

PATTERSON UTI ENERGY INC
Form 10-Q
October 31, 2016

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

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

For the quarterly period ended September 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
(State or other jurisdiction of
incorporation or organization)

75-2504748
(I.R.S. Employer
Identification No.)

10713 W. SAM HOUSTON PKWY N, SUITE 800

HOUSTON, TEXAS
(Address of principal executive offices)

77064
(Zip Code)

(281) 765-7100

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(Registrant's telephone number, including area code)

450 GEARS ROAD, SUITE 500, HOUSTON, TEXAS 77067

(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (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 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 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

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

148,110,448 shares of common stock, \$0.01 par value, as of October 27, 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)

	September 30, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	\$36,972	\$113,346
Accounts receivable, net of allowance for doubtful accounts of \$3,191 and \$3,545		
at September 30, 2016 and December 31, 2015, respectively	146,013	219,672
Federal and state income taxes receivable	3,838	33,454
Inventory	19,851	14,716
Deferred tax assets, net	34,897	65,121
Other	38,722	40,227
Total current assets	280,293	486,536
Property and equipment, net	3,511,740	3,920,708
Goodwill and intangible assets	89,877	92,609
Deposits on equipment purchases	17,700	22,367
Other	9,263	7,264
Total assets	\$3,908,873	\$4,529,484
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	\$82,163	\$82,771
Accrued expenses	154,228	161,611
Current portion of long-term debt, net of debt issuance cost of \$483 at		
December 31, 2015	—	63,267
Total current liabilities	236,391	307,649
Borrowings under revolving credit facility	15,000	—
Long-term debt, net of debt issuance cost of \$1,649 and \$3,350 at September 30, 2016		
and December 31, 2015, respectively	598,351	787,900
Deferred tax liabilities, net	724,564	863,833
Other	10,441	8,971
Total liabilities	1,584,747	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 191,494,741		
and 190,374,801 issued and 148,118,449 and 147,167,561 outstanding at		
September 30, 2016 and December 31, 2015, respectively	1,915	1,904
Additional paid-in capital	1,034,768	1,011,811
Retained earnings	2,197,424	2,458,554
Accumulated other comprehensive income (loss)	675	(4,093)
Treasury stock, at cost, 43,376,292 and 43,207,240 shares at September 30, 2016 and		
December 31, 2015, respectively	(910,656)	(907,045)
Total stockholders' equity	2,324,126	2,561,131
Total liabilities and stockholders' equity	\$3,908,873	\$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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Operating revenues:				
Contract drilling	\$123,684	\$261,817	\$407,578	\$951,616
Pressure pumping	78,165	154,407	248,428	580,752
Oil and natural gas	4,284	6,027	12,973	20,343
Total operating revenues	206,133	422,251	668,979	1,552,711
Operating costs and expenses:				
Contract drilling	74,517	136,718	219,218	503,376
Pressure pumping	77,221	138,597	234,580	494,078
Oil and natural gas	1,846	2,519	5,586	8,096
Depreciation, depletion, amortization and impairment	163,464	332,151	511,209	689,457
Impairment of goodwill	—	124,561	—	124,561
Selling, general and administrative	16,612	18,582	51,671	58,335
Other operating (income) expense, net	(4,118)	(1,362)	(10,285)	4,984
Total operating costs and expenses	329,542	751,766	1,011,979	1,882,887
Operating loss	(123,409)	(329,515)	(343,000)	(330,176)
Other income (expense):				
Interest income	63	323	273	924
Interest expense, net of amount capitalized	(10,244)	(9,254)	(31,722)	(27,044)
Other	19	16	52	16
Total other expense	(10,162)	(8,915)	(31,397)	(26,104)
Loss before income taxes	(133,571)	(338,430)	(374,397)	(356,280)
Income tax benefit	(49,428)	(112,452)	(133,885)	(120,452)
Net loss	\$(84,143)	\$(225,978)	\$(240,512)	\$(235,828)
Net loss per common share:				
Basic	\$(0.58)	\$(1.54)	\$(1.65)	\$(1.61)
Diluted	\$(0.58)	\$(1.54)	\$(1.65)	\$(1.61)
Weighted average number of common shares outstanding:				
Basic	146,326	145,662	146,014	145,317
Diluted	146,326	145,662	146,014	145,317
Cash dividends per common share	\$0.02	\$0.10	\$0.14	\$0.30

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(unaudited, in thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Net loss	\$(84,143)	\$(225,978)	\$(240,512)	\$(235,828)
Other comprehensive income (loss), net of taxes of \$0 for all periods:				
Foreign currency translation adjustment	(2,379)	(2,909)	4,768	(8,454)
Total comprehensive loss	\$(86,522)	\$(228,887)	\$(235,744)	\$(244,282)

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		Additional		Accumulated		
	Number		Paid-in	Retained	Other		
	of						
	Shares	Amount	Capital	Earnings	Comprehensive Income	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	—	—	—	(240,512)	—	—	(240,512)
Foreign currency translation							
adjustment	—	—	—	—	4,768	—	4,768
Shares issued for acquisition	354	3	6,730	—	—	—	6,733
Issuance of restricted stock	785	8	(8)	—	—	—	—
Vesting of restricted stock units	15	—	—	—	—	—	—
Forfeitures of restricted stock	(34)	—	—	—	—	—	—
Stock-based compensation	—	—	21,130	—	—	—	21,130
Tax expense related to stock-							
based compensation	—	—	(4,895)	—	—	—	(4,895)
Payment of cash dividends	—	—	—	(20,618)	—	—	(20,618)
Purchase of treasury stock	—	—	—	—	—	(3,611)	(3,611)
Balance, September 30, 2016	191,495	\$ 1,915	\$ 1,034,768	\$ 2,197,424	\$ 675	\$(910,656)	\$ 2,324,126

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)

	Nine Months Ended September 30,	
	2016	2015
Cash flows from operating activities:		
Net loss	\$(240,512)	\$(235,828)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion, amortization and impairment	511,209	689,457
Impairment of goodwill	—	124,561
Dry holes and abandonments	—	159
Deferred income tax benefit	(109,045)	(110,231)
Stock-based compensation expense	21,130	21,186
Net gain on asset disposals	(9,808)	(7,276)
Tax expense on stock-based compensation	(4,895)	—
Amortization of debt issuance costs	2,184	884
Changes in operating assets and liabilities:		
Accounts receivable	74,742	359,304
Income taxes receivable	28,524	52,037
Inventory and other assets	7,876	26,695
Accounts payable	(19,652)	(120,740)
Accrued expenses	(7,616)	7,274
Other liabilities	(1,431)	(1,443)
Net cash provided by operating activities	252,706	806,039
Cash flows from investing activities:		
Purchases of property and equipment	(80,511)	(608,220)
Proceeds from disposal of assets	18,384	15,920
Cash acquired in acquisition	155	—
Net cash used in investing activities	(61,972)	(592,300)
Cash flows from financing activities:		
Purchases of treasury stock	(3,611)	(8,010)
Dividends paid	(20,618)	(44,064)
Tax benefit related to stock-based compensation	—	458
Debt issuance costs	(3,357)	(1,979)
Proceeds from long-term debt	—	200,000
Repayment of long-term debt	(255,000)	(17,500)
Proceeds from borrowings under revolving credit facility	95,000	54,000
Repayment of borrowings under revolving credit facility	(80,000)	(357,000)
Net cash used in financing activities	(267,586)	(174,095)
Effect of foreign exchange rate changes on cash	478	(6,191)
Net increase (decrease) in cash and cash equivalents	(76,374)	33,453
Cash and cash equivalents at beginning of period	113,346	43,012
Cash and cash equivalents at end of period	\$36,972	\$76,465
Supplemental disclosure of cash flow information:		
Net cash (paid) received during the period for:		

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Interest, net of capitalized interest of \$327 in 2016 and \$4,946 in 2015	\$(21,973)	\$(18,734)
Income taxes	\$44,987	\$63,785
Non-cash investing and financing activities:		
Net increase (decrease) in payables for purchases of property and equipment	\$16,884	\$(95,371)
Issuance of common stock for business acquisition	\$6,733	\$—
Net decrease in deposits on equipment purchases	\$4,667	\$76,516

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 recurring adjustments 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 nine months ended September 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 certain legal settlements were previously included in operating costs of the respective operating segment or within 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 nine months ended September 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.

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The following table presents information necessary to calculate net loss per share for the three and nine month periods ended September 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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
BASIC EPS:				
Net loss	\$(84,143)	\$(225,978)	\$(240,512)	\$(235,828)
Adjust for loss attributed to holders of non-vested restricted stock	—	2,359	—	2,436
Loss attributed to other common stockholders	\$(84,143)	\$(223,619)	\$(240,512)	\$(233,392)
Weighted average number of common shares outstanding, excluding				
non-vested shares of restricted stock	146,326	145,662	146,014	145,317
Basic net loss per common share	\$(0.58)	\$(1.54)	\$(1.65)	\$(1.61)
DILUTED EPS:				
Loss attributed to other common stockholders	\$(84,143)	\$(223,619)	\$(240,512)	\$(233,392)
Weighted average number of common shares outstanding, excluding				
non-vested shares of restricted stock	146,326	145,662	146,014	145,317
Add dilutive effect of potential common shares	—	—	—	—
Weighted average number of diluted common shares outstanding	146,326	145,662	146,014	145,317
Diluted net loss per common share	\$(0.58)	\$(1.54)	\$(1.65)	\$(1.61)
Potentially dilutive securities excluded as anti-dilutive	9,141	7,840	9,141	7,840

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 that have included service conditions 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 such 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 nine month periods ended September 30, 2016 and 2015 follow:

	Three Months Ended September 30, 2016		2015	Nine Months Ended September 30, 2016		2015
Volatility	34.87 %	NA		35.11 %		37.95 %
Expected term (in years)	5.00	NA		5.00		5.00
Dividend yield	0.42 %	NA		2.05 %		2.00 %
Risk-free interest rate	1.20 %	NA		1.40 %		1.37 %

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

	Underlying Shares	Weighted Average Exercise Price Per Share
Outstanding at January 1, 2016	6,307,250	\$ 21.68
Granted	969,900	\$ 18.40
Exercised	—	\$ —
Cancelled	—	\$ —
Expired	(550,000)	\$ 28.26
Outstanding at September 30, 2016	6,727,150	\$ 20.67
Exercisable at September 30, 2016	5,266,379	\$ 20.91

Restricted Stock — For all restricted stock awards made 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 September 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	785,486	\$ 20.58
Vested	(709,008)	\$ 24.66
Forfeited	(34,383)	\$ 24.89
Non-vested restricted stock outstanding September 30, 2016	1,474,345	\$ 22.38

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 September 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	178,254	\$ 19.31
Vested	(15,033)	\$ 27.30
Forfeited	(7,668)	\$ 24.83
Non-vested restricted stock units outstanding September 30, 2016	197,239	\$ 19.94

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 of certain performance goals during a specified period 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 was 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, 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 had the Company's total shareholder return been positive.

In respect of the 2013 Performance Units, for which 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 had the Company's total shareholder return 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	2015	2014	2013	2012
	Performance	Performance	Performance	Performance	Performance
	Unit Awards	Unit Awards	Unit Awards	Unit Awards	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	Performance	Performance	Performance	Performance
	Unit Awards	Unit Awards	Unit Awards	Unit Awards	Unit Awards
Fair value at date of grant	\$ 3,854	\$ 4,052	\$ 5,388	\$ 5,564	\$ 3,065

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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 September 30, 2015	NA	\$ 338	\$ 449	\$ 464	NA
Three months ended September 30, 2016	\$ 321	\$ 338	\$ 449	NA	NA
Nine months ended September 30, 2015	NA	\$ 675	\$ 1,347	\$ 1,391	\$ 255
Nine months ended September 30, 2016	\$ 642	\$ 1,013	\$ 1,347	\$ 464	NA

3. Property and Equipment

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

	September 30, 2016	December 31, 2015
Equipment	\$6,808,201	\$6,963,148
Oil and natural gas properties	201,450	200,923
Buildings	96,950	96,470
Land	22,370	22,370
	7,128,971	7,282,911
Less accumulated depreciation, depletion and impairment	(3,617,231)	(3,362,203)
Property and equipment, net	\$3,511,740	\$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 nine month periods ended September 30, 2016 and management’s expectations of operating results in future periods, the Company concluded that no triggering event occurred during the nine months ended September 30, 2016 with respect to its contract drilling or pressure pumping segments. Management’s expectations of future operating results 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. Depreciation, amortization and impairment expense for the three and nine month periods ended September 30, 2015, included a charge of \$131 million related to the write-down of drilling equipment, primarily related to mechanical drilling rigs and spare mechanical rig components, to their realizable values and \$22.0 million related to the write-down of pressure pumping equipment and certain closed facilities to their realizable values.

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 \$205,000 in the third quarter and approximately \$2.4 million for the nine months ended September 30, 2016 and is included in depreciation, depletion, amortization and impairment in the condensed consolidated statements of operations.

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 and has a separate management team that reports 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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Revenues:				
Contract drilling	\$123,863	\$262,196	\$407,855	\$953,025
Pressure pumping	78,165	154,407	248,428	580,752
Oil and natural gas	4,284	6,027	12,973	20,343
Total segment revenues	206,312	422,630	669,256	1,554,120
Elimination of intercompany revenues (a)	(179)	(379)	(277)	(1,409)
Total revenues	\$206,133	\$422,251	\$668,979	\$1,552,711
Operating income (loss):				
Contract drilling	\$(67,786)	\$(131,256)	\$(173,331)	\$(53,432)
Pressure pumping	(46,569)	(183,464)	(136,553)	(217,224)
Oil and natural gas	582	(1,824)	(1,006)	(10,017)
	(113,773)	(316,544)	(310,890)	(280,673)
Corporate and other	(13,754)	(14,333)	(42,395)	(44,519)
Other operating income (expense), net (b)	4,118	1,362	10,285	(4,984)
Interest income	63	323	273	924
Interest expense	(10,244)	(9,254)	(31,722)	(27,044)
Other	19	16	52	16
Loss before income taxes	\$(133,571)	\$(338,430)	\$(374,397)	\$(356,280)

	September 30, 2016	December 31, 2015
Identifiable assets:		
Contract drilling	\$3,113,229	\$3,457,044
Pressure pumping	677,100	813,704
Oil and natural gas	31,347	34,073
Corporate and other (c)	87,197	224,663
Total assets	\$3,908,873	\$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 operating results of specific segments. This caption also includes expenses related to certain legal settlements net of insurance reimbursements.
- (c) Corporate and other assets primarily include cash on hand, income tax receivables, certain deferred tax assets and the assets of a business acquired in September 2016 that designs, manufactures, repairs and services pipe handling equipment and other rig components, including top drives and tubular tongs.

5. Goodwill and Intangible Assets

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

	Nine Months Ended September 30, 2016
Balance at beginning of period	\$ 86,234
Changes to goodwill	—
Balance at end of period	\$ 86,234

There were no accumulated impairment losses related to goodwill as of September 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 impairment testing purposes, goodwill is evaluated at the reporting unit level. The Company's reporting units for impairment testing are 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 this is the case, any necessary 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 assets, 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 for the amount of the shortfall.

Based on the results of the first step of the goodwill impairment test as of September 30, 2015, management concluded that impairment was indicated in its pressure pumping reporting unit and the Company recognized an impairment charge of \$125 million in the three months ended September 30, 2015. The implied fair value of goodwill was estimated using a variety of valuation methods, including the income and market approaches. The estimate of fair value required the use of significant unobservable inputs, representative of a Level 3 fair value measurement. The inputs included assumptions related to the future performance of the Company's pressure pumping reporting unit, such as future oil and natural gas prices and projected demand for the Company's services, and assumptions related to discount rates, long-term growth rates and control premiums.

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 September 30, 2016 and 2015, and amortization expense of approximately \$2.7 million was recorded in the nine months ended September 30, 2016 and 2015.

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

	September 30, 2016			December 31, 2015		
	Gross		Net	Gross		Net
	Carrying	Accumulated	Carrying	Carrying	Accumulated	Carrying
	Amount	Amortization	Amount	Amount	Amortization	Amount
Customer relationships	\$25,500	\$ (21,857)	\$ 3,643	\$25,500	\$ (19,125)	\$ 6,375

6. Accrued Expenses

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

	September 30, 2016	December 31, 2015
Salaries, wages, payroll taxes and benefits	\$ 23,259	\$ 27,055
Workers' compensation liability	70,073	75,358
Property, sales, use and other taxes	11,082	9,061
Insurance, other than workers' compensation	9,392	12,817
Accrued interest payable	13,925	7,668
Other	26,497	29,652
Total	\$ 154,228	\$ 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 nine months ended September 30, 2016 and 2015 (in thousands):

	Nine Months Ended September 30, 2016 2015	
Balance at beginning of year	\$5,692	\$5,301
Liabilities incurred	84	322
Liabilities settled	(74)	(118)
Accretion expense	126	129
Revision in estimated costs of plugging oil and natural gas wells	42	—
Asset retirement obligation at end of period	\$5,870	\$5,634

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 (“Amendment No. 2”), which amended the Base Credit Agreement. The revolving credit facility permits aggregate borrowings of up to \$500 million outstanding at any time, subject to a borrowing base calculated by reference to the Company’s and certain of its subsidiaries’ eligible equipment, inventory, account receivable and unencumbered cash as described in Amendment No. 2. 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. 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.

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. As a condition precedent, Amendment No. 2 required that the Company repay the entire outstanding principal amount of this term loan.

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. Beginning 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 September 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 June 30, 2016, the applicable margin on LIBOR loans is 2.75% and the applicable margin on base rate loans is 1.75% as of October 1, 2016. Based on the Company's debt to capitalization ratio at September 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 January 1, 2017. 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 September 30, 2016.

Amendment No. 2 limits 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. Amendment No. 2 also 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. In addition, Amendment No. 2 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. Amendment No. 2 also 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.

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 September 30, 2016, the Company had \$15.0 million drawn under the revolving credit facility at a weighted average interest rate of 4.0%, with available borrowing capacity of \$317 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 September 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 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 on July 8, 2016.

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 September 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 \$2.0 million and \$746,000 for the three months ended September 30, 2016 and 2015, respectively. Interest expense related to the amortization of debt issuance costs was approximately \$3.5 million and \$2.0 million for the nine months ended September 30, 2016 and 2015, respectively. Debt issuance costs amortization for the three and nine months ended September 30, 2016 includes \$1.4 million of costs related to the early termination of the 2012 and 2015 term loan agreements.

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

Year ending December 31,	
2016	\$—
2017	—
2018	—
2019	15,000
2020	300,000
Thereafter	300,000
Total	\$615,000

9. Commitments, Contingencies and Other Matters

As of September 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 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 September 30, 2016, no amounts had been drawn under the letters of credit.

As of September 30, 2016, the Company had commitments to purchase approximately \$64.2 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 September 30, 2016, the remaining obligation under these agreements was approximately \$22.0 million, of which approximately \$5.0 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. Repayment of the advance is to be made through discounts applied to purchases from the vendor. As of September 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 nine months ended September 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
Paid on September 24, 2015	0.10	14,712
Total cash dividends	\$ 0.30	\$ 44,064

2016:	Per Share	Total (in thousands)
Paid on March 24, 2016	\$ 0.10	\$ 14,712
Paid on June 23, 2016	0.02	2,953
Paid on September 22, 2016	0.02	2,953
Total cash dividends	\$ 0.14	\$ 20,618

On October 26, 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 December 22, 2016 to holders of record as of December 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 September 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.

On September 15, 2016, the Company issued 353,804 shares of its common stock, valued at \$6.7 million in connection with an acquisition. The transaction was not significant to the Company's consolidated financial statements.

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

	September 30, 2016	
	Shares	Cost
Treasury shares at beginning of period	43,207,240	\$ 907,045

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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 35.8% for the nine months ended September 30, 2016, compared to 33.8% for the nine months ended September 30, 2015. The difference in the effective tax rate is primarily related to the impact of goodwill impairment charges in 2015 and adjustment to the deferred tax liability associated with the conversion of the Company's Canadian operations to a controlled foreign corporation established in 2010.

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.

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

	September 30, 2016		December 31, 2015	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Borrowings under Credit Agreement:				
Revolving credit facility	\$15,000	\$15,000	\$—	\$—
Term loan facility	—	—	70,000	70,000
2015 Term Loan	—	—	185,000	185,000
4.97% Series A Senior Notes	300,000	288,203	300,000	279,635
4.27% Series B Senior Notes	300,000	270,849	300,000	258,806
Total debt	\$615,000	\$574,052	\$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 September 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 6.09% at September 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 6.33% at September 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.

In August 2016, the FASB issued an accounting standard to clarify the presentation of cash receipts and payments in specific situations on the statement of cash flows. 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.

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 \$44.85 during the third quarter of 2016. As a result of the lower level of oil prices, our industry has experienced a severe decline in both contract drilling and pressure pumping activity levels. Activity levels have recently improved. Looking forward, assuming commodity prices remain at or above recent levels, we believe U.S. rig counts will continue to increase.

Low commodity prices have negatively impacted 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 70% in the United States since the recent peak in 2014.

Our rig count in the United States significantly declined during the industry downturn, but has steadily improved on a monthly basis since May 2016. For the third quarter, our average rig count improved to 60 rigs in the United States and two rigs in Canada, up from the second quarter average of 55 rigs in the United States and less than one rig in Canada. In spite of the recent improvement, our rig count is still depressed. As of September 30, 2016, we had 62 drilling rigs operating in the United States, which was a decrease of 71% from the peak of 214 rigs in October 2014. Term contracts have provided support for our operating rig count during the third quarter of 2016. Based on contracts currently in place, we expect an average of 43 rigs operating under term contracts during the fourth quarter of 2016.

Activity levels in our pressure pumping business have recently improved modestly; however, pricing for available work remains low. Looking forward, we expect to see further increases in activity across the industry, especially in the Permian Basin. We have not reactivated any spreads, and we still have 53% of the more than one million hydraulic fracturing horsepower in our fleet stacked.

Our term contract coverage in contract drilling and scalability with respect to labor and other operating costs in contract drilling and pressure pumping have helped 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 64 rigs as of October 25, 2016. If oil prices remain depressed for a sustained period, it 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 third quarter of 2016, our average number of rigs operating in the United States was 60 compared to an average of 105 drilling rigs operating during the same period in 2015. During the third quarter of 2016, our average number of rigs operating in Canada was two compared to an average of four rigs operating during the third 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 September 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 September 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 September 30, 2016 was approximately \$464 million. More than 80% of the total September 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, our term drilling contracts are generally subject to termination by the customer on short notice and provide for an early termination payment to us in the event the contract is terminated by the customer. For contracts on which we have received an early termination notice, our backlog calculation includes the early termination rate, instead of the dayrate, for the period over which we expect to receive the lower rate.

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

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2016		2015		2016		2015	
Contract drilling	\$123,684	60.0 %	\$261,817	62.0 %	\$407,578	60.9 %	\$951,616	61.3 %
Pressure pumping	78,165	37.9 %	154,407	36.6 %	248,428	37.2 %	580,752	37.4 %
Oil and natural gas	4,284	2.1 %	6,027	1.4 %	12,973	1.9 %	20,343	1.3 %
	\$206,133	100.0%	\$422,251	100.0%	\$668,979	100.0%	\$1,552,711	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 third quarter of 2016, our average number of rigs operating was 60 in the United States and two in Canada compared to 105 in the United States and four in Canada in the third quarter of 2015. Our average revenue per operating day was \$21,870 in the third quarter of 2016, including \$1.1 million of early termination revenue, compared to \$26,010 in the third quarter of 2015, including \$28.9 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 84 fracturing jobs during the third quarter of 2016 compared to 137 fracturing jobs during the third quarter of 2015. Our average revenue per fracturing job was \$906,420 in the third quarter of 2016 and \$1.1 million in the third quarter of 2015. Consolidated net loss for the third quarter of 2016 was \$84.1 million compared to consolidated net loss of \$226 million for the third quarter of 2015. The financial results for the three months ended September 30, 2015 included pretax non-cash charges totaling \$280 million. These charges included \$125 million from the impairment of all goodwill associated with our pressure pumping business, \$131 million from the write-down of drilling equipment primarily related to mechanical rigs and spare mechanical rig components, \$22.0 million from the write-down of pressure pumping equipment and closed facilities and \$1.9 million related to the impairment of certain oil and natural gas properties.

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 September 2016, our average number of rigs operating was 62 in the United States and two 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 II of this Report and in Part I of our Annual Report on Form 10-K for the fiscal year ended December 31, 2015.

Our liquidity as of September 30, 2016 included approximately \$43.9 million in working capital, including \$37.0 million of cash and cash equivalents, and \$317 million available under our revolving credit facility. 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 September 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 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 September 30, 2016, no amounts had been drawn under the letters of credit.

As of September 30, 2016, we had commitments to purchase approximately \$64.2 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 September 30, 2016, the remaining obligation under these agreements was approximately \$22.0 million, of which approximately \$5.0 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. Repayment of the advance is to be made through discounts applied to purchases from the vendor. As of September 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. In September 2016, we acquired a business that designs, manufactures, repairs and services pipe handling equipment and other rig components, including top drives and tubular tongs, for customers in North America and in other global oil and gas producing regions.

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 drilling rigs,
- refurbishment and upgrades of existing 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 three and nine month periods ended September 30, 2016 and our expectations of results of operations in future periods, we concluded that no triggering event occurred during the nine months ended September 30, 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 \$205,000 in the third quarter of 2016 and approximately \$2.4 million for the nine months ended September 30, 2016 and is included in depreciation, depletion, amortization and impairment in the condensed consolidated statements of operations.

Liquidity and Capital Resources

Our liquidity as of September 30, 2016 included approximately \$43.9 million in working capital, including \$37.0 million of cash and cash equivalents, and \$317 million available under our revolving credit facility. 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 nine months ended September 30, 2016, our sources of cash flow included:

- \$253 million from operating activities,
- \$18.4 million in proceeds from the disposal of property and equipment,
- \$15.0 million from net borrowings under our revolving credit facility.

During the nine months ended September 30, 2016, we used \$20.6 million to pay dividends on our common stock, \$3.6 million to purchase treasury stock, \$255 million to repay long-term debt, \$3.4 million for debt issuance costs related to Amendment No. 2 and \$80.5 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 nine months ended September 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
Paid on September 22, 2016	0.02	2,953
Total cash dividends	\$0.14	\$ 20,618

On October 26, 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 December 22, 2016 to holders of record as of December 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 September 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 nine months ended September 30, 2016 were as follows (dollars in thousands):

	September 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 (“Amendment No. 2”), which amended the Base Credit Agreement. The revolving credit facility permits aggregate borrowings of up to \$500 million outstanding at any time, 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. 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. 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.

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. As a condition precedent, Amendment No. 2 required us to repay the entire outstanding principal amount of our bank term loans.

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. Beginning 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 September 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 June 30, 2016, the applicable margin on LIBOR loans is 2.75% and the applicable margin on base rate loans is 1.75% as of October 1, 2016. Based on our debt to capitalization ratio at September 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 January 1, 2017. 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 September 30, 2016.

Amendment No. 2 limits 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. Amendment No. 2 also 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. In addition, Amendment No. 2 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. Amendment No. 2 also 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.

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 September 30, 2016, we had \$15.0 million drawn under the revolving credit facility at a weighted average interest rate of 4.00%, with available borrowing capacity of \$317 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 September 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 a condition precedent to Amendment No. 2, we repaid the entire outstanding principal amount under the 2015 Term Loan Agreement and terminated the agreement on July 8, 2016.

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 September 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 September 30, 2016 included approximately \$43.9 million in working capital, including \$37.0 million of cash and cash equivalents, and \$317 million available under our revolving credit facility. 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 September 30, 2016 and 2015:

Contract Drilling	2016	2015	% Change
	(Dollars in thousands)		
Revenues	\$123,684	\$261,817	(52.8)%
Direct operating costs	74,517	136,718	(45.5)%
Margin (1)	49,167	125,099	(60.7)%
Selling, general and administrative	1,301	1,599	(18.6)%
Depreciation, amortization and impairment	115,652	254,756	(54.6)%
Operating loss	\$(67,786)	\$(131,256)	(48.4)%
Operating days	5,655	10,067	(43.8)%
Average revenue per operating day	\$21.87	\$26.01	(15.9)%
Average direct operating costs per operating day	\$13.18	\$13.58	(2.9)%
Average margin per operating day (1)	\$8.69	\$12.43	(30.1)%
Average rigs operating	61	109	(44.0)%
Capital expenditures	\$17,551	\$111,514	(84.3)%

(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 revenue 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.

Depreciation, amortization and impairment expense for the quarter ended September 30, 2015 included a charge of \$131 million related to the write-down of drilling equipment, primarily related to mechanical drilling rigs and spare mechanical rig components, to their realizable values. There was no similar charge for the quarter ended September 30, 2016.

Pressure Pumping	2016	2015	% Change
	(Dollars in thousands)		
Revenues	\$78,165	\$154,407	(49.4)%
Direct operating costs	77,221	138,597	(44.3)%
Margin (1)	944	15,810	(94.0)%
Selling, general and administrative	2,926	4,019	(27.2)%
Depreciation, amortization and impairment	44,587	70,694	(36.9)%
Impairment of goodwill	—	124,561	NA
Operating loss	\$(46,569)	\$(183,464)	(74.6)%

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Fracturing jobs	84	137	(38.7)%
Other jobs	226	517	(56.3)%
Total jobs	310	654	(52.6)%
Average revenue per fracturing job	\$906.42	\$1,081.14	(16.2)%
Average revenue per other job	\$8.96	\$12.17	(26.4)%
Average revenue per total job	\$252.15	\$236.10	6.8 %
Average direct operating costs per total job	\$249.10	\$211.92	17.5 %
Average margin per total job (1)	\$3.05	\$24.17	(87.4)%
Margin as a percentage of revenues (1)	1.2 %	10.2 %	(88.2)%
Capital expenditures	\$8,330	\$29,409	(71.7)%

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(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.

Depreciation, amortization and impairment expense for the quarter ended September 30, 2015 included a charge of \$22.0 million related to the write-down of pressure pumping equipment and certain closed facilities to their realizable values. There was no similar charge for the quarter ended September 30, 2016.

All of the goodwill associated with our pressure pumping business was impaired during the third quarter of 2015.

Oil and Natural Gas Production and Exploration	2016	2015	% Change
	(Dollars in thousands)		
Revenues - Oil	\$3,519	\$5,278	(33.3)%
Revenues - Natural gas and liquids	765	749	2.1 %
Revenues - Total	4,284	6,027	(28.9)%
Direct operating costs	1,846	2,519	(26.7)%
Margin (1)	2,438	3,508	(30.5)%
Depletion and impairment	1,856	5,332	(65.2)%
Operating income (loss)	\$582	\$(1,824)	NA
Capital expenditures	\$2,401	\$2,890	(16.9)%

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

Oil revenues decreased primarily as a result of lower oil production. Depletion and impairment expense in 2016 includes \$205,000 of oil and natural gas property impairments compared to approximately \$1.9 million of oil and natural gas impairments in 2015. Depletion expense is lower primarily due to lower oil production and the impact of impairments in the last twelve months.

Corporate and Other	2016	2015	% Change
	(Dollars in thousands)		
Selling, general and administrative	\$12,385	\$12,964	(4.5)%

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Depreciation	\$1,369	\$1,369	—	
Other operating income:				
Net gain on asset disposals	\$(2,541)	\$(1,362)	86.6	%
Legal settlements, net of insurance reimbursements	(1,577)	—	NA	
Other operating income	\$(4,118)	\$(1,362)	NA	
Interest income	\$63	\$323	(80.5)	%
Interest expense	\$10,244	\$9,254	10.7	%
Other income	\$19	\$16	18.8	%
Capital expenditures	\$395	\$774	(49.0)	%

Lower selling, general and administrative expense reflects lower personnel costs due to headcount reductions. Other operating income includes net gains 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. Amendment No. 2 required that we repay the entire outstanding principal amount of our bank term loans. As a result, we wrote off \$1.4 million of debt issuance costs related to the bank term loans.

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

Contract Drilling	2016	2015	% Change
	(Dollars in thousands)		
Revenues	\$407,578	\$951,616	(57.2)%
Direct operating costs	219,218	503,376	(56.5)%
Margin (1)	188,360	448,240	(58.0)%
Selling, general and administrative	4,538	4,457	1.8 %
Depreciation, amortization and impairment	357,153	497,215	(28.2)%
Operating loss	\$(173,331)	\$(53,432)	224.4 %
Operating days	17,308	36,798	(53.0)%
Average revenue per operating day	\$23.55	\$25.86	(8.9)%
Average direct operating costs per operating day	\$12.67	\$13.68	(7.4)%
Average margin per operating day (1)	\$10.88	\$12.18	(10.7)%
Average rigs operating	63	135	(53.3)%
Capital expenditures	\$46,001	\$422,876	(89.1)%

(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 revenue 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 period. Rigs on standby have very little associated cost.

Depreciation, amortization and impairment expense for 2015 included a charge of \$131 million related to the write-down of drilling equipment primarily related to mechanical drilling rigs and spare mechanical drilling rig components to their realizable values. There was no similar impairment charge for 2016.

Pressure Pumping	2016	2015	% Change
	(Dollars in thousands)		
Revenues	\$248,428	\$580,752	(57.2)%
Direct operating costs	234,580	494,078	(52.5)%
Margin (1)	13,848	86,674	(84.0)%
Selling, general and administrative	8,844	13,463	(34.3)%
Depreciation, amortization and impairment	141,557	165,874	(14.7)%
Impairment of goodwill	—	124,561	NA
Operating loss	\$(136,553)	\$(217,224)	(37.1)%
Fracturing jobs	241	501	(51.9)%
Other jobs	556	1,670	(66.7)%
Total jobs	797	2,171	(63.3)%
Average revenue per fracturing job	\$1,005.81	\$1,108.22	(9.2)%
Average revenue per other job	\$10.84	\$15.29	(29.1)%
Average revenue per total job	\$311.70	\$267.50	16.5 %
Average direct operating costs per total job	\$294.33	\$227.58	29.3 %

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Average margin per total job (1)	\$17.38	\$39.92	(56.5)%
Margin as a percentage of revenues (1)	5.6 %	14.9 %	(62.4)%
Capital expenditures and acquisitions	\$27,662	\$169,228	(83.7)%

(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.

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Depreciation, amortization and impairment expense for 2015 included a charge of \$22.0 million related to the write-down of pressure pumping equipment and certain closed facilities to their realizable values. There was no similar charge for 2016.

All of the goodwill associated with our pressure pumping business was impaired during 2015.

Oil and Natural Gas Production and Exploration	2016	2015	% Change
	(Dollars in thousands)		
Revenues - Oil	\$10,932	\$18,233	(40.0)%
Revenues - Natural gas and liquids	2,041	2,110	(3.3)%
Revenues - Total	12,973	20,343	(36.2)%
Direct operating costs	5,586	8,096	(31.0)%
Margin (1)	7,387	12,247	(39.7)%
Depletion and impairment	8,393	22,264	(62.3)%
Operating loss	\$(1,006)	\$(10,017)	(90.0)%
Capital expenditures	\$5,621	\$14,094	(60.1)%

(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 \$2.4 million of oil and natural gas property impairments compared to approximately \$9.3 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 2015 and 2016.

Corporate and Other	2016	2015	% Change
	(Dollars in thousands)		
Selling, general and administrative	\$38,289	\$40,415	(5.3)%
Depreciation	\$4,106	\$4,104	0.0 %
Other operating (income) expense, net:			
Net gain on asset disposals	\$(9,808)	\$(7,276)	34.8 %
Legal settlements, net of insurance reimbursements	(477)	12,260	(103.9)%
Other operating (income) expense, net	\$(10,285)	\$4,984	NA
Interest income	\$273	\$924	(70.5)%
Interest expense	\$31,722	\$27,044	17.3 %
Other income	\$52	\$16	NA
Capital expenditures	\$1,227	\$2,022	(39.3)%

Lower selling, general and administrative expense reflects lower personnel costs due to headcount reductions. Other operating (income) expense, net includes net gains 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. As a condition precedent, Amendment No. 2 required that we repay the entire outstanding principal amount of our bank term loans. As a result, we wrote off \$1.4 million of debt issuance costs related to the bank term loans.

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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(Dollars in thousands)			
Net loss	\$(84,143)	\$(225,978)	\$(240,512)	\$(235,828)
Income tax benefit	(49,428)	(112,452)	(133,885)	(120,452)
Net interest expense	10,181	8,931	31,449	26,120
Depreciation, depletion, amortization and impairment	163,464	332,151	511,209	689,457
Impairment of goodwill	—	124,561	—	124,561
Adjusted EBITDA	\$40,074	\$127,213	\$168,261	\$483,858

Income Taxes

Our effective income tax rate was 35.8% for the nine months ended September 30, 2016, compared to 33.8% for the nine months ended September 30, 2015. The difference in the effective tax rate is primarily related to the impact of goodwill impairment charges in 2015 and adjustment to the deferred tax liability associated with the conversion of our Canadian operations to a controlled foreign corporation established in 2010.

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.

In August 2016, the FASB issued an accounting standard to clarify the presentation of cash receipts and payments in specific situations on the statement of cash flows. 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.

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 \$44.85 during the third quarter of 2016. As a result of the lower level of oil prices, our industry has experienced a severe decline in both contract drilling and pressure pumping activity levels. Activity levels have recently improved. Looking forward, assuming commodity prices remain at or above recent levels, we believe U.S. rig counts will continue to increase.

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 limited capital expenditures by our customers and low 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 September 30, 2016, we had exposure to interest rate market risk associated with any borrowings that we had under the Base Credit 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. Beginning 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 September 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 June 30, 2016, the applicable margin on LIBOR loans is 2.75% and the applicable margin on base rate loans is 1.75% as of October 1, 2016. Based on our debt to capitalization ratio at September 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 January 1, 2017.

As of September 30, 2016, under our Credit Agreement we had \$15.0 million outstanding under our revolving credit facility at a weighted average interest rate of 4.0%. 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 September 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 September 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.

ITEM 1A. Risk Factors

The Design, Manufacture, Sale and Servicing of Products, including Rig Components, May Subject Us to Liability for Personal Injury, Property Damage and Environmental Contamination Should Such Equipment Fail to Perform to Specifications.

We provide products, including rig components such as top drives, to customers involved in oil and gas exploration, development and production. Because of applications to which our products and services are put, a failure of such equipment, or a failure of our customer to maintain or operate the equipment properly, could cause damage to the equipment, damage to the property of customers and others, personal injury and environmental contamination, leading to claims against us.

Political, Economic and Social Instability Risk and Laws Associated with Conducting International Operations Could Adversely Affect our Opportunities and Future Business.

We currently conduct operations in Canada, and we have incurred selling, general and administrative expenses related to the evaluation of and preparation for other international opportunities. Also, through our recent Warrior acquisition, we sell products, including rig components, for use in numerous oil and gas producing regions outside of North America. International operations are subject to certain political, economic and other uncertainties generally not encountered in U.S. operations, including increased risks of social and political unrest, strikes, terrorism, war, kidnapping of employees, nationalization, forced negotiation or modification of contracts, difficulty resolving disputes and enforcing contractual rights, expropriation of equipment as well as expropriation of oil and gas exploration and drilling rights, changes in taxation policies, foreign exchange restrictions and restrictions on repatriation of income and capital, currency rate fluctuations, increased governmental ownership and regulation of the economy and industry in the markets in which we may operate, economic and financial instability of national oil companies, and restrictive governmental regulation, bureaucratic delays and general hazards associated with foreign sovereignty over certain areas in which operations are conducted.

There can be no assurance that there will not be changes in local laws, regulations and administrative requirements or the interpretation thereof which could have a material adverse effect on the cost of entry into international markets, the profitability of international operations or the ability to continue those operations in certain areas. Because of the impact of local laws, any future international operations in certain areas may be conducted through entities in which local citizens own interests and through entities (including joint ventures) in which we hold only a minority interest or pursuant to arrangements under which we conduct operations under contract to local entities. While we believe that neither operating through such entities nor pursuant to such arrangements would have a material adverse effect on our operations or revenues, there can be no assurance that we will in all cases be able to structure or restructure our operations to conform to local law (or the administration thereof) on terms we find acceptable.

There can be no assurance that we will:

- identify attractive opportunities in international markets,

have sufficient capital resources to pursue and consummate international opportunities,
successfully integrate international drilling rigs, pressure pumping equipment or other assets or businesses,
effectively manage the start-up, development and growth of an international organization and assets,
hire, attract and retain the personnel necessary to successfully conduct international operations, or
receive awards for work and successfully improve our financial condition, results of operations, business or prospects
as a result of the entry into one or more international markets.

In addition, the U.S. Foreign Corrupt Practices Act ("FCPA") and similar anti-bribery laws in other jurisdictions generally prohibit companies and their intermediaries from making improper payments to foreign officials for the purpose of obtaining or retaining business. Some of the parts of the world where contract drilling and pressure pumping activities are conducted or where our consumers for the Warrior products are located have experienced governmental corruption to some degree and, in certain circumstances, strict compliance with anti-bribery laws may conflict with local customs and practice and could impact business. Any

failure to comply with the FCPA or other anti-bribery legislation could subject to us to civil, criminal and/or administrative penalties or other sanctions, which could have a material adverse impact on our business, financial condition and results of operation. We could also face fines, sanctions and other penalties from authorities in the relevant foreign jurisdictions, including prohibition of our participating in or curtailment of business operations in those jurisdictions and the seizure of drilling rigs, pressure pumping equipment or other assets.

We may incur substantial indebtedness to finance an international transaction or operations, and we also may issue equity, convertible or debt securities in connection with any such transactions or operations. Debt service requirements could represent a significant burden on our results of operations and financial condition, and the issuance of additional equity or convertible securities could be dilutive to existing stockholders. Also, international expansion could strain our management, operations, employees and other resources.

The occurrence of one or more events arising from the types of risks described above could have a material adverse impact on our business, financial condition and results of operations.

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 September 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)
July 2016	—	\$ -	—	186,653
August 2016	—	\$ -	—	186,653
September 2016	—	\$ -	—	186,653
Total	—		—	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. On September 15, 2016, we issued an aggregate of 353,804 shares of our common stock to the former owners of Warrior Rig Ltd. in connection with our acquisition of that company. The foregoing transaction did not involve any underwriters, any underwriting discounts or commissions, or any public offering. We believe the offers, sales, and issuances of the these securities were exempt from registration under the Securities Act by virtue of Section 4(a)(2),

because the issuance of securities to the recipients did not involve a public offering. The recipients of the securities in each of these transactions represented their intentions to acquire the securities for investment only and not with a view to or for sale in connection with any distribution thereof, and appropriate legends were placed upon the securities issued in these transactions. All recipients had adequate access, through their relationships with us or otherwise, to information about us. The issuances of these securities were made without any general solicitation or advertising.

ITEM 5. Other Information

On October 26, 2016, the Board of Directors approved modifications to the non-employee director compensation program, such that current compensation for the directors is as follows: Directors who are also our employees do not receive compensation for serving as a director or as a member of a committee of the Board of Directors. All directors are reimbursed for reasonable out-of-pocket expenses incurred in connection with serving as a member of the Board of Directors. Each non-employee director receives annual cash compensation of \$75,000 and shares of restricted stock on January 1 of each year with a grant date value of \$175,000, subject to one-year vesting (subject to acceleration in certain limited situations, including a change of control). Each non-employee director that serves on the Audit Committee or the Compensation Committee receives additional annual cash compensation of \$10,000 per committee on which he or she serves, with the Chair of each such committee receiving \$15,000. The Chair of the Nominating and Corporate Governance Committee receives additional annual cash compensation of \$10,000. The Lead Director receives additional annual cash compensation of \$20,000.

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. (filed August 2, 2016 as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2016 and incorporated herein by reference).
- 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 September 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

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: October 31, 2016