reimbursement Agreement and any letters of credit will be equally and ratably secured by all property subject to such liens securing the Credit Agreement.

Pursuant to a Continuing Guaranty dated as of March 16, 2015, the Company's payment obligations under the Reimbursement Agreement are jointly and severally guaranteed as to payment and not as to collection by subsidiaries of the Company that from time to time guarantee payment under the Credit Agreement.

2015 Term Loan Agreement — On March 18, 2015, the Company entered into a Term Loan Agreement (the "2015 Term Loan Agreement") with Wells Fargo Bank, N.A., as administrative agent and lender, each of the other lenders party thereto, Wells Fargo Securities, LLC, as Lead Arranger and Sole Book Runner, and Bank of America, N.A. and The Bank Of Tokyo-Mitsubishi UFJ, LTD., as Co-Syndication Agents.

The 2015 Term Loan Agreement was a senior unsecured single-advance term loan facility pursuant to which the Company made a term loan borrowing of $200 million on March 18, 2015 (the "Term Loan Borrowing"). The Term Loan Borrowing was payable in quarterly principal installments, together with accrued interest. Loans under the 2015 Term Loan Agreement bore interest, at the Company's election, at the per annum rate of LIBOR rate plus 3.25% or base rate plus 2.25%.

As of June 30, 2016, the Company had $170 million principal amount outstanding under the 2015 Term Loan Agreement at an interest rate of 5.75%. As a condition precedent to Amendment No. 2, the Company repaid the entire outstanding principal amount under the 2015 Term Loan Agreement and terminated the agreement.

Senior Notes — On October 5, 2010, the Company completed the issuance and sale of $300 million in aggregate principal amount of its 4.97% Series A Senior Notes due October 5, 2020 (the "Series A Notes") in a private placement. The Series A Notes bear interest at a rate of 4.97% per annum. The Company pays interest on the Series A Notes on April 5 and October 5 of each year. The Series A Notes will mature on October 5, 2020.

On June 14, 2012, the Company completed the issuance and sale of $300 million in aggregate principal amount of its 4.27% Series B Senior Notes due June 14, 2022 (the "Series B Notes") in a private placement. The Series B Notes bear interest at a rate of 4.27% per annum. The Company pays interest on the Series B Notes on April 5 and October 5 of each year. The Series B Notes will mature on June 14, 2022.

The Series A Notes and Series B Notes are senior unsecured obligations of the Company which rank equally in right of payment with all other unsubordinated indebtedness of the Company. The Series A Notes and Series B Notes are guaranteed on a senior unsecured basis by each of the existing domestic subsidiaries of the Company other than subsidiaries that are not required to be guarantors under the Credit Agreement.

The Series A Notes and Series B Notes are prepayable at the Company's option, in whole or in part, provided that in the case of a partial prepayment, prepayment must be in an amount not less than 5% of the aggregate principal amount of the notes then outstanding, at any time and from time to time at 100% of the principal amount prepaid, plus accrued and unpaid interest to the prepayment date, plus a "make-whole" premium as specified in the note purchase agreements.

The Company must offer to prepay the notes upon the occurrence of any change of control. In addition, the Company must offer to prepay the notes upon the occurrence of certain asset dispositions if the proceeds therefrom are not timely reinvested in productive assets. If any offer to prepay is accepted, the purchase price of each prepaid note is 100% of the principal amount thereof, plus accrued and unpaid interest thereon to the prepayment date.

The respective note purchase agreements require compliance with two financial covenants. The Company must not permit its debt to capitalization ratio to exceed 50% at any time. The note purchase agreements generally define the debt to capitalization ratio as the ratio of (a) total borrowed money indebtedness to (b) the sum of such indebtedness plus consolidated net worth, with consolidated net worth determined as of the last day of the most recently ended fiscal quarter. The Company also must not permit the interest coverage ratio as of the last day of a fiscal quarter to be less than 2.50 to 1.00. The note purchase agreements generally define the interest coverage ratio as the ratio of EBITDA for the four prior fiscal quarters to interest charges for the same period. The Company was in compliance with these covenants at June 30, 2016.

Events of default under the note purchase agreements include failure to pay principal or interest when due, failure to comply with the financial and operational covenants, a cross default event, a judgment in excess of a threshold event, the guaranty agreement ceasing to be enforceable, the occurrence of certain ERISA events, a change of control event and bankruptcy and other insolvency events. If an event of default under the note purchase agreements occurs and is continuing, then holders of a majority in principal amount of the respective notes have the right to declare all the notes then-outstanding to be immediately due and payable. In addition, if the Company defaults in payments on any note, then until such defaults are cured, the holder thereof may declare all the notes held by it pursuant to the note purchase agreement to be immediately due and payable.

In April and August 2015, the Financial Accounting Standards Board ("FASB") issued accounting standards updates to provide guidance for the presentation of debt issuance costs. Under this guidance, debt issuance costs, except those related to line-of-credit arrangements, are presented in the balance sheet as a direct deduction from the carrying amount of the related debt. Debt issuance costs related to line-of-credit arrangements can continue to be classified as a deferred charge. Amortization of debt issuance costs continues to be reported as interest expense. This guidance became effective for the Company during the three months ended March 31, 2016. This guidance was applied retrospectively, and debt issuance costs and long-term debt as of December 31, 2015 have been adjusted. There was no impact on results of operations or cash flows as a result of the adoption of this guidance. Interest expense related to the amortization of debt issuance costs was approximately $746,000 and $743,000 for the three months ended June 30, 2016 and 2015, respectively. Interest expense related to the amortization of debt issuance costs was approximately $1.5 million and $1.3 million for the six months ended June 30, 2016 and 2015, respectively.

Presented below is a schedule of the principal repayment requirements of long-term debt as of June 30, 2016 (in thousands):

Year ending December 31,	
2016	$38,750
2017	191,250
2018	—
2019	—
2020	300,000
Thereafter	300,000
Total	$830,000

On July 8 2016, the Company repaid $230 million of long-term debt that had principal repayments due in 2016 and 2017. As of August 2, 2016, the Company has no term debt due prior to 2020.

9. Commitments, Contingencies and Other Matters

As of June 30, 2016, the Company maintained letters of credit in the aggregate amount of $38.2 million for the benefit of various insurance companies as collateral for retrospective premiums and retained losses which could become payable under the terms of the underlying insurance contracts. These letters of credit expire annually at various times during the year and are typically renewed. As of June 30, 2016, no amounts had been drawn under the letters of credit.

As of June 30, 2016, the Company had commitments to purchase approximately $55.1 million of major equipment for its drilling and pressure pumping businesses.

The Company’s pressure pumping business has entered into agreements to purchase minimum quantities of proppants and chemicals from certain vendors. These agreements expire in 2017 and 2018. As of June 30, 2016, the remaining obligation under these agreements was approximately $23.5 million, of which approximately $6.5 million relates to purchases required during the remainder of 2016. In the event the required minimum quantities are not purchased during any contract year, the Company could be required to make a liquidated damages payment to the respective vendor for any shortfall.

In November 2011, the Company’s pressure pumping business entered into an agreement with a proppant vendor to advance up to $12.0 million to such vendor to finance the construction of certain processing facilities. This advance is secured by the underlying processing facilities and bears interest at an annual rate of 5.0%. Repayment of the advance is to be made through discounts applied to purchases from the vendor and repayment of all amounts advanced must be made no later than October 1, 2017. As of June 30, 2016, advances of approximately $11.8 million had been made under this agreement and principal repayments of approximately $10.6 million had been received, resulting in a balance outstanding of approximately $1.2 million.

The Company is party to various legal proceedings arising in the normal course of its business. The Company does not believe that the outcome of these proceedings, either individually or in the aggregate, will have a material adverse effect on its financial condition, results of operations or cash flows.

10. Stockholders' Equity

Cash Dividends — The Company paid cash dividends during the six months ended June 30, 2015 and 2016 as follows:

2015:	Per Share	Total (in thousands)
Paid on March 25, 2015	$ 0.10	$ 14,640
Paid on June 24, 2015	0.10	14,712
Total cash dividends	$ 0.20	$ 29,352

2016:	Per Share	Total (in thousands)
Paid on March 24, 2016	$ 0.10	$ 14,712
Paid on June 23, 2016	0.02	2,953
Total cash dividends	$ 0.12	$ 17,665

On July 27, 2016, the Company's Board of Directors approved a cash dividend on its common stock in the amount of $0.02 per share to be paid on September 22, 2016 to holders of record as of September 8, 2016. The amount and timing of all future dividend payments, if any, are subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial condition, terms of the Company's debt agreements and other factors.

On September 6, 2013, the Company's Board of Directors approved a stock buyback program that authorizes purchase of up to $200 million of the Company's common stock in open market or privately negotiated transactions. As of June 30, 2016, the Company had remaining authorization to purchase approximately $187 million of the Company's outstanding common stock under the stock buyback program. Shares purchased under a buyback program are accounted for as treasury stock.

Treasury stock acquisitions during the six months ended June 30, 2016 were as follows (dollars in thousands):

	June 30, 2016	
	Shares	Cost
Treasury shares at beginning of period	43,207,240	$907,045
Purchases pursuant to stock buyback program	8,488	183
Acquisitions pursuant to long-term incentive plan	160,564	3,428
Treasury shares at end of period	43,376,292	$910,656

11. Income Taxes

The Company's effective income tax rate was 35.1% for the six months ended June 30, 2016, compared to 44.8% for the six months ended June 30, 2015. The Domestic Production Activities Deduction (the "Section 199 Deduction") was enacted as part of the American Jobs Creation Act of 2004 (as revised by the Emergency Economic Stabilization Act of 2008), and allows a deduction of 9% on the lesser of qualified production activities income or taxable income. For tax purposes, the Company had net operating losses for the years ended December 31, 2015 and 2014, which have been carried back to prior years. These carrybacks resulted in the loss of the benefits of previous Section 199 Deductions. The loss of these benefits was recognized during the six months ended June 30, 2016, which reduced the tax benefit recorded for the six months ended June 30, 2016.

At June 30, 2015, the Company expected a loss before income taxes for financial statement purposes for the year ending December 31, 2015; however the Company expected to have taxable income for the year ending December 31, 2015, and the Section 199 Deduction was expected to provide a permanent tax benefit. On June 15, 2015, legislation was enacted which permanently reduced the Texas Margin Tax rate. This resulted in a permanent tax benefit that was recognized during the quarter ended June 30, 2015. The interplay between the expected loss before income taxes for financial statement purposes, the permanent tax benefit expected to be provided by the Section 199 Deduction and the permanent tax benefit from the Texas Margin Tax rate resulted in a higher effective income tax rate for the six months ended June 30, 2015.

12. Fair Values of Financial Instruments

The carrying values of cash and cash equivalents, trade receivables and accounts payable approximate fair value due to the short-term maturity of these items. These fair value estimates are considered Level 1 fair value estimates in the fair value hierarchy of fair value accounting.

The estimated fair value of the Company's outstanding debt balances (including current portion) as of June 30, 2016 and December 31, 2015 is set forth below (in thousands):

	June 30, 2016		December 31, 2015	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Borrowings under Credit Agreement:				
Term loan facility	$60,000	$60,000	$70,000	$70,000
2015 Term Loan	170,000	170,000	185,000	185,000
4.97% Series A Senior Notes	300,000	279,525	300,000	279,635
4.27% Series B Senior Notes	300,000	259,824	300,000	258,806
Total debt	$830,000	$769,349	$855,000	$793,441

The carrying values of the balances outstanding under the Credit Agreement and the 2015 Term Loan Agreement approximate their fair values as these instruments have floating interest rates. The fair values of the Series A Notes and Series B Notes at June 30, 2016 and December 31, 2015 are based on discounted cash flows associated with the respective notes using current market rates of interest at those respective dates. For the Series A Notes, the current market rates used in measuring this fair value were 6.85% at June 30, 2016 and 6.66% at December 31, 2015. For the Series B Notes, the current market rates used in measuring this fair value were 7.07% at June 30, 2016 and 6.95% at December 31, 2015. These fair value estimates are based on observable market inputs and are considered Level 2 fair value estimates in the fair value hierarchy of fair value accounting.

13. Recently Issued Accounting Standards

In May 2014, the FASB issued an accounting standards update to provide guidance on the recognition of revenue from customers. The FASB clarified this guidance in March, April and May 2016. Under this guidance, an entity will recognize revenue when it transfers promised goods or services to customers in an amount that reflects what it expects in exchange for the goods or services. This guidance also requires more detailed disclosures to enable users of the financial statements to understand the nature, amount, timing and uncertainty, if any, of revenue and cash flows arising from contracts with customers. The requirements in this update are effective during interim and annual periods beginning after December 15, 2017. The Company is currently evaluating the impact this guidance will have on its consolidated financial statements.

In November 2015, the FASB issued an accounting standards update to provide guidance for the presentation of deferred tax liabilities and assets. Under this guidance, for a particular tax-paying component of an entity and within a particular tax jurisdiction, all deferred tax liabilities and assets, as well as any related valuation allowance, shall be offset and presented as a single noncurrent amount. The requirements in this update are effective during interim and annual periods beginning after December 15, 2016. The adoption of this update is not expected to have a material impact on the Company's consolidated financial statements.

In February 2016, the FASB issued an accounting standards update to provide guidance for the accounting for leasing transactions. The requirements in this update are effective during interim and annual periods beginning after December 15, 2018. The Company is currently evaluating the impact this guidance will have on its consolidated financial statements.

In March 2016, the FASB issued an accounting standards update to provide guidance for the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The requirements in this update are effective during interim and annual periods beginning after December 15, 2016. The Company is currently evaluating the impact this guidance will have on its consolidated financial statements.

DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

This Quarterly Report on Form 10-Q (this "Report") and other public filings and press releases by us contain "forward-looking statements" within the meaning of the Securities Act of 1933, as amended (the "Securities Act"), the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and the Private Securities Litigation Reform Act of 1995, as amended. These "forward-looking statements" involve risk and uncertainty. These forward-looking statements include, without limitation, statements relating to: liquidity; revenue and cost expectations and backlog; financing of operations; oil and natural gas prices; source and sufficiency of funds required for building new equipment, upgrading existing equipment and additional acquisitions (if opportunities arise); impact of inflation; demand for our services; competition; equipment availability; government regulation; debt service obligations; and other matters. Our forward-looking statements can be identified by the fact that they do not relate strictly to historical or current facts and often use words such as "anticipates," "believes," "budgeted," "continue," "could," "estimates," "expects," "intends," "may," " "project," "should," "strategy," or "will," or the negative thereof and other words and expressions of similar meaning. The forward-looking statements are based on certain assumptions and analyses we make in light of our experience and our perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate in the circumstances. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct. Forward-looking statements may be made orally or in writing, including, but not limited to, Management's Discussion and Analysis of Financial Condition and Results of Operations included in this Report and other sections of our filings with the United States Securities and Exchange Commission (the "SEC") under the Exchange Act and the Securities Act.

Forward-looking statements are not guarantees of future performance and a variety of factors could cause actual results to differ materially from the anticipated or expected results expressed in or suggested by these forward-looking statements. Factors that might cause or contribute to such differences include, but are not limited to, volatility in customer spending and in oil and natural gas prices that could adversely affect demand for our services and their associated effect on rates, utilization, margins and planned capital expenditures, global economic conditions, excess availability of land drilling rigs and pressure pumping equipment, including as a result of reactivation or construction, equipment specialization and new technologies, competition, adverse industry conditions, adverse credit and equity market conditions, failure by our customers to pay us or satisfy their contractual obligations (particularly with respect to fixed term contracts), difficulty in building and deploying new equipment and integrating acquisitions, shortages, delays in delivery and interruptions in supply of equipment, supplies and materials, weather, loss of key customers, liabilities from operations for which we do not have and receive full indemnification or insurance, ability to effectively identify and enter new markets, governmental regulation, ability to realize backlog, ability to retain management and field personnel, legal proceedings and other factors. Refer to "Risk Factors" contained in Part 1 of our Annual Report on Form 10-K for the year ended December 31, 2015 for a more complete discussion of factors that might affect our performance and financial results. You are cautioned not to place undue reliance on any of our forward-looking statements. These forward-looking statements are intended to relay our expectations about the future, and speak only as of the date they are made. We undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, changes in internal estimates or otherwise, except as required by law.

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

Recent Developments — Oil prices declined significantly during the second half of 2014. The closing price of oil, which was as high as $105.68 per barrel during the third quarter of 2014, averaged $48.69 during 2015 and reached a twelve-year low of $26.19 in February 2016. Oil prices averaged $45.41 during the second quarter of 2016 and were briefly above $50 during June 2016. As a result of the prolonged decline in oil prices, our industry has experienced a severe decline in both contract drilling and pressure pumping activity levels. While activity levels have recently stabilized, we do not expect activity levels to significantly increase until commodity prices improve.

Low commodity prices are negatively impacting spending by exploration and production companies. The impact of these spending reductions is evidenced by the published rig counts, which have declined by more than 75% in the United States since the recent peak in 2014.

Our rig count has also significantly declined. As of June 30, 2016, we had 55 drilling rigs operating in the United States, which was a decrease of 74% from the peak of 214 rigs in October 2014. On average, we operated 55 rigs in the United States during the second quarter of 2016. Term contracts have provided support for our operating rig count during the second quarter of 2016. Based on contracts currently in place, we expect an average of 45 rigs operating under term contracts during the third quarter of 2016 and an average of 42 rigs operating under term contracts during the second half of 2016.

Our pressure pumping business is continuing to experience the effects of reduced spending by customers and downward pressure on pricing. With the weakness in commodity prices, we have seen a significant decrease in the amount of available work, and the profitability of available work has continued to deteriorate. In response, we now have stacked approximately 53% of our fleet of more than 1.0 million hydraulic fracturing horsepower.

In anticipation of this downturn, we began reducing our cost structure in the fourth quarter of 2014. In 2015 and the first half of 2016, we continued to reduce our cost structure and, to date, we have reduced our drilling headcount at a rate generally proportionate with the reduction in our rig count. In pressure pumping, we have reduced our headcount and obtained lower prices on many products and services that we use. We expect our capital expenditures in the remainder of 2016 to primarily consist of maintenance capital, as well as upgrades to our drilling rig fleet. We plan to continue to adjust our cost structure in line with our level of operating activity.

We expect that our term contract coverage in contract drilling and scalability with respect to labor and other operating costs in contract drilling and pressure pumping should position us to weather this downturn. The U.S. rig count has slightly rebounded as crude oil prices have improved from the cyclical lows reached in the first quarter of 2016. Although the outlook for crude oil prices remains uncertain with numerous economic and geopolitical concerns, our rig count in the U.S. has increased from a low of 52 rigs in April 2016 to 58 rigs as of July 28, 2016. In the event oil prices remain depressed for a sustained period, or decline further, these declines could have a material adverse effect on our business, financial condition and results of operations.

Management Overview — We are a leading provider of services to the North American oil and natural gas industry. Our services primarily involve the drilling, on a contract basis, of land-based oil and natural gas wells and pressure pumping services. In addition to these services, we also invest, on a non-operating working interest basis, in oil and natural gas properties.

We operate land-based drilling rigs in oil and natural gas producing regions of the continental United States and western Canada. There continues to be uncertainty with respect to the global economic environment, and oil and natural gas prices have been depressed. During the second quarter of 2016, our average number of rigs operating in the United States was 55 compared to an average of 122 drilling rigs operating during the same period in 2015. During the second quarter of 2016, our average number of rigs operating in Canada was less than one compared to an average of two drilling rigs operating during the second quarter of 2015.

Prior to the decline in oil prices, we addressed our customers' needs for drilling horizontal wells in shale and other unconventional resource plays by expanding our areas of operation and improving the capabilities of our drilling fleet during the last several years. As of June 30, 2016, our rig fleet included 161 APEX® rigs.

With regard to our pressure pumping business, primarily between 2010 and 2014, we added equipment to perform service-intensive fracturing jobs in connection with the development of horizontal shale and other unconventional resource plays. As of June 30, 2016, we had approximately 1.1 million hydraulic horsepower in our pressure pumping fleet. We have increased the horsepower of our pressure pumping fleet by more than eight-fold since the beginning of 2009, although we have not ordered or committed to purchase any new horsepower since October 2014 and there is currently no new horsepower on order. In recent years, low commodity prices and the industry-wide addition of new pressure pumping equipment to the marketplace led to an excess supply of pressure pumping equipment in North America.

We maintain a backlog of commitments for contract drilling revenues under term contracts, which we define as contracts with a fixed term of six months or more. Our contract drilling backlog as of June 30, 2016 was approximately $500 million. More than 60% of the total June 30, 2016 backlog is reasonably expected to remain at the end of 2016. We generally calculate our backlog by multiplying the dayrate under our term drilling contracts by the number of days remaining under the contract. The calculation does not include any revenues related to other fees such as for mobilization, demobilization and customer reimbursables, nor does it include potential reductions in rates for unscheduled standby or during periods in which the rig is moving or incurring maintenance and repair time in excess of what is permitted under the drilling contract. In addition, generally our term drilling contracts are subject to termination by the customer on short notice and provide for an early termination payment to us in the event that the contract is terminated by the customer. For contracts that we have received an early termination notice, our backlog calculation includes the early termination rate, instead of the dayrate, for the period we expect to receive the lower rate.

For the three and six months ended June 30, 2016 and 2015, our operating revenues consisted of the following (in thousands):

	Three Months Ended June 30,				Six Months Ended June 30,			
	2016		2015		2016		2015	
Contract drilling	$115,235	59.4 %	$288,321	61.0 %	$283,894	61.3 %	$689,799	61.0 %
Pressure pumping	73,950	38.2 %	176,624	37.4 %	170,263	36.8 %	426,345	37.7 %
Oil and natural gas	4,722	2.4 %	7,816	1.6 %	8,689	1.9 %	14,316	1.3 %
	$193,907	100.0 %	$472,761	100.0 %	$462,846	100.0 %	$1,130,460	100.0 %

Generally, the profitability of our business is impacted most by two primary factors in our contract drilling segment: our average number of rigs operating and our average revenue per operating day. During the second quarter of 2016, our average number of rigs operating was 55 in the United States and less than one in Canada compared to 122 in the United States and two in Canada in the second quarter of 2015. Our average revenue per operating day was $23,070 in the second quarter of 2016, including $5.4 million of early termination revenue, compared to $25,720 in the second quarter of 2015, including $15.6 million of early termination revenue. The profitability of our pressure pumping segment is impacted most by our number of fracturing jobs during a quarter and our average revenue per fracturing job. We had 74 fracturing jobs during the second quarter of 2016 compared to 148 fracturing jobs during the second quarter of 2015. Our average revenue per fracturing job was $976,300 in the second quarter of 2016 and $1.148 million in the second quarter of 2015. Consolidated net loss for the second quarter of 2016 was $85.9 million compared to consolidated net loss of $19.0 million for the second quarter of 2015.

Our revenues, profitability and cash flows are highly dependent upon prevailing prices for oil and natural gas. During periods of improved commodity prices, the capital spending budgets of oil and natural gas operators tend to expand, which generally results in increased demand for our services. Conversely, in periods when these commodity prices deteriorate, the demand for our services generally weakens, and we experience downward pressure on pricing for our services. Oil and natural gas prices and our monthly average number of rigs operating have significantly declined from recent highs. In June 2016, our average number of rigs operating was 54 in the United States and one in Canada.

We are also highly impacted by operational risks, competition, the availability of excess equipment, labor issues, weather and various other factors that could materially adversely affect our business, financial condition, cash flows and results of operations. Please see “Risk Factors” included in Part I of our Annual Report on Form 10-K for the fiscal year ended December 31, 2015.

Our liquidity as of June 30, 2016 included approximately $164 million in working capital, including $210 million of cash and cash equivalents, and $500 million available under our revolving credit facility. To further solidify our financial position, on July 8, 2016, we amended our bank credit agreement to, among other things, extend the maturity of $357.9 million of our revolving credit facility by 18 months to March 2019. Additionally, we repaid the entire $230 million of bank term loans outstanding as of June 30, 2016 using cash on hand and $70 million drawn from the revolving credit facility. As a result, we believe our current liquidity, together with cash expected to be generated from operations, should provide us with sufficient ability to fund our current plans to maintain and make improvements to our existing equipment, service our debt, pay cash dividends and finance working capital requirements during a recovery. If under current market conditions we desire to pursue opportunities for growth that require additional capital, we believe such pursuit would likely require additional debt or equity financing. However, there can be no assurance that such capital will be available on reasonable terms, if at all.

Commitments and Contingencies — As of June 30, 2016, we maintained letters of credit in the aggregate amount of $38.2 million for the benefit of various insurance companies as collateral for retrospective premiums and retained losses which could become payable under the terms of the underlying insurance contracts. These letters of credit expire annually at various times during the year and are typically renewed. As of June 30, 2016, no amounts had been drawn under the letters of credit.

As of June 30, 2016, we had commitments to purchase approximately $55.1 million of major equipment for our drilling and pressure pumping businesses.

Our pressure pumping business has entered into agreements to purchase minimum quantities of proppants and chemicals from certain vendors. These agreements expire in 2017 and 2018. As of June 30, 2016, the remaining obligation under these agreements was approximately \$23.5 million, of which approximately \$6.5 million relates to purchases required during the remainder of 2016. In the event the required minimum quantities are not purchased during any contract year, we could be required to make a liquidated damages payment to the respective vendor for any shortfall.

In November 2011, our pressure pumping business entered into an agreement with a proppant vendor to advance up to \$12.0 million to such vendor to finance its construction of certain processing facilities. This advance is secured by the underlying processing facilities and bears interest at an annual rate of 5.0%. Repayment of the advance is to be made through discounts applied to purchases from the vendor and repayment of all amounts advanced must be made no later than October 1, 2017. As of June 30, 2016, advances of approximately \$11.8 million had been made under this agreement and repayments of approximately \$10.6 million had been received resulting in a balance outstanding of approximately \$1.2 million.

Trading and Investing — We have not engaged in trading activities that include high-risk securities, such as derivatives and non-exchange traded contracts. We invest cash primarily in highly liquid, short-term investments such as overnight deposits and money market accounts.

Description of Business — We conduct our contract drilling operations primarily in the continental United States and western Canada. We provide pressure pumping services to oil and natural gas operators primarily in Texas and the Appalachian region. Pressure pumping services are primarily well stimulation and cementing for completion of new wells and remedial work on existing wells. We also invest in oil and natural gas assets as a non-operating working interest owner. Our oil and natural gas working interests are located primarily in Texas and New Mexico.

The North American oil and natural gas services industry is cyclical and at times experiences downturns in demand. During these periods, there have been substantially more drilling rigs and pressure pumping equipment available than necessary to meet demand. As a result, drilling and pressure pumping contractors have had difficulty sustaining profit margins and, at times, have incurred losses during the downturn periods. The North American oil and natural gas services industry is currently experiencing a severe downturn.

Construction of new technology drilling rigs increased significantly in the years preceding the current industry downturn. The addition of new technology drilling rigs to the market, combined with a reduction in the drilling of vertical wells, has resulted in excess capacity of older technology drilling rigs. Similarly, the substantial increase in unconventional resource plays led to higher demand for pressure pumping services, and there was a significant increase in the construction of new pressure pumping equipment across the industry. As a result of the decline in oil and natural gas prices and the construction of new equipment, there is an excess of new technology drilling rigs and pressure pumping equipment available. In circumstances of excess capacity, providers of drilling and pressure pumping services have difficulty sustaining profit margins and may sustain losses during downturn periods. We cannot predict either the future level of demand for our contract drilling or pressure pumping services or future conditions in the oil and natural gas contract drilling or pressure pumping businesses.

In addition, unconventional resource plays have substantially increased and some drilling rigs are not capable of drilling these wells efficiently. Accordingly, the utilization of some older technology drilling rigs has been hampered by their lack of capability to efficiently compete for this work. Other ongoing factors which could continue to adversely affect utilization rates and pricing, even in an environment of high oil and natural gas prices and increased drilling activity, include:

- movement of drilling rigs from region to region,
- reactivation of land-based drilling rigs, or
- construction of new technology drilling rigs.

Critical Accounting Policies

In addition to established accounting policies, our condensed consolidated financial statements are impacted by certain estimates and assumptions made by management. No changes in our critical accounting policies have occurred since the filing of our Annual Report on Form 10-K for the fiscal year ended December 31, 2015.

We evaluate the recoverability of our long-lived assets whenever events or changes in circumstances indicate that their carrying amounts may not be recoverable (a "triggering event"). Based on recent commodity prices, our results of operations for the period ended June 30, 2016 and our expectations of results of operations in future periods, we concluded that no triggering event occurred during the second quarter of 2016 with respect to our contract drilling segment or our pressure pumping segment. Our expectations of results of operations in future periods were based on the assumption that activity levels in both segments will begin to recover by early 2017 in response to improved future oil prices.

We review our proved oil and natural gas properties for impairment whenever a triggering event occurs, such as downward revisions in reserve estimates or decreases in expected future oil and natural gas prices. Proved properties are grouped by field and undiscounted cash flow estimates are prepared based on our expectation of future pricing over the lives of the respective fields. These cash flow estimates are reviewed by an independent petroleum engineer. If the net book value of a field exceeds its undiscounted cash flow estimate, impairment expense is measured and recognized as the difference between net book value and fair value. The fair value estimates used in measuring impairment are based on internally developed unobservable inputs including reserve volumes and future production, pricing and operating costs (Level 3 inputs in the fair value hierarchy of fair value accounting). The expected future net cash flows are discounted using an annual rate of 10% to determine fair value. We review unproved oil and natural gas properties quarterly to assess potential impairment. Our impairment assessment is made on a lease-by-lease basis and considers factors such as our intent to drill, lease terms and abandonment of an area. If an unproved property is determined to be impaired, the related property costs are expensed. Impairment expense related to proved and unproved oil and natural gas properties totaled approximately $2.2 million in the first quarter of 2016 and is included in depreciation, depletion, amortization and impairment in the condensed consolidated statements of operations. There was no impairment expense in the second quarter of 2016.

Liquidity and Capital Resources

Our liquidity as of June 30, 2016 included approximately $164 million in working capital, including $210 million of cash and cash equivalents, and $500 million available under our revolving credit facility. To further solidify our financial position, on July 8, 2016, we amended our bank credit agreement to, among other things, extend the maturity of $357.9 million of our revolving credit facility by 18 months to March 2019. Additionally, we repaid the entire $230 million of bank term loans outstanding as of June 30, 2016 using cash on hand and $70 million drawn from the revolving credit facility. As a result, we believe our current liquidity, together with cash expected to be generated from operations, should provide us with sufficient ability to fund our current plans to maintain and make improvements to our existing equipment, service our debt, pay cash dividends and finance working capital requirements during a recovery. If under current market conditions we desire to pursue opportunities for growth that require additional capital, we believe such pursuit would likely require additional debt or equity financing. However, there can be no assurance that such capital will be available on reasonable terms, if at all.

During the six months ended June 30, 2016, our sources of cash flow included:

- $182 million from operating activities,
- $12.4 million in proceeds from the disposal of property and equipment.

During the six months ended June 30, 2016, we used $17.7 million to pay dividends on our common stock, $3.6 million to purchase treasury stock, $25.0 million to repay long-term debt and $51.8 million:

- to make capital expenditures for the betterment and refurbishment of existing drilling rigs and pressure pumping equipment,
- to acquire and procure equipment and facilities to support our drilling and pressure pumping operations, and
- to fund investments in oil and natural gas properties on a non-operating working interest basis.

We paid cash dividends during the six months ended June 30, 2016 as follows:

	Per Share	Total (in thousands)
Paid on March 24, 2016	$ 0.10	$ 14,712
Paid on June 23, 2016	0.02	2,953

Total cash dividends	$ 0.12	$ 17,665

On July 27, 2016, our Board of Directors approved a cash dividend on our common stock in the amount of $0.02 per share to be paid on September 22, 2016 to holders of record as of September 8, 2016. However, the amount and timing of all future dividend payments, if any, are subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial condition, terms of our debt agreements and other factors.

On September 6, 2013, our Board of Directors approved a stock buyback program that authorizes purchase of up to $200 million of our common stock in open market or privately negotiated transactions. As of June 30, 2016, we had remaining authorization to purchase approximately $187 million of our outstanding common stock under the 2013 stock buyback program. Shares purchased under a buyback program are accounted for as treasury stock.

Treasury stock acquisitions during the six months ended June 30, 2016 were as follows (dollars in thousands):

	June 30, 2016	
	Shares	Cost
Treasury shares at beginning of period	43,207,240	$907,045
Purchases pursuant to stock buyback program	8,488	183
Acquisitions pursuant to long-term incentive plan	160,564	3,428
Treasury shares at end of period	43,376,292	$910,656

2012 Credit Agreement — On September 27, 2012, we entered into a Credit Agreement (“Base Credit Agreement”). The Base Credit Agreement (as amended, the “Credit Agreement”) is a committed senior unsecured credit facility that includes a revolving credit facility.

On July 8, 2016, we entered into Amendment No. 2 to the Credit Agreement (the “Amendment No. 2”), which amended the Base Credit Agreement. Amendment No. 2, among other things:

- provided that borrowings under the Credit Agreement will be subject to a borrowing base calculated by reference to our and certain of our subsidiaries’ eligible equipment, inventory, accounts receivable and unencumbered cash as described in Amendment No. 2;
- decreased the permitted amount of certain secured indebtedness by us and our subsidiaries and decreased the permitted amount of certain unsecured indebtedness of our subsidiaries;
- revised the limitation on our ability to make investments in foreign subsidiaries or joint ventures such that, if the book value of all such investments since September 27, 2012 is above 20% of our total consolidated book value of the assets on a pro forma basis, we will not be able to make such investment;
- added a restricted payments covenant that restricts our ability to pay dividends and make equity repurchases, subject to certain exceptions, including an exception allowing such restricted payments if before and immediately after giving effect to such restricted payment, the Pro Forma Debt Service Coverage Ratio (as defined in Amendment No. 2) is at least 1.50 to 1.00; and
- requires that, if our consolidated cash balance, subject to certain exclusions, is more than $100 million at the end of the day on which a borrowing is made, we can only use the proceeds from such borrowing to fund acquisitions, capital expenditures and the repurchase of indebtedness, and if such proceeds are not used in such manner within three business days, we must repay such unused proceeds on the fourth business day following such borrowings.

As a condition precedent, Amendment No. 2 required us to repay the entire outstanding principal amount of our bank term loans. We used $160 million of cash and $70 million drawn under the revolving credit facility to repay the bank term loans.

The revolving credit facility permits aggregate borrowings of up to $500 million outstanding at any time, subject to the borrowing base described above. The revolving credit facility contains a letter of credit facility that is limited to $50 million and a swing line facility that is limited to $20 million, in each case outstanding at any time.

The term loan facility included in the Base Credit Agreement, which facility was terminated in connection with Amendment No. 2, provided for a loan of $100 million, which was drawn on December 24, 2012 and was payable in quarterly principal installments.

Subject to customary conditions, we may request that the lenders’ aggregate commitments with respect to the revolving credit facility be increased by up to $100 million, not to exceed total commitments of $600 million. The maturity date under the Base Credit Agreement was September 27, 2017 for the revolving facility; however, Amendment No. 2 extended the maturity date of $357.9 million in revolving credit commitments of certain lenders to March 27, 2019.

Loans under the Credit Agreement bear interest by reference, at our election, to the LIBOR rate or base rate, provided, that swing line loans bear interest by reference only to the base rate. Until September 27, 2017, the applicable margin on LIBOR rate loans varies from 2.75% to 3.25% and the applicable margin on base rate loans varies from 1.75% to 2.25%, in each case determined based upon our debt to capitalization ratio. On or after September 27, 2017, the applicable margin on LIBOR rate loans varies from 3.25% to 3.75% and the applicable margin on base rate loans varies from 2.25% to 2.75%, in each case determined based on our excess availability under the credit facility. As of June 30, 2016 the applicable margin on LIBOR rate loans was 2.75% and the applicable margin on base rate loans was 1.75%. Based on our debt to capitalization ratio at March 31, 2016, the applicable margin on LIBOR loans is 2.75% and the applicable margin on base rate loans is 1.75% as of July 1, 2016. Based on our debt to capitalization ratio at June 30, 2016, the applicable margin on LIBOR loans will be 2.75% and the applicable margin on base rate loans will be 1.75% as of October 1, 2016. A letter of credit fee is payable by us equal to the applicable margin for LIBOR rate loans times the daily amount available to be drawn under outstanding letters of credit. The commitment fee rate payable to the lenders for the unused portion of the credit facility is 0.50%.

Each of our domestic subsidiaries unconditionally guarantees all existing and future indebtedness and liabilities of the other guarantors and us arising under the Credit Agreement, other than (a) Ambar Lone Star Fluid Services LLC, (b) domestic subsidiaries that directly or indirectly have no material assets other than equity interests in, or capitalization indebtedness owed by, foreign subsidiaries, and (c) any subsidiary having total assets of less than $1 million. Such guarantees also cover our obligations and those of any of our subsidiaries arising under any interest rate swap contract with any person while such person is a lender or an affiliate of a lender under the Credit Agreement.

The Credit Agreement requires compliance with two financial covenants. We must not permit our debt to capitalization ratio to exceed 40%. The Credit Agreement generally defines the debt to capitalization ratio as the ratio of (a) total borrowed money indebtedness to (b) the sum of such indebtedness plus consolidated net worth, with consolidated net worth determined as of the last day of the most recently ended fiscal quarter. We also must not permit the interest coverage ratio as of the last day of a fiscal quarter to be less than 3.00 to 1.00. The Credit Agreement generally defines the interest coverage ratio as the ratio of earnings before interest, taxes, depreciation and amortization ("EBITDA") of the four prior fiscal quarters to interest charges for the same period. We were in compliance with these covenants at June 30, 2016.

The Credit Agreement also contains customary representations, warranties and affirmative and negative covenants. We do not expect that the restrictions and covenants will impair, in any material respect, our ability to operate or react to opportunities that might arise.

Events of default under the Credit Agreement include failure to pay principal or interest when due, failure to comply with the financial and operational covenants, as well as a cross default event, loan document enforceability event, change of control event and bankruptcy and other insolvency events. If an event of default occurs and is continuing, then a majority of the lenders have the right, among others, to (i) terminate the commitments under the Credit Agreement, (ii) accelerate and require us to repay all the outstanding amounts owed under any loan document (provided that in limited circumstances with respect to insolvency and bankruptcy, such acceleration is automatic), and (iii) require us to cash collateralize any outstanding letters of credit.

As of June 30, 2016, we had $60 million principal amount outstanding under the term loan facility at an interest rate of 5.25% and no amounts outstanding under the revolving credit facility. As a condition precedent to Amendment No. 2, we repaid the entire outstanding principal amount under the term loan facility. The borrowing base under the Credit Agreement is currently $500 million. As of August 2, 2016, we had $70 million drawn under the revolving credit facility, with available borrowing capacity of $430 million.

2015 Reimbursement Agreement — On March 16, 2015, we entered into a Reimbursement Agreement (the "Reimbursement Agreement") with The Bank of Nova Scotia ("Scotiabank"), pursuant to which we may from time to time request that Scotiabank issue an unspecified amount of letters of credit. As of June 30, 2016, we had $38.2 million in letters of credit outstanding under the Reimbursement Agreement.

Under the terms of the Reimbursement Agreement, we will reimburse Scotiabank on demand for any amounts that Scotiabank has disbursed under any letters of credit. Fees, charges and other reasonable expenses for the issuance of letters of credit are payable by us at the time of issuance at such rates and amounts as are in accordance with Scotiabank's prevailing practice. We are obligated to pay to Scotiabank interest on all amounts not paid on the date of demand or when otherwise due at the LIBOR rate plus 2.25% per annum, calculated daily and payable monthly, in arrears, on the basis of a calendar year for the actual number of days elapsed, with interest on overdue interest at the same rate as on the reimbursement amounts.

We have also agreed that if obligations under the Credit Agreement are secured by liens on any of our subsidiaries' property, then our reimbursement obligations and (to the extent similar obligations would be secured under the Credit Agreement) other obligations under the Reimbursement Agreement and any letters of credit will be equally and ratably secured by all property subject to such liens securing the Credit Agreement.

Pursuant to a Continuing Guaranty dated as of March 16, 2015 (the "Continuing Guaranty"), our payment obligations under the Reimbursement Agreement are jointly and severally guaranteed as to payment and not as to collection by our subsidiaries that from time to time guarantee payment under the Credit Agreement.

2015 Term Loan Agreement — On March 18, 2015, we entered into a Term Loan Agreement (the "2015 Term Loan Agreement") with Wells Fargo Bank, N.A., as administrative agent and lender, each of the other lenders party thereto, Wells Fargo Securities, LLC, as Lead Arranger and Sole Book Runner, and Bank of America, N.A. and The Bank Of Tokyo-Mitsubishi UFJ, LTD., as Co-Syndication Agents.

The 2015 Term Loan Agreement was a senior unsecured single-advance term loan facility pursuant to which we made a term loan borrowing of $200 million on March 18, 2015 (the "Term Loan Borrowing"). The Term Loan Borrowing was payable in quarterly principal installments, together with accrued interest. Loans under the 2015 Term Loan Agreement bore interest, at our election, at the per annum rate of LIBOR rate plus 3.25% or base rate plus 2.25%.

As of June 30, 2016, we had $170 million principal amount outstanding under the 2015 Term Loan Agreement at an interest rate of 5.75%. As a condition precedent to Amendment No. 2, we repaid the entire outstanding principal amount under the 2015 Term Loan Agreement and terminated the agreement.

Senior Notes — On October 5, 2010, we completed the issuance and sale of $300 million in aggregate principal amount of our 4.97% Series A Senior Notes due October 5, 2020 (the "Series A Notes") in a private placement. The Series A Notes bear interest at a rate of 4.97% per annum. We pay interest on the Series A Notes on April 5 and October 5 of each year. The Series A Notes will mature on October 5, 2020.

On June 14, 2012, we completed the issuance and sale of $300 million in aggregate principal amount of our 4.27% Series B Senior Notes due June 14, 2022 (the "Series B Notes") in a private placement. The Series B Notes bear interest at a rate of 4.27% per annum. We pay interest on the Series B Notes on April 5 and October 5 of each year. The Series B Notes will mature on June 14, 2022.

The Series A Notes and Series B Notes are senior unsecured obligations which rank equally in right of payment with all of our other unsubordinated indebtedness. The Series A Notes and Series B Notes are guaranteed on a senior unsecured basis by each of our domestic subsidiaries other than subsidiaries that are not required to be guarantors under the Credit Agreement.

The Series A Notes and Series B Notes are prepayable at our option, in whole or in part, provided that in the case of a partial prepayment, prepayment must be in an amount not less than 5% of the aggregate principal amount of the notes then outstanding, at any time and from time to time at 100% of the principal amount prepaid, plus accrued and unpaid interest to the prepayment date, plus a "make-whole" premium as specified in the note purchase agreements. We must offer to prepay the notes upon the occurrence of any change of control. In addition, we must offer to prepay the notes upon the occurrence of certain asset dispositions if the proceeds therefrom are not timely reinvested in productive assets. If any offer to prepay is accepted, the purchase price of each prepaid note is 100% of the principal amount thereof, plus accrued and unpaid interest thereon to the prepayment date.

The respective note purchase agreements require compliance with two financial covenants. We must not permit our debt to capitalization ratio to exceed 50% at any time. The note purchase agreements generally define the debt to capitalization ratio as the ratio of (a) total borrowed money indebtedness to (b) the sum of such indebtedness plus consolidated net worth, with consolidated net worth determined as of the last day of the most recently ended fiscal quarter. We also must not permit the interest coverage ratio as of the last day of a fiscal quarter to be less than 2.50 to 1.00. The note purchase agreements generally define the interest coverage ratio as the ratio of EBITDA for the four prior fiscal quarters to interest charges for the same period. We were in compliance with these financial covenants as of June 30, 2016. We do not expect that the restrictions and covenants will impair, in any material respect, our ability to operate or react to opportunities that might arise.

Events of default under the note purchase agreements include failure to pay principal or interest when due, failure to comply with the financial and operational covenants, a cross default event, a judgment in excess of a threshold event, the guaranty agreement ceasing to be enforceable, the occurrence of certain ERISA events, a change of control event and bankruptcy and other insolvency events. If an event of default under the note purchase agreements occurs and is continuing, then holders of a majority in principal amount of the respective notes have the right to declare all the notes then-outstanding to be immediately due and payable. In addition, if we default in payments on any note, then until such defaults are cured, the holder thereof may declare all the notes held by it pursuant to the note purchase agreement to be immediately due and payable.

Our liquidity as of June 30, 2016 included approximately $164 million in working capital, including $210 million of cash and cash equivalents, and $500 million available under our revolving credit facility. To further solidify our financial position, on July 8, 2016, we amended our bank credit agreement to, among other things, extend the maturity of $357.9 million of our revolving credit facility by 18 months to March 2019. Additionally, we repaid the entire $230 million of bank term loans outstanding as of

June 30, 2016 using cash on hand and $70 million drawn from the revolving credit facility. As a result, we believe our current liquidity, together with cash expected to be generated from operations, should provide us with sufficient ability to fund our current plans to maintain and make improvements to our existing equipment, service our debt, pay cash dividends and finance working capital requirements during a recovery. If under current market conditions we desire to pursue opportunities for growth that require additional capital, we believe such pursuit would likely require additional debt or equity financing. However, there can be no assurance that such capital will be available on reasonable terms, if at all.

Results of Operations

The following tables summarize operations by business segment for the three months ended June 30, 2016 and 2015:

Contract Drilling	2016	2015	% Change
	(Dollars in thousands)		
Revenues	$115,235	$288,321	(60.0)%
Direct operating costs	63,803	153,848	(58.5)%
Margin (1)	51,432	134,473	(61.8)%
Selling, general and administrative	1,479	1,420	4.2 %
Depreciation, amortization and impairment	120,402	123,627	(2.6)%
Operating income (loss)	$(70,449)	$9,426	NA
Operating days	4,996	11,211	(55.4)%
Average revenue per operating day	$23.07	$25.72	(10.3)%
Average direct operating costs per operating day	$12.77	$13.72	(6.9)%
Average margin per operating day (1)	$10.29	$11.99	(14.2)%
Average rigs operating	55	123	(55.4)%
Capital expenditures	$16,570	$153,940	(89.2)%

(1) Margin is defined as revenues less direct operating costs and excludes depreciation, amortization and impairment and selling, general and administrative expenses. Average margin per operating day is defined as margin divided by operating days.

The decreases in revenues and direct operating costs primarily result from the decrease in the number of rigs operating. Average revenues per operating day is lower due to market conditions. Average direct operating costs per operating day decreased primarily due to a higher percentage of rigs on standby during the 2016 quarter. Rigs on standby have very little associated cost.

Pressure Pumping	2016	2015	% Change
	(Dollars in thousands)		
Revenues	$73,950	$176,624	(58.1)%
Direct operating costs	69,546	142,756	(51.3)%
Margin (1)	4,404	33,868	(87.0)%
Selling, general and administrative	3,029	4,351	(30.4)%
Depreciation, amortization and impairment	47,400	48,261	(1.8)%
Operating loss	$(46,025)	$(18,744)	145.5 %
Fracturing jobs	74	148	(50.0)%
Other jobs	172	535	(67.9)%
Total jobs	246	683	(64.0)%
Average revenue per fracturing job	$976.30	$1,148.39	(15.0)%
Average revenue per other job	$9.91	$12.45	(20.4)%
Average revenue per total job	$300.61	$258.60	16.2 %
Average direct operating costs per total job	$282.71	$209.01	35.3 %
Average margin per total job (1)	$17.90	$49.59	(63.9)%
Margin as a percentage of revenues (1)	6.0 %	19.2 %	(68.8)%
Capital expenditures	$11,780	$64,009	(81.6)%

(1) Margin is defined as revenues less direct operating costs and excludes depreciation, amortization and impairment and selling, general and administrative expenses. Average margin per total job is defined as margin divided by total jobs. Margin as a percentage of revenues is defined as margin divided by revenues.

Revenues and direct operating costs decreased primarily due to a decrease in the number of fracturing jobs. The total number of jobs decreased as a result of the downturn in the oil and natural gas industry. Margin as a percentage of revenues declined due to competitive pricing.

The reduction in selling, general and administrative expense reflects reductions in headcount and other personnel related costs.

Oil and Natural Gas Production and Exploration	2016	2015	% Change
	(Dollars in thousands)		
Revenues - Oil	$4,056	$7,091	(42.8)%
Revenues - Natural gas and liquids	666	725	(8.1)%
Revenues - Total	4,722	7,816	(39.6)%
Direct operating costs	1,650	2,779	(40.6)%
Margin (1)	3,072	5,037	(39.0)%
Depletion and impairment	1,805	8,668	(79.2)%
Operating income (loss)	$1,267	$(3,631)	NA
Capital expenditures	$1,692	$3,612	(53.2)%

(1) Margin is defined as revenues less direct operating costs and excludes depletion and impairment.

Oil revenues decreased as a result of lower oil production and lower commodity prices. Depletion and impairment expense in 2015 includes approximately $4.1 million of oil and natural gas property impairments. There were no impairments in the three months ended June 30, 2016. Depletion expense is lower primarily due to lower oil production and the impact of significant impairments recognized in recent years.

Corporate and Other	2016	2015	% Change
	(Dollars in thousands)		
Selling, general and administrative	$12,579	$13,445	(6.4)%
Depreciation	$1,368	$1,368	—
Other operating income, net:			
Net gain on asset disposals	$(4,822)	$(2,998)	60.8 %
Interest income	$100	$318	(68.6)%
Interest expense	$10,678	$9,249	15.5 %
Other income	$17	—	NA
Capital expenditures	$491	$606	(19.0)%

Lower selling, general and administrative expense reflects lower personnel costs due to headcount reductions. Other operating income, net includes net gains or losses associated with the disposal of assets related to corporate strategy decisions of the executive management group. Accordingly, the related gains or losses have been excluded from the results of specific segments. Interest expense increased primarily due to lower capitalized interest, as we have reduced our capital expenditure spending in 2016.

The following tables summarize operations by business segment for the six months ended June 30, 2016 and 2015:

Contract Drilling	2016	2015	% Change
	(Dollars in thousands)		
Revenues	$283,894	$689,799	(58.8)%
Direct operating costs	144,701	366,658	(60.5)%
Margin (1)	139,193	323,141	(56.9)%
Selling, general and administrative	3,237	2,858	13.3 %
Depreciation, amortization and impairment	241,501	242,459	(0.4)%
Operating income (loss)	$(105,545)	$77,824	NA
Operating days	11,653	26,731	(56.4)%
Average revenue per operating day	$24.36	$25.81	(5.6)%
Average direct operating costs per operating day	$12.42	$13.72	(9.5)%
Average margin per operating day (1)	$11.94	$12.09	(1.2)%
Average rigs operating	64	148	(56.6)%
Capital expenditures	$28,450	$311,362	(90.9)%

(1) Margin is defined as revenues less direct operating costs and excludes depreciation, amortization and impairment and selling, general and administrative expenses. Average margin per operating day is defined as margin divided by operating days.

The decreases in revenues and direct operating costs primarily result from the decrease in the number of rigs operating. Average direct operating costs per operating day decreased primarily due to lower labor costs and a higher percentage of rigs on standby during the 2016 period. Rigs on standby have very little associated cost.

Pressure Pumping	2016	2015	% Change
	(Dollars in thousands)		
Revenues	$170,263	$426,345	(60.1)%
Direct operating costs	157,359	355,481	(55.7)%
Margin (1)	12,904	70,864	(81.8)%
Selling, general and administrative	5,918	9,444	(37.3)%
Depreciation, amortization and impairment	96,970	95,180	1.9 %
Operating loss	$(89,984)	$(33,760)	166.5 %
Fracturing jobs	157	364	(56.9)%
Other jobs	330	1,153	(71.4)%
Total jobs	487	1,517	(67.9)%
Average revenue per fracturing job	$1,058.99	$1,118.41	(5.3)%
Average revenue per other job	$12.13	$16.69	(27.3)%
Average revenue per total job	$349.62	$281.04	24.4 %
Average direct operating costs per total job	$323.12	$234.33	37.9 %
Average margin per total job (1)	$26.50	$46.71	(43.3)%
Margin as a percentage of revenues (1)	7.6 %	16.6 %	(54.2)%
Capital expenditures and acquisitions	$19,332	$139,819	(86.2)%

(1) Margin is defined as revenues less direct operating costs and excludes depreciation, amortization and impairment and selling, general and administrative expenses. Average margin per total job is defined as margin divided by total jobs. Margin as a percentage of revenues is defined as margin divided by revenues.

Revenues and direct operating costs decreased primarily due to a decrease in the number of fracturing jobs. The total number of jobs decreased as a result of the downturn in the oil and natural gas industry.

The reduction in selling, general and administrative expense reflects reductions in headcount and other personnel related costs.

Oil and Natural Gas Production and Exploration	2016	2015	% Change
	(Dollars in thousands)		
Revenues - Oil	$7,413	$12,955	(42.8)%
Revenues - Natural gas and liquids	1,276	1,361	(6.2)%
Revenues - Total	8,689	14,316	(39.3)%
Direct operating costs	3,740	5,577	(32.9)%
Margin (1)	4,949	8,739	(43.4)%
Depletion and impairment	6,537	16,932	(61.4)%
Operating loss	$(1,588)	$(8,193)	(80.6)%
Capital expenditures	$3,220	$11,204	(71.3)%

(1) Margin is defined as revenues less direct operating costs and excludes depletion and impairment.

Oil revenues decreased as a result of lower oil production and lower commodity prices. Depletion and impairment expense in 2016 includes approximately $2.2 million of oil and natural gas property impairments compared to approximately $7.4 million of oil and natural gas property impairments in 2015. Depletion expense is lower primarily due to lower oil production and the impact of significant impairments recorded in recent years.

Corporate and Other	2016	2015	% Change
	(Dollars in thousands)		
Selling, general and administrative	$25,904	$27,451	(5.6)%
Depreciation	$2,737	$2,735	0.1 %
Other operating (income) expense, net:			
Net gain on asset disposals	$(7,267)	$(5,914)	22.9 %
Legal settlements	1,100	12,260	(91.0)%
Other operating (income) expense, net	$(6,167)	$6,346	NA
Interest income	$210	$601	(65.1)%
Interest expense	$21,478	$17,790	20.7 %
Other income	$33	$—	NA
Capital expenditures	$832	$1,248	(33.3)%

Lower selling, general and administrative expense reflects lower personnel costs due to headcount reductions. Other operating (income) expense, net includes net gains or losses associated with the disposal of assets related to corporate strategy decisions of the executive management group. Accordingly, the related gains or losses have been excluded from the results of specific segments. Interest expense increased primarily due to lower capitalized interest, as we have reduced our capital expenditure spending in 2016.

Adjusted EBITDA

Adjusted earnings before interest, taxes, depreciation and amortization ("Adjusted EBITDA") is not defined by accounting principles generally accepted in the United States of America ("U.S. GAAP"). We define Adjusted EBITDA as net income (loss) plus net interest expense, income tax expense (benefit) and depreciation, depletion, amortization and impairment expense. We present Adjusted EBITDA (a non-U.S. GAAP measure) because we believe it provides to both management and investors additional information with respect to both the performance of our fundamental business activities and our ability to meet our capital expenditures and working capital requirements. Adjusted EBITDA should not be construed as an alternative to the U.S. GAAP measure of net income (loss).

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(Dollars in thousands)			
Net loss	$(85,866)	$(18,975)	$(156,369)	$(9,850)
Income tax benefit	(49,027)	(14,720)	(84,457)	(8,000)
Net interest expense	10,578	8,931	21,268	17,189
Depreciation, depletion, amortization and impairment	170,975	181,924	347,745	357,306
Adjusted EBITDA	$46,660	$157,160	$128,187	$356,645

Income Taxes

Our effective income tax rate was 35.1% for the six months ended June 30, 2016, compared to 44.8% for the six months ended June 30, 2015. The Domestic Production Activities Deduction (the "Section 199 Deduction") was enacted as part of the American Jobs Creation Act of 2004 (as revised by the Emergency Economic Stabilization Act of 2008), and allows a deduction of 9% on the lesser of qualified production activities income or taxable income. For tax purposes, we had net operating losses for the years ended December 31, 2015 and 2014, which have been carried back to prior years. These carrybacks resulted in the loss of the benefits of previous Section 199 Deductions. The loss of these benefits was recognized during the six months ended June 30, 2016, which reduced the tax benefit recorded for the six months ended June 30, 2016.

At June 30, 2015, we expected a loss before income taxes for financial statement purposes for the year ending December 31, 2015; however we expected to have taxable income for the year ending December 31, 2015, and the Section 199 Deduction was expected to provide a permanent tax benefit. On June 15, 2015, legislation was enacted which permanently reduced the Texas Margin Tax rate. This resulted in a permanent tax benefit that was recognized during the quarter ended June 30, 2015. The interplay between the expected loss before income taxes for financial statement purposes, the permanent tax benefit expected to be provided by the Section 199 Deduction and the permanent tax benefit from the Texas Margin Tax rate resulted in a higher effective income tax rate for the six months ended June 30, 2015.

Recently Issued Accounting Standards

In May 2014, the FASB issued an accounting standards update to provide guidance on the recognition of revenue from customers. The FASB clarified this guidance in March, April and May 2016. Under this guidance, an entity will recognize revenue when it transfers promised goods or services to customers in an amount that reflects what it expects in exchange for the goods or services. This guidance also requires more detailed disclosures to enable users of the financial statements to understand the nature, amount, timing and uncertainty, if any, of revenue and cash flows arising from contracts with customers. The requirements in this update are effective during interim and annual periods beginning after December 15, 2017. We are currently evaluating the impact this guidance will have on our consolidated financial statements.

In November 2015, the FASB issued an accounting standards update to provide guidance for the presentation of deferred tax liabilities and assets. Under this guidance, for a particular tax-paying component of an entity and within a particular tax jurisdiction, all deferred tax liabilities and assets, as well as any related valuation allowance, shall be offset and presented as a single noncurrent amount. The requirements in this update are effective during interim and annual periods beginning after December 15, 2016. The adoption of this update is not expected to have a material impact on our consolidated financial statements.

In February 2016, the FASB issued an accounting standards update to provide guidance for the accounting for leasing transactions. The requirements in this update are effective during interim and annual periods beginning after December 15, 2018. We are currently evaluating the impact this guidance will have on our consolidated financial statements.

In March 2016, the FASB issued an accounting standards update to provide guidance for the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The requirements in this update are effective during interim and annual periods beginning after December 15, 2016. We are currently evaluating the impact this guidance will have on our consolidated financial statements.

Volatility of Oil and Natural Gas Prices and its Impact on Operations and Financial Condition

Our revenue, profitability and cash flows are highly dependent upon prevailing prices for oil and natural gas and expectations about future prices. For many years, oil and natural gas prices and markets have been extremely volatile. Prices are affected by many factors beyond our control. Oil prices declined significantly during the second half of 2014. The closing price of oil, which was as high as $105.68 per barrel during the third quarter of 2014, averaged $48.69 during 2015 and reached a twelve-year low of $26.19 in February 2016. Oil prices averaged $45.41 during the second quarter of 2016 and were briefly above $50 during June 2016. As a result of the prolonged decline in oil prices, our industry has experienced a severe decline in both contract drilling and pressure pumping activity levels. While activity levels have recently stabilized, we do not expect activity levels to significantly increase until commodity prices improve.

We expect oil and natural gas prices to continue to be volatile and to affect our financial condition, operations and ability to access sources of capital. Higher oil and natural gas prices do not necessarily result in increased activity because demand for our services is generally driven by our customers’ expectations of future oil and natural gas prices. A continued decline in demand for oil and natural gas or prolonged low oil and natural gas prices would likely result in further reduced capital expenditures by our customers and decreased demand for our drilling rigs and pressure pumping services, which could have a material adverse effect on our operating results, financial condition and cash flows.

ITEM 3. Quantitative and Qualitative Disclosures About Market Risk

As of June 30, 2016, we had exposure to interest rate market risk associated with any borrowings that we had under the Base Credit Agreement, the 2015 Term Loan Agreement and the Reimbursement Agreement.

Loans under the Credit Agreement bear interest by reference, at our election, to the LIBOR rate or base rate, provided, that swing line loans bear interest by reference only to the base rate. Until September 27, 2017, the applicable margin on LIBOR rate loans varies from 2.75% to 3.25% and the applicable margin on base rate loans varies from 1.75% to 2.25%, in each case determined based upon our debt to capitalization ratio. On or after September 27, 2017, the applicable margin on LIBOR rate loans varies from 3.25% to 3.75% and the applicable margin on base rate loans varies from 2.25% to 2.75%, in each case determined based on our excess availability under the credit facility. As of June 30, 2016 the applicable margin on LIBOR rate loans was 2.75% and the applicable margin on base rate loans was 1.75%. Based on our debt to capitalization ratio at March 31, 2016, the applicable margin on LIBOR loans is 2.75% and the applicable margin on base rate loans is 1.75% as of July 1, 2016. Based on our debt to capitalization ratio at June 30, 2016, the applicable margin on LIBOR loans will be 2.75% and the applicable margin on base rate loans will be 1.75% as of October 1, 2016.

Loans under the 2015 Term Loan Agreement bore interest, at our election, at the per annum rate of LIBOR plus 3.25% or base rate plus 2.25%.

As of June 30, 2016, under our Base Credit Agreement we had no amounts outstanding under our revolving credit facility and $60.0 million outstanding under our term loan facility at an interest rate of 5.25%. As of June 30, 2016, we had $170 million principal amount outstanding under the 2015 Term Loan Agreement at an interest rate of 5.75%. As a condition precedent to Amendment No. 2, we repaid amounts outstanding under both term loan facilities and terminated both facilities. As of August 2, 2016, we had $70 million drawn under the revolving credit facility. The interest rate on the borrowings outstanding under our revolving credit facility is variable and adjusts at each interest payment date based on our election of LIBOR or the base rate.

Under the Reimbursement Agreement, we will reimburse Scotiabank on demand for any amounts that Scotiabank has disbursed under any letters of credit. We are obligated to pay to Scotiabank interest on all amounts not paid by us on the date of demand or when otherwise due at the LIBOR rate plus 2.25% per annum. As of June 30, 2016, no amounts had been disbursed under any letters of credit.

We conduct a portion of our business in Canadian dollars through our Canadian land-based drilling operations. The exchange rate between Canadian dollars and U.S. dollars has fluctuated during the last several years. If the value of the Canadian dollar against the U.S. dollar weakens, revenues and earnings of our Canadian operations will be reduced and the value of our Canadian net assets will decline when they are translated to U.S. dollars. This currency risk is not material to our results of operations or financial condition.

The carrying values of cash and cash equivalents, trade receivables and accounts payable approximate fair value due to the short-term maturity of these items.

ITEM 4. Controls and Procedures

Disclosure Controls and Procedures — We maintain disclosure controls and procedures (as such terms are defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Exchange Act), designed to ensure that the information required to be disclosed in the reports that we file with the SEC under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer ("CEO") and Chief Financial Officer

("CFO"), as appropriate, to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of our management, including our CEO and CFO, we conducted an evaluation of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this Quarterly Report on Form 10 Q. Based on that evaluation, our CEO and CFO concluded that our disclosure controls and procedures were effective as of June 30, 2016.

Changes in Internal Control Over Financial Reporting —There were no changes in our internal control over financial reporting during our most recently completed fiscal quarter 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

We are party to various legal proceedings arising in the normal course of our business; we do not believe that the outcome of these proceedings, either individually or in the aggregate, will have a material adverse effect on our financial condition, results of operations or cash flows. See Note 9 to our unaudited condensed consolidated financial statements in Item 1 of Part I – Financial Information.

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

The table below sets forth the information with respect to purchases of our common stock made by us during the quarter ended June 30, 2016.

Period Covered	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares That May Yet Be Purchased Under the Plans or Programs (in thousands)(1)
April 2016 (2)	12,124	$ 18.74	—	186,836
May 2016	—	—	—	186,836
June 2016 (2)	156,928	$ 21.56	8,488	186,653
Total	169,052	$ 21.36	8,488	186,653

(1) On September 9, 2013, we announced that our Board of Directors approved a stock buyback program authorizing purchases of up to $200 million of our common stock in open market or privately negotiated transactions.

(2) We withheld 12,124 shares in April 2016 and 148,440 shares in June 2016 with respect to employees' tax withholding obligations upon vesting of restricted shares. These shares were purchased at fair market value pursuant to the terms of the 2014 Plan and not pursuant to the stock buyback program.

ITEM 5. Other Information

On August 1, 2016, we entered into an Employment Agreement with William Andrew Hendricks, Jr., our President and Chief Executive Officer, pursuant to which Mr. Hendricks will be entitled to receive a base salary of $600,000 per year and will be eligible to participate in the Company's annual bonus arrangement for senior executives. Pursuant to the Patterson-UTI Energy, Inc. 2014 Long Term Incentive Plan, the Compensation Committee granted Mr. Hendricks 36,661 restricted shares of common stock of the Company, which vest over a three-year period. In addition to a base salary, Mr. Hendricks will be entitled to participate in all benefit plans generally available to other senior executive employees and in our incentive plans.

The Employment Agreement has an initial three-year term, subject to automatic annual renewal, and supersedes his previous change in control agreement. Mr. Hendricks may terminate his employment under the Employment Agreement by providing written notice of such termination at least 30 days before the effective date of such termination. Under specified circumstances, we may terminate Mr. Hendricks' employment under the Employment Agreement for "Cause" (as defined in the Employment Agreement) by either (i) providing written notice 10 days before the effective date of such termination and by granting at least 10 days to cure the cause for such termination or (ii) by providing written notice of such termination at least 30 days before the effective date of such termination and by granting at least 20 days to cure the cause for such termination, provided that if the matter is reasonably determined by the Company to not be capable of being cured, Mr. Hendricks may be terminated for cause on the date the written notice is delivered.

The Employment Agreement also provides for, among other things, severance payments and the continuation of certain benefits following termination by the Company of Mr. Hendricks other than for Cause, or termination by Mr. Hendricks for "Good Reason" (as defined in the Employment Agreement). Under these provisions, if Mr. Hendricks' employment is terminated by the Company without Cause, or Mr. Hendricks terminates his employment for Good Reason, (i) Mr. Hendricks will have the right to receive a lump-sum payment consisting of three times the sum of his base salary plus the average annual cash bonus received by him for the three years prior to the date of termination, payable on the 60th day following his termination, (ii) Mr. Hendricks will have the right to receive a pro-rated lump-sum payment equal to his annual cash bonus based on actual results for the year, payable at the same time as annual cash bonuses are paid to active employees, (iii) the Company will accelerate vesting of all options and restricted stock awards on the 60th day following Mr. Hendricks' termination, (iv) Mr. Hendricks will be entitled to receive a number of shares in an amount equal to the amount of any performance units previously granted to him that would have vested at the end of the applicable performance period based on actual results, payable at the same time as if Mr. Hendricks had remained employed through the end of the applicable performance period, and (v) the Company will pay Mr. Hendricks certain accrued obligations and certain obligations pursuant to the terms of employee benefit plans. If a termination by the Company other than for Cause or by Mr. Hendricks for Good Reason, occurs following a "Change in Control of the Company" (as defined in the Employment Agreement), Mr. Hendricks will generally be entitled to the same severance payments and benefits described above except that the pro-rated lump-sum payment for annual cash bonuses will be based on his highest annual cash bonus for the last three years and his performance units will vest at target, both payable within 60 days following his termination.

All of the foregoing severance benefits (other than the accrued obligations and benefit obligations) are conditioned on Mr. Hendricks' execution of a release within 50 days of his termination that is not revoked during any applicable revocation period provided in such release.

The Employment Agreement also contains a non-disparagement covenant and certain confidentiality covenants prohibiting Mr. Hendricks from, among other things, disclosing confidential information. The Employment Agreement also contains non-competition and non-solicitation restrictions, pursuant to which Mr. Hendricks will not be permitted to compete with the Company in certain circumstances for a period of one year following termination of employment. The foregoing summary is qualified in its entirety by reference to the Employment Agreement, a copy of which is filed as Exhibit 10.2 and is incorporated herein by reference.

ITEM 6. Exhibits

The following exhibits are filed herewith or incorporated by reference, as indicated:

3.1	Restated Certificate of Incorporation, as amended (filed August 9, 2004 as Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).
3.2	Amendment to Restated Certificate of Incorporation, as amended (filed August 9, 2004 as Exhibit 3.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).
3.3	Second Amended and Restated Bylaws (filed August 6, 2007 as Exhibit 3.3 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 and incorporated herein by reference).
10.1	Amendment No. 2 to Credit Agreement, dated as of July 8, 2016, by and among the Company, certain subsidiaries of the Company party thereto, Wells Fargo Bank, N.A., as administrative agent, issuer of letters of credit and swing line lender and the other lenders party thereto. (filed July 12, 2016 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).
10.2*	Employment Agreement dated as of August 1, 2016 between Patterson-UTI Energy, Inc. and William Andrew Hendricks, Jr.
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended.
32.1*	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 USC Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101*	The following materials from Patterson-UTI Energy, Inc.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2016, formatted in XBRL (Extensible Business Reporting Language): (i) the Condensed Consolidated Balance Sheets, (ii) the Condensed Consolidated Statements of Operations, (iii) the Condensed Consolidated Statements of Comprehensive Income, (iv) the Condensed Consolidated Statement of Changes in Stockholders' Equity, (v) the Condensed Consolidated Statements of Cash Flows, and (vi) Notes to Condensed Consolidated Financial Statements.

* filed herewith

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SIGNATURE

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.

PATTERSON-UTI ENERGY, INC.

By: /s/ John E. Vollmer III
John E. Vollmer III
Senior Vice President – Corporate Development,
Chief Financial Officer and Treasurer
(Principal Financial and Accounting Officer and Duly Authorized Officer)

Date: August 2, 2016