PIONEER

Pioneer Energy Services

2016 ANNUAL REPORT

2016 Annual Report

EVERY PROJECT IS PERSONAL

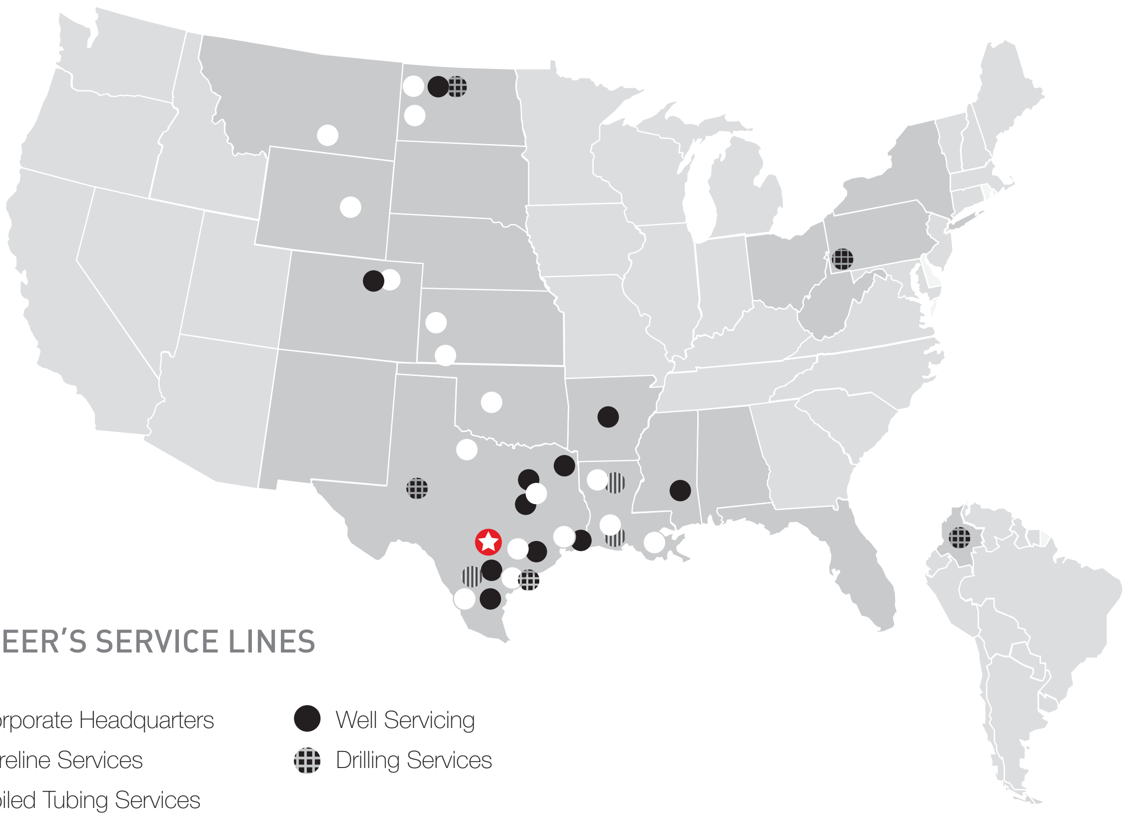
SELECTED FINANCIAL DATA

(In thousands, except per share data)	2016 (1)	2015 (1)	2014 (1)	2013 (1)	2012
Revenues	$277,076	$540,778	$1,055,223	$960,186	$919,443
Net income (loss)	(128,391)	(155,140)	(38,018)	(35,932)	30,032
Adjusted EBITDA(2)	14,237	110,780	277,081	234,742	249,283
Income (loss) per common share - diluted	(1.96)	(2.41)	(0.60)	(0.58)	0.48
Total assets	700,102	821,975	1,171,589	1,229,623	1,339,776
Long-term debt, excluding current installments and debt insurance costs	346,000	395,000	455,053	499,666	518,725
Shareholders' equity	281,398	342,643	495,064	518,433	547,680
Net cash provided by operating activities	5,131	142,719	233,041	174,580	199,366

(1) The selected financial data for the years ended December 31, 2016, 2015, 2014 and 2013 reflects the impact of asset impairment charges of $12.8 million, $129.2 million, $73.0 million, and $54.3 million, respectively.

(2) For a reconciliation of the difference between this financial measure, which is not in accordance with U.S. Generally Accepted Accounting Principles (GAAP), and the most directly comparable financial measure, which is calculated in accordance with GAAP, see the last page of this Annual Report following the Form 10K.

AREAS OF OPERATIONS



PIONEER'S SERVICE LINES

- Corporate Headquarters
- Wireline Services
- Coiled Tubing Services
- Well Servicing
- Drilling Services

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549

FORM 10-K

(Mark one)

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

For the fiscal year ended December 31, 2016
or

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

Commission File Number: 1-8182

PIONEER ENERGY SERVICES CORP.
(Exact name of registrant as specified in its charter)

TEXAS	**74-2088619**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification Number)**
1250 N.E. Loop 410, Suite 1000 San Antonio, Texas	**78209**
(Address of principal executive offices)	**(Zip Code)**

Registrant's telephone number, including area code: (855) 884-0575
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $0.10 par value	**NYSE**

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☑

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

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 Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T 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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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

Large accelerated filer ☐		Accelerated filer ☑
Non-accelerated filer ☐	(Do not check if a smaller reporting company)	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 ☑

The aggregate market value of the registrant's common stock held by nonaffiliates of the registrant as of the last business day of the registrant's most recently completed second fiscal quarter (based on the closing sales price on the New York Stock Exchange (NYSE) on June 30, 2016) was approximately $291 million.

As of January 31, 2017, there were 77,278,844 shares of common stock, par value $0.10 per share, of the registrant issued and outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement related to the registrant's 2017 Annual Meeting of Shareholders are incorporated by reference into Part III of this report.

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PART I

INTRODUCTORY NOTE

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

From time to time, our management or persons acting on our behalf make forward-looking statements to inform existing and potential security holders about our company. These statements may include projections and estimates concerning the timing and success of specific projects and our future backlog, revenues, income and capital spending. Forward-looking statements are generally accompanied by words such as “estimate,” “project,” “predict,” “believe,” “expect,” “anticipate,” “plan,” “intend,” “seek,” “will,” “should,” “goal” or other words that convey the uncertainty of future events or outcomes. Forward-looking statements speak only as of the date on which they are first made, which in the case of forward-looking statements made in this report is the date of this report. Sometimes we will specifically describe a statement as being a forward-looking statement and refer to this cautionary statement.

In addition, various statements contained in this Annual Report on Form 10-K, including those that express a belief, expectation or intention, as well as those that are not statements of historical fact, are forward-looking statements. Such forward-looking statements appear in Item 1—“Business” and Item 3—“Legal Proceedings” in Part I of this report; in Item 5—“Market for Registrant’s Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities,” Item 7—“Management’s Discussion and Analysis of Financial Condition and Results of Operations,” Item 7A—“Quantitative and Qualitative Disclosures About Market Risk” and in the Notes to Consolidated Financial Statements we have included in Item 8 of Part II of this report; and elsewhere in this report. Forward-looking statements speak only as of the date of this report. We disclaim any obligation to update these statements, and we caution you not to place undue reliance on them. We base forward-looking statements on our current expectations and assumptions about future events. While our management considers the expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. These risks, contingencies and uncertainties relate to, among other matters, the following:

- general economic and business conditions and industry trends;
- levels and volatility of oil and gas prices;
- the continued demand for drilling services or production services in the geographic areas where we operate;
- decisions about exploration and development projects to be made by oil and gas exploration and production companies;
- the highly competitive nature of our business;
- technological advancements and trends in our industry, and improvements in our competitors’ equipment;
- the loss of one or more of our major clients or a decrease in their demand for our services;
- future compliance with covenants under our senior secured revolving credit facility and our senior notes;
- operating hazards inherent in our operations;
- the supply of marketable drilling rigs, well servicing rigs, coiled tubing and wireline units within the industry;
- the continued availability of drilling rig, well servicing rig, coiled tubing and wireline unit components;
- the continued availability of qualified personnel;
- the success or failure of our acquisition strategy, including our ability to finance acquisitions, manage growth and effectively integrate acquisitions;
- the political, economic, regulatory and other uncertainties encountered by our operations, and
- changes in, or our failure or inability to comply with, governmental regulations, including those relating to the environment.

We believe the items we have outlined above are important factors that could cause our actual results to differ materially from those expressed in a forward-looking statement contained in this report or elsewhere. We have discussed many of these factors in more detail elsewhere in this report. Other unpredictable or unknown factors could also have material adverse effects on actual results of matters that are the subject of our forward-looking statements. We undertake no obligation to update or revise any forward-looking statements, except as required by applicable securities laws and regulations. We advise our security holders that they should (1) recognize that unpredictable or unknown factors not referred to above could affect the accuracy of our forward-looking statements and (2) use caution and common sense when considering our forward-looking statements. Also, please read the risk factors set forth in Item 1A—“Risk Factors.”

Item 1. Business

Company Overview

Pioneer Energy Services Corp. provides land-based drilling services and production services to a diverse group of independent and large oil and gas exploration and production companies in the United States and internationally in Colombia. We also provide two of our services (coiled tubing and wireline services) offshore in the Gulf of Mexico. Drilling services and production services are fundamental to establishing and maintaining the flow of oil and natural gas throughout the productive life of a well and enable us to meet multiple needs of our clients.

- *Drilling Services Segment*— From 1999 to 2011, we significantly expanded our fleet through acquisitions and the construction of new drilling rigs. As our industry changed with the evolution of shale drilling, we began a transformation process in 2011, by selectively disposing of our older, less capable rigs, while we continued to invest in our rig building program to construct more technologically advanced, pad-optimal rigs to meet the changing needs of our clients.

  As of December 31, 2016, our drilling rig fleet is 100% pad-capable. We offer the latest advancements in pad drilling with our fleet of 16 AC rigs in the US and eight SCR rigs in Colombia, all of which have 1,500 horsepower or greater drawworks. The removal of older, less capable rigs from our fleet and the recent investments in the construction of new drilling rigs has transformed our fleet into a highly capable, pad optimal fleet focused on the horizontal drilling market. We believe this positions us to compete well, grow our presence in the significant shale basins in the US, and improve profitability as the recovery of our industry continues.

  In addition to our drilling rigs, we provide the drilling crews and most of the ancillary equipment needed to operate our drilling rigs. We obtain our contracts for drilling oil and natural gas wells either through competitive bidding or through direct negotiations with existing or potential clients. Our drilling contracts generally provide for compensation on a daywork basis, and sometimes on a turnkey basis. Contract terms generally depend on the complexity and risk of operations, the on-site drilling conditions, the type of equipment used, and the anticipated duration of the work to be performed. The drilling rigs in our fleet are currently assigned to the following divisions:

Drilling Division	Rig Count
South Texas	1
West Texas	7
North Dakota	2
Appalachia	6
Colombia	8
	24

- *Production Services Segment*— In 2008, we acquired two production services companies which significantly expanded our service offerings to include well servicing and wireline services. At the end of 2011, we acquired a coiled tubing services business to further expand our production services offerings. Since the acquisitions of these businesses, we continued to invest in their organic growth and significantly expanded all our production services fleets. However, we temporarily suspended organic growth of our production services fleets during the recent downturn, and continue to selectively update our fleets.

  Our Production Services Segment provides a range of services to a diverse group of exploration and production companies, with our operations concentrated in the major United States onshore oil and gas producing regions in the Mid-Continent and Rocky Mountain states and in the Gulf Coast, both onshore and offshore. The primary production services we offer are the following:

  - Well Servicing. A range of services are required in order to establish production in newly-drilled wells and to maintain production over the useful lives of active wells. We use our well servicing rig fleet to provide these necessary services, including the completion of newly-drilled wells, maintenance and workover of active wells, and plugging and abandonment of wells at the end of their useful lives. As of December 31, 2016, we have a fleet of 114 rigs with 550 horsepower and 11 rigs with 600 horsepower with operations in 10 locations, mostly in the Gulf Coast states, as well as in Arkansas and North Dakota.

- Wireline Services. Oil and gas exploration and production companies require wireline services to better understand the reservoirs they are drilling or producing, and use logging services to accurately characterize reservoir rocks and fluids. To complete a cased-hole well, the production casing must be perforated to establish a flow path between the reservoir and the wellbore. We use our fleet of wireline units to provide these important logging and perforating services in addition to a range of other mechanical services that are needed in order to place equipment in or retrieve equipment or debris from the wellbore, install bridge plugs and control pressure. As of December 31, 2016, we have a fleet of 114 wireline units in 17 operating locations in the Gulf Coast, Mid-Continent and Rocky Mountain states.

- Coiled Tubing Services. Coiled tubing is also an important element of the well servicing industry that allows operators to continue production during service operations on a well under pressure without shutting in the well, thereby reducing the risk of formation damage. Coiled tubing services involve the use of a continuous metal pipe spooled on a large reel for oil and natural gas well applications, such as wellbore clean-outs, nitrogen jet lifts, through-tubing fishing, formation stimulation utilizing acid, chemical treatments and fracturing. Coiled tubing is also used for a number of horizontal well applications such as milling temporary plugs between frac stages. As of December 31, 2016, our coiled tubing business consists of 12 onshore and five offshore coiled tubing units which are deployed through three locations in Texas and Louisiana.

Pioneer Energy Services Corp. (formerly called “Pioneer Drilling Company”) was incorporated under the laws of the State of Texas in 1979 as the successor to a business that had been operating since 1968. Over the last 15 years, we have significantly expanded and transformed our business through acquisitions and organic growth. We conduct our operations through two operating segments: our Drilling Services Segment and our Production Services Segment. Financial information about our operating segments is included in Note 10, *Segment Information*, of the Notes to Consolidated Financial Statements, included in Part II, Item 8, *Financial Statements and Supplementary Data*, of this Annual Report on Form 10-K.

Pioneer Energy Services Corp.’s corporate office is located at 1250 NE Loop 410, Suite 1000, San Antonio, Texas 78209. Our phone number is (855) 884-0575 and our website address is www.pioneeres.com. We make available free of charge through our website our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with the Securities and Exchange Commission (SEC). Information on our website is not incorporated into this report or otherwise made part of this report.

Industry Overview

Demand for oilfield services offered by our industry is a function of our clients’ willingness to make operating expenditures and capital expenditures to explore for, develop and produce hydrocarbons, which is primarily driven by current and expected oil and natural gas prices.

Our business is influenced substantially by both operating and capital expenditures by exploration and production companies. Exploration and production spending is generally categorized as either a capital expenditure or an operating expenditure.

Capital expenditures by oil and gas exploration and production companies tend to be relatively sensitive to volatility in oil or natural gas prices because project decisions are tied to a return on investment spanning a number of months or years. As such, capital expenditure economics often require the use of commodity price forecasts which may prove inaccurate over the amount of time necessary to plan and execute a capital expenditure project (such as a drilling program for a number of wells in a certain area). When commodity prices are depressed for longer periods of time, capital expenditure projects are routinely deferred until prices are forecasted to return to an acceptable level.

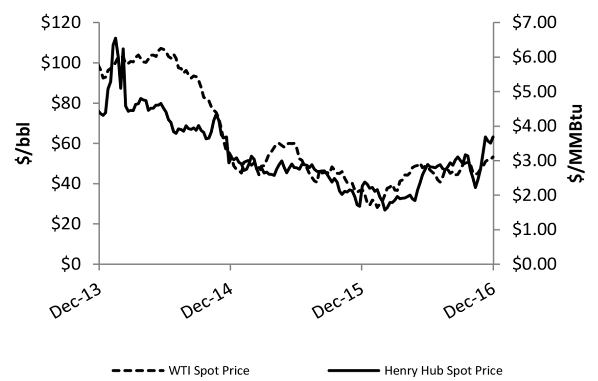
In contrast, both mandatory and discretionary operating expenditures are more stable than capital expenditures for exploration as these expenditures are less sensitive to commodity price volatility. Mandatory operating expenditure projects involve activities that cannot be avoided in the short term, such as regulatory compliance, safety, contractual obligations and certain projects to maintain the well and related infrastructure in operating condition. Discretionary operating expenditure projects may not be critical to the short-term viability of a lease or field and are generally evaluated according to a simple short-term payout criterion that is less dependent on commodity price forecasts.

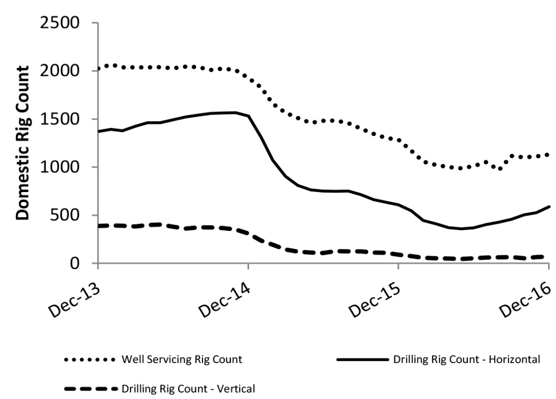
Capital expenditures by exploration and production companies for the drilling of exploratory wells or new wells in proven areas are more directly influenced by current and expected oil and natural gas prices and generally reflect the volatility of commodity prices. In contrast, operating expenditures by exploration and production companies for the maintenance of existing wells, for which a range of production services are required in order to maintain production, are relatively more stable and predictable.

Drilling and production services have historically trended similarly in response to fluctuations in commodity prices. However, because exploration and production companies often adjust their budgets for exploratory drilling first in response to a shift in commodity prices, the demand for drilling services is generally impacted first and to a greater extent than the demand for production services which is more dependent on ongoing expenditures that are necessary to maintain production. Additionally, within the range of production services businesses, those that derive more revenue from production related activity, as opposed to completion of a new well, tend to be less affected by fluctuations in commodity prices and temporary reductions in industry activity.

However, in a severe downturn that is prolonged, both operating and capital expenditures are significantly reduced, and the demand for all our service offerings is significantly impacted.

The trends in spot prices of WTI crude oil and Henry Hub natural gas, and the resulting trends in domestic land rig counts (per Baker Hughes) and domestic well servicing rig counts (per Guiberson/Association of Energy Service Companies) over the last three years are illustrated in the graphs below.





As shown in the charts above, the trends in industry rig counts are influenced primarily by fluctuations in oil prices, which affect the levels of capital and operating expenditures made by our clients.

Colombian oil prices have historically trended in line with West Texas Intermediate (WTI) oil prices. Demand for drilling and production services in Colombia is largely dependent upon its national oil company's long-term exploration and production programs, and to a lesser extent, additional activity from other producers in the region.

Technological advancements and trends in our industry also affect the demand for certain types of equipment, and can affect the overall demand for equipment in our industry. For several years, prior to late 2014, higher oil prices drove industry equipment utilization and revenue rates up, particularly in oil-producing regions and certain shale regions. However, advancements in technology improved the efficiency of drilling rigs and overall demand remained steady, while the demand for certain drilling rigs decreased, particularly in vertical well markets. The decline was a result of higher demand for drilling rigs that are able to drill horizontally and the increased use of "pad drilling" which enables a series of horizontal wells to be drilled in succession by walking or skidding a drilling rig at a single pad-site location, thereby improving the productivity of exploration and production activities. This trend, then coupled with the downturn, resulted in significantly reduced demand for drilling rigs that do not have the ability to walk or skid and to drill horizontal wells.

For additional information concerning the effects of the volatility in oil and gas prices and the effects of technological advancements and trends in our industry, see Item 1A – "Risk Factors" in Part I of this Annual Report on Form 10-K.

Competitive Strengths

Our competitive strengths include:

- *High Quality Assets.* As of December 31, 2016, our drilling rig fleet is 100% pad-capable. We offer the latest advancements in pad drilling with our fleet of 16 AC rigs in the US and eight SCR rigs in Colombia, all of which have 1,500 horsepower or greater drawworks. Our well servicing fleet is 100% tall-masted, 550 to 600 horsepower rigs, and 75% of our onshore coiled tubing units offer larger diameter coil. We also currently have commitments to purchase four new wireline units and 20 new-model well servicing rigs, for which we will trade in 20 of our older well servicing rigs. We believe that our modern and well maintained fleet allows us to realize higher utilization and pricing because we are able to offer our clients technologically advanced equipment that allows them to operate with less downtime and greater efficiency.

- *One of the Leading Providers in the Prominent Domestic Regions.* Our drilling and production services fleets operate in many of the most attractive producing regions in the United States, including the Marcellus, Eagle Ford, Permian Basin and the Bakken. Our drilling rigs are currently located in four divisions throughout the United States and Colombia. We believe the varied capabilities of our drilling rigs make them particularly well suited to these areas where the optimal rig configuration is dictated by local geology and market conditions. In addition, the expansion of our production services fleets has been focused on those regions with the most opportunity for growth. All our fleet equipment is mobile between domestic regions, diversifying our geographic exposure and limiting the impact of any regional slowdown.

- *Provide Services Throughout the Well Life Cycle*. By offering our clients both drilling and production services, we capture revenue throughout the life cycle of a well and diversify our business. Our Drilling Services Segment performs work prior to initial production, and our Production Services Segment provides services such as logging, completion, perforation, workover and maintenance throughout the productive life of a well. We also provide certain end-of-well-life activities such as plugging and abandonment. Drilling and production services activity have historically exhibited different degrees of demand fluctuation, and we believe the diversity of our services reduces our exposure to decreases in demand for any single service activity. Further, the diversity of our service offerings enables us to cross-sell our services, which has allowed us to generate more business from existing clients and increase our profits as we expand our services within existing markets.

- *Industry-Leading Safety Record.* Our safety program called “LiveSafe” focuses on creating an environment where everyone is committed to and recognizes the possibility of always working without incident or injury. The commitment to LiveSafe helps keep our employees safe and reduces our business risk. In 2015, we were recognized by the International Association of Drilling Contractors as the safest land contract driller of the 15 busiest contractors with a total recordable incident rate 46% lower than the industry average, and our 2016 lost time incident rate is the lowest in company history, which was also the third year in a row with improving rates. Our excellent safety record and reputation are critical to winning new business and expanding our relationships with existing clients.

- *Skilled Management Team.* We believe that an important competitive factor in achieving long-term client relationships includes having an experienced and skilled management team, with a focus on the growth and development of our leadership team, maintaining employee continuity and effective succession planning. Our CEO, Wm. Stacy Locke, joined Pioneer in 1995 as President and has over 35 years of industry experience. Our management team has operated through numerous oilfield services cycles and provides us with valuable long-term experience and a detailed understanding of client requirements. We seek to minimize employee turnover, invest in the growth of our employees, and recruit new talent through our focus on employee training and development, safety and competitive compensation.

- *Longstanding and Diversified Clients.* We maintain long-standing, high quality client relationships with a diverse group of large independent oil and gas exploration and production companies including Apache Corporation, Whiting Petroleum Corporation, and PDC Energy. Our largest two clients, Apache Corporation and Whiting Petroleum Corporation, accounted for approximately 12% and 10%, respectively, of our 2016 consolidated revenues. We believe our relationships with our clients are strong and the diversity of our client base offers numerous opportunities for growth as our industry continues to improve.

Strategy

Our strategy has been to become a premier land drilling and production services company through steady and disciplined growth, which we executed through the acquisition and building of our high quality drilling rig fleet and production services businesses. In 2011, we shifted our approach to accommodate changes in the industry, which resulted in a period of combined growth and rejuvenation through the disposition of assets which use older technology. Today, we provide drilling and production services in many of the most attractive drilling markets throughout the United States, and provide drilling services in Colombia.

With the decline in oil prices that began in 2014 and the resulting reductions in our utilization and revenue rates, our near-term efforts have been focused on:

- *Cost Reductions.* Since the beginning of 2015, we have reduced our total headcount by over 50%, reduced wage rates for our operations personnel, reduced incentive compensation, eliminated certain employment benefits and closed ten field offices to reduce overhead and reduce associated lease payments. In 2016, we lowered our capital expenditures by 77%, limiting our capital spending to primarily routine expenditures to maintain our equipment and deferring discretionary upgrades and additions except those that we committed to in 2014 before the market slowdown. We continue to evaluate opportunities to lower our cost structure in response to reduced revenues and to improve profitability.

- *Liquidating Nonstrategic Assets.* Since the beginning of 2015, we have sold 35 drilling rigs and other drilling equipment for aggregate net proceeds of $65.5 million. As of December 31, 2016, we have six additional domestic mechanical and SCR drilling rigs held for sale, along with other drilling equipment, 13 wireline units, 20 older well servicing rigs that will be traded in for 20 new-model rigs in the first quarter of 2017, and certain coiled tubing equipment. We will continue to evaluate our domestic and international fleets for additional drilling rigs or equipment for which a near term sale would be favorable.

- *Maintaining Liquidity and Financial Flexibility.* We most recently amended our revolving credit facility on June 30, 2016, to maintain access to capital but with more flexible financial covenants. In December 2016, we sold 12,075,000 shares of common stock in a public offering, and applied the net proceeds to reduce our outstanding debt under our revolving credit facility. Since the beginning of 2015, we have paid down $105.3 million of debt through January 2017. We currently have availability for equity or debt offerings up to $234.6 million under our shelf registration statement, subject to the limitations imposed by our Revolving Credit Facility and Senior Notes, as well as our Restated Articles of Incorporation which currently limits our issuance of common stock to 100 million shares.

- *Performance of our Core Businesses.* We continue to focus on maintaining our relationships with our clients and vendors through the downturn, and remain committed to our safety and service quality goals. In 2015, we were recognized by the International Association of Drilling Contractors as the safest land contract driller of the 15 busiest contractors, and our 2016 lost time incident rate is the lowest in company history, which was also the third year in a row with improving rates. With the expectation of a modest recovery ahead, we are allocating our resources to the markets with the best opportunities for increased activity and reactivating units in those areas with increasing demand.

We continue to evaluate our business and look for opportunities to further achieve these goals, which we believe will position us to take advantage of future business opportunities and maintain our long-term growth strategy.

Our long-term strategy as a leading land drilling and production services company is to further leverage our relationships with existing clients, expand our client base in the areas where we currently operate and further enhance our geographic diversification through selective expansion. The key elements of this long-term strategy are focused on our:

- *Investments in Our Business.* We have historically invested in the growth and technological advancement of our business by engaging in select rig building opportunities and acquisitions, strategically upgrading our existing assets and disposing of assets which use older technology.

Since the beginning of 2010, we have added significant capacity to our production services offerings through the addition of 51 wireline units, 51 well servicing rigs and 17 coiled tubing units. From 2011 to 2015, we constructed 15 walking AC drilling rigs, five of which were completed in 2015. During 2015 and 2016, we removed all 31 of our mechanical and lower horsepower electric drilling rigs from our fleet, which were the most negatively impacted by the industry downturn, as well as all 12 domestic SCR rigs in our fleet. We achieved this by selling a total of 35 drilling rigs, retiring two, and placing the remaining six as held for sale.

As of December 31, 2016, our drilling rig fleet is 100% pad-capable. We offer the latest advancements in pad drilling with our fleet of 16 AC rigs in the US and eight SCR rigs in Colombia, all of which have 1,500 horsepower or greater drawworks. The removal of older, less capable rigs from our fleet and the recent investments in the construction of new drilling rigs has transformed our fleet into a highly capable, pad optimal fleet focused on the horizontal drilling market. We believe this positions us to compete well, grow our presence in the significant shale basins in the US, and improve profitability as the recovery of our industry continues.

- *Competitive Position in the Prominent Domestic Markets.* Shale plays and non-shale oil or liquid rich environments are increasingly important to domestic hydrocarbon production, and not all drilling rigs are capable of successfully drilling in these unconventional opportunities. Our pad-optimal domestic fleet was designed for operation in the Marcellus, Eagle Ford, Permian Basin and the Bakken. Additionally, the added capacity in our production services fleets was focused on increasing our presence in those regions where demand benefits from shale development.
- *Exposure to Oil and Liquids Rich Natural Gas Drilling Activity.* We believe that our flexible drilling and production services fleets allow us to pursue varied opportunities, enabling us to focus on a favorable mix of natural gas, oil and liquids rich natural gas activity. When natural gas prices fell to low levels, we increased our exposure to oil-related activities by redeploying certain of our assets into predominately oil-producing regions. As our industry continues to recover from the downturn that began in late 2014, we believe our fleets are highly capable and well positioned for deployment to whichever markets offer the most opportunity.

Overview of Our Segments and Services

Drilling Services Segment

A land drilling rig consists of power generation system(s), a hoisting system, a rotating system, pumps and related equipment to circulate and clean drilling fluid, blowout preventers, and other related equipment. Generally, our land drilling rigs operate with crews of five to six persons, and 100% of our drilling rigs have the ability to drill multiple well bores from a single surface location as discussed in more detail below.

There are numerous factors that differentiate land drilling rigs such as the type of power used, drilling depth capabilities or drawworks horsepower, mud pump pressure rating, and the ability to drill multiple well bores from a single surface location or pad.

Regarding the type of power used, mechanical rigs are generally less expensive than their electric counterparts. Mechanical rigs use torque converters, clutches, chains, belts, and transmissions to couple engines directly to various types of equipment. Mechanical rigs are considered less efficient and less precise as the main drives are more challenging to control. SCR rigs and AC rigs are considered electric rigs. Both generate electrical power through one or more engine generator sets. SCR rigs utilize direct current to supply and control DC motors coupled to the various drilling equipment, while AC rigs utilize alternating current and AC motors. Both types of electric rigs are considered safer, more reliable, and more efficient than mechanical rigs. AC rigs are considered to be more energy efficient and provide more precise control of equipment than their SCR counterparts which enhances rig safety and reduces drilling time.

The following table summarizes our current rig fleet composition:

	Multi-well, Pad-capable		
	SCR rigs	**AC rigs**	**Total**
Domestic rigs	—	16	16
Colombia rigs	8	—	8
			24

Technological advancements and trends in our industry affect the demand for certain types of equipment. Every drilling rig in our fleet is equipped with at least 1,500 horsepower drawworks, a top drive, an iron roughneck, an automatic catwalk, and a walking or skidding system. This equipment, which is described in more detail below, provides our clients with drilling rigs that have more varied capabilities for drilling in unconventional plays, and improves our efficiency and safety.

In horizontal well drilling, operators can utilize top drives to reach formations that may not be accessible with conventional rotary drilling. Top drives provide maximum torque and rotational control, improved well control and better hole conditioning. An iron roughneck is a remotely operated pipe handling feature on the rig floor, which is used to help reduce the occurrence of repetitive motion injuries and decrease drill pipe tripping time. An automated catwalk is a drill pipe handling feature used to raise drill pipe, drill collars, casing, and other necessary items to the drilling rig floor. Its function has significant safety advantages and can reduce the overall time required to complete the well.

In recent years, oil and gas exploration and production companies have increased the use of "pad drilling" whereby a series of horizontal wells are drilled in succession by walking or skidding a drilling rig at a single pad-site location. Walking systems increase efficiency by allowing multiple wells to be drilled on the same pad site and permitting the drilling rig to move between wells while drill pipe remains in the derrick and ancillary systems such as engines and mud tanks remain stationary, thus reducing move times and costs. Our omnidirectional walking systems enable the drilling rig to move forward, backward, and side to side which affords the operator additional flexibility.

The following table sets forth historical information regarding utilization for our drilling rig fleet:

	Year ended December 31,				
	2016	2015	2014	2013	2012
Average number of operating rigs for the period	30.9	39.1	62.0	68.2	65.0
Average utilization rate	43%	63%	87%	84%	87%

The utilization of our AC fleet was 74% during both of the years ended December 31, 2016 and 2015.

As our industry changed with the evolution of shale drilling, we began a transformation process in 2011, by selectively disposing of our older, less capable rigs, while we continued to invest in our rig building program to construct more technologically advanced, pad-optimal rigs to meet the changing needs of our clients. From 2011 to 2015, we constructed 15 walking AC drilling rigs, five of which were completed in 2015. During 2015 and 2016, we removed all 31 of our mechanical and lower horsepower electric drilling rigs from our fleet, which were the most negatively impacted by the industry downturn, as well as all 12 domestic SCR rigs in our fleet. We achieved this by selling a total of 35 drilling rigs, retiring two, and placing the remaining six as held for sale. The removal of older, less capable rigs from our fleet and the recent investments in the construction of new drilling rigs has transformed our fleet into a highly capable, pad optimal fleet focused on the horizontal drilling market.

We believe that our drilling rigs and other related equipment are in good operating condition. Our employees perform periodic maintenance and minor repair work on our drilling rigs. We rely on various oilfield service companies for major repair work and overhaul of our drilling equipment when needed. We also engage in periodic improvement and upgrades of our drilling equipment. In the event of major breakdowns or mechanical problems, our rigs could be subject to significant idle time and a resulting loss of revenue if the necessary repair services are not immediately available.

In addition to our drilling rigs, we provide the drilling crews and most of the ancillary equipment needed to operate our drilling rigs. We obtain our contracts for drilling oil and natural gas wells either through competitive bidding or through direct negotiations with existing or potential clients. Our drilling contracts generally provide for compensation on a daywork basis, and sometimes on a turnkey basis. Contract terms generally depend on the complexity and risk of operations, the on-site drilling conditions, the type of equipment used, and the anticipated duration of the work to be performed. Spot market contracts generally provide for the drilling of a single well and typically permit the client to terminate on short notice. We typically enter into longer-term drilling contracts for our newly constructed rigs and/or during periods of high rig demand.

Our business and the profitability of our operations depend on the level of drilling activity by oil and gas exploration and production companies operating in the geographic markets where we operate. The oil and gas exploration and production industry is a historically cyclical industry characterized by significant changes in the levels of exploration and development activities. During periods of reduced drilling activity or excess rig capacity, price competition tends to increase and the profitability of daywork contracts tends to decrease, and in such a competitive price environment, we may be more inclined to enter into turnkey contracts that expose us to greater risk of loss but which offer higher potential contract profitability.

During the last three fiscal years, our drilling contracts have primarily been for daywork drilling. The following table presents, by type of contract, information about the total number of wells we completed for our clients during each of the last three fiscal years.

	Year ended December 31,		
Types of Contracts	2016	2015	2014
Daywork	300	448	1,001
Turnkey	1	17	106
Total number of wells	301	465	1,107

Daywork Contracts. Under daywork drilling contracts, we provide a drilling rig and required personnel to our client who supervises the drilling of the well. We are paid based on a negotiated fixed rate per day while the rig is used. Daywork drilling contracts specify the equipment to be used, the size of the hole and the depth of the well. Under a daywork drilling contract, the client bears a large portion of the out-of-pocket drilling costs and we generally bear no part of the usual risks associated with drilling, such as time delays and unanticipated costs.

Turnkey Contracts. Under a typical turnkey drilling contract, we agree to drill a well for our client to a specified depth and under specified conditions for a fixed price. We provide technical expertise and engineering services, as well as most of the equipment and drilling supplies required to drill the well. We often subcontract for related services, such as the provision of casing crews, cementing and well logging. Under typical turnkey drilling arrangements, we do not receive progress payments and are paid by our client only after we have performed the terms of the drilling contract in full.

For these reasons, the risk to us under a turnkey drilling contract is substantially greater than for a well drilled on a daywork basis because we must assume most of the risks associated with drilling operations that the operator generally assumes under a daywork contract, including the risks of blowout, loss of hole, stuck drill pipe, machinery breakdowns, abnormal drilling conditions and risks associated with subcontractors' services, supplies, cost escalations and personnel. We believe that our experienced management team, our knowledge of geologic formations in our areas of operations, the condition of our drilling equipment and our experienced crews have previously enabled us to make reasonable cost estimates and complete contracts according to our drilling plan. While we do bear the risk of loss for cost overruns and other events that are not specifically provided for in our initial cost estimates, our pricing of turnkey contracts takes such risks into consideration, and we maintain insurance coverage against some, but not all, drilling hazards. During periods of reduced demand for drilling rigs, our overall profitability on turnkey contracts has historically exceeded our profitability on daywork contracts.

Production Services Segment

Our Production Services Segment provides a range of services to a diverse group of exploration and production companies, with our operations concentrated in the major United States onshore oil and gas producing regions in the Mid-Continent and Rocky Mountain states and in the Gulf Coast, both onshore and offshore. As of December 31, 2016, our production services fleets are as follows:

Production Services Fleets			
	550 HP	600 HP	Total
Well servicing rigs, by horsepower (HP) rating	114	11	125
	Offshore	Onshore	Total
Wireline units	6	108	114
Coiled tubing units	5	12	17

Well Servicing. Our well servicing rig fleet provides a range of services, including the completion of newly-drilled wells, maintenance and workover of existing wells, and plugging and abandonment of wells at the end of their useful lives.

Newly drilled wells require completion services to prepare the well for production. Well servicing rigs are frequently used to complete newly drilled wells to minimize the use of higher cost drilling rigs in the completion process. The completion process may involve selectively perforating the well casing in the productive zones to allow oil or gas to flow into the well bore, stimulating and testing these zones and installing the production string and other downhole equipment. The completion process typically requires a few days to several weeks, depending on the nature and type of the completion, and generally requires additional auxiliary equipment. Accordingly, completion services require less well-to-well mobilization of equipment and can provide higher operating margins than regular maintenance work. The demand for completion services is directly related to drilling activity levels, which are sensitive to changes in oil and gas prices.

Regular maintenance is required throughout the life of a well to sustain optimal levels of oil and gas production. Common maintenance services include repairing inoperable pumping equipment in an oil well and replacing defective tubing in a gas well. Our maintenance services involve relatively low-cost, short-duration jobs which are part of normal well operating costs. The need for maintenance does not directly depend on the level of drilling activity, although it is somewhat impacted by short-term fluctuations in oil and gas prices. Accordingly, maintenance services generally experience relatively stable demand; however, when oil or gas prices are too low to justify additional expenditures, operating companies may choose to temporarily shut in producing wells rather than incur additional maintenance costs.

In addition to periodic maintenance, producing oil and gas wells occasionally require major repairs or modifications called workovers, which are typically more complex and more time consuming than maintenance operations. Workover services include extensions of existing wells to drain new formations either through perforating the well casing to expose additional productive zones not previously produced, deepening well bores to new zones or the drilling of lateral well bores to improve reservoir drainage patterns. Our well servicing rigs are also used to convert former producing wells to injection wells through which water or carbon dioxide is then pumped into the formation for enhanced oil recovery operations. Workovers also include major subsurface repairs such as repair or replacement of well casing, recovery or replacement of tubing and removal of foreign objects from the well bore. These extensive workover operations are normally performed by a well servicing rig with additional specialized auxiliary equipment, which may include rotary drilling equipment, mud pumps, mud tanks and fishing tools, depending upon the particular type of workover operation. All of our well servicing rigs are designed to perform complex workover operations. A workover may require a few days to several weeks and generally requires additional auxiliary equipment. The demand for workover services is sensitive to oil and gas producers' intermediate and long-term expectations for oil and gas prices.

Well servicing rigs are also used in the process of permanently closing oil and gas wells no longer capable of producing in economic quantities. Many well operators bid this work on a "turnkey" basis, requiring the service company to perform the entire job, including the sale or disposal of equipment salvaged from the well as part of the compensation received, and complying with state regulatory requirements. Plugging and abandonment work can provide favorable operating margins and is less sensitive to oil and gas pricing than drilling and workover activity since well operators must plug a well in accordance with state regulations when it is no longer productive. We perform plugging and abandonment work throughout our core areas of operation in conjunction with equipment provided by other service companies.

We typically bill clients for our well servicing on an hourly basis during the period that the rig is actively working. We operate through 10 locations, mostly in the Gulf Coast states, as well as in Arkansas and North Dakota. We believe that our fleet is among the newest in the industry, consisting entirely of tall-masted rigs with at least 550 horsepower, capable of working at depths of 20,000 feet. These specifications allow us to operate in areas with deeper well depths and perform jobs that rigs with lesser capabilities cannot. In late 2016, we committed to trade in 20 of our older 550 horsepower well servicing rigs for 20 new-model rigs to be delivered in the first quarter of 2017, further improving the quality of our rig fleet, enhancing our ability to recruit crew talent and competitively positioning us for new service opportunities as the market improves. Our well servicing utilization rates for the years ended December 31, 2016 and 2015 were 41% and 65%, respectively, based on total fleet count.

Wireline Services. Wireline trucks, like well servicing rigs, are utilized throughout the life of a well. Wireline trucks are often used in place of a well servicing rig when there is no requirement to remove tubulars from the well in order to make repairs.

Wireline services typically utilize a single truck equipped with a spool of wireline that is used to lower and raise a variety of specialized tools in and out of the wellbore. Electric wireline contains a conduit that allows signals to be transmitted to or from tools located in the well. These tools can be used to measure pressures and temperatures as well as the condition of the casing and the cement that holds the casing in place. In order for oil and gas exploration and production companies to better understand the reservoirs they are drilling or producing, they require logging services to accurately characterize reservoir rocks and fluids. We provide both open and cased-hole logging services.

Other applications for wireline tools include placing equipment in or retrieving equipment (or debris) from the wellbore, installing bridge plugs, perforating the casing in order to prepare the well for production, or cutting off pipe that is stuck in the well so that the free section can be recovered.

Our wireline operations are deployed through 17 locations in Texas, Kansas, Colorado, Montana, North Dakota, Louisiana, Oklahoma and Wyoming. We are currently actively marketing approximately 65% of our wireline fleet.

Coiled Tubing Services. Coiled tubing is also an important element of the well servicing industry that allows operators to continue production during service operations on a well under pressure without shutting in the well, thereby reducing the risk of formation damage. Coiled tubing services involve the use of a continuous metal pipe spooled on a large reel for oil and natural gas well applications, such as wellbore clean-outs, nitrogen jet lifts, through-tubing fishing, formation stimulation utilizing acid, chemical treatments and fracturing. Coiled tubing is also used for a number of horizontal well applications such as milling temporary plugs between frac stages.

Our coiled tubing operations are deployed through three locations in Texas and Louisiana. Our coiled tubing utilization rates for the years ended December 31, 2016 and 2015 were 22% and 27%, respectively, based on total fleet count.

Seasonality

All our production services operations are impacted by seasonal factors. Our business can be negatively impacted during the winter months due to inclement weather, fewer daylight hours, and holidays. Because our well servicing rigs, wireline units and coiled tubing units are mobile, during periods of heavy snow, ice or rain, we may not be able to move our equipment between locations.

Clients

We provide drilling and production services to numerous independent and large oil and gas exploration and production companies that are active in the geographic areas in which we operate. The following table shows our three largest clients as a percentage of our total revenue for each of our last three fiscal years.

	Total Revenue Percentage
Fiscal year ended December 31, 2016	
Apache Corporation	11.9%
Whiting Petroleum Corporation	10.1%
PDC Energy, Inc	4.4%
Fiscal year ended December 31, 2015	
Whiting Petroleum Corporation	17.8%
Ecopetrol	6.1%
Apache Corporation	4.6%
Fiscal year ended December 31, 2014	
Whiting Petroleum Corporation	11.9%
Ecopetrol	9.9%
Penn Virginia Oil & Gas, LP.	6.0%

Competition

We encounter substantial competition from other drilling contractors and other oilfield service companies. Our primary market areas are highly fragmented and competitive. The fact that drilling and production services equipment are mobile and can be moved from one market to another in response to market conditions heightens the competition in the industry and may result in an oversupply of equipment in an area. Contract drilling companies and other oilfield service companies compete primarily on a regional basis, and the intensity of competition may vary significantly from region to region at any particular time. If demand for drilling or production services improves in a region where we operate, our competitors might respond by moving in suitable rigs and production services equipment from other regions. An influx of equipment from other regions could rapidly intensify competition, reduce profitability and make any improvement in demand for our services short-lived.

Most drilling services contracts and production services contracts are awarded on the basis of competitive bids, which also results in price competition. In addition to pricing and equipment availability, we believe the following factors are also important to our clients in determining which drilling services or production services provider to select:

- the type, capability and condition of each of the competing drilling rigs, well servicing rigs, wireline units and coiled tubing units;
- the mobility and efficiency of the equipment;
- the quality of service and experience of the crews;
- the reputation and safety record of the company providing the services;
- the offering of ancillary services; and
- the ability to provide drilling and production services equipment adaptable to, and personnel familiar with, new technologies and drilling and production techniques.

While we must be competitive in our pricing, our competitive strategy generally emphasizes the quality of our equipment, our safety record, our ability to offer ancillary services, the experience of our crews and the quality of service we provide to differentiate us from our competitors. This strategy is less effective when lower demand for drilling and production services intensifies price competition and makes it more difficult for us to compete on the basis of factors other than price. In all of the markets in which we compete, an oversupply of drilling rigs or production services equipment generally causes greater price competition and reduced profitability.

We believe that an important competitive factor in establishing and maintaining long-term client relationships is having an experienced, skilled and well-trained work force. In recent years, many of our larger clients have placed increased emphasis on the safety performance and quality of the crews, equipment and services provided by their contractors. We have devoted, and will continue to devote, substantial resources toward employee safety and training programs. Although we believe clients consider all of these factors, price is generally the primary factor in determining which service provider is awarded the work. However, we believe that many clients are willing to pay a slight premium for the quality and safe, efficient service we provide.

The drilling contracts we compete for are usually awarded on the basis of competitive bids. Our principal drilling competitors are Helmerich & Payne, Inc., Precision Drilling Corporation, Patterson-UTI Energy, Inc. and Nabors Industries, Ltd.

The largest well servicing providers that we compete with are Key Energy Services, Basic Energy Services, C&J Energy Services, Superior Energy Services, Inc. and CC Forbes. As compared to the other large competitors in this industry, we believe our fleet is one of the youngest, most uniform fleets, which in addition to our safety performance and service quality, has historically allowed us to operate at utilization and hourly rates that are among the highest of our peers.

The wireline market in the United States is dominated by a small number of companies, including ourselves. These competitors include Allied-Horizontal Wireline Services, Renegade Services, C&J Energy Services, KLX Energy Services and Archer Ltd. Additional competitors include Schlumberger Ltd., Halliburton Company and other independents. The market for wireline services is very competitive, but historically we have competed effectively with our competitors because of the diversified services we provide, our performance and strong client service.

The market for coiled tubing has expanded within the oilfield services market over recent years due to technological advances which increased the number of applications for the coiled tubing unit, and the increase in deep well and horizontal drilling. Our primary competitors in the coiled tubing services market currently include C&J Energy Services, Superior Energy Services, Key Energy Services and RPC Inc.

In addition, there are numerous smaller companies that compete in all of our services markets. Some of our competitors have greater financial, technical and other resources than we do. Their greater capabilities in these areas may enable them to:

- better withstand industry downturns;
- compete more effectively on the basis of price and technology;

- retain skilled personnel; and
- build new rigs or acquire and refurbish existing rigs and place them into service more quickly than us in periods of high drilling demand.

The need for our services fluctuates primarily in relation to the price (or anticipated price) of oil and natural gas, which in turn is driven by the supply of and demand for oil and natural gas. The level of our revenues, earnings and cash flows are substantially dependent upon, and affected by, the level of domestic and international oil and gas exploration and development activity, as well as the equipment capacity in any particular region. For a more detailed discussion, see Item 7—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Raw Materials

The materials and supplies we use in our drilling and production services operations include fuels to operate our equipment, drilling mud, drill pipe, drill collars, drill bits, cement and other job materials such as explosives, perforating guns and coiled tubing. We do not rely on a single source of supply for any of these items. While we are not currently experiencing any shortages, from time to time there have been shortages of drilling and production services equipment and supplies during periods of high demand. Shortages could result in increased prices for equipment or supplies that we may be unable to pass on to clients. In addition, during periods of shortages, the delivery times for equipment and supplies can be substantially longer. Any significant delays in our obtaining equipment or supplies could limit our operations and jeopardize our relations with clients. In addition, shortages of equipment or supplies could delay and adversely affect our ability to obtain new contracts for our rigs, which could have a material adverse effect on our financial condition and results of operations.

Operating Risks and Insurance

Our operations are subject to the many hazards inherent in exploration and production activity, including the risks of:

- blowouts;
- cratering;
- fires and explosions;
- loss of well control;
- collapse of the borehole;
- damaged or lost drilling equipment; and
- damage or loss from natural disasters.

Any of these hazards can result in substantial liabilities or losses to us from, among other things:

- suspension of operations;
- damage to, or destruction of, our property and equipment and that of others;
- personal injury and loss of life;
- damage to producing or potentially productive oil and gas formations through which we drill; and
- environmental damage.

We seek to protect ourselves from some but not all operating hazards through insurance coverage. However, some risks are either not insurable or insurance is available only at rates that we consider uneconomical. Those risks include, among other things, pollution liability in excess of relatively low limits. Depending on competitive conditions and other factors, we attempt to obtain contractual protection against uninsured operating risks from our clients. However, clients who provide contractual indemnification protection may not in all cases maintain adequate insurance or otherwise have the financial resources necessary to support their indemnification obligations. Our insurance or indemnification arrangements may not adequately protect us against liability or loss from all the hazards of our operations. The occurrence of a significant event that we have not fully insured or indemnified against or the failure of a client to meet its indemnification obligations to us could materially and adversely affect our results of operations and financial condition. Furthermore, we may be unable to maintain adequate insurance in the future at rates we consider reasonable.

Our current insurance coverage includes property insurance on our rigs, drilling equipment, production services equipment and real property. Our insurance coverage for property damage to our rigs, drilling equipment and production services equipment is based on our estimates of the cost of comparable used equipment to replace the insured property. The policy provides for a deductible of no more than $750,000 per drilling rig and a deductible on production services equipment of $250,000 per occurrence. Our third-party liability insurance coverage is $101 million per occurrence and in the aggregate, with a deductible of $250,000 per occurrence. We also carry insurance coverage for pollution liability up to $20 million with a deductible of $500,000. We believe that we are adequately insured for public liability and property damage to others with respect to our operations. However, such insurance may not be sufficient to protect us against liability for all consequences of well disasters, extensive fire damage or damage to the environment.

In addition, we generally carry insurance coverage to protect against certain hazards inherent in our turnkey contract drilling operations. This insurance covers "control-of-well," including blowouts above and below the surface, redrilling, seepage and pollution. This policy provides coverage of $3 million to $20 million, subject to a deductible of $150,000 or $250,000, depending on the area in which the well is drilled and its target depth. This policy also provides care, custody and control insurance, with a limit of $1 million, subject to a $100,000 deductible.

Employees

We have approximately 1,800 employees, which is down by over 50% from the beginning of 2015. The majority of our employees work in operations for our Drilling Services Segment and Production Services Segment and are primarily compensated on an hourly basis. The number of employees in operations fluctuates depending on the utilization of our drilling rigs, well servicing rigs, wireline units and coiled tubing units at any particular time. None of our employment arrangements are subject to collective bargaining arrangements.

Our operations require the services of employees having the technical training and experience necessary to achieve proper operational standards. As a result, our operations depend, to a considerable extent, on the continuing availability of such personnel. Although we have not encountered material difficulty in hiring and retaining employees in our operations, shortages of qualified personnel have occurred in our industry. If we should suffer any material loss of personnel to competitors or be unable to employ additional or replacement personnel with the requisite level of training and experience to adequately operate our equipment, our operations could be materially and adversely affected. While we believe our wage rates are competitive and our relationships with our employees are satisfactory, a significant increase in the wages paid by other employers could result in a reduction in our workforce, increases in wage rates, or both. The occurrence of either of these events for a significant period of time could have a material adverse effect on our financial condition and results of operations.

Facilities

We lease our corporate office facilities located at 1250 N.E. Loop 410, Suite 1000 San Antonio, Texas 78209. We conduct our business operations through 53 other real estate locations, of which we own 12, in the United States (Texas, Oklahoma, Colorado, Montana, North Dakota, Pennsylvania, Wyoming, Mississippi, Arkansas, Louisiana and Kansas) and internationally in Colombia. These real estate locations are primarily used for regional offices and storage and maintenance yards.

Governmental Regulation

Many aspects of our operations are subject to various federal, state and local laws and governmental regulations, including laws and regulations governing:

- environmental quality;
- pollution control;
- remediation of contamination;
- preservation of natural resources;
- transportation; and
- worker safety.

Our operations are subject to stringent federal, state and local laws, rules and regulations governing the protection of the environment and human health and safety. Some of those laws, rules and regulations relate to the disposal of hazardous substances, oilfield waste and other waste materials and restrict the types, quantities and concentrations of those substances that can be released into the environment. Several of those laws also require removal and remedial action and other cleanup under certain circumstances, commonly regardless of fault. Our operations routinely involve the handling of significant amounts of waste materials, some of which are classified as hazardous substances. Planning, implementation and maintenance of protective measures are required to prevent accidental discharges. Spills of oil, natural gas liquids, drilling fluids and other substances may subject us to penalties and cleanup requirements. Handling, storage and disposal of both hazardous and non-hazardous wastes are also subject to these regulatory requirements. In addition, our operations are often conducted in or near ecologically sensitive areas, such as wetlands, which are subject to special protective measures and which may expose us to additional operating costs and liabilities for accidental discharges of oil, gas, drilling fluids, contaminated water or other substances, or for noncompliance with other aspects of applicable laws and regulations.

Environmental laws and regulations are complex and subject to frequent change. Failure to comply with governmental requirements or inadequate cooperation with governmental authorities could subject a responsible party to administrative, civil or criminal action. We may also be exposed to environmental or other liabilities originating from businesses and assets which we acquired from others. Our compliance with amended, new or more stringent requirements, stricter interpretations of existing requirements or the future discovery of contamination or regulatory noncompliance may require us to make material expenditures or subject us to liabilities that we currently do not anticipate.

There are a variety of regulatory developments, proposals or requirements and legislative initiatives that have been introduced in the United States and international regions in which we operate that are focused on restricting the emission of carbon dioxide, methane and other greenhouse gases.

Hydraulic fracturing of wells and subsurface water disposal are also under public and governmental scrutiny due to concerns regarding potential environmental and physical impacts, including groundwater and drinking water impacts, as well as whether such activities may cause earthquakes. Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale plays, incurred by our clients. The adoption of any federal, state or local laws or the implementation of regulations or ordinances restricting or increasing the costs of hydraulic fracturing could cause a decrease in the completion of new oil and natural gas wells and an associated decrease in demand for our drilling and well servicing activities, any or all of which could adversely affect our financial position, results of operations and cash flows.

Our wireline operations involve the use of radioactive isotopes along with other nuclear, electrical, acoustic, and mechanical devices. Our activities involving the use of isotopes are regulated by the U.S. Nuclear Regulatory Commission and specified agencies of certain states. Additionally, we use high explosive charges for perforating casing and formations, and we use various explosive cutters to assist in wellbore cleanout. Such operations are regulated by the U.S. Department of Justice, Bureau of Alcohol, Tobacco, Firearms, and Explosives and require us to obtain licenses or other approvals for the use of densitometers as well as explosive charges. We have obtained these licenses and approvals when necessary and believe that we are in substantial compliance with these federal requirements.

In addition, our business depends on the demand for land drilling and production services from the oil and gas industry and, therefore, is affected by tax, environmental and other laws relating to the oil and gas industry generally, by changes in those laws and by changes in related administrative regulations. It is possible that these laws and regulations may in the future add significantly to our operating costs or those of our clients, or otherwise directly or indirectly affect our operations.

Among the services we provide, we operate as a motor carrier for the transportation of our own equipment and therefore are subject to regulation by the U.S. Department of Transportation and by various state agencies. These regulatory authorities exercise broad powers, governing activities such as the authorization to engage in motor carrier operations and regulatory safety. There are additional regulations specifically relating to the trucking industry, including testing and specification of equipment and product handling requirements. The trucking industry is subject to possible regulatory and legislative changes that may affect the economics of the industry by requiring changes in operating practices or by changing the demand for common or contract carrier services or the cost of providing truckload services. Some of these possible changes include increasingly stringent environmental regulations, changes in the hours of service regulations which govern the amount of time a driver may drive in any specific period, onboard black box recorder devices or limits on vehicle weight and size.

Interstate motor carrier operations are subject to safety requirements prescribed by the U.S. Department of Transportation. To a large degree, intrastate motor carrier operations are subject to state safety regulations that mirror federal regulations. Such matters as weight and dimension of equipment are also subject to federal and state regulations.

From time to time, various legislative proposals are introduced, including proposals to increase federal, state, or local taxes, including taxes on motor fuels, which may increase our costs or adversely impact the recruitment of drivers. We cannot predict whether, or in what form, any increase in such taxes applicable to us will be enacted.

See Item 1A—"Risk Factors" in Part I of this Annual Report on Form 10-K for a detailed discussion of risks we face concerning laws and governmental regulations.

Available Information

Our Website address is *www.pioneeres.com*. Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports, are available free of charge through our Website as soon as reasonably practicable after we electronically file those materials with, or furnish those materials to, the Securities and Exchange Commission. The public may read and copy these materials at the Securities and Exchange Commission's Public Reference Room at 100 F Street, N.E., Washington, DC 20549. For additional information on the operations of the Securities and Exchange Commission's Public Reference Room, please call 1-800-SEC-0330. In addition, the Securities and Exchange Commission maintains an Internet site at *www.sec.gov* that contains reports, proxy and information statements and other information regarding issuers that file electronically. We have also posted on our Website our: Charters for the Audit, Compensation, and Nominating and Corporate Governance Committees of our Board; Code of Business Conduct and Ethics; Corporate Governance Guidelines; and Company Contact Information. Information on our website is not incorporated into this report or otherwise made part of this report.

Item 1A. Risk Factors

The information set forth in this Item 1A should be read in conjunction with the rest of the information included in this report, including "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 and the financial statements and related notes this report contains. While we attempt to identify, manage and mitigate risks and uncertainties associated with our business to the extent practical under the circumstances, some level of risk and uncertainty will always be present. Additional risks and uncertainties that are not presently known to us or that we currently believe are immaterial also may negatively impact our business, financial condition or operating results.

Set forth below are various risks and uncertainties that could adversely impact our business, financial condition, results of operations and cash flows.

Risks Relating to the Oil and Gas Industry

We derive all our revenues from companies in the oil and gas exploration and production industry, a historically cyclical industry with levels of activity that are significantly affected by the levels and volatility of oil and gas prices.

As a provider of contract land drilling services and oil and gas production services, our business depends on the level of exploration and production activity in the geographic markets where we operate. The oil and gas exploration and production industry is a historically cyclical industry characterized by significant changes in the levels of exploration and development activities.

Oil and gas prices, and market expectations of potential changes in those prices, significantly affect the levels of those activities. Oil and gas prices have been volatile historically and, we believe, will continue to be so in the future. Worldwide political, economic, and military events as well as natural disasters have contributed to oil and gas price volatility historically, and are likely to continue to do so in the future. Many factors beyond our control affect oil and gas prices, including:

- the worldwide supply and demand for oil and gas;
- the cost of exploring for, producing and delivering oil and gas;
- the discovery rate of new oil and gas reserves;
- the rate of decline of existing and new oil and gas reserves;
- available pipeline and other oil and gas transportation capacity;
- the levels of oil and gas storage;
- the ability of oil and gas exploration and production companies to raise capital;
- economic conditions in the United States and elsewhere;
- actions by the Organization of Petroleum Exporting Countries, which we refer to as OPEC;
- political instability in the Middle East and other major oil and gas producing regions;

- governmental regulations, both domestic and foreign;
- domestic and foreign tax policy;
- weather conditions in the United States and elsewhere;
- the pace adopted by foreign governments for the exploration, development and production of their national reserves; and
- the price of foreign imports of oil and gas.

As a result of the decline in oil prices that began in late 2014, our clients maintained minimal spending on exploration and production projects in 2015 and 2016, resulting in a continued decrease in demand for our services.

Oil and natural gas prices, and market expectations of potential changes in these prices, significantly impact the level of worldwide drilling and production services activities. Reduced demand for oil and natural gas generally results in lower prices for these commodities and often impacts the economics of planned drilling projects and ongoing production projects, resulting in the curtailment, reduction, delay or postponement of such projects for an indeterminate period of time. When drilling and production activity and spending declines, both dayrates and utilization historically decline as well.

Beginning in October 2014, oil prices worldwide dropped significantly. Our clients significantly reduced both their operating and capital expenditures during 2015 and 2016, but increases are expected for 2017. If the depressed oil and natural gas prices persist for a prolonged period, or further decline, oil and gas exploration and production companies are likely to continue to cancel or curtail their drilling programs and further reduce production spending on existing wells, thereby reducing demand for our services.

The reduction in spending and activity levels adversely affected our business during 2015 and 2016. If the reduction in the overall level of exploration and development activities, whether resulting from changes in oil and gas prices or otherwise, continues, it could materially and adversely affect us further by negatively impacting:

- our revenues, cash flows and profitability;
- the fair market value of our drilling rig fleet and production services equipment;
- our ability to maintain or increase our borrowing capacity;
- our ability to obtain additional capital to finance our business or make acquisitions, and the cost of that capital;
- the collectability of our receivables; and
- our ability to retain skilled operations personnel whom we would need in the event of an upturn in the demand for our services.

Risks Relating to Our Business

Reduced demand for or excess capacity of drilling services or production services could adversely affect our profitability.

Our profitability in the future will depend on many factors, but largely on pricing and utilization rates for our drilling and production services. A reduction in the demand for drilling rigs or an increase in the supply of drilling rigs, whether through new construction or refurbishment, could decrease the dayrates and utilization rates for our drilling services, which would adversely affect our revenues and profitability. An increase in supply of well servicing rigs, wireline units and coiled tubing units, without a corresponding increase in demand, could similarly decrease the pricing and utilization rates of our production services, which would adversely affect our revenues and profitability.

We operate in a highly competitive, fragmented industry in which price competition could reduce our profitability.

We encounter substantial competition from other drilling contractors and other oilfield service companies. Our primary market areas are highly fragmented and competitive. The fact that drilling and production services equipment are mobile and can be moved from one market to another in response to market conditions heightens the competition in the industry and may result in an oversupply of equipment in an area. Contract drilling companies and other oilfield service companies compete primarily on a regional basis, and the intensity of competition may vary significantly from region to region at any particular time. If demand for drilling or production services improves in a region where we operate, our competitors might respond by moving in suitable rigs and production services equipment from other regions. An influx of equipment from other regions could rapidly intensify competition, reduce profitability and make any improvement in demand for our services short-lived.

Most drilling services contracts and production services contracts are awarded on the basis of competitive bids, which also results in price competition. In addition to pricing and equipment availability, we believe the following factors are also important to our clients in determining which drilling services or production services provider to select:

- the type, capability and condition of each of the competing drilling rigs, well servicing rigs, wireline units and coiled tubing units;
- the mobility and efficiency of the equipment;
- the quality of service and experience of the crews;
- the reputation and safety record of the company providing the services;
- the offering of ancillary services; and
- the ability to provide drilling and production services equipment adaptable to, and personnel familiar with, new technologies and drilling and production techniques.

While we must be competitive in our pricing, our competitive strategy generally emphasizes the quality of our equipment, our safety record, our ability to offer ancillary services, the experience of our crews and the quality of service we provide to differentiate us from our competitors. This strategy is less effective when lower demand for drilling and production services intensifies price competition and makes it more difficult for us to compete on the basis of factors other than price. In all of the markets in which we compete, an oversupply of drilling rigs or production services equipment generally causes greater price competition and reduced profitability.

We face competition from many competitors with greater resources.

Some of our competitors have greater financial, technical and other resources than we do. Their greater capabilities in these areas may enable them to:

- better withstand industry downturns;
- compete more effectively on the basis of price and technology;
- retain skilled personnel; and
- build new rigs or acquire and refurbish existing rigs and place them into service more quickly than us in periods of high drilling demand.

Technological advancements and trends in our industry also affect the demand for certain types of equipment, and can affect the overall demand for equipment in our industry.

Technological advancements and trends in our industry also affect the demand for certain types of equipment, and can affect the overall demand for equipment in our industry. For several years, prior to late 2014, higher oil prices drove industry equipment utilization and revenue rates up, particularly in oil-producing regions and certain shale regions. However, advancements in technology improved the efficiency of drilling rigs and overall demand remained steady, while the demand for certain drilling rigs decreased, particularly in vertical well markets. The decline was a result of higher demand for drilling rigs that are able to drill horizontally and the increased use of "pad drilling" which enables a series of horizontal wells to be drilled in succession by walking or skidding a drilling rig at a single pad-site location, thereby improving the productivity of exploration and production activities. This trend, then coupled with the downturn, resulted in significantly reduced demand for drilling rigs that do not have the ability to walk or skid and to drill horizontal wells, and could further reduce the overall demand for all drilling rigs.

In drilling, all rig classes were severely impacted by the industry downturn. However, AC drilling rigs equipped with either a walking or skidding system are the best suited for horizontal pad drilling and we believe they are the most desirable rig design available.

Although we take measures to ensure that we use advanced technologies for drilling and production services equipment, changes in technology or improvements in our competitors' equipment could make our equipment less competitive or require significant capital investments to keep our equipment competitive, which could have an adverse effect on our financial condition and operating results.

We derive a significant portion of our revenue from a limited number of major clients, and our business, financial condition and results of operations could be materially adversely affected if we are unable to maintain relationships with these clients, or if their demand for our services decreases.

In the past, we have derived a significant portion of our revenue from a limited number of major clients. For the years ended December 31, 2016, 2015 and 2014, our drilling and production services to our top three clients accounted for approximately 26%, 29%, and 28%, respectively, of our revenue. The loss of one or more of our major clients, or their decrease in demand for our services, could have a material adverse effect on our business, financial condition and results of operations. We experienced significantly reduced demand for our services during 2015 and 2016, from all clients, including these major clients. For a detail of our three largest clients as a percentage of our total revenues during the last three fiscal years, see Item 1—"Business" in Part I of this Annual Report on Form 10-K.

Our indebtedness could restrict our operations and make us more vulnerable to adverse economic conditions.

Our indebtedness is primarily a result of the two production services businesses that we acquired in 2008 and the acquisition of Go-Coil in 2011, as well as organic growth investments. At January 31, 2017, our total debt balance of $349.7 million consists of $300 million outstanding under our Senior Notes and $49.7 million outstanding under our Revolving Credit Facility. At January 31, 2017, we had borrowing availability of $88.5 million under our Revolving Credit Facility.

Our current and future indebtedness could have important consequences, including:

- limiting our ability to use operating cash flow in other areas of our business because we must dedicate a substantial portion of these funds to make principal and interest payments on our indebtedness;
- making us more vulnerable to a downturn in our business, our industry or the economy in general as a substantial portion of our operating cash flow could be required to make principal and interest payments on our indebtedness, making it more difficult to react to changes in our business, industry and market conditions;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- impairing our ability to make investments and obtain additional financing for working capital, capital expenditures, acquisitions or other general corporate purposes;
- limiting our ability to obtain additional financing that may be necessary to operate or expand our business;
- putting us at a competitive disadvantage to competitors that have less debt; and
- increasing our vulnerability to rising interest rates.

We currently expect that cash and cash equivalents, cash generated from operations, proceeds from sales of certain non-strategic assets and available borrowings under our Revolving Credit Facility are adequate to cover our liquidity requirements for at least the next 12 months. However, our ability to make payments on our indebtedness, and to fund planned capital expenditures, will depend on our ability to generate cash in the future. This, to a certain extent, is subject to conditions in the oil and gas industry, general economic and financial conditions, competition in the markets where we operate, the impact of legislative and regulatory actions on how we conduct our business and other factors, all of which are beyond our control. If our business does not generate sufficient cash flow from operations to service our outstanding indebtedness, we may have to undertake alternative financing plans, such as:

- refinancing or restructuring our debt;
- selling assets;
- reducing or delaying acquisitions or capital investments, such as refurbishments of our rigs and related equipment; or
- seeking to raise additional capital.

However, we may be unable to implement alternative financing plans, if necessary, on commercially reasonable terms or at all, and any such alternative financing plans might be insufficient to allow us to meet our debt obligations. If we are unable to generate sufficient cash flow or are otherwise unable to obtain the funds required to make principal and interest payments on our indebtedness, or if we otherwise fail to comply with the various covenants in our Revolving Credit Facility or other instruments governing any future indebtedness, we could be in default under the terms of our Revolving Credit Facility or such instruments. In the event of a default, the lenders under our Revolving Credit Facility could elect to declare all the loans made under such facility to be due and payable together with accrued and unpaid interest and terminate their commitments thereunder and we or one or more of our subsidiaries could be forced into bankruptcy or liquidation. Any of the foregoing consequences could materially and adversely affect our business, financial condition, results of operations and prospects.

Our Revolving Credit Facility and our Senior Notes impose significant covenants on us that may affect our ability to successfully operate our business.

Our Revolving Credit Facility limits our ability to take various actions, such as:

- incur additional debt or make prepayments of existing debt;
- create liens on or dispose of our assets;
- pay dividends on stock or repurchase stock;
- enter into acquisitions, mergers, consolidations, sale leaseback transactions, or hedging contracts;
- make capital expenditures;
- make other restricted investments;
- conduct transactions with affiliates; and
- limits our use of the net proceeds of any offering of our equity securities to the repayment of debt outstanding under the Revolving Credit Facility.

In addition, our Revolving Credit Facility requires us to maintain certain financial covenants and to satisfy certain financial conditions, which may require us to reduce our debt or take some other action in order to comply with them.

The Indenture governing our Senior Notes limits us and certain of our subsidiaries in our ability to:

- pay dividends on stock, repurchase stock, redeem subordinated indebtedness or make other restricted payments and investments;
- incur, assume or guarantee additional indebtedness or issue preferred or disqualified stock;
- create liens on our or their assets;
- enter into sale and leaseback transactions;
- sell or transfer assets;
- borrow, pay dividends, or transfer other assets from certain of our subsidiaries;
- consolidate with or merge with or into, or sell all or substantially all of our properties to any other person;
- enter into transactions with affiliates; and
- enter into new lines of business.

The failure to comply with any of these covenants would cause an event of default under our Revolving Credit Facility or our Senior Notes. An event of default, if not waived, could result in acceleration of the outstanding indebtedness, in which case the debt would become immediately due and payable. If this occurs, we may not be able to pay our debt or borrow sufficient funds to refinance it. Even if new financing is available, it may not be available on terms that are acceptable to us. These covenants could also limit our ability to obtain future financing, make needed capital expenditures, withstand a downturn in our business or the economy in general, or otherwise conduct necessary corporate activities. We also may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants under our Revolving Credit Facility and our Senior Notes.

Unexpected cost overruns on our turnkey drilling jobs could adversely affect our financial position and our results of operations.

We have historically derived a portion of our revenues from turnkey drilling contracts, although we do not expect turnkey contracts to represent a significant amount of our revenues in the current industry environment.

Under a typical turnkey drilling contract, we agree to drill a well for our client to a specified depth and under specified conditions for a fixed price. We provide technical expertise and engineering services, as well as most of the equipment and drilling supplies required to drill the well. We often subcontract for related services, such as the provision of casing crews, cementing and well logging. Under typical turnkey drilling arrangements, we do not receive progress payments and are paid by our client only after we have performed the terms of the drilling contract in full. For these reasons, the risk to us under a turnkey drilling contract is substantially greater than for a well drilled on a daywork basis because we must assume most of the risks associated with drilling operations that the operator generally assumes under a daywork contract, including the risks of blowout, loss of hole, stuck drill pipe, machinery breakdowns, abnormal drilling conditions and risks associated with subcontractors' services, supplies, cost escalations and personnel. In addition, since we are only paid by our clients after we have performed the terms of the drilling contract in full, our liquidity can be affected by the number of turnkey contracts that we enter into.

The occurrence of uninsured or under-insured losses or operating cost overruns on our turnkey jobs could have a material adverse effect on our financial position and results of operations. Although we attempt to obtain insurance coverage to reduce certain of the risks inherent in our turnkey drilling operations, adequate coverage may be unavailable in the future and we might have to bear the full cost of such risks, which could have an adverse effect on our financial condition and results of operations.

Our operations involve operating hazards, which, if not insured or indemnified against, could adversely affect our results of operations and financial condition.

Our operations are subject to the many hazards inherent in exploration and production activity, including the risks of:

- blowouts;
- cratering;
- fires and explosions;
- loss of well control;
- collapse of the borehole;
- damaged or lost drilling equipment; and
- damage or loss from natural disasters.

Any of these hazards can result in substantial liabilities or losses to us from, among other things:

- suspension of operations;
- damage to, or destruction of, our property and equipment and that of others;
- personal injury and loss of life;
- damage to producing or potentially productive oil and gas formations through which we drill; and
- environmental damage.

We seek to protect ourselves from some but not all operating hazards through insurance coverage. However, some risks are either not insurable or insurance is available only at rates that we consider uneconomical. Those risks include, among other things, pollution liability in excess of relatively low limits. Depending on competitive conditions and other factors, we attempt to obtain contractual protection against uninsured operating risks from our clients. However, clients who provide contractual indemnification protection may not in all cases maintain adequate insurance or otherwise have the financial resources necessary to support their indemnification obligations. Our insurance or indemnification arrangements may not adequately protect us against liability or loss from all the hazards of our operations. The occurrence of a significant event that we have not fully insured or indemnified against or the failure of a client to meet its indemnification obligations to us could materially and adversely affect our results of operations and financial condition. Furthermore, we may be unable to maintain adequate insurance in the future at rates we consider reasonable.

We could be adversely affected if shortages of equipment, supplies or personnel occur.

From time to time there have been shortages of drilling and production services equipment and supplies during periods of high demand which we believe could recur. Shortages could result in increased prices for equipment or supplies that we may be unable to pass on to clients. In addition, during periods of shortages, the delivery times for equipment and supplies can be substantially longer. Any significant delays in our obtaining equipment or supplies could limit our operations and jeopardize our relations with clients. In addition, shortages of equipment or supplies could delay and adversely affect our ability to obtain new contracts for our rigs, which could have a material adverse effect on our financial condition and results of operations.

Our strategy of constructing drilling rigs during periods of peak demand requires that we maintain an adequate supply of drilling rig components to complete our rig building program. Our suppliers may be unable to continue providing us the needed drilling rig components if their manufacturing sources are unable to fulfill their commitments.

Our operations require the services of employees having the technical training and experience necessary to achieve the proper operational results. As a result, our operations depend, to a considerable extent, on the continuing availability of such personnel. Shortages of qualified personnel have occurred in our industry. If we should suffer any material loss of personnel to competitors or be unable to employ additional or replacement personnel with the requisite level of training and experience to adequately operate our equipment, our operations could be materially and adversely affected. A significant increase in the wages paid by other employers could result in a reduction in our workforce, increases in wage rates, or both. The occurrence of either of these events for a significant period of time could have a material adverse effect on our financial condition and results of operations.

Our acquisition strategy exposes us to various risks, including those relating to difficulties in identifying suitable acquisition opportunities and integrating businesses, assets and personnel, as well as difficulties in obtaining financing for targeted acquisitions and the potential for increased leverage or debt service requirements.

A component of our long-term business strategy is a pursuit of acquisitions of complementary assets and businesses. This acquisition strategy in general involves numerous inherent risks, including:

- unanticipated costs and assumption of liabilities and exposure to unforeseen liabilities of acquired businesses, including environmental liabilities;
- difficulties in integrating the operations and assets of the acquired business and the acquired personnel;
- limitations on our ability to properly assess and maintain an effective internal control environment over an acquired business in order to comply with applicable periodic reporting requirements;
- potential losses of key employees and clients of the acquired businesses;
- risks of entering markets in which we have limited prior experience; and
- increases in our expenses and working capital requirements.

The process of integrating an acquired business may involve unforeseen costs and delays or other operational, technical and financial difficulties that may require a disproportionate amount of management attention and financial and other resources. Our failure to achieve consolidation savings, to incorporate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

In addition, we may not have sufficient capital resources to complete additional acquisitions. Historically, we have funded business acquisitions and the growth of our rig fleet through a combination of debt and equity financing. We may incur substantial additional indebtedness to finance future acquisitions and also may issue equity securities or convertible securities in connection with such acquisitions. 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 our existing shareholders. Furthermore, we may not be able to obtain additional financing on satisfactory terms or at all.

Even if we have access to the necessary capital, we may be unable to continue to identify additional suitable acquisition opportunities, negotiate acceptable terms or successfully acquire identified targets.

Our cash and cash equivalents and short term investments could be adversely affected if the financial institutions in which we hold our cash and cash equivalents fail.

We maintain cash balances at third-party financial institutions in excess of the Federal Deposit Insurance Corporation insurance limit. While we monitor the cash balances in the operating accounts and adjust the balances as appropriate, we may incur a loss to the extent such loss exceeds the insurance limitation, and there could be a material impact on our business, if one of more of the financial institutions with which we deposit fails or is subject to other adverse conditions in the financial or credit markets and bank regulators elect to impose losses on uninsured depositors. To date, we have experienced no loss or lack of access to our invested cash or cash equivalents. However, in the future, our invested cash and cash equivalents could be adversely affected by adverse conditions in the financial and credit markets.

Our international operations are subject to political, economic and other uncertainties not generally encountered in our domestic operations.

Our international operations are subject to political, economic and other uncertainties not generally encountered in our U.S. operations which include, among potential others:

- risks of war, terrorism, civil unrest and kidnapping of employees;
- employee strikes, work stoppages, labor disputes and other slowdowns;
- expropriation, confiscation or nationalization of our assets;

- renegotiation or nullification of contracts;
- foreign taxation, such as the tax for equality and the net-worth tax in Colombia;
- the inability to repatriate earnings or capital due to laws limiting the right and ability of foreign subsidiaries to pay dividends and remit earnings to affiliated companies;
- changing political conditions and changing laws and policies affecting trade and investment;
- concentration of clients;
- regional economic downturns;
- the overlap of different tax structures;
- the burden of complying with multiple and potentially conflicting laws;
- the risks associated with the assertion of foreign sovereignty over areas in which our operations are conducted;
- the risks associated with any lack of compliance with the Foreign Corrupt Practices Act of 1977 ("FCPA") or other anti-corruption laws;
- the risks associated with fluctuating currency values, hard currency shortages and controls of foreign currency exchange, and higher rates of inflation as compared to our domestic operations;
- difficulty in collecting international accounts receivable; and
- potentially longer payment cycles.

Additionally, we may be subject to foreign governmental regulations favoring or requiring the awarding of contracts to local contractors or requiring foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. These regulations could adversely affect our ability to compete.

We are committed to doing business in accordance with applicable anti-corruption laws and our code of conduct and ethics. We are subject, however, to the risk that our employees and agents may take action determined to be in violation of anti-corruption laws, including the FCPA or other similar laws. Any violation of the FCPA or other applicable anti-corruption laws could result in substantial fines, sanctions, civil and/or criminal penalties and curtailment of operations in certain jurisdictions and might materially adversely affect our business, results of operations or financial condition. In addition, actual or alleged violations could damage our reputation and ability to do business. Further, detecting, investigating, and resolving actual or alleged violations is expensive and can consume significant time and attention of our senior management.

Our operations are subject to various laws and governmental regulations that could restrict our future operations and increase our operating costs.

Many aspects of our operations are subject to various federal, state and local laws and governmental regulations, including laws and regulations governing:

- environmental quality;
- pollution control;
- remediation of contamination;
- preservation of natural resources;
- transportation; and
- worker safety.

Our operations are subject to stringent federal, state and local laws, rules and regulations governing the protection of the environment and human health and safety. Some of those laws, rules and regulations relate to the disposal of hazardous substances, oilfield waste and other waste materials and restrict the types, quantities and concentrations of those substances that can be released into the environment. Several of those laws also require removal and remedial action and other cleanup under certain circumstances, commonly regardless of fault. Our operations routinely involve the handling of significant amounts of waste materials, some of which are classified as hazardous substances. Planning, implementation and maintenance of protective measures are required to prevent accidental discharges. Spills of oil, natural gas liquids, drilling fluids and other substances may subject us to penalties and cleanup requirements. Handling, storage and disposal of both hazardous and non-hazardous wastes are also subject to these regulatory requirements. In addition, our operations are often conducted in or near ecologically sensitive areas, such as wetlands, which are subject to special protective measures and which may expose us to additional operating costs and liabilities for accidental discharges of oil, gas, drilling fluids, contaminated water or other substances, or for noncompliance with other aspects of applicable laws and regulations.

The federal Clean Water Act, the Oil Pollution Act (and interpreted by EPA through regulations, including the Clean Water Rule issued in May 2015); the federal Clean Air Act; the federal Resource Conservation and Recovery Act; the federal

Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA; the Safe Drinking Water Act, or SDWA; the federal Outer Continental Shelf Lands Act; the Occupational Safety and Health Act, or OSHA; and their state counterparts and similar statutes are the primary statutes that impose the requirements described above and provide for civil, criminal and administrative penalties and other sanctions for violation of their requirements. The OSHA hazard communication standard, the Environmental Protection Agency "community right-to-know" regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require us to organize and report information about the hazardous materials we use in our operations to employees, state and local government authorities and local citizens. In addition, CERCLA, also known as the "Superfund" law, and similar state statutes impose strict liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered responsible for the release or threatened release of hazardous substances into the environment. These persons include the current owner or operator of a facility where a release has occurred, the owner or operator of a facility at the time a release occurred, and companies that disposed of or arranged for the disposal of hazardous substances found at a particular site. This liability may be joint and several. Such liability, which may be imposed for the conduct of others and for conditions others have caused, includes the cost of removal and remedial action as well as damages to natural resources. Few defenses exist to the liability imposed by many environmental laws and regulations. It is also common for third parties to file claims for personal injury and property damage caused by substances released into the environment.

Environmental laws and regulations are complex and subject to frequent change. Failure to comply with governmental requirements or inadequate cooperation with governmental authorities could subject a responsible party to administrative, civil or criminal action. We may also be exposed to environmental or other liabilities originating from businesses and assets which we acquired from others. Our compliance with amended, new or more stringent requirements, stricter interpretations of existing requirements or the future discovery of contamination or regulatory noncompliance may require us to make material expenditures or subject us to liabilities that we currently do not anticipate.

There are a variety of regulatory developments, proposals or requirements and legislative initiatives that have been introduced in the United States and international regions in which we operate that are focused on restricting the emission of carbon dioxide, methane and other greenhouse gases. Among these developments at the international level is the United Nations Framework Convention on Climate Change, which produced the "Kyoto Protocol" (an internationally applied protocol, which has been ratified in Colombia, which is a location where we provide drilling services) in 1992. More recently, on December 12, 2015, 195 countries adopted under the Framework Convention a resolution known as the "Paris Agreement" to reduce emissions of greenhouse gases with a goal of limiting global warming to below 2 °C (3.6 °F). The Paris Agreement does not establish enforceable emissions reduction targets, but countries may establish greenhouse gas reduction measures pursuant to the agreement. The agreement went into effect on November 4, 2016.

The United States ratified the Paris Agreement in September 2016. In addition, the U.S. Congress has from time to time considered legislation to reduce emissions of greenhouse gases, primarily through the development of greenhouse gas cap and trade programs. Also, more than one-third of the states already have begun implementing legal measures to reduce emissions of greenhouse gases. There have been two multi-state organizations devoted to climate action. The Regional Greenhouse Gas Initiative, or "RGGI," is located in the Northeastern and Mid-Atlantic United States. The Western Regional Climate Action Initiative once included multiple U.S. states and much of Canada but is now comprised of California, British Columbia, Manitoba, Ontario, and Quebec.

In 2007, the United States Supreme Court in Massachusetts, et al. v. EPA, held that carbon dioxide may be regulated as an "air pollutant" under the federal Clean Air Act. On December 7, 2009, the EPA responded to the Massachusetts, et al. v. EPA decision and issued a finding that the current and projected concentrations of greenhouse gases in the atmosphere threaten the public health and welfare of current and future generations, and that certain greenhouse gases from motor vehicles contribute to the atmospheric concentrations of greenhouse gases and hence to the threat of climate change.

Based on these findings, in 2010 the EPA adopted two sets of regulations that restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act, including one that requires a reduction in emissions of greenhouse gases from motor vehicles and another that requires certain construction and operating permit reviews for greenhouse gas emissions from certain large stationary sources. In June 2014, the U.S. Supreme Court invalidated elements of the greenhouse gas permitting rule; however, the EPA can still impose certain greenhouse gas control requirements for certain large stationary sources. In addition, the EPA adopted rules requiring the monitoring and reporting of greenhouse gases from certain sources, including, among others, onshore oil and natural gas production facilities.

In April 2012, the EPA issued regulations specifically applicable to the oil and gas industry that will require operators to significantly reduce volatile organic compounds, or VOC, emissions from natural gas wells that are hydraulically fractured through the use of "green completions" to capture natural gas that would otherwise escape into the air. The EPA also issued regulations that establish standards for VOC emissions from several types of equipment at natural gas well sites, including storage tanks, compressors, dehydrators and pneumatic controllers.

On August 3, 2015, the EPA finalized rules to limit carbon dioxide emissions from new and existing electric utility generating units. New units must meet specified carbon dioxide emissions limitations. The rules for existing units, known as the "Clean Power Plan," will require by 2030 an overall reduction in carbon dioxide emissions of 32% below the amount of carbon dioxide emitted in 2005.

On August 18, 2015, the EPA proposed a rule to reduce methane (a greenhouse gas) and VOC emissions from oil and gas operations. Among other requirements, the proposed rules would impose standards for hydraulically fractured oil wells and equipment leaks at oil and gas production sites and would extend certain existing standards to downstream oil and gas operations.

Although it is not possible at this time to predict whether proposed climate change initiatives will be adopted as initially written, if at all, or how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions. Any additional costs or operating restrictions associated with legislation or regulations regarding greenhouse gas emissions could have a material adverse effect on our operating results and cash flows. In addition, these developments could curtail the demand for fossil fuels such as oil and gas in areas of the world where our clients operate and thus adversely affect demand for our services, which may in turn adversely affect our future results of operations. Finally, we cannot predict with any certainty whether changes to temperature, storm intensity or precipitation patterns as a result of climate change will have a material impact on our operations.

In addition, our business depends on the demand for land drilling and production services from the oil and gas industry and, therefore, is affected by tax, environmental and other laws relating to the oil and gas industry generally, by changes in those laws and by changes in related administrative regulations. It is possible that these laws and regulations may in the future add significantly to our operating costs or those of our clients, or otherwise directly or indirectly affect our operations.

Our wireline operations involve the use of radioactive isotopes along with other nuclear, electrical, acoustic, and mechanical devices. Our activities involving the use of isotopes are regulated by the U.S. Nuclear Regulatory Commission and specified agencies of certain states. Additionally, we use high explosive charges for perforating casing and formations, and we use various explosive cutters to assist in wellbore cleanout. Such operations are regulated by the U.S. Department of Justice, Bureau of Alcohol, Tobacco, Firearms, and Explosives and require us to obtain licenses or other approvals for the use of densitometers as well as explosive charges. We have obtained these licenses and approvals when necessary and believe that we are in substantial compliance with these federal requirements.

Among the services we provide, we operate as a motor carrier for the transportation of our own equipment and therefore are subject to regulation by the U.S. Department of Transportation and by various state agencies. These regulatory authorities exercise broad powers, governing activities such as the authorization to engage in motor carrier operations and regulatory safety. There are additional regulations specifically relating to the trucking industry, including testing and specification of equipment and product handling requirements. The trucking industry is subject to possible regulatory and legislative changes that may affect the economics of the industry by requiring changes in operating practices or by changing the demand for common or contract carrier services or the cost of providing truckload services. Some of these possible changes include increasingly stringent environmental regulations, changes in the hours of service regulations which govern the amount of time a driver may drive in any specific period, onboard black box recorder devices or limits on vehicle weight and size.

Interstate motor carrier operations are subject to safety requirements prescribed by the U.S. Department of Transportation. To a large degree, intrastate motor carrier operations are subject to state safety regulations that mirror federal regulations. Such matters as weight and dimension of equipment are also subject to federal and state regulations.

From time to time, various legislative proposals are introduced, including proposals to increase federal, state, or local taxes, including taxes on motor fuels, which may increase our costs or adversely impact the recruitment of drivers. We cannot predict whether, or in what form, any increase in such taxes applicable to us will be enacted.

Federal and state legislative and regulatory initiatives related to hydraulic fracturing could result in operating restrictions or delays in the completion of oil and natural gas wells that may reduce demand for our drilling and well servicing activities and could adversely affect our financial position, results of operations and cash flows.

Hydraulic fracturing is a commonly used process that involves injection of water, sand, and a minor amount of certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore. Federal agencies have adopted new rules, such as the Bureau of Land Management's (BLM) hydraulic fracturing rule finalized in March 2015, that impose additional requirements on the practice of hydraulic fracturing. In October 2016, the BLM updated its rules to restrict flaring associated with the development of oil and natural gas on public lands, including through hydraulic fracturing. Additional federal regulations may also be developed. Several states are considering legislation to regulate hydraulic fracturing practices that could impose more stringent permitting, transparency, and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. Hydraulic fracturing of wells and subsurface water disposal are also under public and governmental scrutiny due to concerns regarding potential environmental and physical impacts, including groundwater and drinking water impacts, as well as whether such activities may cause earthquakes.

The federal Energy Policy Act of 2005 amended the Underground Injection Control provisions of the federal Safe Drinking Water Act (SDWA) to exclude certain hydraulic fracturing practices from the definition of "underground injection." The EPA has asserted regulatory authority over certain hydraulic fracturing activities involving diesel fuel and has developed guidance relating to such practices. In addition, repeal of the SDWA exclusion of hydraulic fracturing has been advocated by certain advocacy organizations and others in the public. Congress has from time to time considered legislation to repeal the exemption for hydraulic fracturing from the SDWA, which would have the effect of allowing the EPA to promulgate new regulations and permitting requirements for hydraulic fracturing, and to require the disclosure of the chemical constituents of hydraulic fracturing fluids to a regulatory agency, which would make the information public via the Internet. For example, in May 2014, the EPA responded to a petition by environmental groups by issuing an Advanced Notice of Proposed Rulemaking to solicit input regarding whether the agency should require manufacturers and processors of hydraulic fracturing chemicals to report composition and usage of such chemicals and and to disclose associated health and safety studies.

Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having completed a multi-year study of the potential environmental impacts of hydraulic fracturing. The Final Report issued by the EPA in December 2016, concluded that hydraulic fracturing activities can impact drinking water resources under some circumstances and identified conditions under which impacts can be more frequent or severe. In addition, in April 2012, the EPA issued the first federal air standards for natural gas wells that are hydraulically fractured, which will require operators to significantly reduce VOC emissions through the use of "green completions" to capture natural gas that would otherwise escape into the air. These new rules address emissions of various pollutants frequently associated with oil and natural gas production and processing activities by, among other things, requiring new or reworked hydraulically-fractured gas wells to control emissions through flaring until 2015, after which reduced emission (or "green") completions must be used. The rules also establish specific new requirements, which were effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, gas processing plants, and certain other equipment. On September 23, 2013, the EPA published amendments to the rule which would, among other things, provide additional time for recently constructed, modified or reconstructed storage tanks to install emission controls. On December 19, 2014, the EPA published a final rule clarifying certain aspects of the new rules. On May 12, 2016, the EPA finalized a rule to reduce methane (a greenhouse gas) and VOC emissions from oil and gas operations. It is also possible that the EPA will further amend its oil and gas regulations. In this regard, in September 2016, the EPA published notice that it would begin to collect information on methane emissions from 15,000 oil and gas operators relating to almost 700,000 oil and gas facilities. These rules may require a number of modifications to our clients' and our own operations, including the installation of new equipment to control emissions. Compliance with such rules could result in additional costs for us and our clients, including increased capital expenditures and operating costs, which may adversely impact our cash flows and results of operations.

The EPA has also developed effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities to publicly owned treatment works (POTW). The agency's final regulations, published on June 28, 2016, prohibited any discharge of wastewater pollutants from onshore unconventional oil and gas extraction facilities to a POTW. The EPA will also be assessing whether oil and gas wastes should continue to be exempt from being considered hazardous waste under the federal Resource Conservation and Recovery Act, pursuant to a Consent Decree with environmental groups approved in federal court on December 28, 2016. The U.S. Department of the Interior has also finalized regulations relating to the use of hydraulic fracturing techniques on public lands and disclosure of fracturing fluid constituents (i.e. the BLM's hydraulic fracturing rule issued in March 2015) and has conducted hearings on a rule to reduce flaring and venting associated with oil and gas operations on public lands. A final version of the flaring and venting rule was issued in October 2016.

In addition, some states and localities have adopted, and others are considering adopting, regulations or ordinances that could restrict hydraulic fracturing in certain circumstances, that would require, with some exceptions, disclosure of constituents of hydraulic fracturing fluids, or that would impose higher taxes, fees or royalties on natural gas production. Moreover, public debate over hydraulic fracturing and shale gas production continued to see strong public opposition, and has resulted in delays of well permits in some areas.

On June 30, 2014, the State of New York's Court of Appeals upheld the right of individual municipalities in the State of New York to ban hydraulic fracturing using zoning restrictions. In December 2014, New York State Governor Cuomo announced that hydraulic fracturing will be permanently banned in the state. Similarly situated municipalities in other states may seek to ban or restrict resource extraction operations within their borders using zoning restrictions, which could adversely affect the ability of resource extraction enterprises to operate in certain parts of the country, and thus adversely affect demand for our services, which may in turn adversely affect our future results of operations.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale plays, incurred by our clients. The adoption of any federal, state or local laws or the implementation of regulations or ordinances restricting or increasing the costs of hydraulic fracturing could cause a decrease in the completion of new oil and natural gas wells and an associated decrease in demand for our drilling and well servicing activities, any or all of which could adversely affect our financial position, results of operations and cash flows.

Our operations are subject to the risk of cyber attacks that could have a material adverse effect on our consolidated results of operations and consolidated financial condition.

Our information technology systems are subject to possible breaches and other threats that could cause us harm. If our systems for protecting against cyber security risks prove not to be sufficient, we could be adversely affected by, among other things, loss or damage of intellectual property, proprietary information, customer or personnel data; interruption of business operations; or additional costs to prevent, respond to, or mitigate cyber security attacks. These risks could have a material adverse effect on our business, financial condition and result of operations.

Risks Relating to Our Capitalization and Organizational Documents

We do not intend to pay dividends on our common stock in the foreseeable future, and therefore only appreciation of the price of our common stock will provide a return to our shareholders.

We have not paid or declared any dividends on our common stock and currently intend to retain any earnings to fund our working capital needs, reduce debt and fund growth opportunities. Any future dividends will be at the discretion of our board of directors after taking into account various factors it deems relevant, including our financial condition and performance, cash needs, income tax consequences and restrictions imposed by the Texas Business Organizations Code and other applicable laws and by our Revolving Credit Facility and Senior Notes. Our debt arrangements include provisions that generally prohibit us from paying dividends on our capital stock, including our common stock.

We may issue preferred stock whose terms could adversely affect the voting power or value of our common stock.

Our articles of incorporation authorize us to issue, without the approval of our shareholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock.

Provisions in our organizational documents could delay or prevent a change in control of our company even if that change would be beneficial to our shareholders.

The existence of some provisions in our organizational documents could delay or prevent a change in control of our company even if that change would be beneficial to our shareholders. Our articles of incorporation and bylaws contain provisions that may make acquiring control of our company difficult, including:

- provisions regulating the ability of our shareholders to nominate candidates for election as directors or to bring matters for action at annual meetings of our shareholders;
- limitations on the ability of our shareholders to call a special meeting and act by written consent;
- provisions dividing our board of directors into three classes elected for staggered terms; and
- the authorization given to our board of directors to issue and set the terms of preferred stock.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

For a description of our significant properties, see “Business—General” and “Business—Facilities” in Item 1 of this report. We believe that we have sufficient properties to conduct our operations and that our significant properties are suitable for their intended use.

Item 3. Legal Proceedings

Due to the nature of our business, we are, from time to time, involved in routine litigation or subject to disputes or claims related to our business activities, including workers’ compensation claims and employment-related disputes. In the opinion of our management, none of the pending litigation, disputes or claims against us will have a material adverse effect on our financial condition or results of operations.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities

As of January 31, 2017, 77,278,844 shares of our common stock were outstanding, held by 326 shareholders of record. The number of record holders does not necessarily bear any relationship to the number of beneficial owners of our common stock.

Our common stock trades on the New York Stock Exchange under the symbol "PES." The following table sets forth, for each of the periods indicated, the high and low sales prices per share:

	Low	High
Fiscal year ended December 31, 2016		
First Quarter	$ 0.95	$ 2.46
Second Quarter	1.98	5.05
Third Quarter	2.64	4.89
Fourth Quarter	3.35	7.15
Fiscal year ended December 31, 2015		
First Quarter	$ 3.67	$ 6.53
Second Quarter	5.04	8.69
Third Quarter	1.91	6.36
Fourth Quarter	2.02	3.49

The last reported sales price for our common stock on the New York Stock Exchange on January 31, 2017 was $6.30 per share.

We have not paid or declared any dividends on our common stock and currently intend to retain earnings to fund our working capital needs and growth opportunities. Any future dividends will be at the discretion of our board of directors after taking into account various factors it deems relevant, including our financial condition and performance, cash needs, income tax consequences and the restrictions imposed by the Texas Business Organizations Code and other applicable laws and our Revolving Credit Facility and Senior Notes. Our debt arrangements include provisions that generally prohibit us from paying dividends on our capital stock.

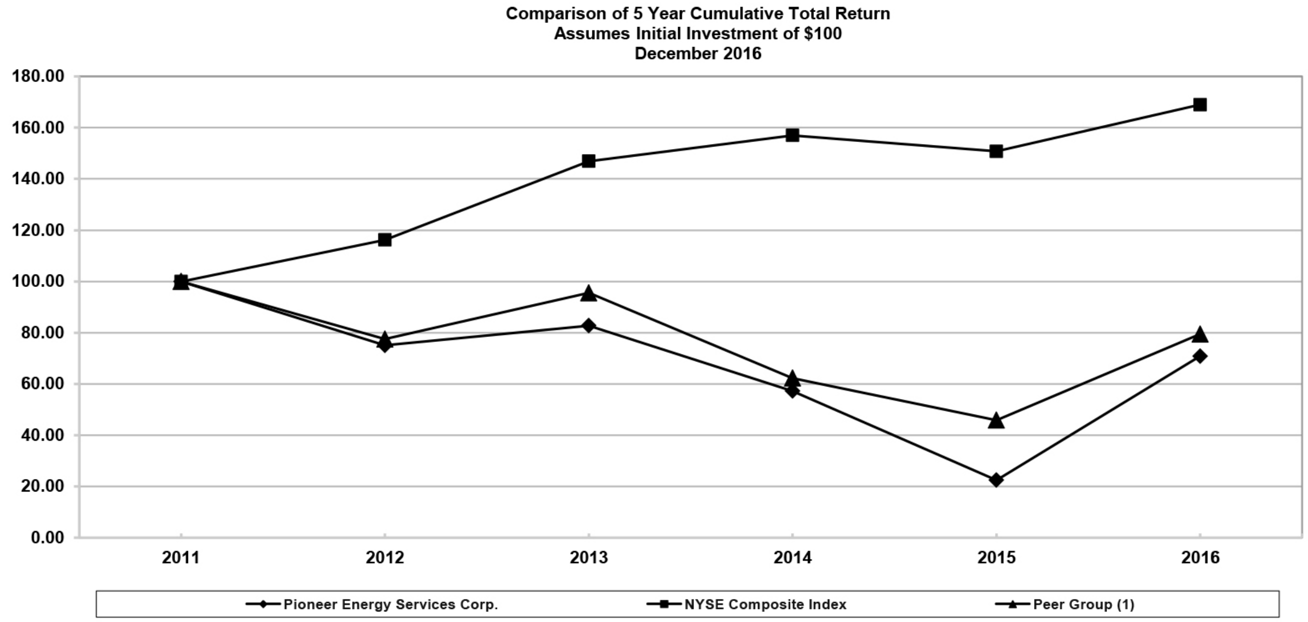
We did not make any unregistered sales of equity securities during the quarter ended December 31, 2016. No shares of our common stock were purchased by or on behalf of our company or any affiliated purchaser during the quarter ended December 31, 2016.

Performance Graph

The following graph compares, for the periods from December 31, 2011 to December 31, 2016, the cumulative total shareholder return on our common stock with the cumulative total return on the companies that comprise the NYSE Composite Index and a peer group index that includes four companies that provide contract drilling services and/or production services.

The companies that comprise the peer group index are Patterson-UTI Energy, Inc., Nabors Industries Ltd., Basic Energy Services, Inc., Key Energy Services and Precision Drilling Corporation. Two of the companies in the peer group, Basic Energy Services, Inc. and Key Energy Services, filed for bankruptcy protection in 2016 under Chapter 11 of the United States Bankruptcy Code.

The comparison assumes that $100 was invested on December 31, 2011 in our common stock, the companies that compose the NYSE Composite Index and the peer group index, and further assumes all dividends were reinvested.



(1) Two of the companies in the peer group, Basic Energy Services and Key Energy Services, filed for bankruptcy protection in 2016 under Chapter 11 of the United States Bankruptcy Code.

Item 6. Selected Financial Data

The following information derives from our audited financial statements. This information should be reviewed in conjunction with “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in Item 7 of this report and the financial statements and related notes this report contains.

	Year ended December 31,				
	2016 (1)	2015 (2)	2014 (3)	2013 (4)	2012
	(In thousands, except per share amounts)				
Statement of Operations Data:					
Revenues	$ 277,076	$ 540,778	$1,055,223	$ 960,186	$ 919,443
Income (loss) from operations	(113,448)	(166,700)	23,984	(6,229)	81,811
Income (loss) before income taxes	(139,123)	(192,719)	(49,322)	(55,778)	46,386
Net earnings (loss) applicable to common shareholders	(128,391)	(155,140)	(38,018)	(35,932)	30,032
Earnings (loss) per common share-basic	$ (1.96)	$ (2.41)	$ (0.60)	$ (0.58)	$ 0.49
Earnings (loss) per common share-diluted	$ (1.96)	$ (2.41)	$ (0.60)	$ (0.58)	$ 0.48
Other Financial Data:					
Net cash provided by operating activities	$ 5,131	$ 142,719	$ 233,041	$ 174,580	$ 199,366
Net cash used in investing activities	(24,767)	(101,656)	(151,918)	(150,676)	(361,231)
Net cash provided by (used in) financing activities	15,670	(61,827)	(73,584)	(20,252)	99,401
Capital expenditures	32,556	142,907	188,121	125,420	379,272

	As of December 31,				
	2016	2015	2014	2013	2012
	(In thousands)				
Balance Sheet Data:					
Working capital	$ 47,994	$ 45,226	$ 121,882	$ 118,547	$ 62,236
Property and equipment, net	584,080	702,585	856,541	937,657	1,014,340
Long-term debt, excluding current portion and debt issuance costs	346,000	395,000	455,053	499,666	518,725
Shareholders’ equity	281,398	342,643	495,064	518,433	547,680
Total assets	700,102	821,975	1,171,589	1,229,623	1,339,776

(1) The statement of operations and other financial data for the year ended December 31, 2016 reflect the impact of impairment charges on our property and equipment of $12.8 million.

(2) The statement of operations and other financial data for the year ended December 31, 2015 reflect the impact of impairment charges on our property and equipment of $114.8 million and an intangible asset impairment charge of $14.3 million.

(3) The statement of operations and other financial data for the year ended December 31, 2014 reflect the impact of impairment charges on our property and equipment of $73.0 million.

(4) The statement of operations and other financial data for the year ended December 31, 2013 reflect the impact of a goodwill impairment charge of $41.7 million and an intangible asset impairment charge of $3.1 million.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Statements we make in the following discussion that express a belief, expectation or intention, as well as those that are not historical fact, are forward-looking statements that are subject to risks, uncertainties and assumptions. Our actual results, performance or achievements, or industry results, could differ materially from those we express in the following discussion as a result of a variety of factors, including general economic and business conditions and industry trends, levels and volatility of oil and gas prices, the continued demand for drilling services or production services in the geographic areas where we operate, decisions about exploration and development projects to be made by oil and gas exploration and production companies, the highly competitive nature of our business, technological advancements and trends in our industry and improvements in our competitors' equipment, the loss of one or more of our major clients or a decrease in their demand for our services, future compliance with covenants under our senior secured revolving credit facility and our senior notes, operating hazards inherent in our operations, the supply of marketable drilling rigs, well servicing rigs, coiled tubing and wireline units within the industry, the continued availability of drilling rig, well servicing rig, coiled tubing and wireline unit components, the continued availability of qualified personnel, the success or failure of our acquisition strategy, including our ability to finance acquisitions, manage growth and effectively integrate acquisitions, the political, economic, regulatory and other uncertainties encountered by our operations, and changes in, or our failure or inability to comply with, governmental regulations, including those relating to the environment. We have discussed many of these factors in more detail elsewhere in this report, including under the headings "Special Note Regarding Forward-Looking Statements" in the Introductory Note to Part I and "Risk Factors" in Item 1A. These factors are not necessarily all the important factors that could affect us. Other unpredictable or unknown factors could also have material adverse effects on actual results of matters that are the subject of our forward-looking statements. All forward-looking statements speak only as of the date on which they are made and we undertake no obligation to publicly update or revise any forward-looking statements whether as a result of new information, future events or otherwise. We advise our shareholders that they should (1) recognize that important factors not referred to above could affect the accuracy of our forward-looking statements and (2) use caution and common sense when considering our forward-looking statements.

Company Overview

Pioneer Energy Services Corp. provides land-based drilling services and production services to a diverse group of independent and large oil and gas exploration and production companies in the United States and internationally in Colombia. We also provide two of our services (coiled tubing and wireline services) offshore in the Gulf of Mexico. Drilling services and production services are fundamental to establishing and maintaining the flow of oil and natural gas throughout the productive life of a well and enable us to meet multiple needs of our clients.

Business Segments

We conduct our operations through two operating segments: our Drilling Services Segment and our Production Services Segment. Financial information about our operating segments is included in Note 10, *Segment Information*, of the Notes to Consolidated Financial Statements, included in Part II, Item 8, *Financial Statements and Supplementary Data*, of this Annual Report on Form 10-K.

- *Drilling Services Segment*—From 1999 to 2011, we significantly expanded our fleet through acquisitions and the construction of new drilling rigs. As our industry changed with the evolution of shale drilling, we began a transformation process in 2011, by selectively disposing of our older, less capable rigs, while we continued to invest in our rig building program to construct more technologically advanced, pad-optimal rigs to meet the changing needs of our clients.

  As of December 31, 2016, our drilling rig fleet is 100% pad-capable. We offer the latest advancements in pad drilling with our fleet of 16 AC rigs in the US and eight SCR rigs in Colombia, all of which have 1,500 horsepower or greater drawworks. The removal of older, less capable rigs from our fleet and the recent investments in the construction of new drilling rigs has transformed our fleet into a highly capable, pad optimal fleet focused on the horizontal drilling market. We believe this positions us to compete well, grow our presence in the significant shale basins in the US, and improve profitability as the recovery of our industry continues.

In addition to our drilling rigs, we provide the drilling crews and most of the ancillary equipment needed to operate our drilling rigs. We obtain our contracts for drilling oil and natural gas wells either through competitive bidding or through direct negotiations with existing or potential clients. Our drilling contracts generally provide for compensation on a daywork basis, and sometimes on a turnkey basis. Contract terms generally depend on the complexity and risk of operations, the on-site drilling conditions, the type of equipment used, and the anticipated duration of the work to be performed. The drilling rigs in our fleet are currently assigned to the following divisions:

Drilling Division	Rig Count
South Texas	1
West Texas	7
North Dakota	2
Appalachia	6
Colombia	8
	24

- *Production Services Segment*— In 2008, we acquired two production services companies which significantly expanded our service offerings to include well servicing and wireline services. At the end of 2011, we acquired a coiled tubing services business to further expand our production services offerings. Since the acquisitions of these businesses, we continued to invest in their organic growth and significantly expanded all our production services fleets. However, we temporarily suspended organic growth of our production services fleets during the recent downturn, and continue to selectively update our fleets.

  Our Production Services Segment provides a range of services to a diverse group of exploration and production companies, with our operations concentrated in the major United States onshore oil and gas producing regions in the Mid-Continent and Rocky Mountain states and in the Gulf Coast, both onshore and offshore. The primary production services we offer are the following:

  - Well Servicing. A range of services are required in order to establish production in newly-drilled wells and to maintain production over the useful lives of active wells. We use our well servicing rig fleet to provide these necessary services, including the completion of newly-drilled wells, maintenance and workover of active wells, and plugging and abandonment of wells at the end of their useful lives. As of December 31, 2016, we have a fleet of 114 rigs with 550 horsepower and 11 rigs with 600 horsepower with operations in 10 locations, mostly in the Gulf Coast states, as well as in Arkansas and North Dakota.

  - Wireline Services. Oil and gas exploration and production companies require wireline services to better understand the reservoirs they are drilling or producing, and use logging services to accurately characterize reservoir rocks and fluids. To complete a cased-hole well, the production casing must be perforated to establish a flow path between the reservoir and the wellbore. We use our fleet of wireline units to provide these important logging and perforating services in addition to a range of other mechanical services that are needed in order to place equipment in or retrieve equipment or debris from the wellbore, install bridge plugs and control pressure. As of December 31, 2016, we have a fleet of 114 wireline units in 17 operating locations in the Gulf Coast, Mid-Continent and Rocky Mountain states.

  - Coiled Tubing Services. Coiled tubing is also an important element of the well servicing industry that allows operators to continue production during service operations on a well under pressure without shutting in the well, thereby reducing the risk of formation damage. Coiled tubing services involve the use of a continuous metal pipe spooled on a large reel for oil and natural gas well applications, such as wellbore clean-outs, nitrogen jet lifts, through-tubing fishing, formation stimulation utilizing acid, chemical treatments and fracturing. Coiled tubing is also used for a number of horizontal well applications such as milling temporary plugs between frac stages. As of December 31, 2016, our coiled tubing business consists of 12 onshore and five offshore coiled tubing units which are deployed through three locations in Texas and Louisiana.

Market Conditions in Our Industry

Industry Overview — Demand for oilfield services offered by our industry is a function of our clients' willingness to make operating expenditures and capital expenditures to explore for, develop and produce hydrocarbons, which is primarily driven by current and expected oil and natural gas prices.

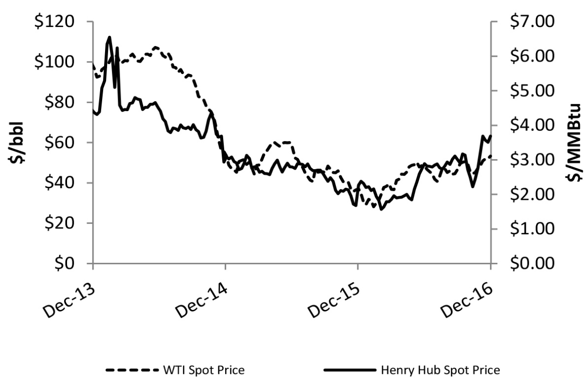
Our business is influenced substantially by both operating and capital expenditures by exploration and production companies. Exploration and production spending is generally categorized as either a capital expenditure or an operating expenditure. Capital expenditures by exploration and production companies for the drilling of exploratory wells or new wells in proven areas are more directly influenced by current and expected oil and natural gas prices and generally reflect the volatility of commodity prices. In contrast, operating expenditures by exploration and production companies for the maintenance of existing wells, for which a range of production services are required in order to maintain production, are relatively more stable and predictable.

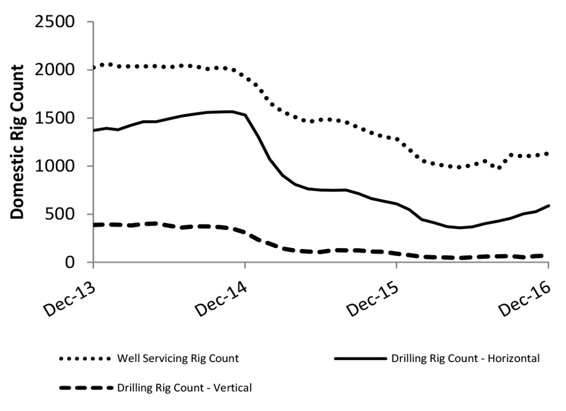
Drilling and production services have historically trended similarly in response to fluctuations in commodity prices. However, because exploration and production companies often adjust their budgets for exploratory drilling first in response to a shift in commodity prices, the demand for drilling services is generally impacted first and to a greater extent than the demand for production services which is more dependent on ongoing expenditures that are necessary to maintain production. Additionally, within the range of production services businesses, those that derive more revenue from production related activity, as opposed to completion of a new well, tend to be less affected by fluctuations in commodity prices and temporary reductions in industry activity.

However, in a severe downturn that is prolonged, both operating and capital expenditures are significantly reduced, and the demand for all our service offerings is significantly impacted.

For additional information concerning the effects of the volatility in oil and gas prices and the effects of technological advancements and trends in our industry, see Item 1A – "Risk Factors" in Part I of this Annual Report on Form 10-K.

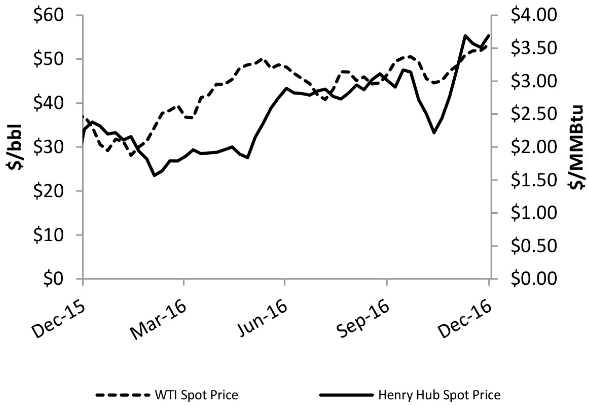
Market Conditions — Since late 2014, oil prices have declined significantly resulting in a downturn in our industry, affecting both drilling and production services. The trends in spot prices of WTI crude oil and Henry Hub natural gas, and the resulting trends in domestic land rig counts (per Baker Hughes) and domestic well servicing rig counts (per Guiberson/ Association of Energy Service Companies) over the last three years are illustrated in the graphs below.

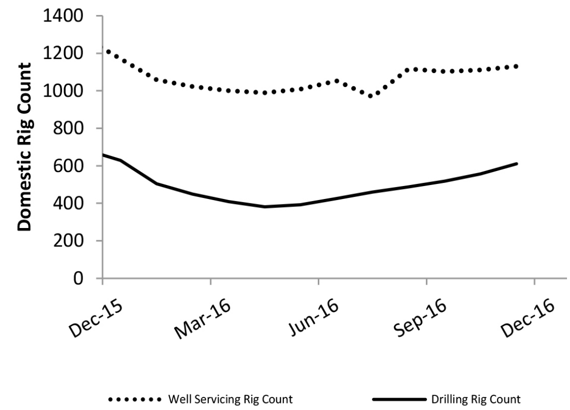




At the end of 2016, the spot prices of WTI crude oil and Henry Hub natural gas were down by 50% and 44%, respectively, as compared to the peak 2014 prices. During this same period, the horizontal and vertical drilling rig counts in the United States dropped by 62% and 83%, respectively, while the domestic well servicing rig count decreased by 46%. Despite the modest recovery in commodity prices during recent months, commodity prices have remained low as compared to the price levels in 2014 and continue to depress activity and pricing for all our service offerings.

The trends in commodity pricing and domestic rig counts over the last 12 months are illustrated below:





Our well servicing and coiled tubing utilization rates for the quarter ended December 31, 2016 were 40% and 21%, respectively, based on total fleet count, and we are currently actively marketing approximately 65% of our wireline fleet. These utilization rates are roughly flat with those of the prior fiscal quarter due to recent stability in commodity prices, while the number of wireline jobs completed during the quarter ended December 31, 2016 increased by 10%, as compared to the prior fiscal quarter.

In drilling, all rig classes were severely impacted by the industry downturn. As a result, term contracts for 19 of our drilling rigs were terminated early, including three that were terminated in early 2016. However, with the moderate improvement in commodity prices in late 2016, several of our AC rigs were subsequently placed on new spot contracts and as of December 31, 2016, the current utilization of our AC rig fleet is 81%. Of the eight rigs in Colombia, four of the drilling rigs in Colombia are earning revenues, three of which are under term contracts. We are actively marketing our idle drilling rigs in Colombia to various operators and we are evaluating other options, including the possibility of the sale of some or all of our assets in Colombia.

As of December 31, 2016, 17 of our drilling rigs are currently under contract, which if not canceled or renewed prior to the end of their terms, will expire as follows:

			Term Contract Expiration by Period				
	Spot Market Contracts	Total Term Contracts	Within 6 Months	6 Months to 1 Year	1 Year to 18 Months	18 Months to 2 Years	2 to 4 Years
Domestic rigs	4	9	2	3	1	3	—
Colombia rigs	1	3	2	—	—	1	—
	5	12	4	3	1	4	—

Our clients significantly reduced both their operating and capital expenditures during 2015 and 2016, but increases are expected for 2017. Although we expect a highly competitive environment in 2017, we expect the recent modest recovery in commodity prices, if it continues, to further increase industry activity and pricing levels and we believe our high-quality equipment and services are well positioned to compete.

Liquidity and Capital Resources

Sources of Capital Resources

Our principal liquidity requirements are for working capital needs, debt service and capital expenditures. Our principal sources of liquidity consist of cash and cash equivalents (which equaled $10.2 million as of December 31, 2016), cash generated from operations, proceeds from sales of certain non-strategic assets and the unused portion of our senior secured revolving credit facility (the "Revolving Credit Facility").

On May 2015, we filed a registration statement that permits us to sell equity or debt in one or more offerings up to a total dollar amount of $300 million. In December 2016, we sold 12,075,000 shares of common stock in a public offering, which resulted in proceeds of approximately $65.4 million, net of underwriting discounts and offering expenses, under the shelf registration statement. As of December 31, 2016, $234.6 million under the shelf registration statement is available for equity or debt offerings, subject to the limitations imposed by our Revolving Credit Facility and Senior Notes, as well as our Restated Articles of Incorporation which currently limits our issuance of common stock to 100 million shares. In the future, we may consider equity and/or debt offerings, as appropriate, to meet our liquidity needs.

In 2014, we issued $300 million of unregistered senior notes with a coupon interest rate of 6.125% that are due in 2022 (the "Senior Notes"). In order to reduce our overall interest expense and lengthen the overall maturity of our senior indebtedness, during 2014, we redeemed all of our then outstanding $425 million of unregistered senior notes with a coupon interest rate of 9.875% that were issued in 2010 and 2011 and were set to mature in 2018, funded primarily by proceeds from the issuance of Senior Notes in 2014 and additional borrowings under our Revolving Credit Facility, as well as some cash on hand.

Our Revolving Credit Facility, as most recently amended on June 30, 2016, provides for a senior secured revolving credit facility, with sub-limits for letters of credit and swing-line loans, of up to a current aggregate commitment amount of $150 million, subject to availability under a borrowing base comprised of certain eligible cash, certain eligible receivables, certain eligible inventory, and certain eligible equipment of ours and certain of our subsidiaries, all of which matures in March 2019.

In accordance with the Revolving Credit Facility terms, all of the net proceeds from our public equity offering in December 2016 were applied to reduce the outstanding borrowing balance, and the total commitment amount available was reduced from $175 million to $150 million. As of January 31, 2017, we had $49.7 million outstanding under our Revolving Credit Facility and $11.8 million in committed letters of credit, which resulted in borrowing availability of $88.5 million under our Revolving Credit Facility. Borrowings under the Revolving Credit Facility are available for selective acquisitions, working capital and other general corporate purposes. There are no limitations on our ability to access the borrowing capacity provided there is no default, all representations and warranties are true and correct, and compliance with financial covenants under the Revolving Credit Facility is maintained. Additional information regarding these covenants is provided in the *Debt Requirements* section below.

At December 31, 2016, we were in compliance with our financial covenants under the Revolving Credit Facility. However, continued compliance with our covenants is largely dependent on our ability to generate sufficient levels of EBITDA, as defined in the Revolving Credit Facility, and/or reduce our debt levels. If we expect our future operating results to decline to a level that indicates we may become unable to comply with the financial covenants in the Revolving Credit Facility, we may seek to amend such provisions to remain in compliance or we may pursue other capital sources, such as equity or other debt transactions. Although we believe that our bank lenders are well-secured under the terms of our Revolving Credit Facility, there is no assurance that the bank lenders will waive or amend our financial covenants under the Revolving Credit Facility.

We currently expect that cash and cash equivalents, cash generated from operations, proceeds from sales of certain non-strategic assets and available borrowings under our Revolving Credit Facility are adequate to cover our liquidity requirements for at least the next 12 months.

Uses of Capital Resources

For the years ended December 31, 2016 and 2015, our primary uses of capital resources were for property and equipment additions, which consisted of the following (amounts in thousands):

	Year ended December 31, 2016	Year ended December 31, 2015
Drilling Services Segment:		
Routine	$ 4,948	$ 13,183
Discretionary	2,454	7,041
Fleet additions	12,464	107,030
Total Drilling Services Segment	19,866	127,254
Production Services Segment:		
Routine	8,259	11,325
Discretionary	4,256	6,018
Fleet additions	—	15,018
Total Production Services Segment	12,515	32,361
Net cash used for purchases of property and equipment	32,381	159,615
Net impact of accruals	175	(16,708)
Total capital expenditures	$ 32,556	$ 142,907

In 2016, we lowered our capital expenditures by 77% in response to the downturn, limiting our capital spending to primarily routine expenditures to maintain our equipment and deferring discretionary upgrades and additions except those that we committed to in 2014 before the market slowdown. Capital expenditures during 2015 primarily related to our five drilling rigs which began construction during 2014 and were completed in 2015, and included $3.0 million of interest costs capitalized during the construction period. Additionally, during 2015, we acquired eight wireline units and nine well servicing rigs that were ordered in 2014. In late 2016, we committed to trade in 20 of our older 550 horsepower well servicing rigs for 20 new-model rigs to be delivered in the first quarter of 2017 and we committed to purchase four new wireline units to be delivered beginning in March 2017.

Currently, we expect to spend approximately $45 million on capital expenditures during 2017, which we expect will be allocated approximately 40% for our Drilling Services Segment and approximately 60% for our Production Services Segment. Our total planned capital expenditures include approximately $20 million for fleet upgrades and additions, including the upgrade of one domestic drilling rig, the exchange of 20 well servicing rigs and the addition of four new wireline units, and other routine capital expenditures. Actual capital expenditures may vary depending on the climate of our industry and any resulting increase or decrease in activity levels, the timing of commitments and payments, and the level of rig build and other expansion opportunities that meet our strategic and return on capital employed criteria. We expect to fund the capital expenditures in 2017 from operating cash flow in excess of our working capital requirements, proceeds from sales of certain non-strategic assets and from borrowings under our Revolving Credit Facility, if necessary.

Working Capital

Our working capital was $48.0 million at December 31, 2016, compared to $45.2 million at December 31, 2015. Our current ratio, which we calculate by dividing current assets by current liabilities, was 1.7 at December 31, 2016, compared to 1.6 at December 31, 2015.

Our operations have historically generated cash flows sufficient to meet our requirements for debt service and normal capital expenditures. However, our working capital requirements generally increase during periods when rig construction projects are in progress, during periods of expansion in our production services business, or when higher percentages of our drilling contracts are turnkey contracts, at which times we have been more likely to access capital through equity or debt financing. During periods of sustained low activity and pricing, we may access additional capital through the use of available funds under our Revolving Credit Facility.

The changes in the components of our working capital were as follows (amounts in thousands):

	December 31, 2016	December 31, 2015	Change
Cash and cash equivalents	$ 10,194	$ 14,160	$ (3,966)
Receivables:			
Trade, net of allowance for doubtful accounts	38,764	47,577	(8,813)
Unbilled receivables	7,417	13,624	(6,207)
Insurance recoveries	17,003	14,556	2,447
Other receivables	8,939	4,059	4,880
Inventory	9,660	9,262	398
Assets held for sale	15,093	4,619	10,474
Prepaid expenses and other current assets	6,926	7,411	(485)
Total current assets	113,996	115,268	(1,272)
Accounts payable	19,208	16,951	2,257
Deferred revenues	1,449	6,222	(4,773)
Accrued expenses:			
Payroll and related employee costs	14,813	13,859	954
Insurance premiums and deductibles	6,446	8,087	(1,641)
Insurance claims and settlements	13,667	14,556	(889)
Interest	5,395	5,508	(113)
Other	5,024	4,859	165
Total current liabilities	66,002	70,042	(4,040)
Working capital	$ 47,994	$ 45,226	$ 2,768

The change in our cash and cash equivalents during the year ended December 31, 2016 is primarily a result of net cash used in investing activities of $24.8 million which was mostly offset by cash provided by financing activities of $15.7 million. Our net cash used in investing activities was primarily for the purchases of property and equipment of $32.4 million and partially offset by $7.6 million of proceeds from the sales of assets. Our net cash provided by financing activities is primarily due to proceeds from borrowings under the Revolving Credit Facility of $16.4 million, net of repayments. In December, we issued equity which resulted in net proceeds of $65.4 million, which were applied to reduce the level of debt outstanding under the Revolving Credit Facility.

The net decrease in our total trade and unbilled receivables from December 31, 2015 to 2016 is primarily the result of the decrease in consolidated revenues of $33.0 million, or 32%, for the quarter ended December 31, 2016 as compared to the quarter ended December 31, 2015. Our trade receivables generally turn over within 90 days.

The increase in our insurance recoveries receivables from December 31, 2015 to 2016 is attributable to an insurance claim receivable of $3.3 million, which was received in January 2017, for a drilling rig that was damaged during the second quarter of 2016. The decrease in our insurance claims and settlements from December 31, 2015 to 2016 is primarily due to a decrease in our insurance company's reserve for workers' compensation claims in excess of our deductibles.

The increase in other receivables from December 31, 2015 to 2016 is primarily due to a $6.3 million receivable arising from the sale of two drilling rigs in December 2016, for which we received the proceeds in January 2017, which was partly offset by a decrease in net income tax receivables for our Colombian operations.

As of December 31, 2016, our consolidated balance sheet reflects $15.1 million of assets held for sale, which primarily represents the fair value of six domestic mechanical and SCR drilling rigs and drilling equipment, 13 wireline units, 20 older well servicing rigs that will be traded in for 20 new-model rigs in the first quarter of 2017, and certain coiled tubing equipment. Our assets held for sale as of December 31, 2015 primarily consisted of four domestic drilling rigs.

Our accounts payable generally turn over within 90 days. Excluding the effect of employee related costs, which do not impact accounts payable, operating costs were roughly flat for the quarter ended December 31, 2016 as compared to the quarter ended December 31, 2015. However, our accounts payable increased from December 31, 2015 to 2016 as a result of increased costs associated with the recent increase in activity, including expenditures associated with the deployment of three international rigs and one domestic rig that mobilized in the fourth quarter.

The decrease in deferred revenues from December 31, 2015 to 2016 is primarily related to deferred revenue for early termination payments on drilling contracts that ended during 2016. Revenues derived from rigs placed on standby or from the early termination of term drilling contracts are deferred and recognized as the amounts become fixed or determinable, over the remainder of the original term or when the rig is sold. (See *Critical Accounting Policies and Estimates* section for more detail.) All of the contracts that were early terminated have expired as of December 31, 2016 and all the associated revenue from the early terminations has been recognized. Deferred revenues as of December 31, 2016 relate to payments received for the mobilization of our domestic and Colombia drilling rigs, which are deferred and recognized on a straight line basis over the related contract term.

The increase in payroll and employee related accruals from December 31, 2015 to 2016 is primarily due to a $0.6 million increase in our accrual for annual bonuses, primarily because the annual bonuses earned in 2015 were reduced by 50% as a part of our cost cutting efforts in 2015.

The decrease in insurance premiums and deductibles from December 31, 2015 to 2016 is primarily due to a decrease in our worker's compensation and health insurance costs resulting from a decrease in our estimated liability for the deductibles under these policies, partly as a result of reduced headcount.

Long-term Debt and Other Contractual Obligations

The following table includes information about the amount and timing of our contractual obligations at December 31, 2016 (amounts in thousands):

	Payments Due by Period				
Contractual Obligations	**Total**	**Within 1 Year**	**2 to 3 Years**	**4 to 5 Years**	**Beyond 5 Years**
Debt	$ 346,000	$ —	$ 46,000	$ —	$ 300,000
Interest on debt	108,901	21,248	41,715	36,750	9,188
Purchase commitments	17,401	17,401	—	—	—
Operating leases	10,280	3,427	4,872	1,865	116
Incentive compensation	16,582	4,543	12,039	—	—
	$ 499,164	$ 46,619	$ 104,626	$ 38,615	$ 309,304

Debt obligations at December 31, 2016 consist of $300 million of principal amount outstanding under our Senior Notes which mature on March 15, 2022 and $46.0 million outstanding under our Revolving Credit Facility which is due at maturity on March 31, 2019. However, we may make principal payments to reduce the outstanding balance under our Revolving Credit Facility prior to maturity when cash and working capital is sufficient.

Interest payment obligations on our Revolving Credit Facility are estimated based on (1) the 6.3% interest rate that was in effect at December 31, 2016, and (2) the outstanding balance of $46.0 million at December 31, 2016 to be paid at maturity on March 31, 2019. Interest payment obligations on our Senior Notes are calculated based on the coupon interest rate of 6.125% due semi-annually in arrears on March 15 and September 15 of each year until maturity on March 15, 2022.

Purchase commitments primarily relate to a commitment to trade in 20 of our older 550 horsepower well servicing rigs for 20 new-model rigs to be delivered in the first quarter of 2017, the upgrade of one drilling rig and a commitment to purchase four new wireline units to be delivered beginning in March 2017. We have placed a total of $1 million on deposit for this equipment.

Operating leases consist of lease agreements for office space, operating facilities, equipment and personal property.

Incentive compensation is payable to our employees, generally contingent upon their continued employment through the date of each respective award's payout. A portion of our incentive compensation is performance-based and therefore the final amount will be determined based on our actual performance relative to a pre-determined peer group over the performance period.

Debt Requirements

The Revolving Credit Facility contains customary mandatory prepayments from the proceeds of certain asset dispositions or equity or debt issuances, which are applied to reduce outstanding revolving and swing-line loans and to cash-collateralize letter of credit exposure, and in certain cases, also reduce the commitment amount available. There are no limitations on our ability to access the borrowing capacity provided there is no default, all representations and warranties are true and correct, and compliance with financial covenants under the Revolving Credit Facility is maintained.

At December 31, 2016, we were in compliance with our financial covenants under the Revolving Credit Facility. Our senior consolidated leverage ratio was 3.1 to 1.0 and our interest coverage ratio was 0.7 to 1.0. However, continued compliance with our covenants is largely dependent on our ability to generate sufficient levels of EBITDA, as defined in the Revolving Credit Facility, and/or reduce our debt levels. If we expect our future operating results to decline to a level that indicates we may become unable to comply with the financial covenants in the Revolving Credit Facility, we may seek to amend such provisions to remain in compliance or we may pursue other capital sources, such as equity or other debt transactions. Although we believe that our bank lenders are well-secured under the terms of our Revolving Credit Facility, there is no assurance that the bank lenders will waive or amend our financial covenants under the Revolving Credit Facility.

The financial covenants contained in our Revolving Credit Facility include the following, all of which are described in more detail in Note 3, *Debt*, of the Notes to Consolidated Financial Statements, included in Part II, Item 8, *Financial Statements and Supplementary Data*, of this Annual Report on Form 10-K:

- A maximum senior consolidated leverage ratio, calculated as senior consolidated debt at the period end, which excludes unsecured and subordinated debt, divided by EBITDA for the trailing twelve month period at each quarter end, as defined in the Revolving Credit Facility.
- A minimum interest coverage ratio, calculated as EBITDA for the trailing twelve month period at each quarter end, as defined in the Revolving Credit Facility, divided by interest expense for the same period.
- A minimum EBITDA requirement, for the periods indicated, as defined in the Revolving Credit Facility.

The Revolving Credit Facility also restricts capital expenditures, as further described in Note 3, *Debt*, of the Notes to Consolidated Financial Statements, included in Part II, Item 8, *Financial Statements and Supplementary Data*, of this Annual Report on Form 10-K.

The Revolving Credit Facility has additional restrictive covenants that, among other things, limit our ability to:

- incur additional debt or make prepayments of existing debt;
- create liens on or dispose of our assets;
- pay dividends on stock or repurchase stock;
- enter into acquisitions, mergers, consolidations, sale leaseback transactions, or hedging contracts;
- make other restricted investments;
- conduct transactions with affiliates; and
- limits our use of the net proceeds of any offering of our equity securities to the repayment of debt outstanding under the Revolving Credit Facility.

In addition, the Revolving Credit Facility contains customary events of default, including without limitation:

- payment defaults;
- breaches of representations and warranties;
- covenant defaults;
- cross-defaults to certain other material indebtedness in excess of specified amounts;
- certain events of bankruptcy and insolvency;
- judgment defaults in excess of specified amounts;
- failure of any guaranty or security document supporting the credit agreement; and
- change of control.

Our obligations under the Revolving Credit Facility are secured by substantially all of our domestic assets (including equity interests in Pioneer Global Holdings, Inc. and 65% of the outstanding voting equity interests, and 100% of non-voting equity interests, of any first-tier foreign subsidiaries owned by Pioneer Global Holdings, Inc., but excluding any equity interest in, and any assets of, Pioneer Services Holdings, LLC) and are guaranteed by certain of our domestic subsidiaries, including Pioneer Global Holdings, Inc. Borrowings under the Revolving Credit Facility are available for acquisitions, working capital and other general corporate purposes.

In addition to the financial covenants under our Revolving Credit Facility, the Indenture governing our Senior Notes also contains certain restrictions which generally restrict our ability to:

- pay dividends on stock, repurchase stock, redeem subordinated indebtedness or make other restricted payments and investments;
- incur, assume or guarantee additional indebtedness or issue preferred or disqualified stock;
- create liens on our assets;
- enter into sale and leaseback transactions;
- sell or transfer assets;
- borrow, pay dividends, or transfer other assets from certain of our subsidiaries;
- consolidate with or merge with or into, or sell all or substantially all of our properties to any other person;
- enter into transactions with affiliates; and
- enter into new lines of business.

If we experience a change of control (as defined in the Indenture), we will be required to make an offer to each holder of the Senior Notes to repurchase all or any part of the Senior Notes at a purchase price equal to 101% of the principal amount of each Senior Note, plus accrued and unpaid interest, if any, to the date of repurchase. If we engage in certain asset sales, within 365 days of such sale we will be required to use the net cash proceeds from such sale, to the extent we do not reinvest those proceeds in our business, to make an offer to repurchase the Senior Notes at a price equal to 100% of the principal amount of each Senior Note, plus accrued and unpaid interest to the repurchase date.

Our Senior Notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by our existing domestic subsidiaries, except for Pioneer Services Holdings, LLC. The subsidiaries that generally operate our non-U.S. business concentrated in Colombia do not guarantee our Senior Notes. The non-guarantor subsidiaries do not have any payment obligations under the Senior Notes, the guarantees or the Indenture. In the event of a bankruptcy, liquidation or reorganization of any non-guarantor subsidiary, such non-guarantor subsidiary will pay the holders of its debt and other liabilities, including its trade creditors, before it will be able to distribute any of its assets to us. In the future, any non-U.S. subsidiaries, immaterial subsidiaries and subsidiaries that we designate as unrestricted subsidiaries under the Indenture will not guarantee the Senior Notes.

Our Senior Notes are not subject to any sinking fund requirements. As of December 31, 2016, there were no restrictions on the ability of subsidiary guarantors to transfer funds to the parent company, and we were in compliance with all covenants pertaining to our Senior Notes.

Results of Operations

Statements of Operations Analysis - Year Ended December 31, 2016 Compared with Year Ended December 31, 2015

The following table provides information about our operations for the years ended December 31, 2016 and 2015 (amounts in thousands, except average number of drilling rigs, utilization rate and revenue day information).

	Year ended December 31,	
	2016	2015
Drilling Services Segment:		
Revenues	$ 119,207	$ 249,318
Operating costs	73,151	144,196
Drilling Services Segment margin	$ 46,056	$ 105,122
Average number of drilling rigs	30.9	39.1
Utilization rate	43%	63%
Revenue days	4,846	9,040
Average revenues per day	$ 24,599	$ 27,579
Average operating costs per day	15,095	15,951
Drilling Services Segment margin per day	$ 9,504	$ 11,628
Production Services Segment:		
Revenues	$ 157,869	$ 291,460
Operating costs	130,798	213,820
Production Services Segment margin	$ 27,071	$ 77,640
Combined:		
Revenues	$ 277,076	$ 540,778
Operating costs	203,949	358,016
Consolidated margin	$ 73,127	$ 182,762
Net loss	$ (128,391)	$ (155,140)
Adjusted EBITDA	$ 14,237	$ 110,780

Drilling Services Segment margin represents contract drilling revenues less contract drilling operating costs. Production Services Segment margin represents production services revenue less production services operating costs. Drilling Services Segment margin and Production Services Segment margin are non-GAAP financial measures which we consider to be important supplemental measures of operating performance. Our management uses these measures to facilitate period-to-period comparisons in operating performance of our reportable segments. We believe that Drilling Services Segment margin and Production Services Segment margin are useful to investors and analysts because they provide a means to evaluate the operating performance of the segments on an ongoing basis using criteria that are used by our internal decision makers. Additionally, the use of these measures highlights operating trends and aids in analytical comparisons. Drilling Services Segment margin and Production Services Segment margin as presented may not be comparable to other similarly titled measures reported by other companies.

Adjusted EBITDA represents income (loss) before interest expense, income tax (expense) benefit, depreciation and amortization, loss on extinguishment of debt and impairments. Adjusted EBITDA is a non-GAAP measure that our management uses to facilitate period-to-period comparisons of our core operating performance and to evaluate our long-term financial performance against that of our peers. We believe that this measure is useful to investors and analysts in allowing for greater transparency of our core operating performance and makes it easier to compare our results with those of other companies within our industry. Adjusted EBITDA should not be considered (a) in isolation of, or as a substitute for, net income (loss), (b) as an indication of cash flows from operating activities or (c) as a measure of liquidity. In addition, Adjusted EBITDA does not represent funds available for discretionary use. Adjusted EBITDA may not be comparable to other similarly titled measures reported by other companies.

A reconciliation of net income (loss), as reported, to Adjusted EBITDA, and a reconciliation of net income (loss), as reported, to consolidated Drilling Services Segment margin and Production Services Segment margin are set forth in the following table.

	Year ended December 31,	
	2016	2015
	(amounts in thousands)	
Reconciliation of net loss and Adjusted EBITDA to consolidated margin:		
Net loss	$ (128,391)	$ (155,140)
Depreciation and amortization	114,312	150,939
Impairment charges	12,815	129,152
Interest expense	25,934	21,222
Loss on extinguishment of debt	299	2,186
Income tax benefit	(10,732)	(37,579)
Adjusted EBITDA	14,237	110,780
General and administrative	61,184	73,903
Bad debt expense (recoveries)	156	(188)
Gain on dispositions of property and equipment, net	(1,892)	(4,344)
Other (income) expense	(558)	2,611
Consolidated margin	$ 73,127	$ 182,762

Both our Drilling Services and Production Services Segments experienced a significant decline in activity during the year ended December 31, 2016, as compared to 2015, due to the current downturn in our industry. Our combined margin decreased during 2016, as compared to 2015, primarily as a result of decreased activity and pricing pressure for all our service offerings.

In response to the downturn in our industry, we took several actions to reduce costs and better scale our business to the reduced revenues. We reduced our total headcount by over 50% since the beginning of 2015. We reduced wage rates for our operations personnel, reduced incentive compensation and eliminated certain employment benefits. We closed ten field offices since the beginning of 2015 to reduce overhead and reduce associated lease payments, amended our revolving credit facility, and sold 35 drilling rigs and other drilling equipment for aggregate net proceeds of $65.5 million. As of December 31, 2016, we have six additional domestic mechanical and SCR drilling rigs held for sale, along with other drilling equipment, 13 wireline units, 20 older well servicing rigs that will be traded in for 20 new-model rigs in the first quarter of 2017, and certain coiled tubing equipment.

Our Drilling Services Segment's revenues decreased by $130.1 million, or 52%, during 2016, as compared to 2015, while operating costs decreased by $71.0 million, or 49%. The decreases in our Drilling Services Segment's revenues and operating costs primarily resulted from a 46% decrease in revenue days due to the significant reduction in demand in our industry.

Demand for drilling rigs influences the types of drilling contracts we are able to obtain, and the type of revenues we earn under our drilling contracts. As a result of the downturn in our industry, several of our clients terminated a number of their drilling contracts with us. Drilling rigs under contracts which are terminated early earn lower standby revenue rates, as compared to daywork rates, and incur minimal operating costs. Alternatively, turnkey drilling contracts result in higher average revenues per day and higher average operating costs per day as compared to daywork drilling contracts, and are more frequently entered into during periods of higher demand. The following table provides the percentages of our drilling revenues by contract type for the years ended December 31, 2016 and 2015:

	Year ended December 31,	
	2016	2015
Daywork contracts (not terminated early)	89%	77%
Daywork contracts terminated early	11%	20%
Turnkey contracts	—%	3%

Our average revenues per day decreased by $2,980 per day, or 11%, while our average operating costs per day decreased by $856 per day, or 5%, for the year ended December 31, 2016, as compared to 2015. Our revenues per day decreased primarily due to the expiration of term contracts that were entered into in 2014 prior to the downturn at higher revenue rates, many of which were terminated early. Our operating costs per day decreased primarily due to our reduced cost structure, especially in Colombia, as well as a reduced contribution from our Colombian operations where costs are typically higher. The decreases in our operating costs per day from the reduced cost structure more than offset the increase resulting from a higher percentage of daywork revenues during 2016, as compared to 2015, versus revenues earned under contracts that were terminated early. For drilling contracts that were terminated early, the amount of drilling revenues and the number of revenue days for the years ended December 31, 2016 and 2015 are as follows:

	Year ended December 31,	
	2016	2015
Revenues (in thousands)	$ 13,274	$ 49,210
Revenue days	495	2,071

Our Production Services Segment's revenues decreased by $133.6 million, or 46%, during 2016, as compared to 2015, while operating costs decreased by $83.0 million, or 39%, respectively. The decreases in our Production Services Segment's revenues and operating costs are a result of the significantly reduced demand for our services in response to the downturn in our industry, which led to decreased activity and increased pricing pressure for all our service offerings, especially our wireline services and coiled tubing operations. The number of wireline jobs we completed decreased by 15% during 2016, as compared to 2015, and our coiled tubing utilization decreased to 22% during 2016, from 27% during 2015. The total rig hours for our well servicing fleet decreased by 36% during 2016, as compared to 2015, while pricing for these services decreased by 16%.

Our depreciation and amortization expense decreased by $36.6 million during 2016, as compared to 2015, primarily as a result of the impairment charges during 2015 to reduce the carrying values of domestic and Colombia drilling rigs and coiled tubing equipment and intangible assets to their estimated fair values, and the sales and disposals of drilling rigs and equipment during 2015. During 2015, we recognized $10.3 million of depreciation on drilling rigs which were subsequently sold or placed as held for sale, and $3.8 million for the amortization of coiled tubing intangible assets which were impaired to zero at the end of 2015. The overall decrease in our depreciation expense was partially offset by $6.1 million of additional depreciation recognized during the year ended December 31, 2016 for the five new drilling rigs which we deployed in 2015.

During the year ended December 31, 2016, we recognized impairment charges of $12.8 million, primarily to reduce the carrying values of assets which were classified as held for sale, to their estimated fair values, based on expected sales prices. During the year ended December 31, 2015, we recognized impairment charges of $129.2 million. For more detail, see Note 2, *Property and Equipment*, of the Notes to Consolidated Financial Statements, included in Part II, Item 8, *Financial Statements and Supplementary Data*, of this Annual Report on Form 10-K.

Our interest expense increased by $4.7 million during 2016, as compared to 2015, primarily due to the increased interest rate under our Revolving Credit Facility which was amended in late 2015 and again in June 2016. Our loss on debt extinguishment represents the write off of debt costs associated with the reduced borrowing capacity of our Revolving Credit Facility as a result of the amendments in 2015 and 2016.

Our effective income tax rate for the year ended December 31, 2016 was 8%, which is lower than the federal statutory rate in the United States primarily due to valuation allowances, the effect of foreign currency translation, state taxes, and other permanent differences. For more detail, see Note 5, *Income Taxes*, of the Notes to Consolidated Financial Statements, included in Part II, Item 8, *Financial Statements and Supplementary Data*, of this Annual Report on Form 10-K.

Our general and administrative expense decreased by approximately $12.7 million, or 17% during 2016, as compared to 2015. This decrease is primarily due to a decrease in compensation and benefit costs during 2016 of $5.2 million, resulting primarily from the reduction in our workforce and reduced employee benefits, and other efforts taken to minimize various administrative costs such as rent, office and travel expenses.

Our net gain of $1.9 million on the disposition of property and equipment during the year ended December 31, 2016 was primarily related to a net gain on the sale of drilling rigs and the disposal of excess drill pipe. These gains were partially offset by a loss on the disposition of damaged drilling equipment. Our net gain of $4.3 million on the disposition of property and equipment during the year ended December 31, 2015 was primarily for the sale of 32 drilling rigs and other drilling equipment.

The increase in our other income is primarily related to net foreign currency gains recognized for our Colombian operations during the year ended December 31, 2016, as compared to net foreign currency losses during 2015.

Statements of Operations Analysis—Year Ended December 31, 2015 Compared with the Year Ended December 31, 2014

The following table provides information about our operations for the years ended December 31, 2015 and 2014 (amounts in thousands, except average number of drilling rigs, utilization rate and revenue day information).

	Year ended December 31,	
	2015	2014
Drilling Services Segment:		
Revenues	$ 249,318	$ 516,473
Operating costs	144,196	348,133
Drilling Services Segment margin	$ 105,122	$ 168,340
Average number of drilling rigs	39.1	62.0
Utilization rate	63%	87%
Revenue days	9,040	19,602
Average revenues per day	27,579	26,348
Average operating costs per day	15,951	17,760
Drilling Services Segment margin per day	$ 11,628	$ 8,588
Production Services Segment:		
Revenues	$ 291,460	$ 538,750
Operating costs	213,820	339,690
Production Services Segment margin	$ 77,640	$ 199,060
Combined:		
Revenues	$ 540,778	$ 1,055,223
Operating costs	358,016	687,823
Consolidated margin	$ 182,762	$ 367,400
Net loss	$ (155,140)	$ (38,018)
Adjusted EBITDA	$ 110,780	$ 277,081

A reconciliation of net income (loss), as reported, to Adjusted EBITDA, and a reconciliation of net income (loss), as reported, to consolidated Drilling Services Segment margin and Production Services Segment margin are set forth in the following table.

	Year ended December 31, 2015	Year ended December 31, 2014
	(amounts in thousands)	
Reconciliation of net loss and Adjusted EBITDA to consolidated margin:		
Net loss	$ (155,140)	$ (38,018)
Depreciation and amortization	150,939	183,376
Impairment charges	129,152	73,025
Interest expense	21,222	38,781
Loss on extinguishment of debt	2,186	31,221
Income tax benefit	(37,579)	(11,304)
Adjusted EBITDA	110,780	277,081
General and administrative	73,903	103,385
Bad debt expense	(188)	1,445
Gain on dispositions of property and equipment, net	(4,344)	(1,859)
Gain on sale of fishing and rental services operations	—	(10,702)
Gain on settlement of litigation	—	(5,254)
Other expense	2,611	3,304
Consolidated margin	$ 182,762	$ 367,400

Both our Drilling Services and Production Services Segments experienced a significant decline in activity during the year ended December 31, 2015, as compared to 2014, due to the downturn in our industry that began in 2015. Our combined margin decreased during 2015 as compared to 2014, primarily as a result of decreased activity and pricing pressure for all our service offerings. The decrease in combined margin was partially offset by an increase in average margin per day in our Drilling Services Segment from rigs that were earning but not working during 2015 and due to the disposal of 36 mechanical and lower horsepower electric drilling rigs from our fleet which generally earned lower margins per day, as well as various actions taken during 2015 to reduce costs.

In response to the downturn in our industry, we took several actions in 2015 to reduce costs and better scale our business to the reduced revenues. We reduced our total headcount by over 50%, reduced wage rates for our operations personnel, reduced incentive compensation and eliminated certain employment benefits. We closed nine location offices to reduce overhead and reduce associated lease payments, amended our revolving credit facility, and sold 32 drilling rigs and other drilling equipment for aggregate net proceeds of $53.6 million.

Our Drilling Services Segment's revenues decreased by $267.2 million, or 52%, and our Drilling Services Segment's operating costs decreased by $203.9 million, or 59%, during 2015 as compared to 2014, primarily resulting from a decrease in revenue days and lower average operating costs per day. Revenue days decreased primarily due to the significant reduction in demand in our industry. Our average revenues per day increased by $1,231 per day, or 5%, for the year ended December 31, 2015, as compared to 2014. Our average revenues per day increased primarily because the drilling rigs which we removed from our fleet, as described above, were generally earning lower dayrates as compared to the rest of our fleet. Our average operating costs per day decreased by $1,809 per day, or 10%, during 2015 as compared to 2014, primarily due to reduced costs from drilling rigs which were early terminated and were thus earning revenues while incurring minimal operating costs.

Demand for drilling rigs influences the types of drilling contracts we are able to obtain, and the type of revenues we earn under our drilling contracts. As a result of the downturn in our industry, several of our clients terminated a number of their drilling contracts with us. Drilling rigs under contracts which are terminated early earn lower standby revenue rates, as compared to daywork rates, and incur minimal operating costs. Alternatively, turnkey drilling contracts result in higher average revenues per day and higher average operating costs per day as compared to daywork drilling contracts, and are more frequently entered into during periods of higher demand. The following table provides the percentages of our drilling revenues by contract type for the years ended December 31, 2015 and 2014:

	Year ended December 31,	
	2015	2014
Daywork contracts (not terminated early)	77%	94%
Daywork contracts terminated early	20%	—%
Turnkey contracts	3%	6%

For drilling contracts that were terminated early, the amount of drilling revenues and the number of revenue days for the years ended December 31, 2015 and 2014 are as follows:

	Year ended December 31,	
	2015	2014
Revenues (in thousands)	$ 49,210	$ 296
Revenue days	2,071	23

Our Production Services Segment's revenues decreased by $247.3 million, or 46%, during 2015 as compared to 2014, while operating costs decreased by $125.9 million, or 37%. The decreases in our Production Services Segment's revenues and operating costs are a result of the significantly reduced demand for our services in response to the downturn in our industry, which led to decreased activity and increased pricing pressure for all our service offerings, especially our wireline services and coiled tubing operations. The number of wireline jobs we completed decreased by 45% during 2015, as compared to 2014. The total rig hours for our well servicing fleet decreased by 25% during 2015, as compared to 2014. Our coiled tubing utilization decreased to 27% during 2015 from 51% during 2014.

Our depreciation and amortization expense decreased by $32.4 million during 2015, respectively, as compared to 2014, primarily as a result of the sales of drilling rigs and equipment during 2015 and 2014, as well as impairment charges to reduce the carrying values of certain drilling rigs to their estimated fair value, and partially offset by the increase in depreciation for the five new-builds which we deployed in 2015.

We recognized $129.2 million of impairment charges during the year ended December 31, 2015 to reduce the carrying values of our eight drilling rigs in Colombia and certain other assets associated with our Colombian operations, all our non-AC electric drilling rigs in our domestic fleet, the property and equipment of our coiled tubing operations, and the intangibles related to our coiled tubing operations to their estimated fair values. During the year ended December 31, 2014, we recorded impairment charges of $73.0 million, primarily to reduce the carrying values of 31 mechanical and lower horsepower drilling rigs to their estimated fair values, based on market appraisals. For more information, see Note 2, *Property and Equipment*, and Note 1, *Organization and Summary of Significant Accounting Policies*, of the Notes to Consolidated Financial Statements, included in Part II, Item 8, *Financial Statements and Supplementary Data*, of this Annual Report on Form 10-K.

Our interest expense decreased by $17.6 million during 2015 as compared to 2014, due to the redemption of our 2010 and 2011 Senior Notes in 2014, which incurred interest at a higher rate than the 2014 Senior Notes which we issued in March 2014, as well as the repayments we made in 2014 and 2015 to reduce the level of debt outstanding under our Revolving Credit Facility.

Our loss on debt extinguishment during the year ended December 31, 2015 represents the write off of debt costs associated with the reduced borrowing capacity of our Revolving Credit Facility which was amended in September and again in December 2015. Our loss on debt extinguishment during the year ended December 31, 2014 represents the tender and redemption premiums and the write-off of net unamortized debt discount and debt issuance costs associated with the 2010 and 2011 Senior Notes that were redeemed in 2014.

Our effective income tax rate for the year ended December 31, 2015 was 19%, which is lower than the federal statutory rate in the United States, primarily due to valuation allowances on Colombian deferred tax assets, the effect of foreign currency translation, impairments, and other permanent differences. For more detail about the valuation allowances, see Note 5, *Income Taxes*, of the Notes to Consolidated Financial Statements, included in Part II, Item 8, *Financial Statements and Supplementary Data*, of this Annual Report on Form 10-K.

Our general and administrative expense decreased by $29.5 million, or 29%, during 2015 as compared to 2014, primarily due to a $22.4 million decrease in compensation costs, net of approximately $2 million of severance costs incurred, as well as other efforts made during the year to minimize various administrative costs. The decrease in compensation expense is primarily due to the reduction in our workforce during 2015, a reduction in stock-based compensation due to a decrease in certain long-term performance-based compensation plans' actual and projected achievement levels, and reduced incentive compensation for 2015.

Our gains on disposition of assets during the year ended December 31, 2015 are primarily related to the sale of 32 of our mechanical and lower horsepower drilling rigs. Our gains on disposition of assets during the year ended December 31, 2014 are primarily related to the sale of our trucking assets in February 2014.

In September 2014, we sold our fishing and rental services operations for total consideration of $16.1 million, resulting in a pretax gain of $10.7 million.

We recognized gains of $5.3 million related to settlements of litigation in our favor related to non-compete agreements during the year ended December 31, 2014.

Our other expense of $2.6 million for the year ended December 31, 2015 is primarily related to net foreign currency losses recognized for our Colombian operations due to the rise in the value of the U.S. dollar relative to the Colombian peso.

Inflation

Inflation has not had a significant impact on our operations during the three years ended December 31, 2016 and we believe that inflation will not have a significant near-term impact on our financial position.

Wage rates for our operations personnel are impacted by inflationary pressures when the demand for drilling and production services increases and the availability of personnel is scarce. Costs for equipment repairs and maintenance, upgrades and new equipment construction are also impacted by inflationary pressures when the demand for our services increases. As a result of the significantly reduced activity levels in our industry, we estimate that we experienced a moderate decrease in both wage rates and equipment costs during 2015 and 2016 for both our Drilling and Production Services Segments. However, we expect that we will experience a moderate increase in 2017 as our industry continues to recover from the recent downturn.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with U.S. GAAP requires us to make estimates and assumptions that affect the amounts reported in our financial statements and accompanying notes. Actual results could differ from those estimates.

Revenue and Cost Recognition—Our Drilling Services Segment earns revenues by drilling oil and gas wells for our clients under daywork or turnkey contracts, which usually provide for the drilling of a single well. Drilling contracts for individual wells are usually completed in less than 30 days. We recognize revenues on daywork contracts for the days completed based on the dayrate each contract specifies. We recognize revenues from our turnkey contracts on the proportional performance basis, based on our estimate of the number of days to complete each contract. All of our revenues are recognized net of applicable sales taxes.

With most drilling contracts, we receive payments contractually designated for the mobilization of rigs and other equipment. Payments received, and costs incurred for the mobilization services are deferred and recognized on a straight line basis over the related contract term. Costs incurred to relocate rigs and other drilling equipment to areas in which a contract has not been secured are expensed as incurred. Reimbursements that we receive for out-of-pocket expenses are recorded as revenue and the out-of-pocket expenses for which they relate are recorded as operating costs.

With most term drilling contracts, we are entitled to receive a full or reduced rate of revenue from our clients if they choose to place a rig on standby or to early terminate the contract before its original expiration term. Generally, these revenues are billed and collected over the remaining term of the contract, as the rig is often placed on standby rather than fully released from the contract, and thus may go back to work at the client's decision any time before the end of the contract. Some of our drilling contracts contain "make-whole" provisions whereby if we are able to secure additional work for the rig with another client, then each party is entitled to a make-whole payment. If the dayrates under the new contract are less than the dayrates in the original contract, we would be entitled to a reduced revenue dayrate from the terminating client, and likewise, the terminating client may be entitled to a payment from us if the new contract dayrates exceed those of the original contract. A client may also choose to early terminate the contract and make an upfront early termination payment based on a per day rate for the remaining term of the contract. Revenues derived from rigs placed on standby or from the early termination of term drilling contracts are deferred and recognized as the amounts become fixed or determinable, over the remainder of the original term or when the rig is sold.

Our Production Services Segment earns revenues for well servicing, wireline services and coiled tubing services pursuant to master services agreements based on purchase orders, contracts or other arrangements with the client that include fixed or determinable prices. Production services jobs are generally short-term and are charged at current market rates. Production service revenue is recognized when the service has been rendered and collectability is reasonably assured.

Long-lived tangible and intangible assets—We evaluate for potential impairment of long-lived tangible and intangible assets subject to amortization when indicators of impairment are present. Circumstances that could indicate a potential impairment include significant adverse changes in industry trends, economic climate, legal factors, and an adverse action or assessment by a regulator. More specifically, significant adverse changes in industry trends include significant declines in revenue rates, utilization rates, oil and natural gas market prices and industry rig counts. In performing an impairment evaluation, we estimate the future undiscounted net cash flows from the use and eventual disposition of long-lived tangible and intangible assets grouped at the lowest level that cash flows can be identified. For our Production Services Segment, we perform an impairment evaluation and estimate future undiscounted cash flows for the individual reporting units (well servicing, wireline and coiled tubing). For our Drilling Services Segment, we perform an impairment evaluation and estimate future undiscounted cash flows for individual domestic drilling rig assets and for our Colombian drilling rig assets as a group. If the sum of the estimated future undiscounted net cash flows is less than the carrying amount of the asset group, then we determine the fair value of the asset group. The amount of an impairment charge is measured as the difference between the carrying amount and the fair value of the assets. The assumptions used in the impairment evaluation for long-lived assets are inherently uncertain and require management judgment.

Deferred taxes—We provide deferred taxes for the basis differences in our property and equipment between financial reporting and tax reporting purposes and other costs such as compensation, net operating loss carryforwards, employee benefit and other accrued liabilities which are deducted in different periods for financial reporting and tax reporting purposes. For property and equipment, basis differences arise from differences in depreciation periods and methods and the value of assets acquired in a business acquisition where we acquire an entity rather than just its assets. For financial reporting purposes, we depreciate the various components of our drilling rigs, well servicing rigs, wireline units and coiled tubing units over 1 to 25 years and refurbishments over 3 to 5 years, while federal income tax rules require that we depreciate drilling rigs, well servicing rigs, wireline units and coiled tubing units over 5 years. Therefore, in the first 5 years of our ownership of a drilling rig, well servicing rig, wireline unit or coiled tubing unit, our tax depreciation exceeds our financial reporting depreciation, resulting in our providing deferred taxes on this depreciation difference. After 5 years, financial reporting depreciation exceeds tax depreciation, and the deferred tax liability begins to reverse.

Accounting estimates—Material estimates that are particularly susceptible to significant changes in the near term relate to our recognition of revenues and costs for turnkey contracts, our estimate of the allowance for doubtful accounts, our determination of depreciation and amortization expenses, our estimates of projected cash flows and fair values for impairment evaluations, our estimate of the valuation allowance for deferred tax assets, our estimate of the liability relating to the self-insurance portion of our health and workers' compensation insurance, our estimate of compensation related accruals and our estimate of sales tax audit liability.

For turnkey drilling contracts, we recognize revenues and accrue estimated costs based on our estimate of the number of days to complete each contract and our estimate of the total costs to complete the contract. If we anticipate a loss on a contract in progress due to a change in our cost estimate, we accrue the entire amount of the estimated loss, including all costs that are included in our revised estimated cost to complete that contract, in our consolidated statement of operations for that reporting period. We did not experience a loss the turnkey contract completed during the year ended December 31, 2016. We incurred a total loss of $0.5 million on 3 of the 17 turnkey contracts completed during the year ended December 31, 2015, and we incurred a total loss of $1.2 million on 13 of the 106 turnkey contracts completed during the year ended December 31, 2014. Revenues and costs during a reporting period could be affected for contracts in progress at the end of a reporting period which have not been completed before our financial statements for that period are released. As of December 31, 2016, we had no turnkey contracts in progress.

We estimate an allowance for doubtful accounts based on the creditworthiness of our clients as well as general economic conditions. We evaluate the creditworthiness of our clients based on commercial credit reports, trade references, bank references, financial information, production information and any past experience we have with the client. Consequently, any change in those factors could affect our estimate of our allowance for doubtful accounts. In some instances, we require new clients to establish escrow accounts or make prepayments. We had an allowance for doubtful accounts of $1.7 million at December 31, 2016.

Our determination of the useful lives of our depreciable assets, which directly affects our determination of depreciation expense and deferred taxes is also a critical accounting estimate. A decrease in the useful life of our property and equipment would increase depreciation expense and reduce deferred taxes. We provide for depreciation of our drilling, production, transportation and other equipment on a straight-line method over useful lives that we have estimated and that range from 1 to 25 years. We record the same depreciation expense whether a drilling rig, well servicing rig, wireline unit or coiled tubing unit is idle or working. Our estimates of the useful lives of our drilling, production, transportation and other equipment are based on our almost 50 years of experience in the oilfield services industry with similar equipment.

We evaluate for potential impairment of long-lived tangible and intangible assets subject to amortization when indicators of impairment are present. During the year ended December 31, 2016, we recognized impairment charges of $12.8 million, primarily to reduce the carrying values of certain assets which were classified as held for sale, to their estimated fair value based on expected sales prices. During the years ended December 31, 2015 and 2014, we recognized impairment charges of $129.2 million and $73.0 million, respectively. For more detail, see Note 2, *Property and Equipment*, of the Notes to Consolidated Financial Statements, included in Part II, Item 8, *Financial Statements and Supplementary Data*, of this Annual Report on Form 10-K.

Despite the modest recovery in commodity prices in the latter half of 2016, we continue to monitor all indicators of potential impairments in accordance with ASC Topic 360, *Property, Plant and Equipment.* Business conditions and our projected cash flows for our Colombian operations improved as compared to the projections used for the impairment analysis in 2015, therefore we did not perform any impairment testing on this business in 2016. However, due to lower than anticipated operating results in 2016 and a decline in our projected cash flows for the coiled tubing reporting unit, we performed an impairment analysis of our coiled tubing long-lived assets at September 30, 2016 which indicated that our projected net undiscounted cash flows associated with the coiled tubing reporting unit were in excess of the net carrying value of the assets, and thus no impairment was present. The most significant inputs used in our impairment analysis of our coiled tubing operations include the projected utilization and pricing of our coiled tubing services, which are classified as Level 3 inputs as defined by Accounting Standards Codification (ASC) Topic 820, *Fair Value Measurements and Disclosures*.

The assumptions used in the impairment evaluation for long-lived assets are inherently uncertain and require management judgment. Although we believe the assumptions and estimates used in our impairment analyses are reasonable and appropriate, different assumptions and estimates could materially impact the analyses and resulting conclusions. If the demand for our services remains at current levels or declines further and any of our assets become or remain idle for an extended amount of time, then our estimated cash flows may further decrease, and the probability of a near term sale may increase. If any of the foregoing were to occur, we may incur additional impairment charges.

As of December 31, 2016, we had $131.4 million of deferred tax assets related to domestic and foreign net operating losses that are available to reduce future taxable income. In assessing the realizability of our deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. As of December 31, 2016, we determined that a valuation allowance should be recorded for a portion of our domestic deferred tax assets, which has been factored into the estimated annual tax rate applied throughout 2016, and is the primary factor causing our effective tax rate to be significantly lower than the statutory rate of 35%. We also have a valuation allowance that fully offsets our $21.1 million of foreign deferred tax assets at December 31, 2016. For more information, see Note 5, *Income Taxes*, of the Notes to Consolidated Financial Statements, included in Part II, Item 8, *Financial Statements and Supplementary Data*, of this Annual Report on Form 10-K.

Our accrued insurance premiums and deductibles as of December 31, 2016 include accruals for costs incurred under the self-insurance portion of our health insurance of approximately $2.0 million and our workers' compensation, general liability and auto liability insurance of approximately $4.4 million. We have stop-loss coverage of $200,000 per covered individual per year under our health insurance and a deductible of $500,000 per occurrence under our workers' compensation insurance. We have a deductible of $250,000 per occurrence under both our general liability insurance and auto liability insurance. We accrue for these costs as claims are incurred using an actuarial calculation that is based on industry and our company's historical claim development data, and we accrue the costs of administrative services associated with claims processing.

Our compensation expense includes estimates for certain of our long-term incentive compensation plans which have performance-based award components dependent upon our performance over a set performance period, as compared to the performance of a pre-defined peer group. The accruals for these awards include estimates which affect our compensation expense, employee related accruals and equity. The accruals are adjusted based on actual achievement levels at the end of the pre-determined performance periods.

We have received an increased number of notices in recent years from state taxing authorities for audits of sales and use tax obligations. We are currently undergoing sales and use tax audits for multi-year periods and we are working to resolve all relevant issues. As of both December 31, 2016 and December 31, 2015, our accrued liability was $0.6 million based on our estimate of the sales and use tax obligations that are expected to result from these audits. Due to the inherent uncertainty of the audit process, we believe that it is reasonably possible that we may incur additional tax assessments with respect to one or more of the audits in excess of the amount accrued. We believe that such an outcome would not have a material adverse effect on our results of operations or financial position. Because certain of these audits are in a preliminary stage, an estimate of the possible loss or range of loss from an adverse result in all or substantially all of these cases cannot reasonably be made.

Recently Issued Accounting Standards

For a detail of recently issued accounting standards, see Note 1, *Organization and Summary of Significant Accounting Policies,* of the Notes to Consolidated Financial Statements, included in Part II, Item 8, *Financial Statements and Supplementary Data*, of this Annual Report on Form 10-K.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

We are subject to interest rate market risk on our variable rate debt. As of December 31, 2016, we had $46 million outstanding under our Revolving Credit Facility, which is our only variable rate debt. The impact of a hypothetical 1% increase or decrease in interest rates on this amount of debt would have resulted in a corresponding increase or decrease, respectively, in interest expense of approximately $0.5 million, and a corresponding increase or decrease, respectively, in net income of approximately $0.3 million during the year ended December 31, 2016. This potential increase or decrease is based on the simplified assumption that the level of variable rate debt remains constant with an immediate across-the-board interest rate increase or decrease as of January 1, 2016.

Foreign Currency Risk

While the U.S. dollar is the functional currency for reporting purposes for our Colombian operations, we enter into transactions denominated in Colombian pesos. Nonmonetary assets and liabilities are translated at historical rates and monetary assets and liabilities are translated at exchange rates in effect at the end of the period. Income statement accounts are translated at average rates for the period. As a result, Colombian Peso denominated transactions are affected by changes in exchange rates. We generally accept the exposure to exchange rate movements without using derivative financial instruments to manage this risk. Therefore, both positive and negative movements in the Colombian Peso currency exchange rate against the U.S. dollar have and will continue to affect the reported amount of revenues, expenses, profit, and assets and liabilities in our consolidated financial statements.

The impact of currency rate changes on our Colombian Peso denominated transactions and balances resulted in foreign currency gains of $0.4 million for the year ended December 31, 2016.

Item 8. Financial Statements and Supplementary Data

PIONEER ENERGY SERVICES CORP.

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Pioneer Energy Services Corp.:

We have audited the accompanying consolidated balance sheets of Pioneer Energy Services Corp. and subsidiaries as of December 31, 2016 and 2015, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2016. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Pioneer Energy Services Corp. and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Pioneer Energy Services Corp.'s internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 17, 2017 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

San Antonio, Texas
February 17, 2017

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Pioneer Energy Services Corp.:

We have audited Pioneer Energy Services Corp.'s internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Pioneer Energy Services Corp.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Pioneer Energy Services Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Pioneer Energy Services Corp. and subsidiaries as of December 31, 2016 and 2015, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2016, and our report dated February 17, 2017 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

San Antonio, Texas
February 17, 2017

PIONEER ENERGY SERVICES CORP. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2016	December 31, 2015
	(in thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 10,194	$ 14,160
Receivables:		
Trade, net of allowance for doubtful accounts	38,764	47,577
Unbilled receivables	7,417	13,624
Insurance recoveries	17,003	14,556
Other receivables	8,939	4,059
Inventory	9,660	9,262
Assets held for sale	15,093	4,619
Prepaid expenses and other current assets	6,926	7,411
Total current assets	113,996	115,268
Property and equipment, at cost	1,058,261	1,146,994
Less accumulated depreciation	474,181	444,409
Net property and equipment	584,080	702,585
Intangible assets, net of accumulated amortization	403	1,944
Other long-term assets	1,623	2,178
Total assets	$ 700,102	$ 821,975
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 19,208	$ 16,951
Deferred revenues	1,449	6,222
Accrued expenses:		
Payroll and related employee costs	14,813	13,859
Insurance premiums and deductibles	6,446	8,087
Insurance claims and settlements	13,667	14,556
Interest	5,395	5,508
Other	5,024	4,859
Total current liabilities	66,002	70,042
Long-term debt, less debt issuance costs	339,473	387,217
Deferred income taxes	8,180	17,502
Other long-term liabilities	5,049	4,571
Total liabilities	418,704	479,332
Commitments and contingencies (Note 11)		
Shareholders' equity:		
Preferred stock, 10,000,000 shares authorized; none issued and outstanding	—	—
Common stock $.10 par value; 100,000,000 shares authorized; 77,146,906 and 64,497,915 shares outstanding at December 31, 2016 and December 31, 2015, respectively	7,766	6,496
Additional paid-in capital	541,823	475,823
Treasury stock, at cost; 515,546 and 458,170 shares at December 31, 2016 and December 31, 2015, respectively	(3,883)	(3,759)
Accumulated deficit	(264,308)	(135,917)
Total shareholders' equity	281,398	342,643
Total liabilities and shareholders' equity	$ 700,102	$ 821,975

See accompanying notes to consolidated financial statements.

PIONEER ENERGY SERVICES CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year ended December 31,		
	2016	2015	2014
	(in thousands, except per share data)		
Revenues:			
Drilling services	$ 119,207	$ 249,318	$ 516,473
Production services	157,869	291,460	538,750
Total revenues	277,076	540,778	1,055,223
Costs and expenses:			
Drilling services	73,151	144,196	348,133
Production services	130,798	213,820	339,690
Depreciation and amortization	114,312	150,939	183,376
General and administrative	61,184	73,903	103,385
Bad debt expense (recovery)	156	(188)	1,445
Impairment charges	12,815	129,152	73,025
Gain on dispositions of property and equipment, net	(1,892)	(4,344)	(1,859)
Gain on sale of fishing and rental services operations	—	—	(10,702)
Gain on litigation	—	—	(5,254)
Total costs and expenses	390,524	707,478	1,031,239
Income (loss) from operations	(113,448)	(166,700)	23,984
Other (expense) income:			
Interest expense, net of interest capitalized	(25,934)	(21,222)	(38,781)
Loss on extinguishment of debt	(299)	(2,186)	(31,221)
Other	558	(2,611)	(3,304)
Total other expense	(25,675)	(26,019)	(73,306)
Loss before income taxes	(139,123)	(192,719)	(49,322)
Income tax benefit	10,732	37,579	11,304
Net loss	$ (128,391)	$ (155,140)	$ (38,018)
Loss per common share—Basic	$ (1.96)	$ (2.41)	$ (0.60)
Loss per common share—Diluted	$ (1.96)	$ (2.41)	$ (0.60)
Weighted average number of shares outstanding—Basic	65,452	64,310	63,161
Weighted average number of shares outstanding—Diluted	65,452	64,310	63,161

See accompanying notes to consolidated financial statements.

PIONEER ENERGY SERVICES CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Shares		Amount		Additional Paid In Capital	Accumulated Earnings (Deficit)	Total Shareholders' Equity
	Common	Treasury	Common	Treasury			
	(In thousands)						
Balance as of December 31, 2013	62,753	(220)	$ 6,275	$ (1,895)	$ 456,812	$ 57,241	$ 518,433
Net loss	—	—	—	—	—	(38,018)	(38,018)
Exercise of options and related income tax effect	929	—	93	—	8,275	—	8,368
Purchase of treasury stock	—	(97)	—	(1,135)	—	—	(1,135)
Income tax effect of stock option forfeitures and expirations	—	—	—	—	(201)	—	(201)
Issuance of restricted stock	455	—	46	—	(46)	—	—
Stock-based compensation expense	—	—	—	—	7,617	—	7,617
Balance as of December 31, 2014	64,137	(317)	$ 6,414	$ (3,030)	$ 472,457	$ 19,223	$ 495,064
Net loss	—	—	—	—	—	(155,140)	(155,140)
Exercise of options and related income tax effect	203	—	20	—	761	—	781
Purchase of treasury stock	—	(141)	—	(729)	—	—	(729)
Income tax effect of restricted stock vesting	—	—	—	—	(884)	—	(884)
Income tax effect of stock option forfeitures and expirations	—	—	—	—	(78)	—	(78)
Issuance of restricted stock	616	—	62	—	(62)	—	—
Stock-based compensation expense	—	—	—	—	3,629	—	3,629
Balance as of December 31, 2015	64,956	(458)	$ 6,496	$ (3,759)	$ 475,823	$ (135,917)	$ 342,643
Net loss	—	—	—	—	—	(128,391)	(128,391)
Sale of common stock, net of offering costs	12,075	—	1,208	—	64,222	—	65,430
Exercise of options and related income tax effect	46	—	5	—	178	—	183
Purchase of treasury stock	—	(58)	—	(124)	—	—	(124)
Income tax effect of restricted stock vesting	—	—	—	—	(1,023)	—	(1,023)
Income tax effect of stock option forfeitures and expirations	—	—	—	—	(1,264)	—	(1,264)
Issuance of restricted stock	586	—	57	—	(57)	—	—
Stock-based compensation expense	—	—	—	—	3,944	—	3,944
Balance as of December 31, 2016	77,663	(516)	$ 7,766	$ (3,883)	$ 541,823	$ (264,308)	$ 281,398

See accompanying notes to consolidated financial statements.

PIONEER ENERGY SERVICES CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended December 31,		
	2016	2015	2014
	(in thousands)		
Cash flows from operating activities:			
Net loss	$ (128,391)	$ (155,140)	$ (38,018)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation and amortization	114,312	150,939	183,376
Allowance for doubtful accounts, net of recoveries	156	248	1,445
Write-off of obsolete inventory	101	—	331
Gain on dispositions of property and equipment, net	(1,892)	(4,344)	(1,859)
Stock-based compensation expense	3,944	3,629	7,617
Amortization of debt issuance costs, discount and premium	1,776	1,691	2,669
Gain on sale of fishing and rental services operations	—	—	(10,702)
Loss on extinguishment of debt	299	2,186	31,221
Impairment charges	12,815	129,152	73,025
Deferred income taxes	(11,608)	(39,286)	(14,761)
Change in other long-term assets	662	420	2,958
Change in other long-term liabilities	478	(132)	(1,352)
Changes in current assets and liabilities:			
Receivables	16,341	114,644	(11,993)
Inventory	(630)	1,267	(1,068)
Prepaid expenses and other current assets	310	1,769	(55)
Accounts payable	1,969	(30,514)	7,167
Deferred revenues	(3,985)	1,922	2,616
Accrued expenses	(1,526)	(35,732)	424
Net cash provided by operating activities	5,131	142,719	233,041
Cash flows from investing activities:			
Purchases of property and equipment	(32,381)	(159,615)	(175,378)
Proceeds from sale of fishing and rental services operations	—	—	15,090
Proceeds from sale of property and equipment	7,577	57,674	8,370
Proceeds from insurance recoveries	37	285	—
Net cash used in investing activities	(24,767)	(101,656)	(151,918)
Cash flows from financing activities:			
Debt repayments	(71,000)	(60,002)	(490,025)
Proceeds from issuance of debt	22,000	—	440,000
Debt issuance costs	(819)	(1,877)	(9,239)
Tender premium costs	—	—	(21,553)
Proceeds from exercise of options	183	781	8,368
Proceeds from issuance of common stock, net of offering costs of $4,001	65,430	—	—
Purchase of treasury stock	(124)	(729)	(1,135)
Net cash provided by (used in) financing activities	15,670	(61,827)	(73,584)
Net increase (decrease) in cash and cash equivalents	(3,966)	(20,764)	7,539
Beginning cash and cash equivalents	14,160	34,924	27,385
Ending cash and cash equivalents	$ 10,194	$ 14,160	$ 34,924
Supplementary disclosure:			
Interest paid	$ 24,516	$ 22,506	$ 43,690
Income tax paid	$ 671	$ 2,691	$ 5,012
Noncash investing and financing activity:			
Change in capital expenditure accruals	$ 175	$ (16,708)	$ 12,743

See accompanying notes to consolidated financial statements.

1. Organization and Summary of Significant Accounting Policies

Business

Pioneer Energy Services Corp. provides land-based drilling services and production services to a diverse group of independent and large oil and gas exploration and production companies in the United States and internationally in Colombia. We also provide two of our services (coiled tubing and wireline services) offshore in the Gulf of Mexico.

As of December 31, 2016, our drilling rig fleet is 100% pad-capable, consisting of 16 AC rigs in the US and eight SCR rigs in Colombia. In addition to our drilling rigs, we provide the drilling crews and most of the ancillary equipment needed to operate our drilling rigs. The drilling rigs in our fleet are currently assigned to the following divisions:

Drilling Division	Rig Count
South Texas	1
West Texas	7
North Dakota	2
Appalachia	6
Colombia	8
	24

Our Production Services Segment provides a range of services to a diverse group of exploration and production companies, with our operations concentrated in the major United States onshore oil and gas producing regions in the Mid-Continent and Rocky Mountain states and in the Gulf Coast, both onshore and offshore. As of December 31, 2016, our production services fleets are as follows:

Production Services Fleets			
	550 HP	600 HP	Total
Well servicing rigs, by horsepower (HP) rating	114	11	125
	Offshore	Onshore	Total
Wireline units	6	108	114
Coiled tubing units	5	12	17

Drilling Contracts

We obtain our contracts for drilling oil and natural gas wells either through competitive bidding or through direct negotiations with existing or potential clients. Our drilling contracts generally provide for compensation on a daywork basis, and sometimes on a turnkey basis. Contract terms generally depend on the complexity and risk of operations, the on-site drilling conditions, the type of equipment used, and the anticipated duration of the work to be performed. Spot market contracts generally provide for the drilling of a single well and typically permit the client to terminate on short notice. We typically enter into longer-term drilling contracts for our newly constructed rigs and/or during periods of high rig demand.

As of December 31, 2016, 13 of our 16 domestic drilling rigs are earning revenues, nine of which are under term contracts, and four of the drilling rigs in Colombia are earning revenues, three of which are under term contracts. The term contracts in Colombia are cancelable by our client without penalty if 30 days' notice is provided, and by us if rig operations are suspended without an associated dayrate. We are actively marketing our idle drilling rigs in Colombia to various operators and we are evaluating other options, including the possibility of the sale of some or all of our assets in Colombia.

Basis of Presentation

The accompanying consolidated financial statements include the accounts of Pioneer Energy Services Corp. and our wholly owned subsidiaries. All intercompany balances and transactions have been eliminated in consolidation. The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America.

In preparing the accompanying consolidated financial statements, we make various estimates and assumptions that affect the amounts of assets and liabilities we report as of the dates of the balance sheets and income and expenses we report for the periods shown in the income statements and statements of cash flows. Our actual results could differ significantly from those estimates. Material estimates that are particularly susceptible to significant changes in the near term relate to our recognition of revenues and costs for turnkey contracts, our estimate of the allowance for doubtful accounts, our determination of depreciation and amortization expenses, our estimates of projected cash flows and fair values for impairment evaluations, our estimate of the valuation allowance for deferred tax assets, our estimate of the liability relating to the self-insurance portion of our health and workers' compensation insurance, our estimate of compensation related accruals and our estimate of sales tax audit liability.

In preparing the accompanying consolidated financial statements, we have reviewed events that have occurred after December 31, 2016, through the filing of this Form 10-K, for inclusion as necessary.

Foreign Currencies

Our functional currency for our foreign subsidiary in Colombia is the U.S. dollar. Nonmonetary assets and liabilities are translated at historical rates and monetary assets and liabilities are translated at exchange rates in effect at the end of the period. Income statement accounts are translated at average rates for the period. Gains and losses from remeasurement of foreign currency financial statements into U.S. dollars and from foreign currency transactions are included in other income or expense.

Revenue and Cost Recognition

Drilling Services—Our Drilling Services Segment earns revenues by drilling oil and gas wells for our clients under daywork or turnkey contracts, which usually provide for the drilling of a single well. Drilling contracts for individual wells are usually completed in less than 30 days. We recognize revenues on daywork contracts for the days completed based on the dayrate each contract specifies. We recognize revenues from our turnkey contracts on the proportional performance basis, based on our estimate of the number of days to complete each contract. All of our revenues are recognized net of applicable sales taxes.

With most drilling contracts, we receive payments contractually designated for the mobilization of rigs and other equipment. Payments received, and costs incurred for the mobilization services are deferred and recognized on a straight line basis over the related contract term. Costs incurred to relocate rigs and other drilling equipment to areas in which a contract has not been secured are expensed as incurred. Reimbursements that we receive for out-of-pocket expenses are recorded as revenue and the out-of-pocket expenses for which they relate are recorded as operating costs. Amortization of deferred mobilization revenues was $1.6 million, $1.1 million and $4.6 million for the years ended December 31, 2016, 2015 and 2014, respectively.

With most term drilling contracts, we are entitled to receive a full or reduced rate of revenue from our clients if they choose to place a rig on standby or to early terminate the contract before its original expiration term. Generally, these revenues are billed and collected over the remaining term of the contract, as the rig is often placed on standby rather than fully released from the contract, and thus may go back to work at the client's decision any time before the end of the contract. Some of our drilling contracts contain "make-whole" provisions whereby if we are able to secure additional work for the rig with another client, then each party is entitled to a make-whole payment. If the dayrates under the new contract are less than the dayrates in the original contract, we would be entitled to a reduced revenue dayrate from the terminating client, and likewise, the terminating client may be entitled to a payment from us if the new contract dayrates exceed those of the original contract. A client may also choose to early terminate the contract and make an upfront early termination payment based on a per day rate for the remaining term of the contract.

Revenues derived from rigs placed on standby or from the early termination of term drilling contracts are deferred and recognized as the amounts become fixed or determinable, over the remainder of the original term or when the rig is sold. As a result of the downturn that began in late 2014, term contracts for 19 of our drilling rigs were terminated early, including three that were terminated in early 2016. As of December 31, 2016, all of these contracts' terms have expired and all the associated revenue from the early terminations has been recognized.

Our current and long-term deferred revenues and costs as of December 31, 2016 and 2015 were as follows (amounts in thousands):

	December 31, 2016	December 31, 2015
Current:		
Deferred revenues	$ 1,449	$ 6,222
Deferred costs	2,290	1,539
Long-term:		
Deferred revenues	202	901
Deferred costs	212	928

Turnkey Drilling Contracts—Under a typical turnkey drilling contract, we agree to drill a well for our client to a specified depth and under specified conditions for a fixed price. We use the proportional performance basis to recognize revenue on our turnkey contracts. We accrue estimated contract costs on turnkey contracts for each day of work completed based on our estimate of the total costs to complete the contract divided by our estimate of the number of days to complete the contract. Contract costs include labor, materials, supplies, repairs and maintenance, operating overhead allocations and allocations of depreciation and amortization expense. If we anticipate a loss on a contract in progress due to a change in our cost estimate, we accrue the entire amount of the estimated loss, including all costs that are included in our revised estimated cost to complete that contract, in our consolidated statement of operations for that reporting period. Our actual results for a contract could differ significantly if our cost estimates for that contract are later revised from our original cost estimates for a contract in progress at the end of a reporting period which was not completed prior to the release of our financial statements.

Production Services—Our Production Services Segment earns revenues for well servicing, wireline services and coiled tubing services pursuant to master services agreements based on purchase orders, contracts or other arrangements with the client that include fixed or determinable prices. Production services jobs are generally short-term and are charged at current market rates. Production service revenue is recognized when the service has been rendered and collectability is reasonably assured.

Concentration of Clients—We derive a significant portion of our revenue from a limited number of major clients. For the years ended December 31, 2016, 2015 and 2014, our drilling and production services to our top three clients accounted for approximately 26%, 29%, and 28%, respectively, of our revenue. For a detail of our three largest clients as a percentage of our total revenues during the last three fiscal years, see Item 1—"Business" in Part I of this Annual Report on Form 10-K.

Cash and Cash Equivalents

For purposes of the statements of cash flows, we consider all highly liquid instruments purchased with a maturity of three months or less to be cash equivalents. Cash equivalents consist of investments in money market accounts. We had no cash equivalents at December 31, 2016. Cash equivalents at December 31, 2015 were $1.3 million.

Trade Accounts Receivable

We record trade accounts receivable at the amount we invoice our clients. These accounts do not bear interest. The allowance for doubtful accounts is our best estimate of the amount of probable credit losses in our accounts receivable as of the balance sheet date. We determine the allowance based on the credit worthiness of our clients and general economic conditions. Consequently, an adverse change in those factors could affect our estimate of our allowance for doubtful accounts.

We review our allowance for doubtful accounts on a monthly basis. Our typical drilling contract provides for payment of invoices in 30 days. We generally do not extend payment terms beyond 30 days and have not extended payment terms beyond 90 days for any of our domestic contracts in the last three fiscal years. Our production services terms generally provide for payment of invoices in 30 days. Balances more than 90 days past due are reviewed individually for collectability. We charge off account balances against the allowance after we have exhausted all reasonable means of collection and determined that the potential for recovery is remote. We do not have any off-balance sheet credit exposure related to our clients.

The changes in our allowance for doubtful accounts consist of the following (amounts in thousands):

	Year ended December 31, 2016	2015	2014
Balance at beginning of year	$ 2,254	$ 2,547	$ 1,356
Increase in allowance charged to expense	404	472	1,445
Accounts charged against the allowance	(980)	(765)	(254)
Balance at end of year	$ 1,678	$ 2,254	$ 2,547

Unbilled Accounts Receivable

The asset "unbilled receivables" represents revenues we have recognized in excess of amounts billed on drilling contracts and production services completed but not yet invoiced. We typically invoice our clients at 15-day intervals during the performance of daywork drilling contracts and upon completion of the daywork contract. Turnkey drilling contracts are invoiced upon completion of the contract.

Our unbilled receivables as of December 31, 2016 and 2015 were as follows (amounts in thousands):

	December 31, 2016	December 31, 2015
Daywork drilling contracts in progress	$ 7,042	$ 11,928
Turnkey drilling contracts in progress	—	606
Production services	375	1,090
	$ 7,417	$ 13,624

Inventories

Inventories primarily consist of drilling rig replacement parts and supplies held for use by our Drilling Services Segment's operations in Colombia, and supplies held for use by our Production Services Segment's operations. Inventories are valued at the lower of cost (first in, first out or actual) or market value.

Prepaid Expenses and Other Current Assets

Prepaid expenses and other current assets include items such as insurance, rent deposits and fees. We routinely expense these items in the normal course of business over the periods these expenses benefit. Prepaid expenses and other current assets also include the current portion of deferred mobilization costs for certain drilling contracts that are recognized on a straight-line basis over the contract term.

Property and Equipment

Property and equipment are carried at cost less accumulated depreciation. Depreciation is provided for our assets over the estimated useful lives of the assets using the straight-line method. We record the same depreciation expense whether a rig is idle or working. We charge our expenses for maintenance and repairs to operating costs. We capitalize expenditures for renewals and betterments to the appropriate property and equipment accounts.

Intangible Assets

Our intangible assets were recorded in connection with the acquisitions of production services businesses and are subject to amortization. As of December 31, 2016 and 2015, the estimated useful lives and components of our intangible asset classes are as follows:

		December 31,	
		2016	2015
	Lives	(amounts in thousands)	
Client relationships:	8 - 9		
Cost		$ 1,547	$ 13,692
Accumulated amortization		(1,149)	(11,782)
Non-compete agreements:	7		
Cost		150	575
Accumulated amortization		(145)	(541)
		$ 403	$ 1,944

The cost of our client relationships are amortized using the straight-line method over their respective estimated economic useful lives and amortization expense for our non-compete agreements is calculated using the straight-line method over the period of the agreements. Amortization expense was $1.5 million, $7.9 million and $8.0 million for the years ended December 31, 2016, 2015 and 2014, respectively. Amortization expense is estimated to be approximately $0.2 million for each of the years ending December 31, 2017 and 2018. Actual amortization amounts may be different due to future acquisitions, impairments, changes in amortization periods, or other factors.

During 2016, we removed $12.1 million and $0.4 million of fully amortized capitalized client relationship and non-compete agreement costs, respectively. Doing so had no net impact to our consolidated balance sheet or consolidated statement of operations as of and for the year ending December 31, 2016.

As a result of the downturn which began in late 2014 and worsened through 2015, our projected cash flows declined and we performed an impairment analysis of our long-lived tangible and intangible assets, which resulted in an impairment charge of $14.3 million recognized in 2015 that reduced the carrying value of our coiled tubing intangible assets to zero. We used an income approach to estimate the fair value of our coiled tubing services reporting unit. The most significant inputs used in our impairment analysis of our coiled tubing operations include the projected utilization and pricing of our coiled tubing services, which are classified as Level 3 inputs as defined by Accounting Standards Codification (ASC) Topic 820, *Fair Value Measurements and Disclosures*. Although we believe the assumptions and estimates used in our impairment analyses are reasonable and appropriate, different assumptions and estimates could materially impact the analyses and resulting conclusions. We assumed a 13% discount rate to estimate the fair value of the coiled tubing services reporting unit. A decrease in this assumption of 5% would have resulted in a decrease to our impairment charge of approximately $2 million. An increase of 1% in either the utilization or pricing assumptions would have resulted in a decrease to our impairment charge of approximately $1 million or $2 million, respectively. Our impairment analysis also resulted in an impairment to our coiled tubing tangible long-lived assets in 2015, which is discussed in more detail in Note 2, *Property and Equipment*.

Other Long-Term Assets

Other long-term assets consist of cash deposits related to the deductibles on our workers' compensation insurance policies, deferred compensation plan investments and the long-term portion of deferred mobilization costs.

Other Current Liabilities

Our other accrued expenses include accruals for items such as property tax, sales tax, and professional and other fees. We routinely expense these items in the normal course of business over the periods these expenses benefit.

Other Long-Term Liabilities

Our other long-term liabilities consist of the noncurrent portion of liabilities associated with our long-term compensation plans, deferred lease liabilities, and the long-term portion of deferred mobilization revenues.

Treasury Stock

Treasury stock purchases are accounted for under the cost method whereby the cost of the acquired common stock is recorded as treasury stock. Gains and losses on the subsequent reissuance of treasury stock shares are credited or charged to additional paid in capital using the average cost method.

Stock-based Compensation

We recognize compensation cost for stock option, restricted stock and restricted stock unit awards based on the fair value estimated in accordance with ASC Topic 718, Compensation—Stock Compensation. For our awards with graded vesting, we recognize compensation expense on a straight-line basis over the service period for each separately vesting portion of the award as if the award was, in substance, multiple awards.

We receive a tax deduction for certain stock option exercises during the period the options are exercised, generally for the excess of the fair market value of our stock on the date of exercise over the exercise price of the options. In accordance with ASC Topic 718, when we have excess tax benefits resulting from the exercise of stock options, we report them as financing cash flows in our consolidated statement of cash flows, unless otherwise disallowed under ASC Topic 740, *Income Taxes*.

Income Taxes

We follow the asset and liability method of accounting for income taxes, under which we recognize deferred tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. We measure our deferred tax assets and liabilities by using the enacted tax rates we expect to apply to taxable income in the years in which we expect to recover or settle those temporary differences. The effect of a change in tax rates on deferred tax assets and liabilities is reflected in income in the period during which the change occurs. A recent change in Colombia tax rates is described in more detail in Note 5, *Income Taxes*.

Related-Party Transactions

During the years ended December 31, 2016, 2015, and 2014, the Company paid approximately $0.2 million, $0.2 million and $0.4 million, respectively, for trucking and equipment rental services, which represented arms-length transactions, to Gulf Coast Lease Service. Joe Freeman, our Senior Vice President of Well Servicing, serves as the President of Gulf Coast Lease Service, which is owned and operated by Mr. Freeman’s two sons. Mr. Freeman does not receive compensation from Gulf Coast Lease Service, and he serves primarily in an advisory role to his sons.

Comprehensive Income

We have not reported comprehensive income due to the absence of items of other comprehensive income in the periods presented.

Recently Issued Accounting Standards

Revenue Recognition. In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, a comprehensive new revenue recognition standard that will supersede nearly all existing revenue recognition guidance. The standard outlines a single comprehensive model for revenue recognition based on the core principle that a company will recognize revenue when promised goods or services are transferred to clients, in an amount that reflects the consideration to which an entity expects to be entitled in exchange for those goods or services.

We are currently evaluating the impact of this guidance. We expect the adoption of this new standard to primarily affect the timing for the recognition of revenues derived from long-term drilling contracts.

We are required to apply this new standard beginning January 1, 2018, with earlier adoption permitted. We do not anticipate early adoption of this standard. Two methods of transition are permitted under this standard: the full retrospective method, in which the standard would be applied retrospectively to each prior reporting period presented, subject to certain allowable exceptions; or the modified retrospective method, in which the standard would be applied to all contracts existing as of the date of initial application, with the cumulative effect of applying the standard recognized in beginning retained earnings. We currently anticipate adopting this standard using the modified retrospective method, but we continue to evaluate both transition options available under the standard.

Debt Issuance Costs. On April 7, 2015, the FASB issued ASU No. 2015-03, *Simplifying the Presentation of Debt Issuance Costs,* which requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts, and that amortization of debt issuance costs be reported as interest expense. The recognition and measurement guidance for debt issuance costs are not affected by the amendments in this ASU. This ASU requires retrospective adoption and was effective for us beginning with our first quarterly filing in 2016. The adoption of this new standard resulted in reclassifying $7.8 million of debt issuance costs from other long-term assets to long-term debt in the accompanying December 31, 2015 consolidated balance sheet.

Leases. In February 2016, the FASB issued ASU No. 2016-02, *Leases*, which among other things, requires lessees to recognize substantially all leases on the balance sheet, with expense recognition that is similar to the current lease standard, and aligns the principles of lessor accounting with the principles of the FASB's new revenue guidance (referenced above). This ASU is effective for us beginning with our first quarterly filing in 2019. We are currently evaluating the potential impact of this guidance and have not yet determined its impact on our financial position and results of operations.

Stock-Based Compensation. In March 2016, the FASB issued ASU No. 2016-09, *Stock Compensation: Improvements to Employee Share-Based Payment Accounting*, to reduce complexity in accounting standards involving several aspects of the accounting for employee 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. This ASU is effective for us beginning with our first quarterly filing in 2017. We do not expect that the adoption of this update will have a material effect on our financial position or results of operations.

Credit Losses. In June 2016, the FASB issued ASU No. 2016-13, *Measurement of Credit Losses on Financial Instruments*, which sets forth an impairment model requiring the measurement of all expected credit losses for financial instruments (including trade receivables) held at the reporting date based on historical experience, current conditions, and reasonable supportable forecasts. This ASU is effective for us beginning with our first quarterly filing in 2020. We do not expect the adoption of this guidance to have a material impact on our financial position or results of operations.

Statement of Cash Flows. In August 2016, the FASB issued ASU No. 2016-15, *Statement of Cash Flows*, which clarifies how companies present and classify certain cash receipts and cash payments in the statement of cash flows. The update is intended to reduce the existing diversity in practice, and is effective for us beginning with our first quarterly filing in 2018. We do not expect the adoption of this guidance to have a material impact on our financial position and results of operations.

Reclassifications

Certain amounts in the consolidated financial statements for the prior years have been reclassified to conform to the current year's presentation.

2. Property and Equipment

As of December 31, 2016 and 2015, the estimated useful lives and costs of our asset classes are as follows:

		As of December 31,	
		2016	2015
	Lives	Cost (amounts in thousands)	
Drilling rigs and equipment	2 - 25	$ 589,243	$ 649,805
Well servicing rigs and equipment	3 - 20	226,294	246,539
Wireline units and equipment	2 - 10	142,909	148,501
Coiled tubing units and equipment	1 - 7	16,512	10,740
Vehicles	3 - 15	45,424	51,776
Office equipment	1 - 10	11,628	11,986
Buildings and improvements	2 - 40	23,884	25,228
Land	—	2,367	2,419
		$ 1,058,261	$ 1,146,994

Our capital expenditures were $32.6 million, $142.9 million and $188.1 million during the years ended December 31, 2016, 2015, and 2014 respectively, which includes $0.2 million, $3.0 million and $0.7 million respectively, of capitalized interest costs incurred during the construction periods of new drilling rigs and other drilling equipment. As of December 31, 2016 and 2015, capital expenditures incurred for property and equipment not yet placed in service was $8.7 million and $18.6 million, respectively, primarily related to new drilling equipment that was ordered in 2014, but which requires a long lead-time for delivery. This equipment will either be used to construct new drilling rigs or as spare equipment for our AC rig fleet. Capital expenditures during 2016 consisted primarily of routine expenditures to maintain our drilling and production services fleets. Capital expenditures during 2015 and 2014 primarily related to our five drilling rigs which began construction during 2014 and were completed in 2015, as well as unit additions to our production services fleets that were ordered in 2014.

We recorded a net gain during the year ended December 31, 2016 of $1.9 million on the disposition of property and equipment, primarily for the sale of three SCR drilling rigs for aggregate proceeds of $11.0 million and the disposal of excess drill pipe for a gain. The net gains on disposition of assets were partially offset by a loss on the disposition of damaged property when one of our AC drilling rigs sustained damages that resulted in a disposal of the damaged components with an aggregate net carrying value of $4.0 million, for which we received insurance proceeds of $3.1 million in January 2017 and recognized a net loss on disposal of $0.9 million. Additionally, we retired two domestic SCR rigs at the end of 2016 and placed the remaining two as held for sale at December 31, 2016.

During the year ended December 31, 2015, we recorded a net gain of $4.3 million on the disposition of property and equipment, primarily for the sale of 32 drilling rigs and other drilling equipment which we sold for aggregate proceeds of $53.6 million. In 2014, we sold our trucking assets and our fishing and rental services operations for a net gain of $10.7 million. (See Note 12, *Sale of Fishing and Rental Services Operations*, for more information.)

As of December 31, 2016, our consolidated balance sheet reflects assets held for sale of $15.1 million, which primarily represents the fair value of six domestic mechanical and SCR drilling rigs and drilling equipment, 13 wireline units, 20 older well servicing rigs that will be traded in for 20 new-model rigs in the first quarter of 2017, and certain coiled tubing equipment.

Impairments

We evaluate for potential impairment of long-lived tangible and intangible assets subject to amortization when indicators of impairment are present. Circumstances that could indicate a potential impairment include significant adverse changes in industry trends, economic climate, legal factors, and an adverse action or assessment by a regulator. More specifically, significant adverse changes in industry trends include significant declines in revenue rates, utilization rates, oil and natural gas market prices and industry rig counts. In performing an impairment evaluation, we estimate the future undiscounted net cash flows from the use and eventual disposition of long-lived tangible and intangible assets grouped at the lowest level that cash flows can be identified. For our Production Services Segment, we perform an impairment evaluation and estimate future undiscounted cash flows for the individual reporting units (well servicing, wireline and coiled tubing).

For our Drilling Services Segment, we perform an impairment evaluation and estimate future undiscounted cash flows for individual domestic drilling rig assets and for our Colombian drilling rig assets as a group. If the sum of the estimated future undiscounted net cash flows is less than the carrying amount of the asset group, then we determine the fair value of the asset group. The amount of an impairment charge is measured as the difference between the carrying amount and the fair value of the assets.

Since late 2014, oil prices have declined significantly resulting in a downturn in our industry, affecting both drilling and production services. As a result, we performed several impairment evaluations during 2014, 2015 and 2016 on our long-lived assets, in accordance with ASC Topic 360, *Property, Plant and Equipment*, summarized below.

As of December 31, 2014, we owned a total of 31 mechanical and lower horsepower electric drilling rigs. We performed impairment testing on all the mechanical and lower horsepower drilling rigs in our fleet as of December 31, 2014, which resulted in a total impairment of $71 million to reduce the carrying value of these assets to their estimated fair values, based on market appraisals which are considered Level 3 inputs as defined by ASC Topic 820, *Fair Value Measurements and Disclosures*. During 2015, we sold 28 of these rigs and placed the remaining three as held for sale.

We also performed an impairment test on our drilling rigs in Colombia as of December 31, 2014, at which time we concluded that the sum of the estimated future undiscounted cash flows associated with our Colombian operations was in excess of the carrying amount and concluded that no impairment was present. As the downturn worsened through the first half of 2015, resulting in significantly reduced revenue and utilization rates, and our projections reflected a more delayed recovery than previously anticipated, we performed impairment testing on all the SCR drilling rigs in our fleet, including the eight drilling rigs in Colombia, and our coiled tubing operations as of June 30, 2015. Our analysis at June 30, 2015 indicated that the carrying value of our coiled tubing reporting unit and the carrying value of our domestic pad-capable SCR drilling rigs (those that are equipped with either a walking or skidding system) were recoverable and thus there was no impairment present at June 30, 2015.

However, our analysis at June 30, 2015 indicated that the carrying values of our then six SCR drilling rigs in our domestic fleet which were not pad-capable, and our Colombian assets as a group, exceeded our estimated undiscounted cash flows for these assets. As a result, we recognized impairment charges of $50.2 million to reduce the carrying values of all eight drilling rigs in Colombia and related drilling equipment, $3.6 million to reduce the carrying value of inventory in Colombia, $6.4 million to reduce the carrying value of nonrecoverable prepaid taxes associated with our Colombian operations, and $9.7 million to reduce the carrying values of our then six SCR drilling rigs that were not pad-capable, to their estimated fair values, which were based on market appraisals. Three of these SCR drilling rigs that were not pad-capable were subsequently sold in 2015, one was placed as held for sale at December 31, 2015, and the remaining two were retired in 2016.

Our projected cash flows declined further as compared to our projections made earlier in the year and at September 30, 2015, we again performed impairment testing on our coiled tubing operations and seven drilling rigs, including our domestic pad-capable SCR rigs, and determined that our carrying values in these assets were recoverable but at risk for future impairment. As the downturn persisted through the remainder of 2015, we again performed impairment testing on these assets at December 31, 2015. As a result, we recognized $14.3 million of impairment related to our coiled tubing intangibles, $16.6 million of impairment to reduce the carrying values of our coiled tubing units and equipment to their estimated fair value, based on market appraisals, and $18.6 million to reduce the carrying values of our then six domestic pad-capable SCR rigs to their estimated fair values, which were also based on market appraisals. Of these six domestic SCR rigs, one was subsequently sold in 2015, three were sold in 2016 and the remaining two were placed as held for sale at December 31, 2016.

Business conditions and our projected cash flows for our Colombian operations improved as compared to the projections used for the impairment analysis in 2015, therefore we did not perform any impairment testing on this business in 2016. However, due to lower than anticipated operating results in 2016 and a decline in our projected cash flows for the coiled tubing reporting unit, we performed an impairment analysis of our coiled tubing long-lived assets at September 30, 2016 which indicated that our projected net undiscounted cash flows associated with the coiled tubing reporting unit were in excess of the net carrying value of the assets, and thus no impairment was present.

During the years ended December 31, 2016, 2015 and 2014, we recognized impairment charges of $11.9 million, $9.9 million, and $2.0 million, respectively, to reduce the carrying values of assets which were classified as held for sale, to their estimated fair values, based on expected sales prices. During the year ended December 31, 2016, we also recognized

$0.9 million of impairment charges to reduce the carrying value of a portion of steel that is on hand for the construction of drilling rigs, which we no longer believe is likely to be used.

The following table summarizes impairment charges recognized during the years ended December 31, 2016, 2015, and 2014 (amounts in thousands):

	Year ended December 31,		
	2016	2015	2014
Assets held for sale	$ 11,897	$ 9,858	$ 1,977
Colombian assets	—	60,130	—
Domestic drilling rigs and equipment	918	28,228	71,048
Coiled tubing assets	—	30,936	—
	$ 12,815	$ 129,152	$ 73,025

In order to estimate our future undiscounted cash flows from the use and eventual disposition of our drilling assets, we incorporated probabilities of selling these assets in the near term, versus working them at a significantly reduced expected rate of utilization through the end of their remaining useful lives. The most significant assumptions used in our analysis are the expected margin per day and utilization, as well as the estimated proceeds upon any future sale or disposal of the assets. We used an income approach to estimate the fair value of our coiled tubing services reporting unit. The most significant inputs used in our impairment analysis of our coiled tubing operations include the projected utilization and pricing of our coiled tubing services, which are classified as Level 3 inputs as defined by Accounting Standards Codification (ASC) Topic 820, *Fair Value Measurements and Disclosures*.

Although we believe the assumptions and estimates used in our impairment analyses are reasonable and appropriate, different assumptions and estimates could materially impact the analyses and resulting conclusions. The assumptions used in the impairment evaluation for long-lived assets are inherently uncertain and require management judgment. These impairment charges are not expected to have an impact on our liquidity or debt covenants; however, they are a reflection of the overall downturn in our industry and decline in our projected future cash flows. If the demand for our services remains at current levels or declines further and any of our assets become or remain idle for an extended amount of time, then our estimated cash flows may further decrease, and the probability of a near term sale may increase. If any of the foregoing were to occur, we may incur additional impairment charges.

3. Debt

Our debt consists of the following (amounts in thousands):

	December 31, 2016	December 31, 2015
Senior secured revolving credit facility	$ 46,000	$ 95,000
Senior notes	300,000	300,000
	346,000	395,000
Less unamortized debt issuance costs	(6,527)	(7,783)
	$ 339,473	$ 387,217

Senior Secured Revolving Credit Facility

We have a credit agreement, as most recently amended on June 30, 2016, with Wells Fargo Bank, N.A. and a syndicate of lenders which provides for a senior secured revolving credit facility, with sub-limits for letters of credit and swing-line loans, of up to a current aggregate commitment amount of $150 million, subject to availability under a borrowing base comprised of certain eligible cash, certain eligible receivables, certain eligible inventory, and certain eligible equipment of ours and certain of our subsidiaries, all of which matures in March 2019 (the “Revolving Credit Facility”). The Revolving Credit Facility contains customary mandatory prepayments from the proceeds of certain asset dispositions or equity or debt issuances, which are applied to reduce outstanding revolving and swing-line loans and to cash-collateralize letter of credit exposure, and in certain cases, also reduce the commitment amount available.

In December 2016, we sold 12,075,000 shares of common stock in a public offering, which resulted in proceeds of approximately $65.4 million, net of underwriting discounts and offering expenses, under the shelf registration statement filed in May 2015. In accordance with the Revolving Credit Facility terms, all of the proceeds were applied to reduce the outstanding borrowing balance, and the total commitment amount available was reduced from $175 million to $150 million.

Borrowings under the Revolving Credit Facility bear interest, at our option, at the LIBOR rate or at the bank prime rate, plus an applicable per annum margin of 5.50% and 4.50%, respectively. The Revolving Credit Facility requires a commitment fee due quarterly based on the average daily unused amount of the commitments of the lenders, a fronting fee due for each letter of credit issued, and a quarterly letter of credit fee due based on the average undrawn amount of letters of credit outstanding during such period. Additionally, the Revolving Credit Facility requires that if on the last business day of each week, our aggregate amount of cash at the end of the preceding day (as calculated pursuant to the Revolving Credit Facility) exceeds $20 million, we pay down the outstanding principal balance by the amount of such excess.

Our obligations under the Revolving Credit Facility are secured by substantially all of our domestic assets (including equity interests in Pioneer Global Holdings, Inc. and 65% of the outstanding voting equity interests, and 100% of non-voting equity interests, of any first-tier foreign subsidiaries owned by Pioneer Global Holdings, Inc., but excluding any equity interest in, and any assets of, Pioneer Services Holdings, LLC) and are guaranteed by certain of our domestic subsidiaries, including Pioneer Global Holdings, Inc. Borrowings under the Revolving Credit Facility are available for acquisitions, working capital and other general corporate purposes.

As of January 31, 2017, we had $49.7 million outstanding under our Revolving Credit Facility and $11.8 million in committed letters of credit, which resulted in borrowing availability of $88.5 million under our Revolving Credit Facility. There are no limitations on our ability to access the borrowing capacity provided there is no default, all representations and warranties are true and correct, and compliance with financial covenants under the Revolving Credit Facility is maintained. At December 31, 2016, we were in compliance with our financial covenants under the Revolving Credit Facility.

The financial covenants contained in our Revolving Credit Facility include the following:

- A maximum senior consolidated leverage ratio, calculated as senior consolidated debt at the period end, which excludes unsecured and subordinated debt, divided by EBITDA for the trailing twelve month period at each quarter end, as defined in the Revolving Credit Facility. The senior consolidated leverage ratio cannot exceed the maximum amounts as follows:

  - 5.00 to 1.00 on September 30, 2017
  - 4.00 to 1.00 on December 31, 2017
  - 3.50 to 1.00 on March 31, 2018
  - 3.25 to 1.00 on June 30, 2018
  - 2.50 to 1.00 at any time after June 30, 2018

- A minimum interest coverage ratio, calculated as EBITDA for the trailing twelve month period at each quarter end, as defined in the Revolving Credit Facility, divided by interest expense for the same period. The interest coverage ratio cannot be less than the minimum amounts as follows:

  - 1.00 to 1.00 for the quarterly period ending September 30, 2017
  - 1.25 to 1.00 for the quarterly period ending December 31, 2017
  - 1.50 to 1.00 at any time after December 31, 2017

- A minimum EBITDA requirement, for the periods indicated, as defined in the Revolving Credit Facility. EBITDA required at the end of forthcoming fiscal quarters cannot be less than the minimum amounts as follows:

  - $7 million for the three-fiscal quarter period ending March 31, 2017
  - $12 million for the four-fiscal quarter period ending June 30, 2017

The Revolving Credit Facility restricts capital expenditures to the following amounts during each forthcoming fiscal year as follows:

- $35 million in fiscal year 2017
- $50 million in fiscal year 2018
- $50 million in fiscal year 2019

The capital expenditure threshold for each of the fiscal years above may be increased by up to 50% of the unused portion of the capital expenditure threshold for the immediate preceding fiscal year, limited to a maximum of $5 million in 2017, and $7.5 million in each of the years 2018 and 2019. In addition to the above requirements, additional capital expenditures may be made up to the amount of net proceeds from equity issuances, or if the following conditions are satisfied:

- the aggregate outstanding commitments under the Revolving Credit Facility do not exceed $150 million;
- the pro forma senior leverage and total leverage ratios, calculated as defined in the Revolving Credit Facility, are less than 2.00 to 1.00 and 4.50 to 1.00, respectively.

Pursuant to the terms above, our capital expenditures are limited to a total of $101.7 million for the fiscal year 2017.

The Revolving Credit Facility has additional restrictive covenants that, among other things, limit our ability to:

- incur additional debt or make prepayments of existing debt;
- create liens on or dispose of our assets;
- pay dividends on stock or repurchase stock;
- enter into acquisitions, mergers, consolidations, sale leaseback transactions, or hedging contracts;
- make other restricted investments;
- conduct transactions with affiliates; and
- limits our use of the net proceeds of any offering of our equity securities to the repayment of debt outstanding under the Revolving Credit Facility.

In addition, the Revolving Credit Facility contains customary events of default, including without limitation:

- payment defaults;
- breaches of representations and warranties;
- covenant defaults;
- cross-defaults to certain other material indebtedness in excess of specified amounts;
- certain events of bankruptcy and insolvency;
- judgment defaults in excess of specified amounts;
- failure of any guaranty or security document supporting the credit agreement; and
- change of control.

Senior Notes

In 2014, we issued $300 million of unregistered senior notes with a coupon interest rate of 6.125% that are due in 2022 (the “Senior Notes”). The Senior Notes were sold at 100% of their face value. After deductions were made for the $6.1 million for underwriters’ fees and other debt offering costs, we received $293.9 million of net proceeds. In order to reduce our overall interest expense and lengthen the overall maturity of our senior indebtedness, during 2014, we redeemed all of our then outstanding $425 million of unregistered senior notes with a coupon interest rate of 9.875% that were issued in 2010 and 2011 and were set to mature in 2018, funded primarily by proceeds from the issuance of Senior Notes in 2014 and additional borrowings under our Revolving Credit Facility, as well as some cash on hand.

The Senior Notes will mature on March 15, 2022 with interest due semi-annually in arrears on March 15 and September 15 of each year. We have the option to redeem the Senior Notes, in whole or in part, at any time on or after March 15, 2017 in each case at the redemption price specified in the Indenture dated March 18, 2014 (the “Indenture”) plus any accrued and unpaid interest and any additional interest (as defined in the Indenture) thereon to the date of redemption. Prior to March 15, 2017, we may also redeem the Senior Notes, in whole or in part, at a “make-whole” redemption price specified in the Indenture, plus any accrued and unpaid interest and any additional interest thereon to the date of redemption. In addition, prior to March 15, 2017, we may, on one or more occasions, redeem up to 35% of the aggregate principal amount of the Senior Notes at a redemption price equal to 106.125% of the principal amount thereof, plus accrued and unpaid interest and additional interest, if any, to the redemption date, with the net cash proceeds of certain equity offerings, provided that at least 65% of the aggregate principal amount of the Senior Notes remains outstanding after the occurrence of such redemption and that the redemption occurs within 120 days of the date of the closing of such equity offering.

In accordance with a registration rights agreement with the holders of our Senior Notes, we filed an exchange offer registration statement on Form S-4 with the Securities and Exchange Commission that became effective on October 2, 2014. The exchange offer registration statement enabled the holders of our Senior Notes to exchange their senior notes for publicly registered notes with substantially identical terms. References to the "Senior Notes" herein include the senior notes issued in the exchange offer.

If we experience a change of control (as defined in the Indenture), we will be required to make an offer to each holder of the Senior Notes to repurchase all or any part of the Senior Notes at a purchase price equal to 101% of the principal amount of each Senior Note, plus accrued and unpaid interest, if any, to the date of repurchase. If we engage in certain asset sales, within 365 days of such sale we will be required to use the net cash proceeds from such sale, to the extent we do not reinvest those proceeds in our business, to make an offer to repurchase the Senior Notes at a price equal to 100% of the principal amount of each Senior Note, plus accrued and unpaid interest to the repurchase date.

The Indenture, among other things, limits us and certain of our subsidiaries in our ability to:

- pay dividends on stock, repurchase stock, redeem subordinated indebtedness or make other restricted payments and investments;
- incur, assume or guarantee additional indebtedness or issue preferred or disqualified stock;
- create liens on our or their assets;
- enter into sale and leaseback transactions;
- sell or transfer assets;
- borrow, pay dividends, or transfer other assets from certain of our subsidiaries;
- consolidate with or merge with or into, or sell all or substantially all of our properties to any other person;
- enter into transactions with affiliates; and
- enter into new lines of business.

The Senior Notes are not subject to any sinking fund requirements. The Senior Notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by certain of our existing domestic subsidiaries and by certain of our future domestic subsidiaries. (See Note 14, *Guarantor/Non-Guarantor Condensed Consolidated Financial Statements*.)

Debt Issuance Costs

Costs incurred in connection with the Revolving Credit Facility were capitalized and are being amortized using the straight-line method over the term of the Revolving Credit Facility which matures in March 2019. Costs incurred in connection with the issuance of our Senior Notes were capitalized and are being amortized using the straight-line method (which approximates amortization using the interest method) over the term of the Senior Notes which mature in March 2022.

Capitalized debt costs related to the issuance of our long-term debt were approximately $6.5 million and $7.8 million as of December 31, 2016 and 2015, respectively. We recognized approximately $1.8 million, $1.7 million and $2.1 million of associated amortization during the years ended December 31, 2016, 2015 and 2014, respectively. Additionally, during the years ended December 31, 2016 and 2015, we recognized $0.3 million and $2.2 million, respectively, of loss on extinguishment of debt for the write off of unamortized debt issuance costs associated with the reduction of borrowing capacity under our Revolving Credit Facility. During 2014, we recognized a loss on debt extinguishment of $31.2 million for the redemption of the 2010 and 2011 Senior Notes, which included redemption premiums of $21.6 million, $4.8 million of net unamortized discount and $4.8 million of unamortized debt issuance costs.

4. Leases

We lease our corporate office facilities in San Antonio, Texas at a payment escalating from $46,502 per month in January 2017 to $50,246 per month beginning in January 2020. We recognize rent expense on a straight-line basis for our corporate office lease. We also lease real estate at 41 other locations, which are primarily used for field offices and storage and maintenance yards, and we lease office and other equipment under non-cancelable operating leases, most of which contain renewal options and some of which contain escalation clauses.

Future lease obligations required under non-cancelable operating leases as of December 31, 2016 were as follows (amounts in thousands):

Year ended December 31,	
2017	$ 3,427
2018	2,673
2019	2,199
2020	1,394
2021	471
Thereafter	116
	$ 10,280

During 2015, we ceased use of several location offices which were under long-term leases and recognized an expense in order to accrue the fair value of future lease obligations associated with the facilities which we are no longer using, in accordance with ASC Topic 420, *Exit or Disposal Obligations*. These accrued lease obligations, which were $0.1 million and $0.3 million as of December 31, 2016 and 2015, respectively, have been included in our current and long-term liabilities, according to the lease terms, and are not reflected in the table above. Including the impact of lease termination penalties, total lease related exit costs incurred for the year ended December 31, 2015 was $0.5 million. Rent expense under operating leases, including rental exit costs, was $5.0 million, $6.2 million and $5.9 million for the years ended December 31, 2016, 2015 and 2014, respectively.

5. Income Taxes

The jurisdictional components of loss before income taxes consist of the following (amounts in thousands):

	Year ended December 31,		
	2016	2015	2014
Domestic	$ (122,277)	$ (123,499)	$ (49,050)
Foreign	(16,846)	(69,220)	(272)
Loss before income taxes	$ (139,123)	$ (192,719)	$ (49,322)

The components of our income tax expense (benefit) consist of the following (amounts in thousands):

	Year ended December 31,		
	2016	2015	2014
Current taxes:			
Federal	$ (219)	$ (535)	$ (112)
State	(95)	401	1,325
Foreign	1,189	1,238	3,149
	875	1,104	4,362
Deferred taxes:			
Federal	(12,500)	(42,113)	(17,438)
State	902	29	1,304
Foreign	(9)	3,401	468
	(11,607)	(38,683)	(15,666)
Income tax benefit	$ (10,732)	$ (37,579)	$ (11,304)

The difference between the income tax benefit and the amount computed by applying the federal statutory income tax rate of 35% to loss before income taxes consists of the following (amounts in thousands):

	Year ended December 31,		
	2016	2015	2014
Expected tax expense (benefit)	$ (48,693)	$ (67,452)	$ (17,263)
Valuation allowance	38,324	20,329	496
State income taxes	(3,033)	(2,066)	1,214
Foreign currency translation loss	838	8,660	2,699
Net tax benefits and nondeductible expenses in foreign jurisdictions	407	2,135	1,128
Incentive stock options	97	83	(208)
Nondeductible expenses for tax purposes	386	577	920
Expiration of capital loss	641	—	—
Effects of change in tax laws	516	—	(171)
Other, net	(215)	155	(119)
Income tax benefit	$ (10,732)	$ (37,579)	$ (11,304)

Income tax expense (benefit) was allocated as follows (amounts in thousands):

	Year ended December 31,		
	2016	2015	2014
Continuing operations	$ (10,732)	$ (37,579)	$ (11,304)
Shareholders' equity	2,287	962	201
	$ (8,445)	$ (36,617)	$ (11,103)

Deferred income taxes arise from temporary differences between the tax basis of assets and liabilities and their reported amounts in the consolidated financial statements. The components of our deferred income tax assets and liabilities were as follows (amounts in thousands):

	Year ended December 31,	
	2016	2015
Deferred tax assets:		
Domestic net operating loss carryforward	$ 122,769	$ 84,853
Foreign net operating loss carryforward	8,640	3,909
Intangibles	33,722	37,634
Property and equipment	11,809	10,317
Employee benefits and insurance claims accruals	6,802	6,307
Employee stock-based compensation	6,732	8,093
Accounts receivable reserve	626	849
Inventory	613	631
Accrued expenses not deductible for tax purposes	232	453
Accrued revenue not income for book purposes	277	695
Capital loss carryforward	—	666
	192,222	154,407
Valuation allowance	(57,820)	(18,627)
Deferred tax liabilities:		
Property and equipment	(142,582)	(153,282)
Net deferred tax assets (liabilities)	$ (8,180)	$ (17,502)

As of December 31, 2016, we had $131.4 million of deferred tax assets related to domestic and foreign net operating losses that are available to reduce future taxable income. In assessing the realizability of our deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible.

In performing this analysis as of December 31, 2016 in accordance with ASC Topic 740, *Income Taxes*, we assessed the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit the use of deferred tax assets. A significant piece of objective negative evidence evaluated is the projected cumulative loss incurred over the three-year period ended December 31, 2016. Such objective negative evidence limits the ability to consider other subjective positive evidence, such as projections for taxable income in future years. Due to the continued downturn in our industry, we were in a net deferred tax asset position at the end of 2016, and as a result, we recognized a benefit only to the extent that reversals of deferred income tax liabilities are expected to generate income tax expense in each relevant jurisdiction in future periods which would offset our deferred tax assets.

Our domestic net operating losses have a 20 year carryforward period and can be used to offset future domestic taxable income until their expiration, beginning in 2030, with the latest expiration in 2036. However, we determined that a valuation allowance should be recorded against a portion of the benefit generated in 2016. The valuation allowance is the primary factor causing our effective tax rate to be significantly lower than the statutory rate of 35%. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income are reduced or increased or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective evidence such as projected future taxable income.

The majority of our foreign net operating losses have an indefinite carryforward period. However, as a result of the conditions leading to the impairment of our assets in Colombia during 2015 and the continued industry downturn, we have a valuation allowance that fully offsets our $21.1 million of foreign deferred tax assets at December 31, 2016.

Additionally, we reversed a valuation allowance of $0.7 million related to a deferred tax asset for a capital loss that expired in 2016.

Deferred income taxes have not been provided on the future tax consequences attributable to differences between the financial statements carrying amounts of existing assets and liabilities and the respective tax basis of our foreign subsidiary based on the determination that such differences are essentially permanent in duration in that the earnings of the subsidiary is expected to be indefinitely reinvested in foreign operations. As of December 31, 2016, the cumulative undistributed earnings of the subsidiary was a loss of approximately $41.2 million. If earnings were not considered indefinitely reinvested, deferred income taxes would have been recorded after consideration of foreign tax credits. It is not practicable to estimate the amount of additional tax that might be payable on earnings, if distributed.

In November 2015, the FASB issued ASU No. 2015-17, *Balance Sheet Classification of Deferred Taxes*, which requires that deferred tax assets and liabilities be classified as noncurrent on the balance sheet rather than being separately presented as current and noncurrent portions. On December 31, 2015, we elected to early adopt ASU No. 2015-17 prospectively, thus reclassifying $6.8 million of current deferred tax assets to noncurrent on the accompanying consolidated balance sheet.

On December 23, 2014, the Colombian government enacted a tax reform bill that among other things, increased the tax for equality ("CREE") rate from 9% to 14% in 2015, 15% in 2016, 17% in 2017 and 18% in 2018. Deferred tax assets and liabilities (with the exception of net operating losses) must now be based on the higher combined income tax rate and CREE rate of 39% in 2015, 40% in 2016, 42% in 2017 and 43% in 2018. However, as of December 31, 2015, we recorded a valuation allowance that fully offsets our foreign deferred tax assets relating to net operating losses and other tax benefits. At this time, a new net-worth tax was also enacted for all Colombian entities. The tax is calculated based on an entity's net equity as of January 1, 2015. The tax expense is recognized when the net-worth tax is assessed, annually from 2015 through 2017. Based on our Colombian operation's net equity, our net-worth tax obligation was $1.2 million for 2015, $0.7 million for 2016 and is expected to be approximately $0.3 million for 2017. The net worth tax is not deductible for income tax purposes.

On December 29, 2016, the Colombian government again enacted a tax reform bill that eliminated the tax for equality ("CREE"), increased the general corporate tax rate from 25% to 40% in 2017, 37% in 2018, 33% in 2019 and created a new 5% dividend tax, among other things. A few other notable provisions include a shorter twelve-year carryforward period for net operating losses generated after 2016, a longer statute of limitations for returns filed after 2016 and annual limits on tax depreciation allowed.

We have no unrecognized tax benefits relating to ASC Topic 740 and no unrecognized tax benefit activity during the year ended December 31, 2016.

We record interest and penalty expense related to income taxes as interest and other expense, respectively. At December 31, 2016, no interest or penalties have been or are required to be accrued. Our open tax years are 2010 and forward for our federal and most state income tax returns in the United States and 2011 and forward for our income tax returns in Colombia.

6. Fair Value of Financial Instruments

The FASB's Accounting Standards Codification (ASC) Topic 820, *Fair Value Measurements and Disclosures*, defines fair value and provides a hierarchal framework associated with the level of subjectivity used in measuring assets and liabilities at fair value.

At December 31, 2016 and December 31, 2015, our financial instruments consist primarily of cash, trade and other receivables, trade payables, phantom stock unit awards which are described in Note 8, *Equity Transactions and Stock-Based Compensation Plans*, and long-term debt. The carrying value of cash, trade and other receivables, and trade payables are considered to be representative of their respective fair values due to the short-term nature of these instruments.

The fair value of our long-term debt is estimated using a discounted cash flow analysis, based on rates that we believe we would currently pay for similar types of debt instruments. This discounted cash flow analysis is based on inputs defined by ASC Topic 820 as level 2 inputs, which are observable inputs for similar types of debt instruments. The following table presents the supplemental fair value information about long-term debt (amounts in thousands):

	December 31, 2016		December 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Total debt, net of debt issuance costs	$ 339,473	$ 326,249	$ 387,217	$ 242,354

7. Earnings Per Common Share

The following table presents a reconciliation of the numerators and denominators of the basic earnings per share and diluted earnings per share computations (amounts in thousands, except per share data):

	Year ended December 31,		
	2016	2015	2014
Numerator (both basic and diluted):			
Net loss	$ (128,391)	$ (155,140)	$ (38,018)
Denominator:			
Weighted-average shares (denominator for basic earnings per share)	65,452	64,310	63,161
Diluted effect of outstanding stock options, restricted stock and restricted stock unit awards	—	—	—
Denominator for diluted earnings per share	65,452	64,310	63,161
Loss per common share—Basic	$ (1.96)	$ (2.41)	$ (0.60)
Loss per common share—Diluted	$ (1.96)	$ (2.41)	$ (0.60)
Potentially dilutive securities excluded as anti-dilutive	4,953	4,832	3,949

8. Equity Transactions and Stock-Based Compensation Plans

Equity Transactions

In May 2015, we filed a registration statement that permits us to sell equity or debt in one or more offerings up to a total dollar amount of $300 million. In December 2016, we sold 12,075,000 shares of common stock in a public offering, which resulted in proceeds of approximately $65.4 million, net of underwriting discounts and offering expenses, under the shelf registration statement. As of December 31, 2016, $234.6 million under the shelf registration statement is available for equity or debt offerings, subject to the limitations imposed by our Revolving Credit Facility and Senior Notes, as well as our Restated Articles of Incorporation which currently limits our issuance of common stock to 100 million shares. In the future, we may consider equity and/or debt offerings, as appropriate, to meet our liquidity needs.

Stock-based Compensation Plans

We have stock-based award plans that are administered by the Compensation Committee of our Board of Directors, which selects persons eligible to receive awards and determines the number, terms, conditions and other provisions of the awards.

At December 31, 2016, the total shares available for future grants to employees and directors under existing plans were 4,603,268, which excludes awards we grant in the form of phantom stock unit awards which are expected to be paid in cash. For more information about the shares available under existing plans, see Part III, Item 12, *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*, of this Annual Report on Form 10-K. In January 2017, our Board of Directors approved the grant of the following awards, each with a three-year vesting term:

	Number of Shares or Units
Stock options	268,185
Restricted stock unit awards	630,197
	898,382

We grant stock option and restricted stock awards with vesting based on time of service conditions. We grant restricted stock unit awards with vesting based on time of service conditions, and in certain cases, subject to performance and market conditions. In 2016, we granted phantom stock unit awards with vesting based on time of service, performance and market conditions, which were classified as liability awards under ASC Topic 718, *Compensation—Stock Compensation* since we expect to settle the awards in cash when they become vested. We recognize compensation cost for stock option, restricted stock, restricted stock unit, and phantom stock unit awards based on the fair value estimated in accordance with ASC Topic 718. For our awards with graded vesting, we recognize compensation expense on a straight-line basis over the service period for each separately vesting portion of the award as if the award was, in substance, multiple awards.

The following table summarizes the stock-based compensation expense recognized, by award type, and the compensation expense recognized for phantom stock unit awards during the years ended December 31, 2016, 2015 and 2014 (amounts in thousands):

	Year ended December 31,		
	2016	2015	2014
Stock option awards	$ 766	$ 923	$ 1,275
Restricted stock awards	421	399	548
Restricted stock unit awards	2,757	2,307	5,794
	$ 3,944	$ 3,629	$ 7,617
Phantom stock unit awards	$ 1,971	$ —	$ —

The following table summarizes the unrecognized compensation cost (amounts in thousands) to be recognized and the weighted-average period remaining (in years) over which the compensation cost is expected to be recognized, by award type, as of December 31, 2016:

	Weighted-Average Period Remaining	Unrecognized Compensation Cost
Stock options	0.93	$ 415
Restricted stock awards	0.38	175
Restricted stock unit awards	1.37	1,476
Phantom stock unit awards	2.33	5,016
		$ 7,082

Stock Options

We grant stock option awards which generally become exercisable over a three-year period and expire ten years after the date of grant. Our stock-based compensation plans require that all stock option awards have an exercise price that is not less than the fair market value of our common stock on the date of grant. We issue shares of our common stock when vested stock option awards are exercised.

We estimate the fair value of each option grant on the date of grant using a Black-Scholes option pricing model. The following table summarizes the assumptions used in the Black-Scholes option pricing model based on a weighted-average calculation for the options granted during the years ended December 31, 2016, 2015 and 2014:

	Year ended December 31,		
	2016	2015	2014
Expected volatility	70%	64%	66%
Risk-free interest rates	1.5%	1.4%	1.7%
Expected life in years	5.70	5.52	5.49
Grant-date fair value	$0.80	$2.31	$4.87

The assumptions used in the Black-Scholes option pricing model are based on multiple factors, including historical exercise patterns of homogeneous groups with respect to exercise and post-vesting employment termination behaviors, expected future exercising patterns for these same homogeneous groups and volatility of our stock price. As we have not declared dividends since we became a public company, we did not use a dividend yield. In each case, the actual value that will be realized, if any, will depend on the future performance of our common stock and overall stock market conditions. There is no assurance the value an optionee actually realizes will be at or near the value we have estimated using the Black-Scholes options-pricing model.

The following table summarizes our stock option activity from December 31, 2015 through December 31, 2016:

	Number of Shares	Weighted-Average Exercise Price Per Share	Weighted-Average Remaining Contract Term in Years	Aggregate Intrinsic Value (in thousands)[(1)]
Outstanding stock options as of December 31, 2015	4,221,954	$9.58		
Granted	905,966	1.31		
Forfeited	(696,691)	12.79		
Exercised	(46,804)	3.92		
Outstanding stock options as of December 31, 2016	4,384,425	$7.42	4.8	$7,741
Stock options exercisable as of December 31, 2016	3,197,508	$9.35	3.3	$2,125

(1) Intrinsic value is the amount by which the market price of our common stock exceeds the exercise price of the stock options.

The aggregate intrinsic value of stock options exercised during the years ended December 31, 2016, 2015 and 2014 was $12 thousand, $0.4 million and $5.6 million, respectively. We receive a tax deduction for certain stock option exercises during the period the options are exercised, generally for the excess of the fair market value of our stock on the date of exercise over the exercise price of the options. In accordance with ASC Topic 718, when we have excess tax benefits resulting from the exercise of stock options, we report them as financing cash flows in our consolidated statement of cash flows, unless otherwise disallowed under ASC Topic 740, *Income Taxes*.

The following table summarizes our nonvested stock option activity from December 31, 2015 through December 31, 2016:

	Number of Shares	Weighted-Average Grant-Date Fair Value Per Share
Nonvested stock options as of December 31, 2015	514,154	$3.19
Granted	905,966	0.80
Vested	(233,203)	3.55
Nonvested stock options as of December 31, 2016	1,186,917	$1.29

Restricted Stock

We grant restricted stock awards that vest over a one-year period with a fair value based on the closing price of our common stock on the date of the grant. When restricted stock awards are granted, or when restricted stock unit awards are converted to restricted stock, shares of our common stock are considered issued, but subject to certain restrictions.

The weighted-average grant-date fair value per share of restricted stock awards granted during the years ended December 31, 2016, 2015 and 2014 were $2.76, $7.40 and $14.33, respectively. The aggregate fair value of restricted stock awards vested during these same periods were $0.1 million, $0.4 million and $1.3 million, respectively.

The following table summarizes our restricted stock activity from December 31, 2015 through December 31, 2016:

	Number of Shares	Weighted-Average Grant-Date Fair Value per Share
Nonvested restricted stock as of December 31, 2015	47,296	$7.41
Granted	166,664	2.76
Vested	(47,296)	7.41
Nonvested restricted stock as of December 31, 2016	166,664	$2.76

Restricted Stock Units

We grant restricted stock unit awards with vesting based on time of service conditions only ("time-based RSUs"), and we grant restricted stock unit awards with vesting based on time of service, which are also subject to performance and market conditions ("performance-based RSUs"). Shares of our common stock are issued to recipients of restricted stock units only when they have satisfied the applicable vesting conditions. Our time-based RSUs generally vest over a three-year period, with fair values based on the closing price of our common stock on the date of grant. Our performance-based RSUs generally cliff vest after 39 months from the date of grant and are granted at a target number of issuable shares, for which the final number of shares of common stock is adjusted based on our actual achievement levels that are measured against predetermined performance conditions. The number of shares of common stock awarded will be based upon the Company's achievement in certain performance conditions, as compared to a predefined peer group, over the performance period, generally three years.

Approximately half of the performance-based RSUs outstanding are subject to a market condition based on relative total shareholder return, as compared to that of our predetermined peer group, and therefore the fair value of these awards is measured using a Monte Carlo simulation model. Compensation expense for equity awards with a market condition is reduced only for estimated forfeitures; no adjustment to expense is otherwise made, regardless of the number of shares issued. The remaining performance-based RSUs are subject to performance conditions, based on our EBITDA and return on capital employed, relative to our predetermined peer group, and therefore the fair value is based on the closing price of our common stock on the date of grant, applied to the estimated number of shares that will be awarded. Compensation expense ultimately recognized for awards with performance conditions will be equal to the fair value of the restricted stock unit award based on the actual outcome of the service and performance conditions.

In April 2016, we determined that 72% of the target number of shares granted during 2013 were actually earned based on the Company's achievement of the performance measures as described above, resulting in a reduction of 75,757 shares being issued. As of December 31, 2016, we estimate that our actual achievement level for our outstanding performance-based RSUs will be approximately 100% of the predetermined performance conditions.

The following table summarizes our restricted stock unit activity from December 31, 2015 through December 31, 2016:

	Time-Based Award		Performance-Based Award	
	Number of Time-Based Award Units	Weighted-Average Grant-Date Fair Value per Unit	Number of Performance-Based Award Units	Weighted-Average Grant-Date Fair Value per Unit
Nonvested restricted stock units as of December 31, 2015	386,533	$6.93	957,295	$7.57
Granted	264,009	1.47	—	—
Achieved performance adjustment	—	—	(75,757)	8.29
Vested	(225,895)	7.21	(195,721)	8.29
Forfeited	(26,857)	2.46	—	—
Nonvested restricted stock units as of December 31, 2016	397,790	$3.45	685,817	$7.28

The following table presents the weighted-average grant-date fair value per share of restricted stock units granted and the aggregate intrinsic value of restricted stock units vested (converted) during the years ended December 31, 2016, 2015 and 2014:

	Year ended December 31,		
	2016	2015	2014
Time-based RSUs:			
Grant-date fair value of awards granted (per share)	$1.47	$4.08	$8.64
Aggregate intrinsic value of awards vested (in thousands)	$ 314	$ 1,575	$ 2,679
Performance-based RSUs:			
Grant-date fair value of awards granted (per share)	—	$6.66	$9.67
Aggregate intrinsic value of awards vested (in thousands)	$ 609	$ 1,402	$ 2,330

Phantom Stock Unit Awards

In 2016, we granted 1,268,068 phantom stock unit awards that cliff-vest after 39 months from the date of grant, with vesting based on time of service, performance and market conditions. The number of units ultimately awarded will be based upon the Company's achievement in certain performance conditions, as compared to a predefined peer group, over the three-year performance period, and each unit awarded will entitle the employee to a cash payment equal to the stock price of our common stock on the date of vesting, subject to a maximum of four times the stock price on the date of grant.

These awards are classified as liability awards under ASC Topic 718, *Compensation—Stock Compensation*, because we expect to settle the awards in cash when they vest, and are remeasured at fair value at each reporting period until they vest. Approximately half of the phantom stock unit awards granted are subject to a market condition based on relative total shareholder return, as compared to that of our predetermined peer group, and therefore the fair value of these awards is measured using a Monte Carlo simulation model. The remaining phantom stock unit awards are subject to performance conditions, based on our EBITDA and return on capital employed, relative to our predetermined peer group, and the fair value of these awards is measured using a Black-Scholes pricing model. The fair value of these awards is measured using inputs that are defined as Level 3 inputs under ASC Topic 820, *Fair Value Measurements and Disclosures*.

9. Employee Benefit Plans and Insurance

We maintain a 401(k) retirement plan for our eligible employees. Under this plan, we may make a matching contribution, on a discretionary basis, equal to a percentage of each eligible employee's annual contribution, which we determine annually. Our matching contributions for the years ended December 31, 2016, 2015 and 2014 were $0.3 million, $4.2 million and $6.4 million, respectively. Effective February 1, 2016, in an effort to reduce costs in response to the downturn in our industry, we suspended matching contributions. This benefit was reinstated in January 2017.

We maintain a self-insurance program, for major medical and hospitalization coverage for employees and their dependents, which is partially funded by employee payroll deductions. We have provided for reported claims costs as well as incurred but not reported medical costs in the accompanying consolidated balance sheets. We have a maximum liability of $200,000 per covered individual per year. Amounts in excess of the stated maximum are covered under a separate policy provided by an insurance company. Accrued insurance premiums and deductibles at December 31, 2016 and 2015 include $2.0 million and $2.4 million, respectively, for our estimate of incurred but unpaid costs related to the self-insurance portion of our health insurance.

We are self-insured for up to $500,000 per incident for all workers' compensation claims submitted by employees for on-the-job injuries. We accrue our workers' compensation claim cost estimates based on historical claims development data and we accrue the cost of administrative services associated with claims processing. We also have a deductible of $250,000 per occurrence under both our general liability insurance and auto liability insurance. Accrued insurance premiums and deductibles at December 31, 2016 and 2015 include $4.4 million and $5.5 million, respectively, for our estimate of costs relative to the self-insured portion of our workers' compensation, general liability and auto liability insurance. Based upon our past experience, management believes that we have adequately provided for potential losses. However, future multiple occurrences of serious injuries to employees could have a material adverse effect on our financial position and results of operations.

10. Segment Information

We have two operating segments referred to as the Drilling Services Segment and the Production Services Segment which is the basis management uses for making operating decisions and assessing performance.

Our Drilling Services Segment provides contract land drilling services to a diverse group of exploration and production companies through our four drilling divisions in the US, and internationally in Colombia. In addition to our drilling rigs, we provide the drilling crews and most of the ancillary equipment needed to operate our drilling rigs.

Our Production Services Segment provides a range of services, including well servicing, wireline services and coiled tubing services, to a diverse group of exploration and production companies, with our operations concentrated in the major United States onshore oil and gas producing regions in the Mid-Continent and Rocky Mountain states and in the Gulf Coast, both onshore and offshore.

The following table sets forth certain financial information for our two operating segments and corporate as of and for the years ended December 31, 2016, 2015 and 2014 (amounts in thousands):

	As of and for the year ended December 31,		
	2016	2015	2014
Drilling Services Segment:			
Revenues	$ 119,207	$ 249,318	$ 516,473
Operating costs	73,151	144,196	348,133
Segment margin	$ 46,056	$ 105,122	$ 168,340
Identifiable assets	$ 452,290	$ 518,208	$ 702,987
Depreciation and amortization	60,769	80,265	116,425
Capital expenditures	19,796	113,060	112,483
Production Services Segment:			
Revenues	$ 157,869	$ 291,460	$ 538,750
Operating costs	130,798	213,820	339,690
Segment margin	$ 27,071	$ 77,640	$ 199,060
Identifiable assets	$ 233,481	$ 281,530	$ 442,755
Depreciation and amortization	52,293	69,335	66,326
Capital expenditures	12,321	29,228	74,652
Corporate:			
Identifiable assets	$ 14,331	$ 22,237	$ 25,847
Depreciation and amortization	1,250	1,339	625
Capital expenditures	439	619	986
Total:			
Revenues	$ 277,076	$ 540,778	$ 1,055,223
Operating costs	203,949	358,016	687,823
Consolidated margin	$ 73,127	$ 182,762	$ 367,400
Identifiable assets	$ 700,102	$ 821,975	$ 1,171,589
Depreciation and amortization	114,312	150,939	183,376
Capital expenditures	32,556	142,907	188,121

The following table reconciles the consolidated margin of our two operating segments and corporate reported above to income (loss) from operations as reported on the consolidated statements of operations for the years ended December 31, 2016, 2015 and 2014 (amounts in thousands):

	Year ended December 31,		
	2016	2015	2014
Consolidated margin	$ 73,127	$ 182,762	$ 367,400
Depreciation and amortization	(114,312)	(150,939)	(183,376)
General and administrative	(61,184)	(73,903)	(103,385)
Bad debt recovery (expense)	(156)	188	(1,445)
Impairment charges	(12,815)	(129,152)	(73,025)
Gain on dispositions of property and equipment, net	1,892	4,344	1,859
Gain on sale of fishing and rental services operations	—	—	10,702
Gain on litigation	—	—	5,254
Income (loss) from operations	$ (113,448)	$ (166,700)	$ 23,984

The following table sets forth certain financial information for our international operations in Colombia as of and for the years ended December 31, 2016, 2015 and 2014 (amounts in thousands):

	As of and for the year ended December 31,		
	2016	2015	2014
Revenues	$ 6,808	$ 43,878	$ 104,520
Identifiable assets	36,337	54,590	142,321

Identifiable assets for our international operations in Colombia include five drilling rigs that are owned by our Colombia subsidiary and three drilling rigs that are owned by one of our domestic subsidiaries and leased to our Colombia subsidiary.

11. Commitments and Contingencies

In connection with our operations in Colombia, our foreign subsidiaries have obtained bonds for bidding on drilling contracts, performing under drilling contracts, and remitting customs and importation duties. We have guaranteed payments of $36.3 million relating to our performance under these bonds as of December 31, 2016.

We have received an increased number of notices in recent years from state taxing authorities for audits of sales and use tax obligations. We are currently undergoing sales and use tax audits for multi-year periods and we are working to resolve all relevant issues. As of both December 31, 2016 and December 31, 2015, our accrued liability was $0.6 million based on our estimate of the sales and use tax obligations that are expected to result from these audits. Due to the inherent uncertainty of the audit process, we believe that it is reasonably possible that we may incur additional tax assessments with respect to one or more of the audits in excess of the amount accrued. We believe that such an outcome would not have a material adverse effect on our results of operations or financial position. Because certain of these audits are in a preliminary stage, an estimate of the possible loss or range of loss from an adverse result in all or substantially all of these cases cannot reasonably be made.

Due to the nature of our business, we are, from time to time, involved in litigation or subject to disputes or claims related to our business activities, including workers' compensation claims and employment-related disputes. Legal costs relating to these matters are expensed as incurred. In the opinion of our management, none of the pending litigation, disputes or claims against us will have a material adverse effect on our financial condition, results of operations or cash flow from operations.

12. Sale of Fishing and Rental Services Operations

On September 17, 2014, we entered into an asset sales agreement with Basic Energy Services L.P. ("Basic") for the sale of our fishing and rental services ("F&R") operations for total consideration of $16.1 million, which consisted of $15.1 million of cash received at closing and $1.0 million which was held in escrow for a period of 180 days. Under the terms of the sales agreement, Basic purchased two real estate locations and all F&R tools and equipment for which we had a total net book value of $4.3 million at the date of sale. We recognized a $10.7 million gain on the sale of our F&R operations, which net of income taxes was $6.6 million. Cash proceeds from the sale were used to repay long-term debt obligations.

For the nine months ended September 30, 2014, F&R operations represented approximately 1% of our consolidated revenues and approximately 1% of our consolidated pretax income. Total assets for F&R at the date of sale represented less than 1% of our total assets at September 30, 2014. The sale of the F&R operations did not represent a strategic shift for our company, did not have a significant effect on our operating results, and did not represent discontinued operations based on the criteria of ASU No. 2014-08, *Discontinued Operations.* Statement of operations information for the F&R operations is as follows for the year ended December 31, 2014 (amounts in thousands):

Revenues	$ 7,828
Operating costs	5,097
F&R margin	$ 2,731
Loss before income taxes	$ (162)

13. Quarterly Results of Operations (unaudited)

The following table summarizes quarterly financial data for the years ended December 31, 2016 and 2015 (in thousands, except per share data):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Year ended December 31, 2016					
Revenues	$ 74,952	$ 62,290	$ 68,353	$ 71,481	$ 277,076
Loss from operations	(23,014)	(26,025)	(29,885)	(34,524)	(113,448)
Income tax benefit	1,958	1,990	1,698	5,086	10,732
Net loss	(27,699)	(29,991)	(34,620)	(36,081)	(128,391)
Loss per share:					
Basic	$ (0.43)	$ (0.46)	$ (0.53)	$ (0.53)	$ (1.96)
Diluted	$ (0.43)	$ (0.46)	$ (0.53)	$ (0.53)	$ (1.96)
Year ended December 31, 2015					
Revenues	$ 193,814	$ 135,011	$ 107,480	$ 104,473	$ 540,778
Loss from operations	(8,334)	(75,108)	(17,972)	(65,286)	(166,700)
Income tax benefit	4,450	2,586	6,682	23,861	37,579
Net loss	(12,019)	(77,281)	(17,540)	(48,300)	(155,140)
Loss per share:					
Basic	$ (0.19)	$ (1.20)	$ (0.27)	$ (0.75)	$ (2.41)
Diluted	$ (0.19)	$ (1.20)	$ (0.27)	$ (0.75)	$ (2.41)

14. Guarantor/Non-Guarantor Condensed Consolidating Financial Statements

Our Senior Notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by all existing wholly owned domestic subsidiaries, except for Pioneer Services Holdings, LLC. The subsidiaries that generally operate our non-U.S. business concentrated in Colombia do not guarantee our Senior Notes. The non-guarantor subsidiaries do not have any payment obligations under the Senior Notes, the guarantees or the Indenture.

In the event of a bankruptcy, liquidation or reorganization of any non-guarantor subsidiary, such non-guarantor subsidiary will pay the holders of its debt and other liabilities, including its trade creditors, before it will be able to distribute any of its assets to us. In the future, any non-U.S. subsidiaries, immaterial subsidiaries and subsidiaries that we designate as unrestricted subsidiaries under the Indenture will not guarantee the Senior Notes. As of December 31, 2016, there were no restrictions on the ability of subsidiary guarantors to transfer funds to the parent company.

As a result of the guarantee arrangements, we are presenting the following condensed consolidating balance sheets, statements of operations and statements of cash flows of the issuer, the guarantor subsidiaries and the non-guarantor subsidiaries.

CONDENSED CONSOLIDATING BALANCE SHEETS
(in thousands)

	December 31, 2016				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 9,898	$ (764)	$ 1,060	$ —	$ 10,194
Receivables, net of allowance	480	64,946	7,210	(513)	72,123
Intercompany receivable (payable)	(24,836)	35,427	(10,591)	—	—
Inventory	—	5,659	4,001	—	9,660
Assets held for sale	—	15,035	58	—	15,093
Prepaid expenses and other current assets	1,280	4,014	1,632	—	6,926
Total current assets	(13,178)	124,317	3,370	(513)	113,996
Net property and equipment	2,501	556,062	25,517	—	584,080
Investment in subsidiaries	577,965	24,270	—	(602,235)	—
Intangible assets, net of accumulated amortization	—	403	—	—	403
Deferred income taxes	65,041	—	—	(65,041)	—
Other long-term assets	583	626	414	—	1,623
Total assets	$ 632,912	$ 705,678	$ 29,301	$ (667,789)	$ 700,102
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 546	$ 16,317	$ 2,345	$ —	$ 19,208
Deferred revenues	—	680	769	—	1,449
Accrued expenses	9,316	34,765	1,777	(513)	45,345
Total current liabilities	9,862	51,762	4,891	(513)	66,002
Long-term debt, less debt issuance costs	339,473	—	—	—	339,473
Deferred income taxes	—	73,249	(28)	(65,041)	8,180
Other long-term liabilities	2,179	2,702	168	—	5,049
Total liabilities	351,514	127,713	5,031	(65,554)	418,704
Total shareholders' equity	281,398	577,965	24,270	(602,235)	281,398
Total liabilities and shareholders' equity	$ 632,912	$ 705,678	$ 29,301	$ (667,789)	$ 700,102

	December 31, 2015				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 17,221	$ (5,612)	$ 2,551	$ —	$ 14,160
Receivables, net of allowance	74	67,174	12,568	—	79,816
Intercompany receivable (payable)	(24,836)	31,108	(6,272)	—	—
Inventory	—	5,591	3,671	—	9,262
Assets held for sale	—	4,619	—	—	4,619
Prepaid expenses and other current assets	1,200	4,767	1,444	—	7,411
Total current assets	(6,341)	107,647	13,962	—	115,268
Net property and equipment	3,311	667,321	31,953	—	702,585
Investment in subsidiaries	657,090	42,240	—	(699,330)	—
Intangible assets, net of accumulated amortization	—	1,944	—	—	1,944
Other long-term assets	85,501	944	722	(84,989)	2,178
Total assets	$ 739,561	$ 820,096	$ 46,637	$ (784,319)	$ 821,975
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 616	$ 14,628	$ 1,707	$ —	$ 16,951
Deferred revenues	—	5,570	652	—	6,222
Accrued expenses	8,373	37,023	1,473	—	46,869
Total current liabilities	8,989	57,221	3,832	—	70,042
Long-term debt, less debt issuance costs	387,217	—	—	—	387,217
Deferred income taxes	—	102,491	—	(84,989)	17,502
Other long-term liabilities	712	3,294	565	—	4,571
Total liabilities	396,918	163,006	4,397	(84,989)	479,332
Total shareholders' equity	342,643	657,090	42,240	(699,330)	342,643
Total liabilities and shareholders' equity	$ 739,561	$ 820,096	$ 46,637	$ (784,319)	$ 821,975

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(in thousands)

	Year ended December 31, 2016				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$ —	$ 270,268	$ 6,808	$ —	$ 277,076
Costs and expenses:					
Operating costs	—	194,515	9,434	—	203,949
Depreciation and amortization	1,250	106,193	6,869	—	114,312
General and administrative	21,657	38,564	1,515	(552)	61,184
Bad debt expense (recovery)	—	156	—	—	156
Impairment charges	—	12,260	555	—	12,815
Gain on dispositions of property and equipment, net	—	(1,838)	(54)	—	(1,892)
Intercompany leasing	—	(4,860)	4,860	—	—
Total costs and expenses	22,907	344,990	23,179	(552)	390,524
Income (loss) from operations	(22,907)	(74,722)	(16,371)	552	(113,448)
Other (expense) income:					
Equity in earnings of subsidiaries	(63,374)	(17,835)	—	81,209	—
Interest expense, net of interest capitalized	(25,845)	(88)	(1)	—	(25,934)
Loss on extinguishment of debt	(299)	—	—	—	(299)
Other	18	1,430	(338)	(552)	558
Total other (expense) income	(89,500)	(16,493)	(339)	80,657	(25,675)
Income (loss) before income taxes	(112,407)	(91,215)	(16,710)	81,209	(139,123)
Income tax (expense) benefit [1]	(15,984)	27,841	(1,125)	—	10,732
Net income (loss)	$ (128,391)	$ (63,374)	$ (17,835)	$ 81,209	$ (128,391)

	Year ended December 31, 2015				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$ —	$ 496,900	$ 43,878	$ —	$ 540,778
Costs and expenses:					
Operating costs	—	322,458	35,558	—	358,016
Depreciation and amortization	1,338	137,987	11,614	—	150,939
General and administrative	21,515	50,710	2,230	(552)	73,903
Bad debt expense (recovery)	—	571	(759)	—	(188)
Impairment charges	—	73,270	56,632	(750)	129,152
Gain on dispositions of property and equipment, net	117	(4,350)	(111)	—	(4,344)
Intercompany leasing	—	(4,860)	4,860	—	—
Total costs and expenses	22,970	575,786	110,024	(1,302)	707,478
Income (loss) from operations	(22,970)	(78,886)	(66,146)	1,302	(166,700)
Other (expense) income:					
Equity in earnings of subsidiaries	(126,553)	(74,459)	—	201,012	—
Interest expense, net of interest capitalized	(21,128)	(117)	23	—	(21,222)
Loss on extinguishment of debt	(2,186)	—	—	—	(2,186)
Other	6	1,687	(3,752)	(552)	(2,611)
Total other (expense) income	(149,861)	(72,889)	(3,729)	200,460	(26,019)
Income (loss) before income taxes	(172,831)	(151,775)	(69,875)	201,762	(192,719)
Income tax (expense) benefit [1]	16,941	25,222	(4,584)	—	37,579
Net income (loss)	$ (155,890)	$ (126,553)	$ (74,459)	$ 201,762	$ (155,140)

[1] The income tax expense (benefit) reflected in each column does not include any tax effect of the equity in earnings (losses) of subsidiaries.

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Continued)
(in thousands)

	Year ended December 31, 2014				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$ —	$ 950,703	$ 104,520	$ —	$ 1,055,223
Costs and expenses:					
Operating costs	—	611,392	76,431	—	687,823
Depreciation and amortization	1,336	168,157	13,883	—	183,376
General and administrative	27,314	72,878	3,745	(552)	103,385
Bad debt expense (recovery)	—	1,329	116	—	1,445
Impairment charges	—	73,025	—	—	73,025
Gain on dispositions of property and equipment, net	—	(1,796)	(63)	—	(1,859)
Gain on sale of fishing and rental services operations	—	(10,702)	—	—	(10,702)
Gain on litigation	(5,254)	—	—	—	(5,254)
Intercompany leasing	—	(4,860)	4,860	—	—
Total costs and expenses	23,396	909,423	98,972	(552)	1,031,239
Income (loss) from operations	(23,396)	41,280	5,548	552	23,984
Other (expense) income:					
Equity in earnings of subsidiaries	21,254	(3,767)	—	(17,487)	—
Interest expense, net of interest capitalized	(38,562)	(223)	4	—	(38,781)
Loss on extinguishment of debt	(31,221)	—	—	—	(31,221)
Other	21	2,985	(5,758)	(552)	(3,304)
Total other (expense) income	(48,508)	(1,005)	(5,754)	(18,039)	(73,306)
Income (loss) before income taxes	(71,904)	40,275	(206)	(17,487)	(49,322)
Income tax (expense) benefit [1]	33,886	(19,021)	(3,561)	—	11,304
Net income (loss)	$ (38,018)	$ 21,254	$ (3,767)	$ (17,487)	$ (38,018)

[1] The income tax expense (benefit) reflected in each column does not include any tax effect of the equity in earnings (losses) of subsidiaries.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(in thousands)

	Year ended December 31, 2016				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows from operating activities	$ (39,344)	$ 45,035	$ (560)	$ —	$ 5,131
Cash flows from investing activities:					
Purchases of property and equipment	(452)	(31,049)	(880)	—	(32,381)
Proceeds from sale of property and equipment	—	7,523	54	—	7,577
Proceeds from insurance recoveries	—	37	—	—	37
	(452)	(23,489)	(826)	—	(24,767)
Cash flows from financing activities:					
Debt repayments	(71,000)	—	—	—	(71,000)
Proceeds from issuance of debt	22,000	—	—	—	22,000
Debt issuance costs	(819)	—	—	—	(819)
Proceeds from exercise of options	183	—	—	—	183
Proceeds from common stock, net of offering costs	65,430	—	—	—	65,430
Purchase of treasury stock	(124)	—	—	—	(124)
Intercompany contributions/distributions	16,803	(16,698)	(105)	—	—
	32,473	(16,698)	(105)	—	15,670
Net increase (decrease) in cash and cash equivalents	(7,323)	4,848	(1,491)	—	(3,966)
Beginning cash and cash equivalents	17,221	(5,612)	2,551	—	14,160
Ending cash and cash equivalents	$ 9,898	$ (764)	$ 1,060	$ —	$ 10,194

	Year ended December 31, 2015				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows from operating activities	$ 4,067	$ 147,643	$ (8,991)	$ —	$ 142,719
Cash flows from investing activities:					
Purchases of property and equipment	(663)	(157,336)	(1,885)	269	(159,615)
Proceeds from sale of property and equipment	32	57,444	467	(269)	57,674
Proceeds from insurance recoveries	—	285	—	—	285
	(631)	(99,607)	(1,418)	—	(101,656)
Cash flows from financing activities:					
Debt repayments	(60,000)	(2)	—	—	(60,002)
Debt issuance costs	(1,877)	—	—	—	(1,877)
Proceeds from exercise of options	781	—	—	—	781
Purchase of treasury stock	(729)	—	—	—	(729)
Intercompany contributions/distributions	47,922	(48,130)	208	—	—
	(13,903)	(48,132)	208	—	(61,827)
Net increase (decrease) in cash and cash equivalents	(10,467)	(96)	(10,201)	—	(20,764)
Beginning cash and cash equivalents	27,688	(5,516)	12,752	—	34,924
Ending cash and cash equivalents	$ 17,221	$ (5,612)	$ 2,551	$ —	$ 14,160

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Continued)
(in thousands)

	Year ended December 31, 2014				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows from operating activities	$ (59,405)	$ 265,171	$ 27,275	$ —	$ 233,041
Cash flows from investing activities:					
Purchases of property and equipment	(1,029)	(158,392)	(15,957)	—	(175,378)
Proceeds from sale of fishing and rental services operations	15,090	—	—	—	15,090
Proceeds from sale of property and equipment	—	8,069	301	—	8,370
	14,061	(150,323)	(15,656)	—	(151,918)
Cash flows from financing activities:					
Debt repayments	(490,000)	(25)	—	—	(490,025)
Proceeds from issuance of debt	440,000	—	—	—	440,000
Debt issuance costs	(9,239)	—	—	—	(9,239)
Tender premium costs	(21,553)	—	—	—	(21,553)
Proceeds from exercise of options	8,368	—	—	—	8,368
Purchase of treasury stock	(1,135)	—	—	—	(1,135)
Intercompany contributions/distributions	118,223	(118,280)	57	—	—
	44,664	(118,305)	57	—	(73,584)
Net increase (decrease) in cash and cash equivalents	(680)	(3,457)	11,676	—	7,539
Beginning cash and cash equivalents	28,368	(2,059)	1,076	—	27,385
Ending cash and cash equivalents	$ 27,688	$ (5,516)	$ 12,752	$ —	$ 34,924

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A. Controls and Procedures

In accordance with Exchange Act Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2016, to ensure that information required to be disclosed in our reports filed or submitted under the Exchange Act is (1) recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms and (2) accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

In the ordinary course of business, we may make changes to our systems and processes to improve controls and increase efficiency, and make changes to our internal controls over financial reporting in order to ensure that we maintain an effective internal control environment. There has been no change in our internal control over financial reporting that occurred during the three months ended December 31, 2016 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

The management of Pioneer Energy Services Corp. is responsible for establishing and maintaining adequate internal control over financial reporting. Pioneer Energy Services Corp.'s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that: (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of Pioneer Energy Services Corp. are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Pioneer Energy Services Corp.'s management assessed the effectiveness of Pioneer Energy Services Corp.'s internal control over financial reporting as of December 31, 2016. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework (2013). Based on our assessment we have concluded that, as of December 31, 2016, Pioneer Energy Services Corp.'s internal control over financial reporting was effective based on those criteria.

KPMG LLP, the independent registered public accounting firm that audited the consolidated financial statements of Pioneer Energy Services Corp. included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of Pioneer Energy Services Corp.'s internal control over financial reporting as of December 31, 2016. This report is included in Item 8, *Financial Statements and Supplementary Data*.

Item 9B. Other Information

Not applicable.

PART III

In Items 10, 11, 12, 13 and 14 below, we are incorporating by reference the information we refer to in those Items from the definitive proxy statement for our 2017 Annual Meeting of Shareholders. We intend to file that definitive proxy statement with the SEC on or about April 17, 2017 (and, in any event, not later than 120 days after the end of the fiscal year covered by this report).

Item 10. Directors, Executive Officers and Corporate Governance

Please see the information appearing in the proposal for the election of directors and under the headings "Executive Officers," "Information Concerning Meetings and Committees of the Board of Directors," "Code of Business Conduct and Ethics and Corporate Governance Guidelines" and "Section 16(a) Beneficial Ownership Reporting Compliance" in the definitive proxy statement for our 2017 Annual Meeting of Shareholders for the information this Item 10 requires.

Item 11. Executive Compensation

Please see the information appearing under the headings "Compensation Discussion and Analysis," "Director Compensation," "Executive Compensation," "Compensation Committee Interlocks and Insider Participation" and "Report of the Compensation Committee" in the definitive proxy statement for our 2017 Annual Meeting of Shareholders for the information this Item 11 requires.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Please see the information appearing under the heading "Security Ownership of Certain Beneficial Owners and Management" in the definitive proxy statement for our 2017 Annual Meeting of Shareholders for the information this Item 12 requires.

Equity Compensation Plan Information

The following table summarizes, as of December 31, 2016, the indicated information regarding our Amended and Restated 2007 Incentive Plan ("the 2007 Incentive Plan") and the Pioneer Drilling Company 2003 Stock Plan. The material features of these plans are described in Note 8, *Equity Transactions and Stock-Based Compensation Plans*, of the Notes to Consolidated Financial Statements, included in Part II, Item 8, *Financial Statements and Supplementary Data*, of this Annual Report on Form 10-K.

Plan category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants And Rights(1)	Weighted Average Exercise Price of Outstanding Options, Warrants And Rights(2)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans(3)
Equity compensation plans approved by security holders	5,468,158	$ 7.42	4,603,268
Equity compensation plans not approved by security holders	—	—	—
	5,468,158	$ 7.42	4,603,268

(1) Includes (a) 3,507,006 shares subject to issuance pursuant to outstanding awards of stock options and 1,083,733 shares subject to issuance pursuant to outstanding awards of restricted stock units (assuming the target level of performance achievement) under the 2007 Incentive Plan; and (b) 877,419 shares subject to issuance pursuant to outstanding awards of stock options under the Pioneer Drilling Company 2003 Stock Plan. It does not include awards we grant in the form of phantom stock unit awards which are expected to be paid in cash.

(2) The weighted-average exercise price does not take into account the shares issuable upon vesting of outstanding awards of restricted stock units, which have no exercise price.

(3) Represents 3,335,701 shares available for future issuance in the form of restricted stock under the 2007 Incentive Plan as of December 31, 2016.

From January 1, 2017 to February 17, 2017, we granted options to purchase 268,185 shares of our common stock and restricted stock unit awards covering 630,197 shares of our common stock to 82 employees and executive officers. Applying the share counting rules under the 2007 Incentive Plan, these grants reduce the total number of shares available for issuance under the 2007 Incentive Plan by 1,137,134. Factoring in forfeitures that have occurred from January 1, 2017 to February 17, 2017, this leaves 3,466,134 shares available for issuance as of February 17, 2017. Pursuant to the terms of the 2007 Incentive Plan, if full value awards are issued, the fungible share pool approach under the 2007 Incentive Plan would deplete the shares available for issuance at a rate of 1.38 shares per share actually covered by an award.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Please see the information appearing in the proposal for the election of directors and under the heading "Certain Relationships and Related Transactions" in the definitive proxy statement for our 2017 Annual Meeting of Shareholders for the information this Item 13 requires.

Item 14. Principal Accounting Fees and Services

Please see the information appearing in the proposal for the ratification of the appointment of our independent registered public accounting firm in the definitive proxy statement for our 2017 Annual Meeting of Shareholders for the information this Item 14 requires.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(1) Financial Statements.

See Index to Consolidated Financial Statements included in Item 8, *Financial Statements and Supplementary Data*.

(2) Financial Statement Schedules.

No financial statement schedules are submitted because either they are inapplicable or because the required information is included in the consolidated financial statements or notes thereto.

(3) Exhibits.

The following exhibits are filed as part of this report:

Exhibit Number		Description
3.1*	-	Restated Articles of Incorporation of Pioneer Energy Services Corp. (Form 8-K dated July 30, 2012 (File No. 1-8182, Exhibit 3.1)).
3.2*	-	Amended and Restated Bylaws of Pioneer Energy Services Corp. (Form 8-K dated July 30, 2012 (File No. 1-8182, Exhibit 3.2)).
4.1*	-	Form of Certificate representing Common Stock of Pioneer Energy Services Corp. (Form 10-Q dated August 7, 2012 (File No. 1-8182, Exhibit 4.1)).
4.2*	-	Indenture, dated March 11, 2010, by and among Pioneer Drilling Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee (Form 8-K dated March 12, 2010 (File No. 1-8182, Exhibit 4.1)).
4.3*	-	Registration Rights Agreement, dated March 11, 2010, by and among Pioneer Drilling Company, the subsidiary guarantors party thereto and the initial purchasers party thereto (Form 8-K dated March 12, 2010 (File No. 1-8182, Exhibit 4.2)).
4.4*	-	First Supplemental Indenture, dated November 21, 2011, by and among Pioneer Drilling Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee (Form 8-K dated November 21, 2011 (File No. 1-8182, Exhibit 4.2)).
4.5*	-	Registration Rights Agreement, dated November 21, 2011, by and among Pioneer Drilling Company, the subsidiary guarantors party thereto and the initial purchasers party thereto (Form 8-K dated November 21, 2011 (File No. 1-8182, Exhibit 4.3)).
4.6*	-	Second Supplemental Indenture, dated October 1, 2012, by and among Pioneer Coiled Tubing Services, LLC, Pioneer Energy Services Corp., the other subsidiary guarantors and Wells Fargo Bank, National Association, as trustee (Form 10-Q dated November 1, 2012 (File No. 1-8182, Exhibit 4.6)).
4.7*	-	Indenture, dated March 18, 2014, by and among Pioneer Energy Services Corp., the subsidiaries named as guarantors therein and Wells Fargo Bank, National Association, as trustee (Form 8-K dated March 18, 2014 (File No. 1-8182, Exhibit 4.1)).
4.8*	-	Registration Rights Agreement, dated March 18, 2014, by and among Pioneer Energy Services Corp., the subsidiaries named as guarantors therein and the initial purchasers party thereto (Form 8-K dated March 18, 2014 (File No. 1-8182, Exhibit 10.1)).
10.1+*	-	Pioneer Drilling Company's 1999 Stock Plan and Form of Stock Option Agreement (Form 10-K dated June 22, 2001 (File No. 1-8182, Exhibit 10.7)).
10.2+*	-	Pioneer Drilling Company 2003 Stock Plan (Form S-8 dated November 18, 2003 (File No. 333-110569, Exhibit 4.4)).
10.3+*	-	Pioneer Drilling Company Amended and Restated 2007 Incentive Plan (Form 10-Q dated November 3, 2011 (File No. 1-8182, Exhibit 10.1)).
10.4+*	-	Pioneer Energy Services Corp. 2007 Incentive Plan Form of Stock Option Agreement (Form 10-Q dated July 30, 2015 (File No. 1-8182, Exhibit 10.1)).

10.5+* - Pioneer Energy Services Corp. 2007 Incentive Plan Form of Stock Option Agreement (Form 10-Q dated July 30, 2015 (File No. 1-8182, Exhibit 10.2)).

10.6+* - Pioneer Energy Services Corp. 2007 Incentive Plan Form of Restricted Stock Unit Award Agreement (Form 10-Q dated July 30, 2015 (File No. 1-8182, Exhibit 10.3)).

10.7+* - Pioneer Energy Services Corp. 2007 Incentive Plan Form of Long-Term Incentive Restricted Stock Unit Award Agreement (Form 10-Q dated July 30, 2015 (File No. 1-8182, Exhibit 10.4)).

10.8+* - Pioneer Energy Services Corp. 2007 Incentive Plan Form of Non-Employee Director Restricted Stock Award Agreement (Form 10-Q dated July 30, 2015 (File No. 1-8182, Exhibit 10.5)).

10.9+* - Pioneer Energy Services Corp. 2007 Incentive Plan Form of Long-Term Incentive Cash Award Agreement (Form 10-Q dated July 30, 2015 (File No. 1-8182, Exhibit 10.6)).

10.10+* - Pioneer Drilling Company Amended and Restated Key Executive Severance Plan (Form 10-Q for the dated August 5, 2008 (File No. 1-8182, Exhibit 10.4)).

10.11+* - Pioneer Drilling Company Form of Indemnification Agreement (Form 8-K dated August 8, 2007 (File No. 1-8182, Exhibit 10.1)).

10.12+* - Pioneer Drilling Company Employee Relocation Policy Executive Officers – Package A (Form 8-K dated August 8, 2007 (File No. 1-8182, Exhibit 10.3)).

10.13* - Amended and Restated Credit Agreement, dated as of June 30, 2011 among Pioneer Drilling Company, the lenders party thereto, and Wells Fargo Bank, N.A., as administrative agent, issuing lender and swing line lender (Form 8-K dated July 5, 2011 (File No. 1-8182, Exhibit 10.1)).

10.14* - First Amendment dated as of March 3, 2014, by and among Pioneer Energy Services Corp. (f/k/a Pioneer Drilling Company), a Texas corporation, the lenders party thereto, and Wells Fargo Bank, N.A., as administrative agent for the lenders (Form 8-K dated March 4, 2014 (File No. 1-8182, Exhibit 4.1)).

10.15* - Second Amendment dated as of September 22, 2014, by and among Pioneer Energy Services Corp. (f/k/a Pioneer Drilling Company), a Texas corporation, the lenders party thereto, and Wells Fargo Bank, N.A., as administrative agent for the lenders (Form 8-K dated September 23, 2014 (File No. 1-8182, Exhibit 4.1)).

10.16* - Third Amendment dated as of September 15, 2015, by and among Pioneer Energy Services Corp., a Texas corporation, the lenders party thereto, and Wells Fargo Bank, N.A., as administrative agent for the lenders (Form 8-K dated September 15, 2015 (File No. 1-8182, Exhibit 4.1)).

10.17* - Fourth Amendment dated as of December 23, 2015, by and among Pioneer Energy Services Corp., a Texas corporations, the lenders party thereto, and Wells Fargo Bank, N.A., as administrative agent for the lenders (Form 8-K dated December 23, 2015 (File No. 1-8182, Exhibit 4.1)).

10.18* - Fifth Amendment dated as of June 30, 2016, by and among Pioneer Energy Services Corp., a Texas corporations, the lenders party thereto, and Wells Fargo Bank, N.A., as administrative agent for the lenders (Form 8-K dated July 1, 2016 (File No. 1-8182, Exhibit 4.1)).

10.19+* - Employment Letter, effective January 7, 2009, from Pioneer Drilling Company to Lorne E. Phillips (Form 8-K dated January 14, 2009 (File No. 1-8182, Exhibit 10.1)).

10.20+* - Pioneer Energy Services Corp. Nonqualified Retirement Savings and Investment Plan (Form 8-K dated January 30, 2013 (File No. 1-8182, Exhibit 10.1)).

10.21+* - Pioneer Energy Services Corp. Amended and Restated 2007 Incentive Plan (Appendix A of definitive proxy statement on Schedule 14A dated April 12, 2013 (File No. 1-8182)).

10.22+* - Pioneer Energy Services Corp. Amended and Restated 2007 Incentive Plan (Appendix A of definitive proxy statement on Schedule 14A dated April 9, 2014 (File No. 1-8182)).

10.23+* - Pioneer Energy Services Corp. Amended and Restated 2007 Incentive Plan (Appendix A of definitive proxy statement on Schedule 14A dated April 20, 2015 (File No. 1-8182)).

10.24+* - Employment Letter, effective May 1, 2012, from Pioneer Drilling Company to Brian L. Tucker (Form 10-Q dated April 29, 2016 (File No. 1-8182, Exhibit 10.1)).

10.25+*	-	Pioneer Energy Services Corp. Amended and Restated 2007 Incentive Plan (Appendix A of definitive proxy statement on Schedule 14A dated April 18, 2016 (File No. 1-8182)).
10.26+*	-	Pioneer Energy Services Corp. 2007 Incentive Plan Form of Performance Phantom Stock Unit Award Agreement (Form 10-Q dated July 28, 2016 (File No. 1-8182, Exhibit 10.3)).
12.1**	-	Computation of ratio of earnings to fixed charges.
21.1**	-	Subsidiaries of Pioneer Energy Services Corp.
23.1**	-	Consent of Independent Registered Public Accounting Firm.
31.1**	-	Certification by Wm. Stacy Locke, President and Chief Executive Officer, pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934.
31.2**	-	Certification by Lorne E. Phillips, Executive Vice President and Chief Financial Officer, pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934.
32.1#	-	Certification by Wm. Stacy Locke, President and Chief Executive Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2#	-	Certification by Lorne E. Phillips, Executive Vice President and Chief Financial Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101**	-	The following financial statements from Pioneer Energy Services Corp.'s Form 10-K for the year ended December 31, 2016, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statements of Shareholders' Equity, (iv) Consolidated Statements of Cash Flows, and (v) Notes to Consolidated Financial Statements.

* Incorporated by reference to the filing indicated.

** Filed herewith.

\# Furnished herewith.

\+ Management contract or compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

PIONEER ENERGY SERVICES CORP.

February 17, 2017

/S/ WM. STACY LOCKE
Wm. Stacy Locke
Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/S/ DEAN A. BURKHARDT Dean A. Burkhardt	Chairman	February 17, 2017
/S/ WM. STACY LOCKE Wm. Stacy Locke	President, Chief Executive Officer and Director (Principal Executive Officer)	February 17, 2017
/S/ LORNE E. PHILLIPS Lorne E. Phillips	Executive Vice President and Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)	February 17, 2017
/S/ C. JOHN THOMPSON C. John Thompson	Director	February 17, 2017
/S/ JOHN MICHAEL RAUH John Michael Rauh	Director	February 17, 2017
/S/ SCOTT D. URBAN Scott D. Urban	Director	February 17, 2017

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PIONEER ENERGY SERVICES CORP. AND SUBSIDIARIES
Reconciliation of Net Income (Loss) to Adjusted EBITDA
(in thousands)

	Year ended December 31,				
	2016	2015	2014	2013	2012
Reconciliation of net income (loss) to Adjusted EBITDA:					
Net income (loss)	$ (128,391)	$ (155,140)	$ (38,018)	$ (35,932)	$ 30,032
Depreciation and amortization	114,312	150,939	183,376	187,918	164,717
Impairment charges	12,815	129,152	73,025	54,292	1,131
Interest expense	25,934	21,222	38,781	48,310	37,049
Loss on extinguishment of debt	299	2,186	31,221	—	—
Income tax expense (benefit)	(10,732)	(37,579)	(11,304)	(19,846)	16,354
Adjusted EBITDA*	$ 14,237	$ 110,780	$ 277,081	$ 234,742	$ 249,283

*Adjusted EBITDA represents income (loss) before interest expense, income tax (expense) benefit, depreciation and amortization, loss on extinguishment of debt and impairments. Adjusted EBITDA is a non-GAAP measure that our management uses to facilitate period-to-period comparisons of our core operating performance and to evaluate our long-term financial performance against that of our peers. We believe that this measure is useful to investors and analysts in allowing for greater transparency of our core operating performance and makes it easier to compare our results with those of other companies within our industry. Adjusted EBITDA should not be considered (a) in isolation of, or as a substitute for, net income (loss), (b) as an indication of cash flows from operating activities or (c) as a measure of liquidity. In addition, Adjusted EBITDA does not represent funds available for discretionary use. Adjusted EBITDA may not be comparable to other similarly titled measures reported by other companies.

DIRECTORS

DEAN A. BURKHARDT
Consultant to energy industry

SCOTT D. URBAN
Partner in Edgewater Energy

JOHN MICHAEL RAUH
Retired
Kerr-McGee Corporation

C. JOHN THOMPSON
Chairman and Chief Executive Officer
Ventana Capital Advisors, Inc.

WM. STACY LOCKE
President and
Chief Executive Officer
Pioneer Energy Services Corp.

OFFICERS

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President and
Chief Executive Officer

LORNE E. PHILLIPS
Executive Vice President and
Chief Financial Officer

BRIAN L. TUCKER
Executive Vice President and
President of Drilling Services

CARLOS R. PEÑA
Executive Vice President,
President of Production Services,
General Counsel, Secretary and
Compliance Officer

BILL W. BOUZIDEN
Senior Vice President of Wireline
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JOE P. FREEMAN
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A copy of the Company's annual report on Form 10-K is available, without charge, upon request to the address listed above.

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STOCK LISTING
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As of March 20, 2017, the approximate number of common shareholders of record was 302.

Pioneer Energy Services

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