PIONEER

Pioneer Energy Services

2015 ANNUAL REPORT

EVERY PROJECT

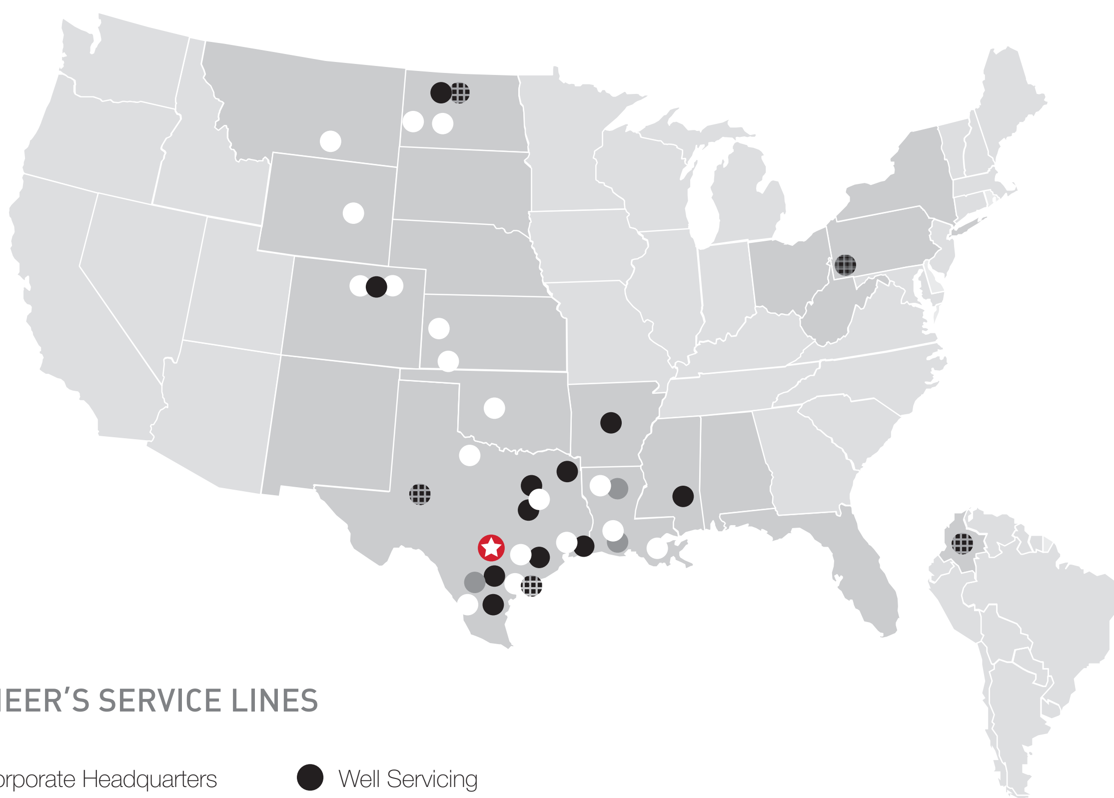
IS PERSONAL

SELECTED FINANCIAL DATA

(In thousands, except per share data)	2015 (4)	2014 (3)	2013 (2)	2012	2011
Revenues	$540,778	$1,055,223	$960,186	$919,443	$715,941
Net income (loss)	(155,140)	(38,018)	(35,932)	30,032	11,177
Adjusted EBITDA(1)	110,780	277,081	234,742	249,283	183,870
Income (loss) per common share - diluted	(2.41)	(0.60)	(0.58)	0.48	0.19
Total assets	829,776	1,171,589	1,229,623	1,339,776	1,172,754
Long-term debt and capital lease obligations, excluding current installments	395,000	455,053	499,666	518,725	418,728
Shareholders' equity	342,643	495,064	518,433	547,680	510,445
Net cash provided by operating activities	142,719	233,041	174,580	199,366	144,879

(1) 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 10-K.
(2) Net income (loss) includes goodwill, property and equipment, and intangible asset impairment charges of $54.3 million ($33.1 million net of tax).
(3) Net income (loss) includes property and equipment impairment charges of $73.0 million ($45.3 million net of tax).
(4) Net income (loss) includes intangible asset and property and equipment impairment charges of $129.2 million ($102.8 million net of tax).

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, 2015
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, 2015) was approximately $400 million.

As of January 28, 2016, there were 64,500,273 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 2016 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 duty 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-build 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 new-build program to construct more technologically advanced, pad-optimal rigs to meet the changing needs of our clients. We have a current fleet of 31 drilling rigs, 94% of which are pad-capable, and 15 of which are AC walking rigs built within the last five years and engineered to optimize pad drilling. The removal of older, less capable rigs from our fleet and the recent investments in the construction of new-builds 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 upon recovery of our industry.

  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 either a daywork or 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	7
West Texas	6
North Dakota	6
Appalachia	4
Colombia	8
	31

  Since late 2014, oil prices have declined significantly resulting in a downturn in our industry, affecting both drilling and production services. In drilling, all rig classes have been 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. We completed construction of five new-build 1,500 horsepower AC drilling rigs during 2015. We sold 32 of our mechanical and lower horsepower electric drilling rigs during 2015, which were the most negatively impacted by the industry downturn, and placed an additional 4 rigs as held for sale as of year-end.

  Currently, 14 of our 23 domestic drilling rigs are earning revenues, 12 of which are under term contracts. Of the eight rigs in Colombia, three are under term contracts, but have been put on standby by our client and are not earning revenue. We are actively marketing our idle drilling rigs in Colombia to various operators to diversify our client base, and evaluating other options, including the possibility of the sale of some or all of our assets in Colombia.

  In response to the significant decline in oil prices over the last year, term contracts for 19 of our drilling rigs have been terminated early, including three which were terminated in early 2016, resulting in a total of $62.8 million of early termination payments. Revenues derived from these early terminations are deferred and recognized over the remainder of the original term of the drilling contracts. We recognized $49.2 million and

$0.3 million of revenue for early termination payments during the years ended December 31, 2015 and 2014, respectively, and we will recognize the remaining $13.3 million in 2016.

- *Production Services Segment*— In March 2008, we acquired two production services companies which significantly expanded our service offerings to include well servicing and wireline services. Through these business acquisitions, we also obtained fishing and rental services operations, which were subsequently sold on September 17, 2014. We also acquired a coiled tubing services business at the end of 2011 to further expand our production services offerings. Since the acquisitions of these businesses, we continued to invest in their organic growth and have significantly expanded all our production services 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, 2015, 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, 2015, we have a fleet of 125 wireline units in 17 operating locations in the Gulf Coast, Mid-Continent and Rocky Mountain states.

  - Coiled Tubing Services. Coiled tubing is an important element of the well servicing industry that allows operators to continue production during service operations 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, 2015, 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 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 11, *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 in turn is affected by current and expected oil and natural gas prices.

For the several years prior to late 2014, generally increasing oil prices drove industry equipment utilization and revenue rates up, particularly in oil-producing regions and certain shale regions. Even though advancements in technology improved the efficiency of drilling rigs, demand remained steady, particularly for drilling rigs that are able to drill horizontally. Since late 2014, oil prices have declined significantly resulting in a downturn in our industry, affecting both drilling and production services. If oil and natural gas prices remain at current levels for an extended period of time, or if oil prices decline further, then industry equipment utilization and revenue rates would likely decrease further. We expect continued pricing pressure, low activity levels and a highly competitive environment in 2016, but we believe our high-quality equipment and services are well positioned to compete.

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 tend to be less affected by fluctuations in commodity prices and temporary reductions in industry activity.

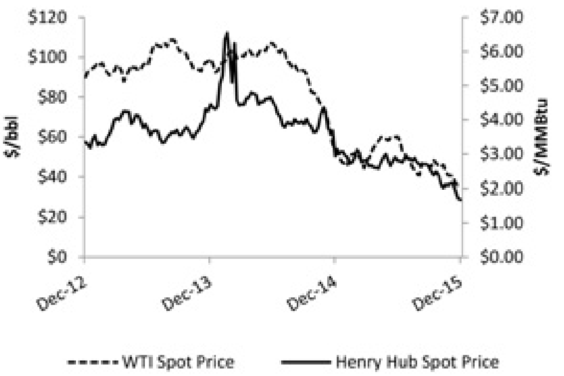
Our business is influenced substantially by both operating and capital expenditures by exploration and production companies. Exploration and production spending is generally categorized as either a capital expenditure or an operating expenditure.

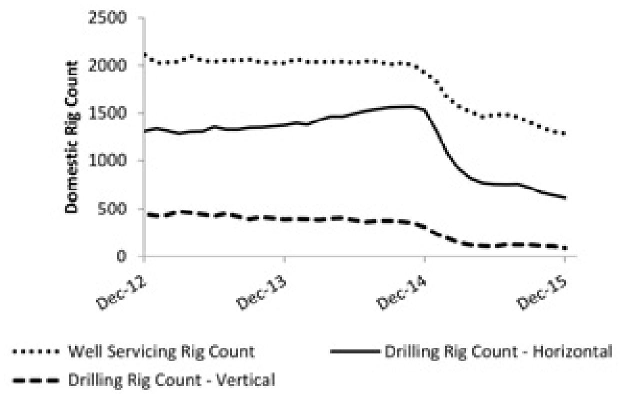
Capital expenditures by oil and gas exploration and production companies tend to be relatively sensitive to volatility in oil or natural gas prices because project decisions are tied to a return on investment spanning a number of months or years. As such, capital expenditure economics often require the 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, because existing oil and natural gas wells require ongoing spending to maintain production, expenditures by exploration and production companies for the maintenance of existing wells, which requires a range of production services, are relatively stable and more predictable. However, in a severe downturn that is prolonged, both operating and capital expenditures are significantly reduced. Our clients significantly reduced both their operating and capital expenditures during 2015 and we expect further reductions to their budgets for 2016.

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. At the end of 2015, the spot prices of WTI crude oil and Henry Hub natural gas were down by 66% and 74%, 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 61% and 78%, respectively, while the domestic well servicing rig count decreased by 38%, as compared to the respective highest counts during 2014.

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.

Technological advancements and trends in our industry also affect the demand for certain types of equipment. In recent years, and especially during the recent downturn, demand has significantly decreased for certain drilling rigs, particularly in vertical well markets. The decline is a result of higher demand for drilling rigs that are able to drill horizontally and the increased use of "pad drilling." Pad drilling enables a series of horizontal wells to be drilled in succession by a walking or skidding drilling rig at a single pad-site location, thereby improving the productivity of exploration and production activities. This trend has 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 have been 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.

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

Competitive Strengths

Our competitive strengths include:

- *One of the Leading Providers in the Prominent Domestic Regions.* Our drilling rigs operate in many of the most attractive producing regions in the United States, including the Marcellus and Eagle Ford shales, the Permian Basin and the Bakken. Our drilling rigs are currently located in four divisions throughout the United States and Colombia, but are mobile between domestic regions, diversifying our geographic exposure and limiting the impact of any regional slowdown. We believe the varied capabilities of our drilling rigs make them well suited to these areas where the optimal rig configuration is dictated by local geology and market conditions.

- *High Quality Assets.* Excluding the drilling rigs that we expect to sell in the near-term and which are classified as held for sale at year-end, 94% of our drilling rigs are pad-capable, and all but one of our AC rigs have been built within the last five years. Over 75% of our production services assets have been built since 2007, and all of our well servicing rigs have at least 550 horsepower. We believe that our modern and well maintained fleet allows us to realize higher contract and utilization rates because we are able to offer our clients equipment that is more reliable and requires less downtime than older equipment.

- *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.

- *Excellent Safety Record.* Our 2015 total recordable incident rate is the lowest we have achieved since our company's inception. 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. We believe that by building strong relationships among our people, we can achieve an excellent safety record. Our excellent safety record and reputation are critical to winning new business and expanding our relationships with existing clients. Our commitment to safety helps us to keep our employees safe and reduces our business risk.

- *Experienced Management Team.* We believe that important competitive factors in establishing and maintaining long-term client relationships include having an experienced and skilled management team and maintaining employee continuity. 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 maximize employee continuity and minimize employee turnover 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 Whiting Petroleum Corporation, Apache Corporation, EQT Corporation and Marathon Oil Corporation. Our largest client, Whiting Petroleum Corporation, accounted for approximately 18% of our 2015 consolidated revenues.

Strategy

In past years, our strategy was to become a premier land drilling and production services company through steady and disciplined growth. We executed this strategy by acquiring and building a high quality drilling rig fleet and production services business which we operate in many of the most attractive drilling markets throughout the United States and in Colombia.

With the recent decline in oil prices and the reductions in our utilization and revenue rates in 2015, our near-term efforts are focused on:

- *Cost Reductions.* During 2015, we reduced our total headcount by 52%, 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, and we will continue to evaluate opportunities to lower our cost structure in response to reduced revenues.

- *Liquidating Nonstrategic Assets.* During 2015, we sold 32 drilling rigs and other drilling equipment for aggregate net proceeds of $53.6 million, and have four additional rigs placed as held for sale at year-end. 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 amended our revolving credit facility in September 2015 and again in December 2015, which continues to provide access to capital but has more flexible financial covenants, and we have availability for equity or debt offerings up to $300 million under our shelf registration statement. Additionally, we paid down $60 million of debt during 2015.

- *Performance of our Core Businesses.* We will continue to focus on maintaining our relationships with our clients and vendors through the downturn, and continue to focus on our service quality and safety. During this difficult time, we remain committed to our safety and service quality goals, and our 2015 total recordable incident rate is the lowest we have achieved since our company's inception.

We will continue to evaluate our business and look for opportunities to further achieve these goals in 2016, which we believe will position us to take advantage of future business opportunities and continue our long-term growth strategy.

Our long-term strategy is to maintain and leverage our position as a leading land drilling and production services company, continue to expand 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 the Growth of our Business.* We have historically invested in the growth of our business by strategically upgrading our existing assets and disposing of assets which use older technology, and engaging in select new-build opportunities and acquisitions.

  Over the last five years, we have added significant capacity to our production services offerings through the addition of 62 wireline units, 51 well servicing rigs and 17 coiled tubing units. We constructed ten AC drilling rigs from 2011 to 2013 and we completed construction of five new-build 1,500 horsepower AC drilling rigs during 2015. We sold 32 of our mechanical and lower horsepower electric drilling rigs during 2015, which were the most negatively impacted by the industry downturn, and placed an additional 4 rigs as held for sale as of year-end.

  We have a current fleet of 31 drilling rigs, 94% of which are pad-capable, and 15 of which are AC walking rigs built within the last five years and engineered to optimize pad drilling. The removal of older, less capable rigs from our fleet and the recent investments in the construction of new-builds 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 upon recovery of our industry.

- *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. The 15 new-build drilling rigs which we constructed in the last five years are well suited for our operations in the Marcellus/Utica and Eagle Ford shales, the Permian Basin and the Bakken. Additionally, we have added significant capacity in recent years to our production services fleets, which we believe are well positioned to capitalize on 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. With natural gas prices at low levels in recent years, we intentionally increased our exposure to oil-related activities by redeploying certain of our assets into predominately oil-producing regions. With the recent decline in oil prices, 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

There are numerous factors that differentiate land drilling rigs, including their power generation systems and their drilling depth capabilities. A land drilling rig consists of engines, a hoisting system, a rotating system, pumps and related equipment to circulate drilling fluid, blowout preventers and related equipment. Generally, drilling rigs operate with crews of five to six persons.

Diesel or natural gas engines are typically the main power sources for a drilling rig. Power requirements for drilling jobs may vary considerably, but most land drilling rigs employ two or more engines to generate between 500 and 2,000 horsepower, depending on well depth and rig design. Most drilling rigs capable of drilling in deep formations, involving depths greater than 15,000 feet, use diesel-electric power units to generate and deliver electric current through cables to electrical switch gears, then to direct-current electric motors attached to the equipment in the hoisting, rotating and circulating systems.

Generally, a drilling rig's hoisting system is made up of a mast, or derrick, a traveling block and hook assembly that attaches to the rotating system, a mechanism known as the drawworks, a drilling line and ancillary equipment. The drawworks mechanism consists of a revolving drum, around which the drilling line is wound, and a series of shafts, clutches and chain and gear drives for generating speed changes and reverse motion. The drawworks also houses the main brake, which has the capacity to stop and sustain the weights used in the drilling process. When heavy loads are being lowered, a hydraulic or electric auxiliary brake assists the main brake to absorb the great amount of energy developed by the mass of the traveling block, hook assembly, drill pipe, drill collars and drill bit or casing being lowered into the well.

The rotating equipment from top to bottom consists of a top drive, drill pipe, drill collars and the drill bit. We refer to the equipment between the top drive and the drill bit as the drill stem. In a top drive system, the top drive hangs from a hook or a traveling block. The top drive has a passageway for drilling mud to pass into the drill pipe, and it has an AC electric motor connected via a gearbox to a threaded drive shaft which connects to and rotates the drill pipe. Drilling fluid enters the drill stem through a hose, called the rotary hose, attached to the top drive. The drill pipe and drill collars are both steel tubes through which drilling fluid can be pumped. Drill pipe, sometimes called drill string, comes in 30-foot sections, or joints, with threaded sections on each end. Drill collars are heavier than drill pipe and both are threaded on the ends. Collars are used on the bottom of the drill stem to apply weight to the drilling bit. At the end of the drill stem is the bit, which chews up the formation rock and dislodges it so that drilling fluid can circulate the fragmented material back up to the surface where the circulating system filters it out of the fluid.

Drilling fluid, often called mud, is a mixture of clays, chemicals and water or oil, which is carefully formulated for the particular well being drilled. Drilling mud accounts for a major portion of the cost incurred and equipment used in drilling a well. Bulk storage of drilling fluid materials, the pumps and the mud-mixing equipment are placed at the start of the circulating system. Working mud pits and reserve storage are at the other end of the system. Between these two points, the circulating system includes auxiliary equipment for drilling fluid maintenance and equipment for well pressure control. Within the system, the drilling mud is typically routed from the mud pits to the mud pump and from the mud pump through a standpipe and the rotary hose to the drill stem. The drilling mud travels down the drill stem to the bit, up the annular space between the drill stem and the borehole and through the blowout preventer stack to the return flow line. It then travels to a shale shaker for removal of rock cuttings, and then back to the mud pits, which are usually steel tanks. The reserve pits, usually one or two fairly shallow excavations, are used for waste material and excess water around the location.

Drilling rigs use long strings of drill pipe and drill collars to drill wells. Drilling rigs are also used to set heavy strings of large-diameter pipe, or casing, inside the borehole. Because the total weight of the drill string and the casing can exceed 500,000 pounds, drilling rigs require significant hoisting and braking capacities. The actual drilling depth capability of a rig may be less than or more than its rated depth capability due to numerous factors, including the size, weight and amount of the drill pipe on the rig. The intended well depth and the drill site conditions determine the amount of drill pipe and other equipment needed to drill a well.

Technological advancements and trends in our industry affect the demand for certain types of equipment. In a continuing effort to improve our drilling rig fleet, every drilling rig in our fleet has been equipped with a top drive and iron roughneck, and all but two of our drilling rigs are equipped with a walking or skidding system and automatic catwalk. These upgrades, which are described in more detail below, provide our clients with drilling rigs that have more varied capabilities for drilling in unconventional plays, and they improve 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. 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 a walking or skidding 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.

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 significantly reduces pick up and lay down time, thereby decreasing operator costs for handling casing.

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

	Year ended December 31,				
	2015	**2014**	**2013**	**2012**	**2011**
Average number of operating rigs for the period	39.1	62.0	68.2	65.0	69.3
Average utilization rate	63%	87%	84%	87%	73%

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 new-build program to construct more technologically advanced, pad-optimal rigs to meet the changing needs of our clients. During 2015, we completed construction of five new-build 1,500 horsepower AC drilling rigs and removed a total of 36 of our mechanical and lower horsepower drilling rigs from our fleet, which were the most negatively impacted by the industry downturn. The removal of older, less capable rigs from our fleet and the recent investments in the construction of new-builds 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 either a daywork or 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 enter into longer-term drilling contracts for our newly constructed rigs and/or during periods of high rig demand. Currently, we have contracts with original terms of six months to four years in duration.

Currently, 14 of our 23 domestic drilling rigs are earning revenues, 12 of which are under term contracts. Of the eight rigs in Colombia, three are under term contracts, but have been put on standby by our client and are not earning revenue. The term contracts in Colombia are cancelable without penalty, by our client 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 to diversify our client base, and evaluating other options, including the possibility of the sale of some or all of our assets in Colombia.

Including these three contracts in Colombia, 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 Contracts and 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:							
Earning under contract	2	8	1	2	—	1	4
Earning but not working	—	4	3	1	—	—	—
Colombia Rigs (on standby)	—	3	—	1	—	—	2
	2	15	4	4	—	1	6

In response to the significant decline in oil prices over the last year, term contracts for 19 of our drilling rigs have been terminated early, including three which were terminated in early 2016, resulting in a total of $62.8 million of early termination payments. Revenues derived from these early terminations are deferred and recognized over the remainder of the original term of the drilling contracts. We recognized $49.2 million and $0.3 million of revenue for early termination payments during the years ended December 31, 2015 and 2014, respectively, and we will recognize the remaining $13.3 million in 2016.

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	**2015**	**2014**	**2013**
Daywork	448	1,001	970
Turnkey	17	106	27
Total number of wells	465	1,107	997

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 turnkey contract, we agree to drill a well for our client to a specified depth and under specified conditions for a fixed price, regardless of the time required or the problems encountered in drilling the well. 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.

The risks to us under a turnkey contract are substantially greater than on a well drilled on a daywork basis. This is primarily because under a turnkey contract we assume most of the risks associated with drilling operations generally assumed by the operator in a daywork contract, including the risk 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 employ or contract for engineering expertise to analyze seismic, geologic and drilling data to identify and reduce some of the drilling risks we assume. We use the results of this analysis to evaluate the risks of a proposed contract and seek to account for such risks in our bid preparation. We believe that our operating experience, qualified drilling personnel, risk management program, internal engineering expertise and access to proficient third-party engineering contractors have allowed us to reduce some of the risks inherent in turnkey drilling operations. We also maintain insurance coverage against some, but not all, drilling hazards. However, 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.

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, 2015, 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	119	125
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 rigs with at least 550 horsepower, capable of working at depths of 20,000 feet. Our well servicing utilization rates for the years ended December 31, 2015 and 2014 were 65% and 97%, 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 60% of our wireline fleet.

Coiled Tubing Services. Coiled tubing is an important element of the well servicing industry that allows operators to continue production during service operations 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, 2015, our coiled tubing business consists of 12 onshore and five offshore coiled tubing units which are deployed through three locations in Texas and Louisiana. Our coiled tubing utilization rates for the years ended December 31, 2015 and 2014 were 27% and 51%, 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, 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%
Fiscal year ended December 31, 2013	
Whiting Petroleum Corporation	12.6%
Ecopetrol	10.7%
Apache Corporation	5.9%

Competition

Drilling Services Segment

We encounter substantial competition from other drilling contractors. Our primary market areas are highly fragmented and competitive. The fact that drilling rigs are mobile and can be moved from one market to another in response to market conditions heightens the competition in the industry.

The drilling contracts we compete for are usually awarded on the basis of competitive bids. Our principal competitors are Helmerich & Payne, Inc., Precision Drilling Corporation, Patterson-UTI Energy, Inc. and Nabors Industries, Ltd. In addition to pricing and rig availability, we believe the following factors are also important to our clients in determining which drilling contractors to select:

- the type and condition of each of the competing drilling rigs;
- the mobility and efficiency of the rigs;

- the quality of service and experience of the rig crews;
- the safety records of our company;
- the offering of ancillary services; and
- the ability to provide drilling equipment adaptable to, and personnel familiar with, new technologies and drilling 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 rig crews and the quality of service we provide to differentiate us from our competitors.

Drilling 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 services improves in a region where we operate, our competitors might respond by moving in suitable rigs from other regions. An influx of rigs from other regions could rapidly intensify competition and make any improvement in demand for drilling rigs in a particular region short-lived.

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

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

Production Services Segment

The market for production services is highly competitive. Competition is influenced by such factors as price, capacity, availability of work crews, type and condition of equipment and reputation and experience of the service provider, including safety record. 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 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 production services markets.

The need for well servicing, wireline and coiled tubing 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. Generally, as the supply of these commodities decreases and demand increases, service and maintenance requirements increase as oil and natural gas producers attempt to maximize the productivity of their wells in a higher priced environment.

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 and cement. 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 equipment and supplies during periods of high demand. Shortages could result in increased prices for drilling 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 obtaining drilling equipment or supplies could limit our drilling operations and jeopardize our relations with clients. In addition, shortages of drilling equipment or supplies could delay and adversely affect our ability to obtain new contracts for our drilling 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 the exploration and production of oil and natural gas, including the risks of:

- blowouts;
- fires and explosions;
- loss of well control;
- collapse of the borehole;
- lost or stuck drill strings; 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 drilling 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 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 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 not be able 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 on drilling rigs of $500,000 per occurrence ($750,000 deductible for rigs with an insured value greater than $10 million), 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, $5 million, $10 million, $15 million or $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 currently have approximately 1,700 employees, which is down 50% over the last 12 months. 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 57 other real estate locations, of which we own 14, 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

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, as amended by the Oil Pollution Act (and interpreted by EPA in 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 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 will open for signature in April 2016 and will only become fully effective if it is ratified by at least 55 countries that collectively produce at least 55% of the world's greenhouse gas emissions.

The United States is a party to and helped negotiate the Paris Agreement, but has not yet ratified the agreement. 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.

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 hydraulic fracturing rule finalized in March 2015, that impose additional requirements on the practice of 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 minor 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.

Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a study of the potential environmental impacts of hydraulic fracturing. A Progress Report was issued by the EPA in May 2014 and a draft report was issued for comment in June 2015; peer review of the information provided in the Progress Report is underway. 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 August 18, 2015, the EPA proposed a rule to reduce methane (a greenhouse gas) and VOC emissions from oil and gas operations. It is also possible that the EPA will modify the proposed rule or further amend its oil and gas regulations. 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 is also developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities. The proposed regulations were published on April 7, 2015. 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 possible rule to reduce flaring and venting associated with oil and gas operations on public lands. A proposed rule is expected in 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.

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.

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 foreign supply of 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;
- the price of foreign imports of oil and gas; and
- the overall supply and demand for oil and gas.

As a result of the decline in oil prices that began in late 2014 and continued through 2015, our clients will likely maintain minimal spending on exploration and production projects in the near term, 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.

Since October 2014, oil prices worldwide have dropped significantly. If the current 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. Our clients significantly reduced both their operating and capital expenditures during 2015 and we expect further reductions to their budgets for 2016.

The recent reduction in spending and activity levels has adversely affected our business during 2015 and 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 drilling or production 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 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 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 affect the demand for certain types of equipment.

Technological advancements and trends in our industry affect the demand for certain types of equipment. In recent years, and especially during the recent downturn, demand has significantly decreased for certain drilling rigs, particularly in vertical well markets. The decline is a result of higher demand for drilling rigs that are able to drill horizontally and the increased use of "pad drilling." Pad drilling enables a series of horizontal wells to be drilled in succession by a walking or skidding drilling rig at a single pad-site location, thereby improving the productivity of exploration and production activities. This trend has 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 have been 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, 2015, 2014 and 2013, our drilling and production services to our top three clients accounted for approximately 29%, 28%, and 29%, respectively, of our revenue, and in 2015, 2014 and 2013, one client, Whiting Petroleum Corporation, accounted for 18%, 12% and 13%, 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, from all clients including these major clients, and we expect further reductions during 2016.

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 December 31, 2015, our total debt balance of $395.0 million consists of $300 million outstanding under our Senior Notes and $95 million outstanding under our Revolving Credit Facility. At December 31, 2015, we had borrowing availability of $87.7 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 anticipate that our cash generated by operations, proceeds from the expected sales of certain non-strategic assets and our ability to borrow under the currently unused portion of our Revolving Credit Facility should allow us to meet our routine financial obligations for at least the next twelve 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:

- limitations on the incurrence of additional indebtedness;
- restrictions on investments, capital expenditures, mergers or consolidations, asset dispositions, acquisitions, repurchases of capital stock, transactions with affiliates and other transactions without the lenders' consent; and
- limitation on dividends and distributions.

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 our and certain of our subsidiaries' ability to:

- pay dividends on stock;
- repurchase stock or redeem subordinated debt or make other restricted payments;
- incur, assume or guarantee additional indebtedness or issue disqualified stock;
- create liens on the our assets;
- enter into sale and leaseback transactions;
- pay dividends, engage in loans, 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 another 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. 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. 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.

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 drilling and production services 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 drilling and production services equipment or supplies could limit drilling and production services operations and jeopardize our relations with clients. In addition, shortages of drilling and production services 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, and our recent acquisitions in particular, involve 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, we can provide no assurance that access to our invested cash and cash equivalents will not be impacted 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;
- 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, as amended by the Oil Pollution Act (and interpreted by EPA in 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 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 will open for signature in April 2016 and will only become fully effective if it is ratified by at least 55 countries that collectively produce at least 55% of the world's greenhouse gas emissions.

The United States is a party to and helped negotiate the Paris Agreement, but has not yet ratified the agreement. 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 hydraulic fracturing rule finalized in March 2015, that impose additional requirements on the practice of 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 minor 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.

Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a study of the potential environmental impacts of hydraulic fracturing. A Progress Report was issued by the EPA in May 2014 and a draft report was issued for comment in June 2015; peer review of the information provided in the Progress Report is underway. 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 August 18, 2015, the EPA proposed a rule to reduce methane (a greenhouse gas) and VOC emissions from oil and gas operations. It is also possible that the EPA will modify the proposed rule or further amend its oil and gas regulations. 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 is also developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities. The proposed regulations were published on April 7, 2015. 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 possible rule to reduce flaring and venting associated with oil and gas operations on public lands. A proposed rule is expected in 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, or customer 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 28, 2016, 64,500,273 shares of our common stock were outstanding, held by 345 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, 2015		
First Quarter	$ 3.74	$ 6.40
Second Quarter	5.09	8.08
Third Quarter	2.10	5.46
Fourth Quarter	2.10	3.32
Fiscal year ended December 31, 2014		
First Quarter	$ 7.72	$ 12.95
Second Quarter	12.11	17.54
Third Quarter	13.70	18.38
Fourth Quarter	4.22	13.06

The last reported sales price for our common stock on the New York Stock Exchange on January 28, 2016 was $1.31 per share.

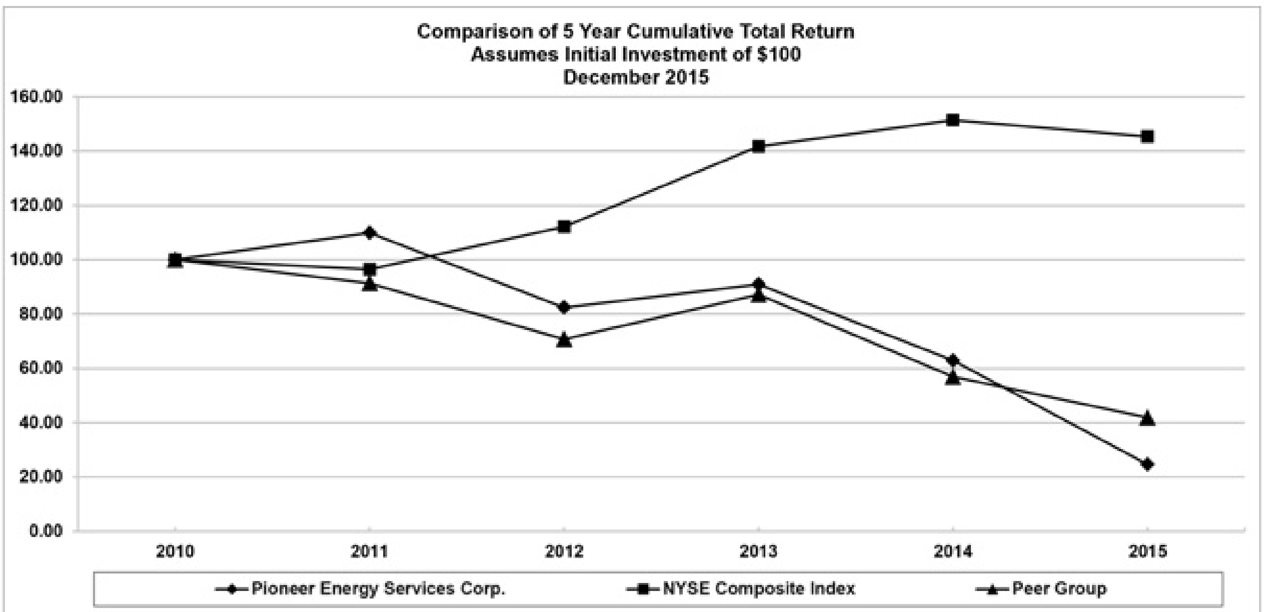
We have not paid or declared any dividends on our common stock and currently intend to retain earnings to fund our working capital needs and growth opportunities. Any future dividends will be at the discretion of our board of directors after taking into account various factors it deems relevant, including 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, other than dividends on our preferred stock. We currently have no preferred stock outstanding.

We did not make any unregistered sales of equity securities during the quarter ended December 31, 2015. 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, 2015.

Performance Graph

The following graph compares, for the periods from December 31, 2010 to December 31, 2015, 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 five 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., Precision Drilling Corporation and Key Energy Services.

The comparison assumes that $100 was invested on December 31, 2010 in our common stock, the companies that compose the NYSE Composite Index and the peer group index, and further assumes all dividends were reinvested.



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,				
	2015 (1)	2014 (2)	2013 (3)	2012	2011
	(In thousands, except per share amounts)				
Statement of Operations Data:					
Revenues	$ 540,778	$1,055,223	$ 960,186	$ 919,443	$ 715,941
Income (loss) from operations	(166,700)	23,984	(6,229)	81,811	57,458
Income (loss) before income taxes	(192,719)	(49,322)	(55,778)	46,386	20,833
Net earnings (loss) applicable to common shareholders	(155,140)	(38,018)	(35,932)	30,032	11,177
Earnings (loss) per common share-basic	$ (2.41)	$ (0.60)	$ (0.58)	$ 0.49	$ 0.19
Earnings (loss) per common share-diluted	$ (2.41)	$ (0.60)	$ (0.58)	$ 0.48	$ 0.19
Other Financial Data:					
Net cash provided by operating activities	$ 142,719	$ 233,041	$ 174,580	$ 199,366	$ 144,879
Net cash used in investing activities	(101,656)	(151,918)	(150,676)	(361,231)	(307,484)
Net cash provided by (used in) financing activities	(61,827)	(73,584)	(20,252)	99,401	226,791
Capital expenditures	142,907	188,121	125,420	379,272	237,787

	As of December 31,				
	2015	2014	2013	2012	2011
	(In thousands)				
Balance Sheet Data:					
Working capital	$ 45,226	$ 121,882	$ 118,547	$ 62,236	$ 129,932
Property and equipment, net	702,585	856,541	937,657	1,014,340	793,956
Long-term debt and capital lease obligations, excluding current installments	395,000	455,053	499,666	518,725	418,728
Shareholders' equity	342,643	495,064	518,433	547,680	510,445
Total assets	829,776	1,171,589	1,229,623	1,339,776	1,172,754

(1) 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.

(2) 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.

(3) 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.

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 our business through acquisitions and organic growth.

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 11, *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-build 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 new-build program to construct more technologically advanced, pad-optimal rigs to meet the changing needs of our clients. We have a current fleet of 31 drilling rigs, 94% of which are pad-capable, and 15 of which are AC walking rigs built within the last five years and engineered to optimize pad drilling. The removal of older, less capable rigs from our fleet and the recent investments in the construction of new-builds 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 upon recovery of our industry.

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 either a daywork or 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	7
West Texas	6
North Dakota	6
Appalachia	4
Colombia	8
	31

Since late 2014, oil prices have declined significantly resulting in a downturn in our industry, affecting both drilling and production services. In drilling, all rig classes have been 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. We completed construction of five new-build 1,500 horsepower AC drilling rigs during 2015. We sold 32 of our mechanical and lower horsepower electric drilling rigs during 2015, which were the most negatively impacted by the industry downturn, and placed an additional 4 rigs as held for sale as of year-end.

Currently, 14 of our 23 domestic drilling rigs are earning revenues, 12 of which are under term contracts. Of the eight rigs in Colombia, three are under term contracts, but have been put on standby by our client and are not earning revenue. We are actively marketing our idle drilling rigs in Colombia to various operators to diversify our client base, and evaluating other options, including the possibility of the sale of some or all of our assets in Colombia.

In response to the significant decline in oil prices over the last year, term contracts for 19 of our drilling rigs have been terminated early, including three which were terminated in early 2016, resulting in a total of $62.8 million of early termination payments. Revenues derived from these early terminations are deferred and recognized over the remainder of the original term of the drilling contracts. We recognized $49.2 million and $0.3 million of revenue for early termination payments during the years ended December 31, 2015 and 2014, respectively, and we will recognize the remaining $13.3 million in 2016.

- *Production Services Segment*— In March 2008, we acquired two production services companies which significantly expanded our service offerings to include well servicing and wireline services. Through these business acquisitions, we also obtained fishing and rental services operations, which were subsequently sold on September 17, 2014. We also acquired a coiled tubing services business at the end of 2011 to further expand our production services offerings. Since the acquisitions of these businesses, we continued to invest in their organic growth and have significantly expanded all our production services 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, 2015, 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, 2015, we have a fleet of 125 wireline units in 17 operating locations in the Gulf Coast, Mid-Continent and Rocky Mountain states.

- Coiled Tubing Services. Coiled tubing is an important element of the well servicing industry that allows operators to continue production during service operations 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, 2015, 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.'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.

Market Conditions in Our Industry

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 in turn is affected by current and expected oil and natural gas prices.

For the several years prior to late 2014, generally increasing oil prices drove industry equipment utilization and revenue rates up, particularly in oil-producing regions and certain shale regions. Even though advancements in technology improved the efficiency of drilling rigs, demand remained steady, particularly for drilling rigs that are able to drill horizontally. Since late 2014, oil prices have declined significantly resulting in a downturn in our industry, affecting both drilling and production services. If oil and natural gas prices remain at current levels for an extended period of time, or if oil prices decline further, then industry equipment utilization and revenue rates would likely decrease further. We expect continued pricing pressure, low activity levels and a highly competitive environment in 2016, but we believe our high-quality equipment and services are well positioned to compete.

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 tend to be less affected by fluctuations in commodity prices and temporary reductions in industry activity.

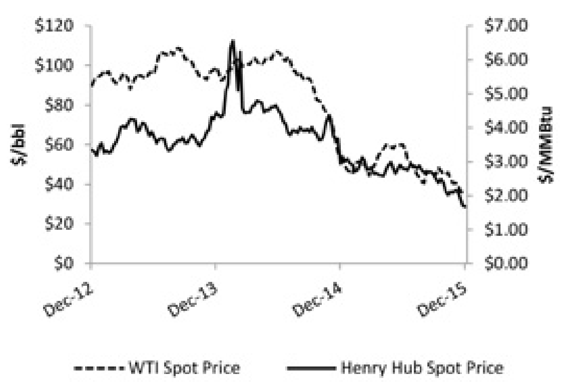
Our business is influenced substantially by both operating and capital expenditures by exploration and production companies. Exploration and production spending is generally categorized as either a capital expenditure or an operating expenditure.

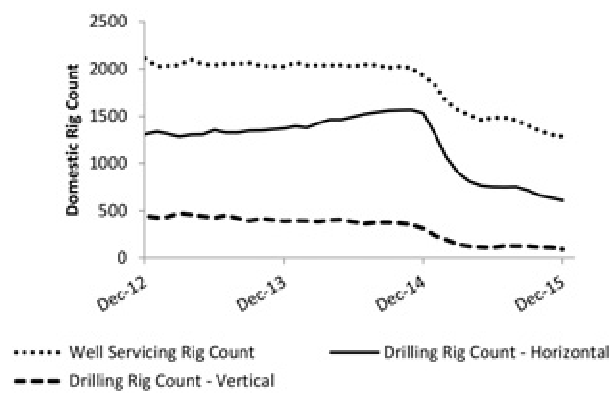
Capital expenditures by oil and gas exploration and production companies tend to be relatively sensitive to volatility in oil or natural gas prices because project decisions are tied to a return on investment spanning a number of months or years. As such, capital expenditure economics often require the 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, because existing oil and natural gas wells require ongoing spending to maintain production, expenditures by exploration and production companies for the maintenance of existing wells, which requires a range of production services, are relatively stable and more predictable. However, in a severe downturn that is prolonged, both operating and capital expenditures are significantly reduced. Our clients significantly reduced both their operating and capital expenditures during 2015 and we expect further reductions to their budgets for 2016.

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. At the end of 2015, the spot prices of WTI crude oil and Henry Hub natural gas were down by 66% and 74%, 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 61% and 78%, respectively, while the domestic well servicing rig count decreased by 38%, as compared to the respective highest counts during 2014.

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.

Technological advancements and trends in our industry also affect the demand for certain types of equipment. In recent years, and especially during the recent downturn, demand has significantly decreased for certain drilling rigs, particularly in vertical well markets. The decline is a result of higher demand for drilling rigs that are able to drill horizontally and the increased use of "pad drilling." Pad drilling enables a series of horizontal wells to be drilled in succession by a walking or skidding drilling rig at a single pad-site location, thereby improving the productivity of exploration and production activities. This trend has 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 have been 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.

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

Liquidity and Capital Resources

Sources of Capital Resources

Our principal liquidity requirements have been for working capital needs, debt service, capital expenditures and selective acquisitions. Our principal sources of liquidity consist of cash and cash equivalents (which equaled $14.2 million as of December 31, 2015), cash generated from operations, including payments from the early terminations of drilling contracts, proceeds from sales of certain non-strategic assets and the unused portion of our senior secured revolving credit facility (the "Revolving Credit Facility").

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. As of December 31, 2015, the entire $300 million under the shelf registration statement is available for equity or debt offerings. In the future, we may consider equity and/or debt offerings, as appropriate, to meet our liquidity needs.

In March 2010 and November 2011, we issued an aggregate $425 million of unregistered senior notes with a coupon interest rate of 9.875% that were set to mature in 2018 (the "2010 and 2011 Senior Notes"). The net proceeds from the 2010 issuance were used to repay a portion of the borrowings outstanding under our Revolving Credit Facility and a portion of the net proceeds from the 2011 issuance were used to fund the acquisition of the coiled tubing business in December 2011.

In March 2014, we issued $300 million of unregistered senior notes with a coupon interest rate of 6.125% that are due in 2022 (the "2014 Senior Notes"), the net proceeds from which, combined with cash on hand, were used to fund the repayment of $300 million of aggregate principal amount of 2010 and 2011 Senior Notes in March and May 2014. In October 2014, we redeemed the remaining $125.0 million in aggregate principal amount of the 2010 and 2011 Senior Notes, primarily funded by proceeds from our revolving credit facility and through cash on hand.

Our Revolving Credit Facility, as amended on December 23, 2015, provides for a senior secured revolving credit facility, with sub-limits for letters of credit and swing-line loans, of up to an aggregate principal amount of $200 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. As of December 31, 2015, we had $95 million outstanding under our Revolving Credit Facility and $17.3 million in committed letters of credit, which resulted in borrowing availability of $87.7 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. Additional information regarding these covenants is provided in the *Debt Requirements* section below. Borrowings under the Revolving Credit Facility are available for selective acquisitions, working capital and other general corporate purposes.

We currently expect that cash and cash equivalents, cash generated from operations, including payments from the early terminations of drilling contracts, 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, 2015 and 2014, our primary uses of capital resources were for property and equipment additions which consisted of the following (amounts in thousands):

	Year ended December 31,	
	2015	2014
Drilling Services Segment:		
Routine	$ 13,183	$ 43,403
Discretionary	7,041	24,340
Fleet additions	107,030	34,618
Total Drilling Services Segment	127,254	102,361
Production Services Segment:		
Routine	11,325	22,927
Discretionary	6,018	21,854
Fleet additions	15,018	28,236
Total Production Services Segment	32,361	73,017
Net cash used for purchases of property and equipment	159,615	175,378
Net impact of accruals	(16,708)	12,743
Total Capital Expenditures	$ 142,907	$ 188,121

Our Drilling Services Segment incurred $87.8 million and $37.2 million of costs, including accruals for capital expenditures, on the construction of our new-build drilling rigs during the years ended December 31, 2015 and 2014, respectively. Additionally, during the year ended December 31, 2014, we performed significant upgrade projects to various rigs in our drilling fleet including, among others, the installation of five additional walking systems, three additional automatic catwalks and one additional top drive, the upgrade of one drilling rig to higher horsepower, and we upgraded four rigs with higher horsepower mud pumps. In connection with drilling equipment upgrades and the construction of new-build drilling rigs, we capitalized $3.0 million and $0.7 million of interest costs during the years ended December 31, 2015 and 2014, respectively.

Our Production Services Segment acquired eight wireline units and nine well servicing rigs during the year ended December 31, 2015, that were ordered in 2014. During the year ended December 31, 2014, we acquired six wireline units, seven well servicing rigs and four coiled tubing units.

Currently, we expect to spend approximately $25 million on capital expenditures during 2016. We expect that the total capital expenditures for 2016 will be allocated approximately 60% for our Drilling Services Segment and approximately 40% for our Production Services Segment. Our planned capital expenditures for the year ending December 31, 2016 include the remaining payments for our new-build drilling rigs, routine capital expenditures and certain drilling equipment that was ordered in 2014 but requires a long lead time for delivery. 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 new-build and other expansion opportunities that meet our strategic and return on capital employed criteria. We expect to fund capital expenditures in 2016 from operating cash flow in excess of our working capital requirements, including payments from the early terminations of drilling contracts, proceeds from sales of certain non-strategic assets and from borrowings under our Revolving Credit Facility, if necessary.

Working Capital

Our working capital was $45.2 million at December 31, 2015, compared to $121.9 million at December 31, 2014. Our current ratio, which we calculate by dividing current assets by current liabilities, was 1.6 at December 31, 2015, compared to 1.8 at December 31, 2014.

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 new-build rig construction projects are in progress or when higher percentages of our drilling contracts are turnkey contracts, at which times we are more likely to access capital through debt or equity financing.

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

	December 31, 2015	December 31, 2014	Change
Cash and cash equivalents	$ 14,160	$ 34,924	$ (20,764)
Receivables:			
Trade, net of allowance for doubtful accounts	47,577	136,161	(88,584)
Unbilled receivables	13,624	38,002	(24,378)
Insurance recoveries	14,556	10,900	3,656
Other receivables	4,059	5,138	(1,079)
Deferred income taxes	—	10,998	(10,998)
Inventory	9,262	14,117	(4,855)
Assets held for sale	4,619	9,909	(5,290)
Prepaid expenses and other current assets	7,411	8,925	(1,514)
Total current assets	115,268	269,074	(153,806)
Accounts payable	16,951	64,305	(47,354)
Current portion of long-term debt	—	27	(27)
Deferred revenues	6,222	3,315	2,907
Accrued expenses:			
Payroll and related employee costs	13,859	40,058	(26,199)
Insurance premiums and deductibles	8,087	12,829	(4,742)
Insurance claims and settlements	14,556	10,900	3,656
Interest	5,508	5,432	76
Other	4,859	10,326	(5,467)
Total current liabilities	70,042	147,192	(77,150)
Working capital	$ 45,226	$ 121,882	$ (76,656)

The decrease in cash and cash equivalents during the year ended December 31, 2015 is primarily due to $159.6 million of cash used for purchases of property and equipment and $60.0 million used for debt repayment, offset by $142.7 million of cash provided by operating activities, which includes early termination payments made on certain drilling contracts and $57.7 million of proceeds from the sale of assets.

The net decrease in our total trade and unbilled receivables as of December 31, 2015 as compared to December 31, 2014 is primarily the result of the decrease in consolidated revenues of $178.6 million, or 63%, for the quarter ended December 31, 2015 as compared to the quarter ended December 31, 2014.

The increase in both our insurance recoveries receivables and our insurance claims and settlements accrued expenses as of December 31, 2015 as compared to December 31, 2014 is primarily due to an increase in our insurance company's reserve for workers' compensation claims in excess of our deductibles.

The decrease in other receivables as of December 31, 2015 as compared to December 31, 2014 is primarily due to the collection of a $1.4 million receivable that was recognized in connection with the settlement of a noncompete agreement in 2014 and $1.0 million related to the sale of our fishing and rental operations in September 2014 which was held in escrow for six months. These decreases were partially offset by a decrease in income taxes payable due to a decrease in activity for our Colombian operations.

On December 31, 2015, we elected to prospectively adopt ASU No. 2015-17, *Balance Sheet Classification of Deferred Taxes*, thus reclassifying $6.8 million of current deferred tax assets to noncurrent in our consolidated balance sheet. The prior reporting period was not retrospectively adjusted. The remaining decrease in current deferred income taxes as of December 31, 2015 as compared to December 31, 2014 is primarily due to reduced annual bonus accruals which were higher for 2014 as compared to 2015, as well as the valuation allowance on our Colombian deferred tax assets recognized during 2015.

The decrease in inventory as of December 31, 2015 as compared to December 31, 2014 is primarily due to $3.6 million of impairment charges recognized in the second quarter of 2015 to reduce the carrying value of inventory associated with our Colombian operations, as well as a $1.6 million decrease in our inventory balance for our wireline and coiled tubing operations, primarily as a result of decreased activity.

As of December 31, 2015, our consolidated balance sheet reflects $4.6 million of assets held for sale, primarily consisting of four drilling rigs which we expect to sell in the near term. Our assets held for sale as of December 31, 2014 primarily consisted of nine drilling rigs which we sold in 2015.

The decrease in prepaid and other current assets as of December 31, 2015 as compared to December 31, 2014 is primarily due to a $1.1 million decrease in prepaid insurance costs. Our costs for various insurance policies have decreased as a result of reduced exposure, including reduced headcount and lower insured property values resulting from sales of assets during the year.

The decrease in accounts payable as of December 31, 2015 as compared to December 31, 2014 is primarily the result of the decrease in consolidated operating costs of $117.4 million, or 63%, for the quarter ended December 31, 2015 as compared to the quarter ended December 31, 2014.

The increase in deferred revenues as of December 31, 2015 as compared to December 31, 2014 is primarily related to deferred revenue for early termination payments. 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.)

The decrease in accrued payroll and employee related costs as of December 31, 2015 as compared to December 31, 2014 is primarily due to a 52% reduction in headcount during 2015, as well as lower accruals for our 2015 annual bonuses at an amount below target, as compared to 2014 bonuses which were earned at an amount above the target level.

The decrease in insurance premiums and deductibles as of December 31, 2015 as compared to December 31, 2014 is primarily due to a decrease in our workers compensation and health insurance costs resulting from a decrease in our estimated liability for the deductibles under these policies primarily due to reduced headcount.

The decrease in other accrued expenses as of December 31, 2015 as compared to December 31, 2014 is primarily due to a decrease in our sales tax accruals, primarily due to timing of payments for audits that were completed during 2014.

Long-term Debt and Other Contractual Obligations

The following table includes information about the amount and timing of our contractual obligations at December 31, 2015 (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	$ 395,000	$ —	$ —	$ 95,000	$ 300,000
Interest on debt	137,606	23,249	46,497	40,297	27,563
Purchase commitments	15,482	15,482	—	—	—
Operating leases	12,504	3,618	5,329	3,112	445
Incentive compensation and severance	9,271	4,736	4,535	—	—
Total	$ 569,863	$ 47,085	$ 56,361	$ 138,409	$ 328,008

At December 31, 2015, debt obligations consist of $300 million of principal amount outstanding under our Senior Notes and $95 million outstanding under our Revolving Credit Facility. The $95 million outstanding under our Revolving

Credit Facility is due at maturity on March 31, 2019. However, we may make principal payments to reduce the outstanding balance prior to maturity when cash and working capital is sufficient. The $300 million principal amount outstanding under our 2014 Senior Notes will mature on March 15, 2022.

Interest payment obligations on our Revolving Credit Facility are estimated based on (1) the 5.1% interest rate that was in effect at December 31, 2015, and (2) the outstanding balance of $95 million at December 31, 2015 to be paid at maturity on March 31, 2019. Interest payment obligations on our 2014 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.

Purchase commitments primarily relate to purchases of new equipment and equipment upgrades. In addition, $7.5 million of the purchase commitments in the table above represent obligations for drilling equipment that was ordered during 2014, but which require a long lead time for delivery.

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.

Debt Requirements

The Revolving Credit Facility contains customary mandatory prepayments from the proceeds of certain asset dispositions or debt issuances, which are applied to reduce outstanding revolving and swing-line loans and cash-collateralize letter of credit exposure. 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, 2015, we were in compliance with our financial covenants under the Revolving Credit Facility. Our senior consolidated leverage ratio was 1.0 to 1.0, and our interest coverage ratio was 5.5 to 1.0. The financial covenants contained in our Revolving Credit Facility include the following:

- A maximum senior consolidated leverage ratio, which excludes unsecured and subordinated debt, that cannot exceed 2.50 to 1.00 on December 31, 2015, 3.00 to 1.00 on March 31, 2016, 3.50 to 1.00 on June 30, 2016, 4.25 to 1.00 on September 30, 2016, 4.75 to 1.00 during the period commencing December 31, 2016 through and including June 30, 2017, 4.25 to 1.00 on September 30, 2017, 3.50 to 1.00 during the period commencing December 31, 2017 through and including March 31, 2018, 3.25 to 1.00 on June 30, 2018, and 2.50 to 1.00 at any time thereafter.
- A minimum interest coverage ratio that cannot be less than 1.50 to 1.00 during the period commencing December 31, 2015 through and including June 30, 2016, 1.25 to 1.00 during the period commencing September 30, 2016 through and including September 30, 2017, and 1.50 to 1.00 at any time thereafter.

The Revolving Credit Facility also does not restrict capital expenditures as long as (a) no event of default under the Revolving Credit Facility exists or would result from such expenditures, and (b) such expenditures do not cause total capital expenditures to exceed $50 million for the fiscal year. The capital expenditure threshold may be increased by any unused portion of the capital expenditure threshold from the immediate preceding fiscal year up to $25 million.

The Revolving Credit Facility has additional restrictive covenants that, among other things, limit the incurrence of additional debt, investments, liens, dividends, acquisitions, prepayments of indebtedness, asset dispositions, mergers and consolidations, transactions with affiliates, repurchases of capital stock, hedging contracts, sale leasebacks and other matters customarily restricted in such agreements. 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 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;
- pay dividends, engage in loans, 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, 2015, 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, 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	Year ended December 31, 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
Combined margin	$ 182,762	$ 367,400
Adjusted EBITDA	$ 110,780	$ 277,081

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. We believe that Drilling Services Segment margin and Production Services Segment margin are useful measures for evaluating financial performance, although they are not measures of financial performance under GAAP. However, Drilling Services Segment margin and Production Services Segment margin are common measures of operating performance used by investors, financial analysts, rating agencies and Pioneer Energy Services Corp.'s management. 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. We use this non-GAAP measure, together with our GAAP financial metrics, to assess our financial performance and evaluate our overall progress towards meeting our long-term financial objectives. We believe that this measure is useful to investors and analysts in allowing for greater transparency of our 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 combined Drilling Services Segment margin and Production Services Segment margin to net income (loss), as reported, and a reconciliation of Adjusted EBITDA to net income (loss), as reported, are set forth in the following table.

	Year ended December 31,	
	2015	2014
	(amounts in thousands)	
Reconciliation of combined margin and Adjusted EBITDA to net income (loss):		
Combined margin	$ 182,762	$ 367,400
General and administrative	(73,903)	(103,385)
Bad debt (expense) recovery	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 income (expense)	(2,611)	(3,304)
Adjusted EBITDA	110,780	277,081
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 (expense) benefit	37,579	11,304
Net income (loss)	$ (155,140)	$ (38,018)

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 current downturn in our industry. 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.

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 also influences the types of drilling contracts we are able to obtain. Turnkey drilling contracts result in higher average revenues per day and higher average operating costs per day as compared to daywork drilling contracts. During the years ended December 31, 2015 and 2014, we completed 17 and 106 turnkey contracts, which represented 3% and 6% of our total drilling revenues, respectively.

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.

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 52%, 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 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.

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. 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. 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 3, *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 March and May 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.

Statements of Operations Analysis—Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013

The following table provides information about our operations for the years ended December 31, 2014 and 2013 (amounts in thousands, except average number of drilling rigs, utilization rate and revenue day information).

	Year ended December 31,	
	2014	**2013**
Drilling Services Segment:		
Revenues	$ 516,473	$ 528,327
Operating costs	348,133	354,380
Drilling Services Segment margin	$ 168,340	$ 173,947
Average number of drilling rigs	62.0	68.2
Utilization rate	87%	84%
Revenue days	19,602	20,977
Average revenues per day	26,348	25,186
Average operating costs per day	17,760	16,894
Drilling Services Segment margin per day	$ 8,588	$ 8,292
Production Services Segment:		
Revenues	$ 538,750	$ 431,859
Operating costs	339,690	276,296
Production Services Segment margin	$ 199,060	$ 155,563
Combined:		
Revenues	$ 1,055,223	$ 960,186
Operating costs	687,823	630,676
Combined margin	$ 367,400	$ 329,510
Adjusted EBITDA	$ 277,081	$ 234,742

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

	Year ended December 31, 2014	2013
	(amounts in thousands)	
Reconciliation of combined margin and Adjusted EBITDA to net loss:		
Combined margin	$ 367,400	$ 329,510
General and administrative	(103,385)	(94,183)
Bad debt expense	(1,445)	(767)
Gain on dispositions of property and equipment	1,859	1,421
Gain on sale of fishing and rental services operations	10,702	—
Gain on settlement of litigation	5,254	—
Other expense	(3,304)	(1,239)
Adjusted EBITDA	277,081	234,742
Depreciation and amortization	(183,376)	(187,918)
Impairment charges	(73,025)	(54,292)
Interest expense	(38,781)	(48,310)
Loss on extinguishment of debt	(31,221)	—
Income tax benefit	11,304	19,846
Net loss	$ (38,018)	$ (35,932)

Our Drilling Services Segment’s revenues decreased by $11.9 million, or 2%, during 2014 as compared to 2013, resulting primarily from a decrease in revenue days of 7%, partially offset by an increase in revenues per day of 5%, or $1,162 per day. Our Drilling Services Segment’s operating costs decreased by $6.2 million, or 2%, during 2014 as compared to 2013, primarily resulting from a decrease in revenue days, partially offset by higher operating costs per day which increased by 5%, or $866 per day. Revenue days decreased primarily due to the sale of eight drilling rigs in October 2013, some of which had been earning a standby dayrate during 2013, and due to lower utilization in Colombia where we experienced downtime primarily due to client delays in preparing well sites during the first half of 2014. Overall decreases in revenues and operating costs were partially offset by an increase in domestic revenues and operating costs per day during 2014.

Our average revenues per day increased by 5% or $1,162 per day, while our average operating costs per day increased by 5% or $866 per day, during 2014, as compared to 2013. Our average revenues and operating costs per day increased primarily due to increased turnkey work performed during 2014 as well as higher labor costs during 2014 which are reimbursed by the client, resulting in higher average revenues and operating costs per day.

Demand for drilling rigs influences the types of drilling contracts we are able to obtain. As demand for drilling rigs decreases, daywork rates move down and we may switch to performing more turnkey drilling contracts to maintain higher utilization rates and to improve our Drilling Services Segment’s margins. Turnkey drilling contracts result in higher average revenues per day and higher average operating costs per day as compared to daywork drilling contracts. During the years ended December 31, 2014 and 2013, we completed 106 and 27 turnkey contracts, respectively, representing 6% and 3% of our total drilling revenues for each year, respectively. During 2014, we experienced an increase in demand for turnkey programs using lower horsepower rigs to drill a series of surface holes on pad sites.

Our Production Services Segment's revenues increased by $106.9 million, or 25%, during 2014, as compared to 2013, while operating costs increased by $63.4 million, or 23%. The increases in our Production Services Segment's revenues and operating costs are primarily a result of the increased demand for our services. The number of wireline jobs we completed increased by 3% during 2014, as compared to 2013. The total rig hours for our well servicing fleet increased by 12%, during 2014, as compared to 2013. Our coiled tubing utilization increased to 51% during 2014 from 47% during 2013. Increased pricing for these services also contributed to the increase in revenues, which was primarily due to a greater mix of higher priced jobs performed in our wireline and coiled tubing businesses. The greater mix of higher cost wireline and coiled tubing jobs performed also resulted in the increase in operating costs during 2014, as compared to 2013.

Our general and administrative expense increased by approximately $9.2 million, or 10%, during 2014, as compared to 2013, primarily due to an increase in payroll and compensation related expenses as we are projecting higher incentive compensation based on our company's performance, as well as $1.9 million of severance costs.

During 2014, we recorded total gains on dispositions of our property and equipment of $1.9 million, of which $1.1 million related to the sale of our trucking assets in February 2014. During 2013, we recorded total gains on dispositions of our property and equipment of $1.4 million, of which $0.8 million related to the sale of two mechanical drilling rigs that were previously idle in our East Texas division. Additionally, we disposed of four wireline units and other wireline equipment in 2013.

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

We recorded 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 $3.3 million for 2014 is primarily related to net foreign currency loss recognized for our Colombian operations due to the rise in the value of the U.S. dollar relative to the Colombian peso.

Our depreciation and amortization expenses decreased by $4.5 million during 2014 as compared to 2013, primarily as a result of the sales of equipment during 2013, as well as the impairment charge to write down coiled tubing intangible assets to fair value as of June 30, 2013.

During the year ended December 31, 2014, we recorded $71.0 million of impairment charges to reduce the carrying values of our 31 mechanical and lower horsepower electric drilling rigs to their estimated fair value. Additionally, we recorded $2.0 million of impairment charges during the year ended December 31, 2014 to reduce the carrying values of certain other assets, which were placed as held for sale during the year, to their estimated fair values, based on expected sales price. During the year ended December 31, 2013, we recorded $44.8 million of impairment charges to reduce the goodwill and intangible asset carrying values of our coiled tubing reporting unit, which were originally recorded in connection with the acquisition of Go-Coil, L.L.C. on December 31, 2011. For more information, see Note 3, *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 $9.5 million during 2014, as compared to 2013, primarily due to the repayment of 2010 and 2011 Senior Notes which incurred interest at a higher rate than the 2014 Senior Notes which we issued in March 2014.

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, 2014 was 23%, which is lower than the federal statutory rate in the United States, primarily due to the effect of foreign currency translation, other permanent differences, valuation allowance and the impact of state income taxes. Items such as non-deductible expenses and state income taxes had a reverse effect on the income tax rate due to the negative pre-tax earnings.

Inflation

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. We experienced modest wage rate increases in our Production Services Segment during 2013 and 2014.

Costs for equipment repairs and maintenance, upgrades and new equipment construction are also impacted by inflationary pressures when the demand for drilling services increases. We estimate that we experienced an increase in these costs of approximately 5% to 10% during 2013 and a more moderate increase during 2014.

As a result of the significantly reduced activity levels in our industry during 2015, we estimate that we experienced a moderate decrease in both wage rate and equipment costs during 2015 for both our Drilling and Production Services Segments, and we expect modest decreases in 2016 as well.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Critical Accounting Policies and 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 60 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 percentage-of-completion method based on our estimate of the number of days to complete each contract. All of our revenues are recognized net of applicable sales taxes.

Our management has determined that it is appropriate to use the proportional performance basis to recognize revenue on our turnkey contracts. Although our turnkey contracts do not have express terms that provide us with rights to receive payment for the work that we perform prior to drilling wells to the agreed-on depth, we use this method because, as provided in applicable accounting literature, we believe we achieve a continuous sale for our work-in-progress and believe, under applicable state law, we ultimately could recover the fair value of our work-in-progress even in the event we were unable to drill to the agreed-on depth in breach of the applicable contract. However, in the event we were unable to drill to the agreed-on depth in breach of the contract, ultimate recovery of that value would be subject to negotiations with the client and the possibility of litigation.

If a client defaults on its payment obligation to us under a turnkey contract, we would need to rely on applicable law to enforce our lien rights, because our turnkey contracts do not expressly grant to us a security interest in the work we have completed under the contract and we have no ownership rights in the work-in-progress or completed drilling work, except any rights arising under the applicable lien statute on foreclosure. If we were unable to drill to the agreed-on depth in breach of the contract, we also would need to rely on equitable remedies outside of the contract available in applicable courts to recover the fair value of our work-in-progress under a turnkey contract.

The risks to us under a turnkey contract are substantially greater than on a contract drilled on a daywork basis. Under a turnkey contract, we assume most of the risks associated with drilling operations that are generally assumed by the operator in a daywork contract, including the risks of blowout, loss of hole, stuck drill pipe, machinery breakdowns and abnormal drilling conditions, as well as risks associated with subcontractors' services, supplies, cost escalations and operations personnel.

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. In addition, the occurrence of uninsured or under-insured losses or operating cost overruns on our turnkey contracts could have a material adverse effect on our financial position and results of operations. Therefore, 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.

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, and our estimate of compensation related accruals.

We consider the recognition of revenues and costs on turnkey contracts to be critical accounting estimates. For these types of 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. 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.

Our initial cost estimates for turnkey contracts do not include cost estimates for risks such as stuck drill pipe or loss of circulation. When we encounter, during the course of our drilling operations, conditions unforeseen in the preparation of our original cost estimate, we increase our cost estimate to complete the contract. If we anticipate a loss on a contract in progress at the end of a reporting period 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. However, our actual costs could substantially exceed our estimated costs if we encounter problems such as lost circulation, stuck drill pipe or an underground blowout on contracts still in progress subsequent to the release of the financial statements.

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. We are more likely to encounter losses on turnkey contracts in periods in which revenue rates are lower for all types of contracts. However, during periods of reduced demand for drilling rigs, our overall profitability on turnkey contracts has historically exceeded our profitability on daywork contracts.

We incurred a total loss of $0.5 million on three of the 17 turnkey contracts which were 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. As of December 31, 2015, we had $0.6 million of unbilled receivables related to one turnkey contract in progress, which was completed prior to the issuance of these consolidated financial statements.

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 $2.3 million at December 31, 2015.

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 more than 45 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. 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 2015 on our long-lived assets, in accordance with ASC Topic 360, *Property, Plant and Equipment*.

Our impairment analysis resulted in $60.2 million of impairment charges related to our Colombian operations, $14.3 million related to our coiled tubing operations intangible assets, $16.6 million related to our coiled tubing operations tangible assets and $18.6 million for the impairment of domestic drilling rigs, in order to reduce the carrying value of these assets to their estimated fair values, which were primarily based on market appraisals, which are considered Level 3 inputs as defined by ASC Topic 820, *Fair Value Measurements and Disclosures*. Additionally, we recognized $9.7 million of impairment charges to reduce the carrying values of certain other assets placed as held for sale during the year to their estimated fair values, based on expected sales prices. For more information, see Note 3, *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.

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 ASC Topic 820, *Fair Value Measurements and Disclosures*. 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.

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. If the demand for our drilling services remains at current levels or declines further and any of our rigs 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.

Although we believe the assumptions and estimates used in our analysis are reasonable and appropriate, different assumptions and estimates could materially impact the analysis 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.

As of December 31, 2015, we had $88.8 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 only recognize a tax benefit to the extent of taxable income that we expect to earn in the jurisdiction in future periods.

As of December 31, 2015, we had a valuation allowance of $0.7 million related to a deferred tax asset for a capital loss which we don't believe will be realized in future periods and a valuation allowance of $2.8 million against net operating losses and other tax benefits in certain states.

Except for these items, we estimate that our domestic operations will result in taxable income in excess of our net operating losses and we expect to apply the net operating losses against the current year taxable income and taxable income that we have estimated in future periods. However, as a result of the conditions leading to the impairment of our assets in Colombia, we recorded a valuation allowance of $15.1 million that fully offsets our foreign deferred tax assets relating to net operating losses and other tax benefits.

Our accrued insurance premiums and deductibles as of December 31, 2015 include accruals for costs incurred under the self-insurance portion of our health insurance of approximately $2.4 million and our workers' compensation, general liability and auto liability insurance of approximately $5.5 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 stock-based 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 stock-based 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.

Recently Issued Accounting Standards

Revenue Recognition. In May 2014, the 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 required to apply this new standard beginning with our first quarterly filing in 2018. We are currently evaluating the potential impact of this guidance, but at this time, do not expect that the adoption of this new standard will have a material effect on our financial position or results of operations.

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. In August 2015, these provisions were further amended with guidance from the Securities and Exchange Commission Staff that they would not object to an entity deferring and presenting debt issuance costs related to line-of-credit arrangements as an asset and subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. The recognition and measurement guidance for debt issuance costs are not affected by the amendments in this ASU. This ASU requires retrospective adoption and will be effective for us beginning with our first quarterly filing in 2016. Early adoption is permitted. We do not expect the adoption of this new standard to have a material impact on our financial position or results of operations.

Deferred Income Tax Classification. In November 2015, the FASB issued ASU No. 2015-17, *Balance Sheet Classification of Deferred Taxes*, which requires that the net of deferred tax assets and liabilities be classified as noncurrent on the balance sheet by jurisdiction rather than being separately presented as current and noncurrent portions. We are required to adopt the new standard beginning with our first quarterly filing in 2017; however, early adoption is permitted and the standard may be applied either retrospectively or on a prospective basis to all deferred tax assets and liabilities. 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. The prior reporting period was not retrospectively adjusted.

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, 2015, we had $95.0 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 $1.0 million, and a corresponding increase or decrease, respectively, in net income of approximately $0.6 million during the year ended December 31, 2015. 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, 2015.

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 losses of $2.7 million for the year ended December 31, 2015.

Item 8. Financial Statements and Supplementary Data

PIONEER ENERGY SERVICES CORP.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2015 and 2014, 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, 2015. 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, 2015 and 2014, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2015, 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, 2015, 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, 2016 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

As discussed in Note 1 to the consolidated financial statements, the Company has changed its method of accounting for classification of deferred tax assets and liabilities on the balance sheet in 2015 due to the adoption of Accounting Standards Update No. 2015-17, *Balance Sheet Classification of Deferred Taxes*.

/s/ KPMG LLP

San Antonio, Texas
February 17, 2016

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, 2015, 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, 2015, 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, 2015 and 2014, 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, 2015, and our report dated February 17, 2016 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

San Antonio, Texas
February 17, 2016

PIONEER ENERGY SERVICES CORP. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2015	December 31, 2014
	(in thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 14,160	$ 34,924
Receivables:		
Trade, net of allowance for doubtful accounts	47,577	136,161
Unbilled receivables	13,624	38,002
Insurance recoveries	14,556	10,900
Other receivables	4,059	5,138
Deferred income taxes	—	10,998
Inventory	9,262	14,117
Assets held for sale	4,619	9,909
Prepaid expenses and other current assets	7,411	8,925
Total current assets	115,268	269,074
Property and equipment, at cost	1,146,994	1,702,273
Less accumulated depreciation	444,409	845,732
Net property and equipment	702,585	856,541
Intangible assets, net of accumulated amortization	1,944	24,223
Noncurrent deferred income taxes	18	2,753
Other long-term assets	9,961	18,998
Total assets	$ 829,776	$ 1,171,589
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 16,951	$ 64,305
Current portion of long-term debt	—	27
Deferred revenues	6,222	3,315
Accrued expenses:		
Payroll and related employee costs	13,859	40,058
Insurance premiums and deductibles	8,087	12,829
Insurance claims and settlements	14,556	10,900
Interest	5,508	5,432
Other	4,859	10,326
Total current liabilities	70,042	147,192
Long-term debt, less current portion	395,000	455,053
Noncurrent deferred income taxes	17,520	69,578
Other long-term liabilities	4,571	4,702
Total liabilities	487,133	676,525
Commitments and contingencies (Note 12)		
Shareholders' equity:		
Preferred stock, 10,000,000 shares authorized; none issued and outstanding	—	—
Common stock $.10 par value; 100,000,000 shares authorized; 64,497,915 and 63,820,126 shares outstanding at December 31, 2015 and December 31, 2014, respectively	6,496	6,414
Additional paid-in capital	475,823	472,457
Treasury stock, at cost; 458,170 and 317,103 shares at December 31, 2015 and December 31, 2014, respectively	(3,759)	(3,030)
Accumulated earnings (deficit)	(135,917)	19,223
Total shareholders' equity	342,643	495,064
Total liabilities and shareholders' equity	$ 829,776	$ 1,171,589

See accompanying notes to consolidated financial statements.

PIONEER ENERGY SERVICES CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year ended December 31,		
	2015	2014	2013
	(in thousands, except per share data)		
Revenues:			
Drilling services	$ 249,318	$ 516,473	$ 528,327
Production services	291,460	538,750	431,859
Total revenues	540,778	1,055,223	960,186
Costs and expenses:			
Drilling services	144,196	348,133	354,380
Production services	213,820	339,690	276,296
Depreciation and amortization	150,939	183,376	187,918
General and administrative	73,903	103,385	94,183
Bad debt expense (recovery)	(188)	1,445	767
Impairment charges	129,152	73,025	54,292
Gain on dispositions of property and equipment, net	(4,344)	(1,859)	(1,421)
Gain on sale of fishing and rental services operations	—	(10,702)	—
Gain on litigation	—	(5,254)	—
Total costs and expenses	707,478	1,031,239	966,415
Income (loss) from operations	(166,700)	23,984	(6,229)
Other (expense) income:			
Interest expense, net of interest capitalized	(21,222)	(38,781)	(48,310)
Loss on extinguishment of debt	(2,186)	(31,221)	—
Other	(2,611)	(3,304)	(1,239)
Total other expense	(26,019)	(73,306)	(49,549)
Income (loss) before income taxes	(192,719)	(49,322)	(55,778)
Income tax (expense) benefit	37,579	11,304	19,846
Net income (loss)	$ (155,140)	$ (38,018)	$ (35,932)
Income (loss) per common share—Basic	$ (2.41)	$ (0.60)	$ (0.58)
Income (loss) per common share—Diluted	$ (2.41)	$ (0.60)	$ (0.58)
Weighted average number of shares outstanding—Basic	64,310	63,161	62,213
Weighted average number of shares outstanding—Diluted	64,310	63,161	62,213

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, 2012	62,166	(135)	$ 6,217	$ (1,264)	$ 449,554	$ 93,173	$ 547,680
Net loss	—	—	—	—	—	(35,932)	(35,932)
Exercise of options and related income tax effect	271	—	27	—	1,239	—	1,266
Purchase of treasury stock	—	(85)	—	(631)	—	—	(631)
Income tax effect of restricted stock vesting	—	—	—	—	(265)	—	(265)
Income tax effect of stock option forfeitures and expirations	—	—	—	—	(56)	—	(56)
Issuance of restricted stock	316	—	31	—	(31)	—	—
Stock-based compensation expense	—	—	—	—	6,371	—	6,371
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

See accompanying notes to consolidated financial statements.

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

	Year ended December 31, 2015	2014	2013
		(in thousands)	
Cash flows from operating activities:			
Net income (loss)	$ (155,140)	$ (38,018)	$ (35,932)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	150,939	183,376	187,918
Allowance for doubtful accounts, net of recoveries	248	1,445	801
Write-off of obsolete inventory	—	331	152
Gain on dispositions of property and equipment, net	(4,344)	(1,859)	(1,421)
Stock-based compensation expense	3,629	7,617	6,371
Amortization of debt issuance costs, discount and premium	1,691	2,669	3,095
Gain on sale of fishing and rental services operations	—	(10,702)	—
Loss on extinguishment of debt	2,186	31,221	—
Impairment charges	129,152	73,025	54,292
Deferred income taxes	(39,286)	(14,761)	(22,125)
Change in other long-term assets	420	2,958	(5,741)
Change in other long-term liabilities	(132)	(1,352)	(1,928)
Changes in current assets and liabilities:			
Receivables	114,644	(11,993)	(16,168)
Inventory	1,267	(1,068)	(1,273)
Prepaid expenses and other current assets	1,769	(55)	3,729
Accounts payable	(30,514)	7,167	(166)
Deferred revenues	1,922	2,616	(3,181)
Accrued expenses	(35,732)	424	6,157
Net cash provided by operating activities	142,719	233,041	174,580
Cash flows from investing activities:			
Purchases of property and equipment	(159,615)	(175,378)	(165,356)
Proceeds from sale of fishing and rental services operations	—	15,090	—
Proceeds from sale of property and equipment	57,674	8,370	13,836
Proceeds from insurance recoveries	285	—	844
Net cash used in investing activities	(101,656)	(151,918)	(150,676)
Cash flows from financing activities:			
Debt repayments	(60,002)	(490,025)	(60,874)
Proceeds from issuance of debt	—	440,000	40,000
Debt issuance costs	(1,877)	(9,239)	(13)
Tender premium costs	—	(21,553)	—
Proceeds from exercise of options	781	8,368	1,266
Purchase of treasury stock	(729)	(1,135)	(631)
Net cash used in financing activities	(61,827)	(73,584)	(20,252)
Net increase (decrease) in cash and cash equivalents	(20,764)	7,539	3,652
Beginning cash and cash equivalents	34,924	27,385	23,733
Ending cash and cash equivalents	$ 14,160	$ 34,924	$ 27,385
Supplementary disclosure:			
Interest paid	$ 22,506	$ 43,690	$ 46,274
Income tax paid	$ 2,691	$ 5,012	$ 3,154
Noncash investing and financing activity:			
Change in capital expenditure accruals	$ (16,708)	$ 12,743	$ (39,936)

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.

We have a current fleet of 31 drilling rigs, 94% of which are pad-capable, and 15 of which are AC walking rigs built within the last five years and engineered to optimize pad drilling. 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	7
West Texas	6
North Dakota	6
Appalachia	4
Colombia	8
	31

Since late 2014, oil prices have declined significantly resulting in a downturn in our industry, affecting both drilling and production services. In drilling, all rig classes have been 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. We completed construction of five new-build 1,500 horsepower AC drilling rigs during 2015. We sold 32 of our mechanical and lower horsepower electric drilling rigs during 2015, which were the most negatively impacted by the industry downturn, and placed an additional four rigs as held for sale as of year-end.

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, 2015, 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	119	125
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 either a daywork or 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 enter into longer-term drilling contracts for our newly constructed rigs and/or during periods of high rig demand. Currently, we have contracts with original terms of six months to four years in duration.

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.

In response to the significant decline in oil prices over the last year, term contracts for 19 of our drilling rigs have been terminated early, including three which were terminated in early 2016, resulting in a total of $62.8 million of early termination payments. We recognized $49.2 million and $0.3 million of revenue for early termination payments during the years ended December 31, 2015 and 2014, respectively, and we will recognize the remaining $13.3 million in 2016.

Currently, 14 of our 23 domestic drilling rigs are earning revenues, 12 of which are under term contracts. Of the eight rigs in Colombia, three are under term contracts, but have been put on standby by our client and are not earning revenue. The term contracts in Colombia are cancelable without penalty, by our client 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 to diversify our client base, and evaluating other options, including the possibility of the sale of some or all of our assets in Colombia.

Including these three contracts in Colombia, 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 Contracts and 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:							
Earning under contract	2	8	1	2	—	1	4
Earning but not working	—	4	3	1	—	—	—
Colombia Rigs (on standby)	—	3	—	1	—	—	2
	2	15	4	4	—	1	6

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, and our estimate of compensation related accruals.

In preparing the accompanying consolidated financial statements, we have reviewed events that have occurred after December 31, 2015, 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 60 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 percentage-of-completion method 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.

The assets "prepaid expenses and other current assets" and "other long-term assets" include the current and long-term portions of deferred mobilization costs for certain drilling contracts. The liabilities "deferred revenues" and "other long-term liabilities" include the current and long-term portions of deferred mobilization revenues for certain drilling contracts and amounts collected on contracts in excess of revenues recognized, including amounts collected for early terminations of long-term drilling contracts. As of December 31, 2015, we had $6.2 million and $1.5 million of current deferred revenues and costs, respectively. Our deferred costs and revenues primarily relate to prepayments of long-term contracts for our domestic drilling rigs. Amortization of deferred mobilization revenues was $1.1 million, $4.6 million and $5.3 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Turnkey Drilling Contracts—Our management has determined that it is appropriate to use the proportional performance basis to recognize revenue on our turnkey contracts. Although our turnkey contracts do not have express terms that provide us with rights to receive payment for the work that we perform prior to drilling wells to the agreed-on depth, we use this method because, as provided in applicable accounting literature, we believe we achieve a continuous sale for our work-in-progress and believe, under applicable state law, we ultimately could recover the fair value of our work-in-progress even in the event we were unable to drill to the agreed-on depth in breach of the applicable contract. However, in the event we were unable to drill to the agreed-on depth in breach of the contract, ultimate recovery of that value would be subject to negotiations with the client and the possibility of litigation.

If a client defaults on its payment obligation to us under a turnkey contract, we would need to rely on applicable law to enforce our lien rights, because our turnkey contracts do not expressly grant to us a security interest in the work we have completed under the contract and we have no ownership rights in the work-in-progress or completed drilling work, except any rights arising under the applicable lien statute on foreclosure. If we were unable to drill to the agreed-on depth in breach of the contract, we also would need to rely on equitable remedies outside of the contract available in applicable courts to recover the fair value of our work-in-progress under a turnkey contract.

The risks to us under a turnkey contract are substantially greater than on a contract drilled on a daywork basis. Under a turnkey contract, we assume most of the risks associated with drilling operations that are generally assumed by the operator in a daywork contract, including the risks of blowout, loss of hole, stuck drill pipe, machinery breakdowns and abnormal drilling conditions, as well as risks associated with subcontractors' services, supplies, cost escalations and operations personnel.

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. In addition, the occurrence of uninsured or under-insured losses or operating cost overruns on our turnkey contracts could have a material adverse effect on our financial position and results of operations. Therefore, 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, 2015, 2014 and 2013, our drilling and production services to our top three clients accounted for approximately 29%, 28%, and 29%, respectively, of our revenue, and in 2015, 2014 and 2013, our largest client, Whiting Petroleum Corporation, accounted for 18%, 12% and 13%, respectively, of our revenue.

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. Cash equivalents at December 31, 2015 and 2014 were $1.3 million and $2.6 million, respectively.

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 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,		
	2015	**2014**	**2013**
Balance at beginning of year	$ 2,547	$ 1,356	$ 1,044
Increase in allowance charged to expense	472	1,445	801
Accounts charged against the allowance	(765)	(254)	(489)
Balance at end of year	$ 2,254	$ 2,547	$ 1,356

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 totaled $13.6 million at December 31, 2015, of which $11.9 million represented revenue recognized but not yet billed on daywork drilling contracts in progress, $1.1 million related to unbilled receivables for our Production Services Segment and $0.6 million related to one turnkey contract in progress, which was completed prior to the issuance of these consolidated financial statements. At December 31, 2014, our unbilled receivables totaled $38.0 million, of which $32.8 million represented revenue recognized but not yet billed on daywork drilling contracts in progress, $4.4 million related to unbilled receivables for our Production Services Segment, and $0.8 million related to turnkey drilling contract revenues.

Inventories

Inventories primarily consist of drilling rig replacement parts, 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. 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).

Due to several significant adverse factors affecting our coiled tubing services reporting unit, including increased competition in certain coiled tubing markets, turnover of key personnel and lower than anticipated utilization, all of which contributed to a decline in our projected cash flows for the coiled tubing reporting unit, we performed an impairment analysis of our long-lived tangible and intangible assets as of June 30, 2013. Our analysis resulted in a non-cash impairment charge of $3.1 million which we recognized during 2013 to reduce our intangible asset carrying value of client relationships, and a non-cash impairment charge of $41.7 million to reduce the carrying value of goodwill to zero.

As a result of the downturn which began in late 2014 and worsened through the first half of 2015, we performed impairment testing on our coiled tubing operations as of June 30, 2015 which indicated that the carrying value of our coiled tubing reporting unit was recoverable and thus there was no impairment present at June 30, 2015. However, as the downturn persisted through 2015, our projected cash flows declined further as compared to our projections made earlier in the year and we performed another impairment analysis of our long-lived tangible and intangible assets as of December 31, 2015, which resulted in an impairment charge of $14.3 million which we recognized during the fourth quarter of 2015. As a result of this impairment, the carrying value of our coiled tubing intangible assets was reduced to zero. This impairment charge did not have an impact on our liquidity or debt covenants; however, it was a reflection of the overall downturn in our industry and a decline in our projected cash flows for the coiled tubing reporting unit. Our impairment analysis performed in the fourth quarter of 2015 also resulted in an impairment to our coiled tubing tangible long-lived assets, which is discussed in more detail in Note 3, *Property and Equipment*.

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 ASC Topic 820, *Fair Value Measurements and Disclosures*. Although we believe the assumptions and estimates used in our analysis are reasonable and appropriate, different assumptions and estimates could materially impact the analysis 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.

As of December 31, 2015 and 2014, the estimated useful lives and components of our intangible asset classes are as follows:

		December 31,	
		2015	2014
	Lives	(amounts in thousands)	
Client relationships:	5 - 9		
Cost		$ 13,592	$ 55,282
Accumulated amortization		(11,682)	(31,370)
Non-compete agreements:	4 - 7		
Cost		675	1,355
Accumulated amortization		(641)	(1,044)
		$ 1,944	$ 24,223

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 $7.9 million, $8.0 million and $8.5 million for the years ended December 31, 2015, 2014 and 2013, respectively. Amortization expense is estimated to be approximately $1.5 million, $0.2 million, and $0.2 million for the years ending December 31, 2016, 2017, and 2018, respectively. Actual amortization amounts may be different due to future acquisitions, impairments, changes in amortization periods, or other factors.

Other Long-Term Assets

Other long-term assets consist of debt issuance costs net of amortization, cash deposits related to the deductibles on our workers' compensation insurance policies 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, Colombian net wealth 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, the long-term portion of deferred revenues and other deferred liabilities.

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.

Related-Party Transactions

During the years ended December 31, 2015 and 2014, the Company paid approximately $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 years presented.

Recently Issued Accounting Standards

Revenue Recognition. In May 2014, the 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 required to apply this new standard beginning with our first quarterly filing in 2018. We are currently evaluating the potential impact of this guidance, but at this time, do not expect that the adoption of this new standard will have a material effect on our financial position or results of operations.

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. In August 2015, these provisions were further amended with guidance from the Securities and Exchange Commission Staff that they would not object to an entity deferring and presenting debt issuance costs related to line-of-credit arrangements as an asset and subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. The recognition and measurement guidance for debt issuance costs are not affected by the amendments in this ASU. This ASU requires retrospective adoption and will be effective for us beginning with our first quarterly filing in 2016. Early adoption is permitted. We do not expect the adoption of this new standard to have a material impact on our financial position or results of operations.

Deferred Income Tax Classification. In November 2015, the FASB issued ASU No. 2015-17, *Balance Sheet Classification of Deferred Taxes*, which requires that the net of deferred tax assets and liabilities be classified as noncurrent on the balance sheet by jurisdiction rather than being separately presented as current and noncurrent portions. We are required to adopt the new standard beginning with our first quarterly filing in 2017; however, early adoption is permitted and the standard may be applied either retrospectively or on a prospective basis to all deferred tax assets and liabilities. 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. The prior reporting period was not retrospectively adjusted.

Reclassifications

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

2. 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, subject to certain adjustments. The sales price 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 for potential claims due to Basic. 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. Basic also purchased certain other assets and assumed certain liabilities related to our F&R operations. In addition, Basic offered employment to the F&R employees and we agreed to provide transition services to Basic after the close of the transaction. We recognized a $10.7 million gain on the sale of our F&R operations, net of costs directly attributable to the sale. Net of income taxes, the gain 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 as of September 30, 2014. The sale of the F&R operations does not represent a strategic shift for our company and has not had a significant effect on our operating results. Therefore, the sale of our F&R operations does 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 (amounts in thousands):

	Year ended December 31,	
	2014	2013
Revenues	$ 7,828	$ 12,459
Operating costs	5,097	8,000
F&R margin	$ 2,731	$ 4,459
Income (loss) before income taxes	$ (162)	$ 242

3. Property and Equipment

Our total capital expenditures of $142.9 million and $188.1 million during 2015 and 2014, respectively, primarily relate to our five new-build drilling rigs which began construction during 2014, as well as unit additions to our production services fleets. As of December 31, 2015 and 2014, capital expenditures incurred for property and equipment not yet placed in service was $18.6 million and $82.7 million, respectively. During the years ended December 31, 2015, 2014 and 2013, we capitalized $3.0 million, $0.7 million and $0.9 million, respectively, of interest costs incurred primarily during the construction periods of new-build drilling rigs and other drilling equipment.

As of December 31, 2015 and 2014, the estimated useful lives and costs of our asset classes are as follows:

		December 31, 2015	December 31, 2014
	Lives	Cost (amounts in thousands)	
Drilling rigs and equipment	2 - 25	$ 649,805	$ 1,168,404
Well servicing rigs and equipment	3 - 20	246,539	232,771
Wireline units and equipment	2 - 10	148,501	146,748
Coiled tubing units and equipment	1 - 7	10,740	60,389
Vehicles	3 - 15	51,776	55,014
Office equipment	1 - 10	11,986	11,521
Buildings and improvements	2 - 40	25,228	25,007
Land	—	2,419	2,419
		$ 1,146,994	$ 1,702,273

During the year ended December 31, 2015, we sold 32 of our mechanical and lower horsepower electric drilling rigs and other drilling equipment for aggregate net proceeds of $53.6 million. 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, and we sold our trucking assets in February 2014. During 2013, we sold ten mechanical drilling rigs, four wireline units and other production services equipment, for which we also recognized $9.5 million of impairment to reduce the carrying values to their estimated fair values, based on sales prices, when we designated these assets as held for sale.

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. In drilling, all rig classes have been 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. In recent years, and especially during the recent downturn, demand has significantly decreased for certain drilling rigs, particularly in vertical well markets. The decline is a result of higher demand for drilling rigs that are able to drill horizontally and the increased use of "pad drilling." Pad drilling enables a series of horizontal wells to be drilled in succession by a walking or skidding drilling rig at a single pad-site location, thereby improving the productivity of exploration and production activities. This trend has resulted in significantly reduced demand for drilling rigs that do not have the ability to walk or skid and to drill horizontal wells.

As a result, we performed several impairment evaluations during 2014 and 2015 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 $71.0 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 at year-end. Additionally, we recorded $2.0 million of impairment charges during the year ended December 31, 2014 to reduce the carrying values of certain other assets, which were placed as held for sale during the year, to their estimated fair values, based on expected sales price. 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 non-AC electric 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 the pad-capable non-AC drilling rigs in our fleet (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 indicated that the carrying values of the non-AC drilling rigs in our domestic fleet which are not pad-capable, and our Colombian assets as a group, exceeded our estimated undiscounted cash flows for these assets. Therefore, an impairment charge was necessary to reduce the carrying values of these assets to their estimated fair values, which were based on market appraisals. As a result, we recognized impairment charges of $50.2 million during the second quarter of 2015 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 the six non-AC electric drilling rigs in our domestic fleet that are not pad-capable, to their estimated fair values. We subsequently sold three of these domestic non-AC drilling rigs that are not pad-capable and placed another as held for sale at year-end. We have two remaining in our fleet.

Our projected cash flows declined further as compared to our projections made earlier in the year and at September 30, 2015, we performed impairment testing on our coiled tubing operations and seven drilling rigs, including our domestic pad-capable non-AC rigs. We determined that our carrying values in these assets were recoverable, but that the assets were at risk for future impairment if our projected cash flows continued to decline. 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 five domestic pad-capable non-AC rigs to their estimated fair values, which were also based on market appraisals.

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 ASC Topic 820, *Fair Value Measurements and Disclosures*.

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. If the demand for our drilling services remains at current levels or declines further and any of our rigs 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.

During the year ended December 31, 2015, we also recognized impairment charges of $9.7 million to reduce the carrying values of assets which were classified as held for sale, to their estimated fair values, based on expected sales prices.

Although we believe the assumptions and estimates used in our analysis are reasonable and appropriate, different assumptions and estimates could materially impact the analysis 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.

4. Debt

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

	December 31, 2015	December 31, 2014
Senior secured revolving credit facility	$ 95,000	$ 155,000
Senior notes	300,000	300,000
Other	—	80
	395,000	455,080
Less current portion	—	(27)
	$ 395,000	$ 455,053

Senior Secured Revolving Credit Facility

We have a credit agreement, as amended on September 15, 2015 and again on December 23, 2015, 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 an aggregate principal amount of $200 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 debt issuances, which are applied to reduce outstanding revolving and swing-line loans and cash-collateralize letter of credit exposure, but in no event will reduce the borrowing availability under the Revolving Credit Facility to the lesser of $200 million and the then-applicable borrowing base.

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 4.75% and 3.75%, 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 the calendar month, our aggregate amount of cash exceeds $25 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 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 December 31, 2015, we had $95 million outstanding under our Revolving Credit Facility and $17.3 million in committed letters of credit, which resulted in borrowing availability of $87.7 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, 2015, we were in compliance with our financial covenants under the Revolving Credit Facility. Our senior consolidated leverage ratio was 1.0 to 1.0, and our interest coverage ratio was 5.5 to 1.0. The financial covenants contained in our Revolving Credit Facility include the following:

- A maximum senior consolidated leverage ratio, which excludes unsecured and subordinated debt, that cannot exceed 2.50 to 1.00 on December 31, 2015, 3.00 to 1.00 on March 31, 2016, 3.50 to 1.00 on June 30, 2016, 4.25 to 1.00 on September 30, 2016, 4.75 to 1.00 during the period commencing December 31, 2016 through and including June 30, 2017, 4.25 to 1.00 on September 30, 2017, 3.50 to 1.00 during the period commencing December 31, 2017 through and including March 31, 2018, 3.25 to 1.00 on June 30, 2018, and 2.50 to 1.00 at any time thereafter.
- A minimum interest coverage ratio that cannot be less than 1.50 to 1.00 during the period commencing December 31, 2015 through and including June 30, 2016, 1.25 to 1.00 during the period commencing September 30, 2016 through and including September 30, 2017, and 1.50 to 1.00 at any time thereafter.

The Revolving Credit Facility also does not restrict capital expenditures as long as (a) no event of default under the Revolving Credit Facility exists or would result from such expenditures, and (b) such expenditures do not cause total capital expenditures to exceed $50 million for the fiscal year. The capital expenditure threshold may be increased by any unused portion of the capital expenditure threshold from the immediate preceding fiscal year up to $25 million.

The Revolving Credit Facility has additional restrictive covenants that, among other things, limit the incurrence of additional debt, investments, liens, dividends, acquisitions, prepayments of indebtedness, asset dispositions, mergers and consolidations, transactions with affiliates, repurchases of capital stock, hedging contracts, sale leasebacks and other matters customarily restricted in such agreements. 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 March 2010 and November 2011, we issued an aggregate $425 million of unregistered senior notes with a coupon interest rate of 9.875% that were set to mature in 2018 (the "2010 and 2011 Senior Notes"). The net proceeds from the 2010 issuance were used to repay a portion of the borrowings outstanding under our Revolving Credit Facility and a portion of the net proceeds from the 2011 issuance were used to fund the acquisition of the coiled tubing business in December 2011. In order to reduce our overall interest expense and lengthen the overall maturity of our senior indebtedness, during 2014, we redeemed all of our outstanding 2010 and 2011 Senior Notes, funded primarily by proceeds from the issuance of our 2014 Senior Notes and additional borrowings under our Revolving Credit Facility, as well as some cash on hand.

In March 2014, we issued $300 million of unregistered senior notes with a coupon interest rate of 6.125% that are due in 2022 (the "2014 Senior Notes"). The 2014 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 which were used to fund the repayment of $300 million of aggregate principal amount of 2010 and 2011 Senior Notes in March and May 2014. In October 2014, we redeemed the remaining $125.0 million in aggregate principal amount of the 2010 and 2011 Senior Notes, primarily funded by proceeds from our revolving credit facility and through cash on hand. 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.

The 2014 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 2014 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 2014 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 2014 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 2014 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 2014 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;
- pay dividends, engage in loans, 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 2014 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 \$7.8 million and \$9.8 million as of December 31, 2015 and 2014, respectively. We recognized approximately \$1.7 million, \$2.1 million and \$2.1 million of associated amortization during the years ended December 31, 2015, 2014 and 2013, respectively. Additionally, we recognized \$2.2 million 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 which was amended in September and again in December 2015.

5. Leases

We lease our corporate office facilities in San Antonio, Texas at a payment escalating from \$42,511 per month in January 2016 to \$50,246 per month in December 2020. We recognize rent expense on a straight-line basis for our corporate office lease. We also lease real estate at 43 other locations, which are primarily used for field offices and storage and maintenance yards, and we lease vehicles, 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, 2015 were as follows (amounts in thousands):

Year ended December 31,		
2016	$	3,618
2017		2,982
2018		2,347
2019		1,925
2020		1,187
Thereafter		445
	$	12,504

During 2015, we ceased use of several location offices which were under long-term leases and recognized an expense of $0.3 million 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 have been included in our current and long-term liabilities, according to the lease terms, 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 $6.2 million, $5.9 million and $6.0 million for the years ended December 31, 2015, 2014 and 2013, respectively.

6. Income Taxes

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

	Year ended December 31,		
	2015	2014	2013
Domestic	$ (123,499)	$ (49,050)	$ (66,147)
Foreign	(69,220)	(272)	10,369
Income (loss) before income tax	$ (192,719)	$ (49,322)	$ (55,778)

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

	Year ended December 31,		
	2015	2014	2013
Current tax:			
Federal	$ (535)	$ (112)	$ (380)
State	401	1,325	879
Foreign	1,238	3,149	2,302
	1,104	4,362	2,801
Deferred taxes:			
Federal	(42,113)	(17,438)	(21,034)
State	29	1,304	(3,520)
Foreign	3,401	468	1,907
	(38,683)	(15,666)	(22,647)
Income tax expense (benefit)	$ (37,579)	$ (11,304)	$ (19,846)

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

	Year ended December 31,		
	2015	2014	2013
Expected tax expense (benefit)	$ (67,452)	$ (17,263)	$ (19,522)
State income taxes	(2,066)	1,214	(1,717)
Incentive stock options	83	(208)	66
Net tax benefits and nondeductible expenses in foreign jurisdictions	2,135	957	(92)
Foreign currency translation loss	8,660	2,699	617
Nondeductible expenses for tax purposes	577	920	863
Valuation allowance	20,329	496	—
Other, net	155	(119)	(61)
Income tax expense (benefit)	$ (37,579)	$ (11,304)	$ (19,846)

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

	Year ended December 31,		
	2015	2014	2013
Continuing operations	$ (37,579)	$ (11,304)	$ (19,846)
Shareholders' equity	962	201	321
Income tax expense (benefit)	$ (36,617)	$ (11,103)	$ (19,525)

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,	
	2015	2014
Deferred tax assets:		
Capital loss carryforward	$ 666	$ 1,009
Intangibles	37,634	33,542
Employee benefits and insurance claims accruals	6,307	12,146
Accounts receivable reserve	849	908
Inventory	631	—
Employee stock-based compensation	8,093	8,440
Accrued expenses not deductible for tax purposes	453	1,391
Accrued revenue not income for book purposes	695	429
Domestic net operating loss carryforward	84,853	84,782
Foreign net operating loss carryforward	3,909	2,562
	144,090	145,209
Valuation allowance	(18,627)	(1,504)
Deferred tax liabilities:		
Property and equipment	(142,965)	(199,532)
Net deferred tax assets (liabilities)	$ (17,502)	$ (55,827)

As of December 31, 2015, we had $88.8 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 only recognize a tax benefit to the extent of taxable income that we expect to earn in the jurisdiction in future periods.

Except for the items listed below, we estimate that our domestic operations will result in taxable income in excess of our net operating losses and we expect to apply the net operating losses against the current year taxable income and taxable income that we have estimated in future periods. The 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 2029, with the latest expiration in 2033. The 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, we recorded a valuation allowance of $15.1 million that fully offsets our foreign deferred tax assets relating to net operating losses and other tax benefits.

As of December 31, 2015, we had a valuation allowance of $0.7 million related to a deferred tax asset for a capital loss which we don't believe will be realized in future periods and a valuation allowance of $2.8 million against net operating losses and other tax benefits in certain states.

Deferred income taxes have not been provided on the future tax consequences attributable to difference between the financial statements carrying amounts of existing assets and liabilities and the respective tax bases 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, 2015, the cumulative undistributed earnings/losses of the subsidiary was approximately a $20.3 million loss. 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.

As discussed in Note 1, *Organization and Summary of Significant Accounting Policies,* 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. The prior reporting period was not retrospectively adjusted.

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 and is expected to be approximately $0.7 million and $0.3 million for 2016 and 2017, respectively. The net worth tax is not deductible for income tax purposes.

We have no unrecognized tax benefits relating to ASC Topic 740 and no unrecognized tax benefit activity during the year ended December 31, 2015.

We adopted a policy to record interest and penalty expense related to income taxes as interest and other expense, respectively. At December 31, 2015, no interest or penalties have been or are required to be accrued. Our open tax years for our federal income tax returns in the United States and our income tax returns in Colombia are for the years ended December 31, 2010 to 2014.

7. Fair Value of Financial Instruments

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, 2015 and December 31, 2014, our financial instruments consist primarily of cash, trade and other receivables, trade payables 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 at December 31, 2015 and December 31, 2014 (amounts in thousands):

	December 31, 2015		December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Total debt	$ 395,000	$ 242,354	$ 455,080	$ 415,785

8. Earnings Per Common Share

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

	Year ended December 31,		
	2015	2014	2013
Basic			
Net income (loss)	$ (155,140)	$ (38,018)	$ (35,932)
Weighted-average shares	64,310	63,161	62,213
Income (loss) per common share—Basic	$ (2.41)	$ (0.60)	$ (0.58)
Diluted			
Net income (loss)	$ (155,140)	$ (38,018)	$ (35,932)
Weighted-average shares Outstanding	64,310	63,161	62,213
Diluted effect of outstanding stock options, restricted stock and restricted stock unit awards	—	—	—
	64,310	63,161	62,213
Income (loss) per common share—Diluted	$ (2.41)	$ (0.60)	$ (0.58)

Potentially dilutive stock options, restricted stock and restricted stock unit awards representing a total of 4,832,438, 3,949,464 and 5,507,765 shares of common stock for the years ended December 31, 2015, 2014 and 2013, respectively, were excluded from the computation of diluted weighted average shares outstanding due to their antidilutive effect.

9. 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. As of December 31, 2015, the entire $300 million under the shelf registration statement is available for equity or debt offerings. In the future, we may consider equity 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, 2015, the total shares available for future grants to employees and directors under existing plans were 1,932,441, which excludes awards we grant in the form of phantom stock unit awards which are expected to be paid in cash. In January 2016, 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	905,966
Restricted stock unit awards	225,834
	1,131,800
Phantom stock unit awards	1,268,068

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*. 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 compensation expense recognized for stock option, restricted stock and restricted stock unit awards during the years ended December 31, 2015, 2014 and 2013 (amounts in thousands):

	Year ended December 31,		
	2015	2014	2013
Stock option awards	$ 923	$ 1,275	$ 1,771
Restricted stock awards	399	548	576
Restricted stock unit awards	2,307	5,794	4,024
	$ 3,629	$ 7,617	$ 6,371

The following table summarizes the unrecognized compensation cost (amounts in thousands) to be recognized for stock options, restricted stock and restricted stock unit awards, and the weighted-average period remaining (in years) over which the compensation cost is expected to be recognized, as of December 31, 2015:

	Weighted-Average Period Remaining	Unrecognized Compensation Cost
Stock options	0.84	$ 452
Restricted stock awards	0.39	137
Restricted stock unit awards	1.20	3,417
		$ 4,006

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 years ended December 31, 2015, 2014 and 2013:

	Year ended December 31,		
	2015	2014	2013
Expected volatility	64%	66%	66%
Risk-free interest rates	1.4%	1.7%	1.0%
Expected life in years	5.52	5.49	5.53
Grant-date fair value	$2.31	$4.87	$4.36

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 represents stock option activity from December 31, 2013 through December 31, 2015:

	Number of Shares	Weighted-Average Exercise Price Per Share	Weighted-Average Remaining Contract Life in Years
Outstanding stock options as of December 31, 2013	5,532,213	$10.18	
Granted	221,440	8.44	
Forfeited	(155,100)	14.82	
Exercised	(928,777)	9.01	
Outstanding stock options as of December 31, 2014	4,669,776	$10.18	
Granted	341,638	4.12	
Forfeited	(586,160)	13.18	
Exercised	(203,300)	3.84	
Outstanding stock options as of December 31, 2015	4,221,954	$9.58	4.3
Stock options exercisable as of December 31, 2015	3,707,800	$10.13	3.8

At December 31, 2015, aggregate outstanding and aggregate exercisable stock options had no intrinsic value. Intrinsic value is the difference between the exercise price of a stock option and the closing market price of our common stock, which was $2.17 on December 31, 2015.

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, 2013 through December 31, 2015:

	Number of Shares	Weighted-Average Grant-Date Fair Value Per Share
Nonvested stock options as of December 31, 2013	757,041	$4.74
Granted	221,440	4.87
Vested	(433,211)	4.77
Nonvested stock options as of December 31, 2014	545,270	$4.77
Granted	341,638	2.31
Vested	(364,721)	4.70
Forfeited	(8,033)	5.23
Nonvested stock options as of December 31, 2015	514,154	$3.19

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 following table summarizes our restricted stock activity from December 31, 2013 through December 31, 2015:

	Number of Shares	Weighted-Average Grant-Date Fair Value per Share
Nonvested restricted stock as of December 31, 2013	105,204	$8.18
Granted	32,100	14.33
Vested	(88,620)	8.20
Nonvested restricted stock as of December 31, 2014	48,684	$12.20
Granted	47,296	7.40
Vested	(48,684)	12.19
Nonvested restricted stock as of December 31, 2015	47,296	$7.41

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 one-third of the performance-based RSUs granted during 2012 and 2013, and half of the performance-based RSUs granted during 2014 and 2015, 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 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 2015, we determined that 64% of the target number of shares granted during 2012 were actually earned based on the Company's achievement of certain performance measures, as compared to the predefined peer group, over the performance period from January 1, 2012 through December 31, 2014, resulting in a reduction of 68,299 shares being issued. The performance-based RSUs granted during 2012 vested and were converted to common stock at the end of April 2015.

As of December 31, 2015, we estimated that our actual achievement level for the performance-based RSUs granted during 2013, 2014 and 2015 will be approximately 60%, 80% and 100% of the predetermined performance conditions, respectively. Therefore, the outstanding 957,295 restricted stock units would be adjusted to represent 796,055 shares of our common stock if these achievement levels are maintained through the applicable performance periods.

The following table summarizes our restricted stock unit activity from December 31, 2013 through December 31, 2015:

	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, 2013	627,712	$7.93	673,762	$9.19
Granted	360,665	8.64	400,503	9.67
Achieved performance adjustment	—	—	22,091	10.23
Vested	(267,430)	8.16	(155,647)	10.23
Forfeited	(45,868)	8.07	(78,897)	9.30
Nonvested restricted stock units as of December 31, 2014	675,079	$8.21	861,812	$9.24
Granted	151,919	4.08	634,272	6.66
Achieved performance adjustment	—	—	(68,299)	9.85
Vested	(340,225)	8.11	(227,454)	9.29
Forfeited	(100,240)	7.21	(243,036)	8.87
Nonvested restricted stock units as of December 31, 2015	386,533	$6.93	957,295	$7.57

10. 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, 2015, 2014 and 2013 were $4.2 million, $6.4 million and $6.0 million, respectively.

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, 2015 and 2014 include $2.4 million and $3.4 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, 2015 and 2014 include $5.5 million and $9.0 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.

11. 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 tables set forth certain financial information for our two operating segments and corporate as of and for the years ending December 31, 2015, 2014 and 2013 (amounts in thousands):

	As of and for the year ended December 31, 2015			
	Drilling Services Segment	Production Services Segment	Corporate	Total
Identifiable assets	$ 518,208	$ 281,530	$ 30,038	$ 829,776
Revenues	$ 249,318	$ 291,460	$ —	$ 540,778
Operating costs	144,196	213,820	—	358,016
Segment margin	$ 105,122	$ 77,640	$ —	$ 182,762
Depreciation and amortization	$ 80,265	$ 69,335	$ 1,339	$ 150,939
Capital expenditures	$ 113,060	$ 29,228	$ 619	$ 142,907

	As of and for the year ended December 31, 2014			
	Drilling Services Segment	Production Services Segment	Corporate	Total
Identifiable assets	$ 702,987	$ 442,755	$ 25,847	$ 1,171,589
Revenues	$ 516,473	$ 538,750	$ —	$ 1,055,223
Operating costs	348,133	339,690	—	687,823
Segment margin	$ 168,340	$ 199,060	$ —	$ 367,400
Depreciation and amortization	$ 115,714	$ 66,326	$ 1,336	$ 183,376
Capital expenditures	$ 112,483	$ 74,652	$ 986	$ 188,121

	As of and for the year ended December 31, 2013			
	Drilling Services Segment	Production Services Segment	Corporate	Total
Identifiable assets	$ 785,119	$ 414,278	$ 30,226	$ 1,229,623
Revenues	$ 528,327	$ 431,859	$ —	$ 960,186
Operating costs	354,380	276,296	—	630,676
Segment margin	$ 173,947	$ 155,563	$ —	$ 329,510
Depreciation and amortization	$ 122,201	$ 64,604	$ 1,113	$ 187,918
Capital expenditures	$ 78,708	$ 44,541	$ 2,171	$ 125,420

The following table reconciles the segment profits reported above to income from operations as reported on the consolidated statements of operations for the years ended December 31, 2015, 2014 and 2013 (amounts in thousands):

	Year ended December 31,		
	2015	2014	2013
Segment margin	$ 182,762	$ 367,400	$ 329,510
Depreciation and amortization	(150,939)	(183,376)	(187,918)
General and administrative	(73,903)	(103,385)	(94,183)
Bad debt (expense) recovery	188	(1,445)	(767)
Impairment charges	(129,152)	(73,025)	(54,292)
Gain on dispositions of property and equipment, net	4,344	1,859	1,421
Gain on sale of fishing and rental services operations	—	10,702	—
Gain on litigation	—	5,254	—
Income (loss) from operations	$ (166,700)	$ 23,984	$ (6,229)

The following table sets forth certain financial information for our international operations in Colombia as of and for the years ended December 31, 2015, 2014 and 2013 (amounts in thousands):

	As of and for the year ended December 31,		
	2015	2014	2013
Identifiable assets	$ 54,590	$ 142,321	$ 150,719
Revenues	$ 43,878	$ 104,520	$ 115,631

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.

12. 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 $40.2 million relating to our performance under these bonds as of December 31, 2015.

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.

13. Quarterly Results of Operations (unaudited)

The following table summarizes quarterly financial data for the years ended December 31, 2015 and 2014 (in thousands, except per share data):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Year ended December 31, 2015					
Revenues	$ 193,814	$ 135,011	$ 107,480	$ 104,473	$ 540,778
Income (loss) from operations	(8,334)	(75,108)	(17,972)	(65,286)	(166,700)
Income tax (expense) benefit	4,450	2,586	6,682	23,861	37,579
Net income (loss)	(12,019)	(77,281)	(17,540)	(48,300)	(155,140)
Earnings (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)
Year ended December 31, 2014					
Revenues	$ 239,034	$ 259,812	$ 273,267	$ 283,110	$1,055,223
Income (loss) from operations	17,935	21,917	32,804	(48,672)	23,984
Income tax (expense) benefit	(37)	1,070	(9,927)	20,198	11,304
Net income (loss)	(2,579)	(319)	12,453	(47,573)	(38,018)
Earnings (loss) per share:					
Basic	$ (0.04)	$ (0.01)	$ 0.20	$ (0.75)	$ (0.60)
Diluted	$ (0.04)	$ (0.01)	$ 0.19	$ (0.75)	$ (0.60)

14. Guarantor/Non-Guarantor Condensed Consolidated Financial Statements

Our Senior Notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by all 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. As of December 31, 2015, 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 consolidated balance sheets, statements of operations and statements of cash flows of the issuer, the guarantor subsidiaries and the non-guarantor subsidiaries.

CONDENSED CONSOLIDATED BALANCE SHEETS
(unaudited, in thousands)

	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	12,814	(246)	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	14,208	(246)	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
Noncurrent deferred income taxes	84,014	—	18	(84,014)	18
Other long-term assets	8,295	962	704	—	9,961
Total assets	$ 746,369	$ 820,114	$ 46,883	$ (783,590)	$ 829,776
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	1,719	(246)	46,869
Total current liabilities	8,989	57,221	4,078	(246)	70,042
Long-term debt, less current portion	395,000	—	—	—	395,000
Noncurrent deferred income taxes	(975)	102,509	—	(84,014)	17,520
Other long-term liabilities	712	3,294	565	—	4,571
Total liabilities	403,726	163,024	4,643	(84,260)	487,133
Total shareholders' equity	342,643	657,090	42,240	(699,330)	342,643
Total liabilities and shareholders' equity	$ 746,369	$ 820,114	$ 46,883	$ (783,590)	$ 829,776

	December 31, 2014				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 27,688	$ (5,516)	$ 12,752	$ —	$ 34,924
Receivables, net of allowance	1,641	151,048	37,512	—	190,201
Intercompany receivable (payable)	(24,836)	55,567	(30,728)	(3)	—
Deferred income taxes	1,827	8,196	975	—	10,998
Inventory	—	7,208	6,909	—	14,117
Assets held for sale	—	9,909	—	—	9,909
Prepaid expenses and other current assets	1,217	6,554	1,154	—	8,925
Total current assets	7,537	232,966	28,574	(3)	269,074
Net property and equipment	4,179	763,994	89,118	(750)	856,541
Investment in subsidiaries	850,807	116,799	—	(967,606)	—
Intangible assets, net of accumulated amortization	—	24,223	—	—	24,223
Noncurrent deferred income taxes	90,664	—	2,753	(90,664)	2,753
Other long-term assets	10,122	1,955	6,921	—	18,998
Total assets	$ 963,309	$ 1,139,937	$ 127,366	$ (1,059,023)	$ 1,171,589
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 735	$ 57,910	$ 5,660	$ —	$ 64,305
Current portion of long-term debt	—	27	—	—	27
Deferred revenues	—	3,315	—	—	3,315
Accrued expenses	11,109	64,063	4,376	(3)	79,545
Total current liabilities	11,844	125,315	10,036	(3)	147,192
Long-term debt, less current portion	455,000	53	—	—	455,053
Noncurrent deferred income taxes	138	160,104	—	(90,664)	69,578
Other long-term liabilities	513	3,658	531	—	4,702
Total liabilities	467,495	289,130	10,567	(90,667)	676,525
Total shareholders' equity	495,814	850,807	116,799	(968,356)	495,064
Total liabilities and shareholders' equity	$ 963,309	$ 1,139,937	$ 127,366	$ (1,059,023)	$ 1,171,589

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited, in thousands)

	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)

	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 CONSOLIDATED STATEMENTS OF OPERATIONS
(Continued)
(Unaudited, in thousands)

	Year ended December 31, 2013				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$ —	$ 844,555	$ 115,631	$ —	$ 960,186
Costs and expenses:					
Operating costs	—	548,628	82,048	—	630,676
Depreciation and amortization	1,113	173,516	13,289	—	187,918
General and administrative	25,272	65,962	3,501	(552)	94,183
Bad debt expense (recovery)	67	700	—	—	767
Impairment charges	—	54,292	—	—	54,292
Gain on dispositions of property and equipment, net	—	(283)	(1,138)	—	(1,421)
Intercompany leasing	—	(4,860)	4,860	—	—
Total costs and expenses	26,452	837,955	102,560	(552)	966,415
Income (loss) from operations	(26,452)	6,600	13,071	552	(6,229)
Other (expense) income:					
Equity in earnings of subsidiaries	11,861	6,260	—	(18,121)	—
Interest expense, net of interest capitalized	(48,302)	(37)	29	—	(48,310)
Other	9	1,990	(2,686)	(552)	(1,239)
Total other (expense) income	(36,432)	8,213	(2,657)	(18,673)	(49,549)
Income (loss) before income taxes	(62,884)	14,813	10,414	(18,121)	(55,778)
Income tax (expense) benefit [1]	26,952	(2,952)	(4,154)	—	19,846
Net income (loss)	$ (35,932)	$ 11,861	$ 6,260	$ (18,121)	$ (35,932)

[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 CONSOLIDATED STATEMENTS OF CASH FLOWS
(unaudited, in thousands)

	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

	Year ended December 31, 2014				
	Parent	Guarantor	Non-	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 property and equipment	—	8,069	301	—	8,370
Proceeds from sale of fishing and rental services operations	15,090	—	—	—	15,090
	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

	Year ended December 31, 2013				
	Parent	Guarantor	Non-	Eliminations	Consolidated
Cash flows from operating activities	$ (66,941)	$ 240,108	$ 1,413	$ —	$ 174,580
Cash flows from investing activities:					
Purchases of property and equipment	(2,649)	(151,363)	(11,344)	—	(165,356)
Proceeds from sale of property and equipment	8	12,510	1,318	—	13,836
Proceeds from insurance recoveries	—	844	—	—	844
	(2,641)	(138,009)	(10,026)	—	(150,676)
Cash flows from financing activities:					
Debt repayments	(60,000)	(874)	—	—	(60,874)
Proceeds from issuance of debt	40,000	—	—	—	40,000
Debt issuance costs	(13)	—	—	—	(13)
Proceeds from exercise of options	1,266	—	—	—	1,266
Purchase of treasury stock	(631)	—	—	—	(631)
Intercompany contributions/distributions	98,849	(97,883)	(966)	—	—
	79,471	(98,757)	(966)	—	(20,252)
Net increase (decrease) in cash and cash equivalents	9,889	3,342	(9,579)	—	3,652
Beginning cash and cash equivalents	18,479	(5,401)	10,655	—	23,733
Ending cash and cash equivalents	$ 28,368	$ (2,059)	$ 1,076	$ —	$ 27,385

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, 2015, 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.

There has been no change in our internal control over financial reporting that occurred during the three months ended December 31, 2015 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, 2015. 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, 2015, 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, 2015. 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 2016 Annual Meeting of Shareholders. We intend to file that definitive proxy statement with the SEC on or about April 15, 2016.

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 2016 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 2016 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 headings "Equity Compensation Plan Information" and "Security Ownership of Certain Beneficial Owners and Management" in the definitive proxy statement for our 2016 Annual Meeting of Shareholders for the information this Item 12 requires.

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 2016 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 2016 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)).

10.11+* - Pioneer Energy Services Corp. 2007 Incentive Plan Form of Long-Term Incentive Cash Award Agreement (Form 10-Q dated July 31, 2014 (File No. 1-8182, Exhibit 10.7)).

10.12+* - 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)).

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

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

10.15* - 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)).

10.16* - 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)).

10.17* - 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)).

10.18* - 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)).

10.19* - 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)).

10.20+* - Employment Letter, effective March 1, 2008, from Pioneer Drilling Company to Joseph B. Eustace (Form 8-K dated March 5, 2008 (File No. 1-8182, Exhibit 10.1)).

10.21+* - Confidentiality and Non-Competition Agreement, dated February 29, 2008, by and between Pioneer Drilling Company, Pioneer Production Services, Inc. and Joe Eustace (Form 8-K dated March 5, 2008 (File No. 1-8182, Exhibit 10.2)).

10.22+* - 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)).

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

10.24+* - 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)).

10.25+* - 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)).

10.26+* - 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)).

10.27+* - Retirement and Consulting Services Agreement and Complete Release of All Claims, effective January 1, 2015, by and between Pioneer Energy Services Corp and F.C. "Red" West.

10.28+* - Waiver and Release Agreement, dated as of March 2, 2015, between Pioneer Drilling Services, Ltd. and Joseph B. Eustace (Form 10-Q dated April 30, 2015 (File No. 1-8182, Exhibit 10.1)).

10.29+**	-	Pioneer Energy Services Corp. Amended and Restated 2007 Incentive Plan Form of Performance Phantom Stock Unit Award Agreement.
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, 2015, 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, 2016

/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, 2016
/S/ WM. STACY LOCKE Wm. Stacy Locke	President, Chief Executive Officer and Director (Principal Executive Officer)	February 17, 2016
/S/ LORNE E. PHILLIPS Lorne E. Phillips	Executive Vice President and Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)	February 17, 2016
/S/ C. JOHN THOMPSON C. John Thompson	Director	February 17, 2016
/S/ JOHN MICHAEL RAUH John Michael Rauh	Director	February 17, 2016
/S/ SCOTT D. URBAN Scott D. Urban	Director	February 17, 2016

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

	Year ended December 31,				
	2015	2014	2013	2012	2011
Reconciliation of Adjusted EBITDA to net income (loss):					
Adjusted EBITDA*	$ 110,780	$ 277,081	$ 234,742	$ 249,283	$ 183,870
Depreciation and amortization	(150,939)	(183,376)	(187,918)	(164,717)	(132,832)
Impairment charges	(129,152)	(73,025)	(54,292)	(1,131)	(484)
Interest expense	(21,222)	(38,781)	(48,310)	(37,049)	(29,721)
Loss on extinguishment of debt	(2,186)	(31,221)	—	—	—
Income tax (expense) benefit	37,579	11,304	19,846	(16,354)	(9,656)
Net income (loss)	$ (155,140)	$ (38,018)	$ (35,932)	$ 30,032	$ 11,177

*Adjusted EBITDA represents income (loss) before interest expense, income tax (expense) benefit, depreciation and amortization, loss on extinguishment of debt and impairments. We use this non-GAAP measure, together with our GAAP financial metrics, to assess our financial performance and evaluate our overall progress towards meeting our long-term financial objectives. We believe that this measure is useful to investors and analysts in allowing for greater transparency of our 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

WM. STACY LOCKE
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,
General Counsel, Secretary and
Compliance Officer

BILL W. BOUZIDEN
Senior Vice President of Wireline
Services and Coiled Tubing Services

JOE P. FREEMAN
Senior Vice President
of Well Servicing

CORPORATE INFORMATION

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AUDITORS
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17802 IH-10, Suite 101
Promenade Two
San Antonio, Texas 78257

SHAREHOLDER CONTACT
Daniel Petro
Director of Corporate Development and
Investor Relations
855.884.0575
Fax 210.828.8228
investorrelations@pioneeres.com

A copy of the Company's annual report on Form 10-K is available, without charge, upon request to the address listed above.

STOCK LISTING
The New York Stock Exchange: PES

As of March 21, 2016, the approximate number of common shareholders of record was 344.

INVESTOR RELATIONS
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