PIONEER

2018 ANNUAL REPORT

PIONEER ENERGY SERVICES

EVERY project is ***PERSONAL***

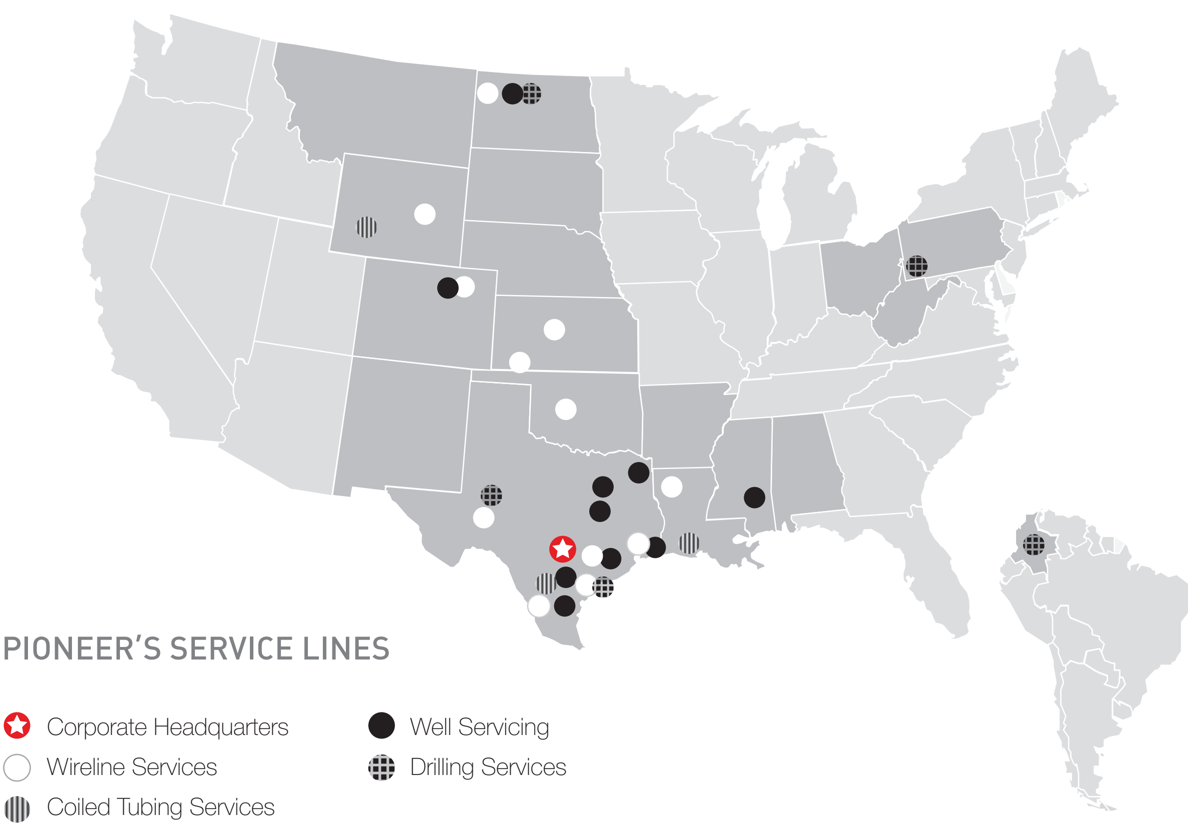
SELECTED FINANCIAL DATA (1)

(In thousands, except per share data)	2018	2017	2016	2015	2014
Revenues	$590,097	$446,455	$277,076	$540,778	$1,055,223
Net loss	(49,011)	(75,118)	(128,391)	(155,140)	(38,018)
Adjusted EBITDA[2]	89,655	49,873	14,237	110,780	277,081
Loss per common share - diluted	(0.63)	(0.97)	(1.96)	(2.41)	(0.60)
Total assets	741,550	766,869	700,102	821,975	1,171,589
Long-term debt, excluding current installments and debt insurance costs	475,000	475,000	346,000	395,000	455,053
Shareholders' equity	165,058	210,096	281,398	342,643	495,064
Net cash provided by (used in) operating activities	39,656	(5,817)	5,131	142,719	233,041

(1) The selected financial data for the years ended December 31, 2018, 2017, 2016, 2015 and 2014 reflects the impact of asset impairment charges of $4.4 million, $1.9 million, $12.8 million, $129.2 million, and $73.0 million, respectively.

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

AREAS OF OPERATIONS



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, 2018

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 every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☑
Non-accelerated filer ☐	Smaller reporting company ☐
	Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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, 2018) was approximately $442.9 million.

As of January 31, 2019, there were 78,454,853 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 2019 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 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 term loan, ABL facility and senior notes;
- operating hazards inherent in our operations;
- the supply of marketable drilling rigs, well servicing rigs, coiled tubing units and wireline units within the industry;
- the continued availability of new components for drilling rigs, well servicing rigs, coiled tubing units and wireline units;
- the continued availability of qualified personnel;
- the success or failure of our acquisition strategy;
- the occurrence of cybersecurity incidents;
- the political, economic, regulatory and other uncertainties encountered by our operations, and
- changes in, or our failure or inability to comply with, governmental regulations, including those relating to the environment.

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

ITEM 1. BUSINESS

Company Overview

Pioneer Energy Services Corp. provides land-based drilling services and production services to a diverse group of oil and gas exploration and production companies in the United States and internationally in Colombia. 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.

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

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

  We provide a comprehensive service offering which includes the drilling rig, crews, supplies and most of the ancillary equipment needed to operate our drilling rigs which are deployed through our division offices in the following regions:

	Rig Count
Domestic drilling:	
Marcellus/Utica	6
Permian Basin and Eagle Ford	8
Bakken	2
International drilling	8
	24

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

  Today, our production services business segments provide a range of well, wireline and coiled tubing services to a diverse group of exploration and production companies, with our operations concentrated in the major domestic onshore oil and gas producing regions in the Gulf Coast, Mid-Continent and Rocky Mountain states. 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, 2018,we have a fleet of 113 rigs with 550 horsepower and 12 rigs with 600 horsepower with operations in 10 locations, mostly in the Gulf Coast states, as well as in North Dakota and Colorado.

  - *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, 2018, we have a fleet of 105 wireline units, which are deployed through 13 operating locations in the Gulf Coast, Mid-Continent and Rocky Mountain states.

- *Coiled Tubing Services.* Coiled tubing is another important element of the well servicing industry that allows operators to continue production during service operations on a well under pressure without shutting in the well, thereby reducing the risk of formation damage. Coiled tubing services involve the use of a continuous flexible metal pipe which is spooled on a large reel and inserted into the wellbore to perform a variety of 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, 2018, we have a current fleet of nine coiled tubing units, the majority of which offer larger diameter coil (larger than two inches), deployed through two operating locations that provide services in Texas, Wyoming and surrounding areas.

Pioneer Energy Services Corp. was incorporated under the laws of the State of Texas in 1979 as the successor to a business that had been operating since 1968. Since then, we have significantly expanded and transformed our business through acquisitions and organic growth. Our business is comprised of two business lines — Drilling Services and Production Services. We report our Drilling Services business as two reportable segments: (i) Domestic Drilling and (ii) International Drilling. We report our Production Services business as three reportable segments: (i) Well Servicing, (ii) Wireline Services, and (iii) Coiled Tubing Services. 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.

Industry Overview

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

Our business is influenced substantially by exploration and production companies' spending that 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 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.

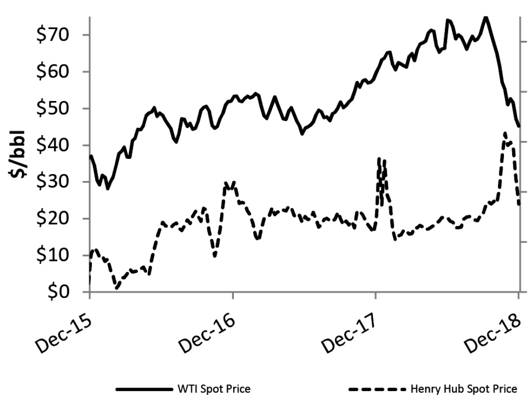
Capital expenditures for the drilling and completion of exploratory and development wells in proven areas are more directly influenced by current and expected oil and natural gas prices and generally reflect the volatility of commodity prices. In contrast, operating expenditures for the maintenance of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

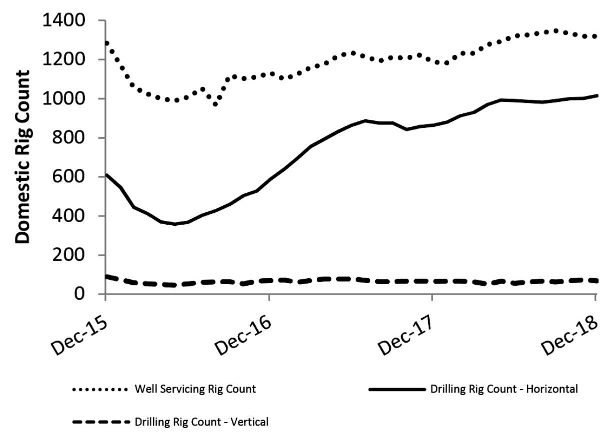
Drilling and production services have historically trended similarly in response to fluctuations in commodity prices. However, because exploration and production companies often adjust their budgets for exploration and development drilling first in response to a change in commodity prices, the demand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

However, in a severe downturn that is prolonged, both operating and capital expenditures are significantly reduced, and the demand for all our service offerings is significantly impacted. After a prolonged downturn, among the production services, the demand for completion-oriented services generally improves first, as exploration and production companies begin to complete wells that were previously drilled but not completed during the downturn, and to complete newly drilled wells as the demand for drilling services improves during recovery.

From time to time, temporary regional slowdowns or constraints occur in our industry due to a variety of factors, including, among others, infrastructure or takeaway capacity limitations, labor shortages, increased regulatory or environmental pressures, or an influx of competitors in a particular region. Any of these factors can influence the profitability of operations in the affected region. However, term contract coverage for our drilling services business and the mobility of all our equipment between regions limits our exposure to the impact of regional constraints and fluctuations in demand.

Our industry experienced a severe down cycle from late 2014 through 2016, during which WTI oil prices dipped below $30 per barrel in early 2016. A modest recovery in commodity prices began in the latter half of 2016 with WTI oil prices steadily increasing from just under $50 per barrel at the end of June 2016 to approximately $60 per barrel at the end of 2017. In 2018, WTI oil prices continued to increase to a high of $75 per barrel in October, but then decreased to $45 per barrel at the end of 2018, and averaged approximately $50 per barrel during January 2019. 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.





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

Technological advancements and trends in our industry also affect the demand for certain types of equipment, and can affect the overall demand for the services our industry provides. Enhanced directional and horizontal drilling techniques have allowed exploration and production operators to drill increasingly longer lateral wellbores which enable higher hydrocarbon production per well, and reduce the overall number of wells needed to achieve the desired production. This trend toward longer lateral wellbores also increases demand for the more specialized equipment, such as high-spec drilling rigs, higher horsepower well servicing rigs equipped with taller masts, larger diameter coiled tubing units, and other higher power ancillary equipment, which is needed in order to drill, complete and provide services to the full length of the wellbore. Our domestic drilling and production services fleets are highly capable and designed for operation in today's long lateral, pad-oriented environment.

For additional information concerning the potential effects of volatility in oil and gas prices and other industry trends, see Item 1A – "Risk Factors" in Part I and in the section entitled "Market Conditions in Our Industry" in Part II, Item 7 of this Annual Report on Form 10-K.

Competitive Strengths

Our competitive strengths include:

- *Modern Fleets Designed for Optimal Performance.* Our fleets are predominantly comprised of equipment designed to optimize recovery from and servicing of the unconventional wells which are most desirable in our industry today. Our current drilling rig fleet is 100% pad-capable and offers the latest advancements in pad drilling. We have 16 AC rigs in the US and eight SCR rigs in Colombia, all of which have 1,500 horsepower or greater drawworks, and we are currently completing construction of a 17^{th} AC drilling rig with a three-year term contract, which we expect to deploy in early 2019 to the Permian Basin. Our well servicing fleet is 100% tall-masted, 550 to 600 horsepower rigs, making them well suited for operating in today's long lateral environment. Additionally, the majority of our onshore coiled tubing units are shale-ready units which offer larger diameter coil, and we have added capacity to our wireline fleet focused on higher-spec units designed for completion work in unconventional areas, units which offer greaseless electric wireline used to reach further depths in longer laterals and *EcoQuiet*^{SM} units designed to reduce noise when operating in proximity to urban areas. We believe that our modern and well-maintained fleets allow us to realize higher utilization and pricing because we are able to offer our clients technologically advanced equipment that allows them to operate in the most challenging markets, with less downtime and greater efficiency.

- *A Leading Provider in Domestic Shale Regions.* Our drilling and production services fleets operate in many of the most attractive producing regions in the United States, including the Utica, Marcellus, Eagle Ford, Niobrara, multiple shales in the Permian Basin, SCOOP/STACK and Bakken. We believe our drilling rigs are particularly well suited to these areas where the optimal rig configuration is dictated by local geology and market conditions, and we have focused the expansion of our production services fleets to these regions with the most opportunity for growth. All our fleet equipment is mobile between domestic regions, diversifying our geographic exposure and limiting the impact of any regional slowdown.

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

- *Industry-Leading Safety Record.* Our safety program called "LiveSafe" focuses on creating an environment where everyone is committed to and recognizes the possibility of always working without incident or injury. The commitment to LiveSafe helps keep our employees safe and reduces our business risk. In 2018, our domestic drilling business achieved record safety results and based on currently available industry data, was ranked first among the top 10 most active contractors. In addition, our well servicing segment achieved its lowest total recordable incident rate in its history. As a result, for the second year in a row, our consolidated total recordable incident rate was below 1.0 and we lowered our lost time incident rates for the fifth consecutive year, achieving the lowest in our company's history. Our excellent safety record and reputation are critical to winning new business and expanding our relationships with existing clients. We are proud of each of our employees' daily and personal commitments to a culture of dignity, respect and safety.

- *Skilled Management Team.* We believe that an important competitive factor in managing our business successfully and achieving long-term client relationships includes having an experienced and skilled management team. Our leadership team has operated through numerous oilfield services cycles and provides us with valuable long-term experience that enables us to manage our business through continually changing industry and market conditions. Our operations managers are knowledgeable about the various operational and regional challenges our clients face and we believe their skill and expertise enhances the value we are able to provide our clients and strengthens those relationships. To build and preserve the value of our experienced management team, we seek to minimize employee turnover, invest in the growth of our employees, and recruit new talent through our focus on employee training and development, safety and competitive compensation.

- *Longstanding and Diversified Clients.* We maintain long-standing, high quality client relationships with a diverse group of oil and gas exploration and production companies. Our largest three clients, Gran Tierra Energy, Inc., Apache

Corporation and QEP Energy Company, accounted for approximately 8%, 6% and 6%, respectively, of our 2018 consolidated revenues. We believe our relationships with our clients are strong and the diversity of our client base offers numerous opportunities for growth.

Strategy

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

Our long-term strategy as a premier land drilling and production services company is to further leverage our relationships with existing clients, within and across business lines, expand our client base in the areas where we currently operate, grow our geographic diversification through selective expansion, and continue to identify and develop opportunities to enhance our service offerings. The key elements of this long-term strategy are focused on our:

- *Performance in our Core Businesses.* We maintain a continual focus on our relationships with our clients and vendors, and our commitment to safety and service quality goals. In 2018, our domestic drilling business achieved record safety results and based on currently available industry data, was ranked first among the top 10 most active contractors. In addition, our well servicing segment achieved its lowest total recordable incident rate in its history. As a result, for the second year in a row, our consolidated total recordable incident rate was below 1.0 and we lowered our lost time incident rates for the fifth consecutive year, achieving the lowest in our company's history. Our excellent safety record and reputation are critical to winning new business and expanding our relationships with existing clients.

- *Investments in Our Business.* We have historically invested in the growth and technological advancement of our business by engaging in select rig building opportunities and acquisitions, strategically upgrading our existing assets and disposing of assets which use older technology. From 2011 to 2016, we constructed 15 walking AC drilling rigs and removed all non-AC drilling rigs from our domestic fleet. Our current drilling rig fleet is 100% pad-capable and offers the latest advancements in pad drilling. We have 16 AC rigs in the US and eight SCR rigs in Colombia, all of which have 1,500 horsepower or greater drawworks, and we are currently completing construction of a 17th AC drilling rig with a three-year term contract, which we expect to deploy in early 2019 to the Permian Basin. The removal of older, less capable rigs from our fleet and investments in the construction of new drilling rigs has transformed our fleet into a highly capable, pad optimal fleet focused on the horizontal drilling market. Since the beginning of 2010, we have added significant capacity to our production services offerings through the addition of 42 wireline units, 51 well servicing rigs and 9 coiled tubing units, all of which are net of various dispositions and replacements which were made to continuously rejuvenate our fleet with new equipment using the latest advancements in technologies. We believe this positions us to compete well, grow our presence in the significant shale basins in the US, and improve profitability.

- *A Leading Provider in Domestic Shale Regions.* The investments we've made in our business have been focused on increasing our presence in regions where demand benefits from shale development. Shale plays are increasingly important to domestic hydrocarbon production, and not all rigs are capable of successfully working in these unconventional producing regions. Our domestic drilling and production services fleets are highly capable and designed for operation in today's long lateral, pad-oriented environment. We are currently operating in the Utica, Marcellus, Eagle Ford, Niobrara, multiple shales in the Permian Basin, SCOOP/STACK and Bakken. We continue to allocate our resources to the markets with the best opportunities for increased activity, and to upgrade / reactivate previously idle units in areas with increasing demand.

Though we have remained committed to our long-term strategy, in recent years, our industry has suffered a severe downturn which began in late 2014 and persisted through 2016, followed by a slow but moderate recovery in 2017 and 2018, but with commodity prices that have since languished. During this time, our recent and near term efforts have been focused on the following initiatives:

- *Adapting our Business.* During 2015 and 2016, we took various actions to reduce costs and preserve cash, including a significant reduction in headcount, reduced wage rates, incentive compensation and employment benefits, the closure of field office locations, and we limited our capital spending to primarily routine expenditures that were necessary to maintain our equipment. With increasing activity and pricing during 2017 and 2018, we resumed our efforts to build value in our core businesses to fit the current and anticipated market trends by redeploying assets to areas with improving demand, selectively upgrading our fleets and executing limited strategic growth.

- *Improving Liquidity and Financial Flexibility.* In December 2016, we sold 12.1 million shares of common stock in a public offering, and applied the net proceeds to reduce our outstanding debt under our revolving credit facility. In November 2017, we entered into a new senior secured asset-based lending facility (the "ABL Facility") and a term loan agreement (the "Term Loan"), the proceeds of which were used to repay and extinguish our prior revolving credit facility which was set to mature in 2019. The ABL Facility and Term Loan provide us greater financial flexibility and increased liquidity. We currently have availability for equity or debt offerings up to $300 million under our shelf registration statement, subject to the limitations imposed by our Term Loan, ABL Facility and Senior Notes.

- *Liquidating Nonstrategic Assets.* Since the beginning of 2015, we have sold 39 non-AC domestic drilling rigs, 33 of our older wireline units, seven of our smaller diameter coiled tubing units and various other drilling and coiled tubing equipment for aggregate net proceeds of over $75 million. At December 31, 2018, we have $3.6 million of assets remaining held for sale, including two domestic drilling rigs, three coiled tubing units and other drilling equipment. We continue to evaluate our domestic and international fleets for additional drilling rigs or equipment for which a near term sale would be favorable.

- *Selectively Optimizing our Fleets.* As our vendors and competitors experienced financial pressure resulting from the industry downturn, we took advantage of favorable asset pricing conditions to enhance our production services fleets, including the exchange of 20 older well servicing rigs for 20 new-model rigs in 2017 and the purchase of seven new wireline units and two new large diameter coiled tubing units in 2017 and 2018.

- *Redeploying our Leadership Talent*. Effective January 1, 2019, several of our executive leaders are taking on expanded roles to further leverage their existing talents to the entire organization. A Chief Operating Officer has been appointed to centralize operational and sales leadership for all business segments, and a Chief Strategy Officer has been appointed to lead a team designed to identify market opportunities, execute strategic initiatives and enhance our fleet performance across all business units.

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

Overview of Our Segments and Services

Our business is comprised of two business lines — Drilling Services and Production Services. We report our Drilling Services business as two reportable segments: (i) Domestic Drilling and (ii) International Drilling. We report our Production Services business as three reportable segments: (i) Well Servicing, (ii) Wireline Services, and (iii) Coiled Tubing Services. 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

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

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

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

The following table summarizes our current rig fleet composition by segment:

	Multi-well, Pad-capable		
	SCR rigs	AC rigs	Total
Domestic drilling	—	16	16
International drilling	8	—	8
			24

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

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

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

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.

Daywork contracts are comprehensive agreements under which we provide a comprehensive service offering, including the drilling rig, crew, supplies and most of the ancillary equipment necessary to operate the rig. We obtain our contracts for drilling oil and natural gas wells either through competitive bidding or through direct negotiations with existing or potential clients. 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. Drilling contracts for individual wells are usually completed in less than 30 days. We typically enter into longer-term drilling contracts for our newly constructed rigs and/or during periods of high rig demand.

Production Services

Our production services business segments provide a range of well, wireline and coiled tubing services to a diverse group of exploration and production companies, with our operations concentrated in the major domestic onshore oil and gas producing regions in the Gulf Coast, Mid-Continent and Rocky Mountain states.

Newly drilled wells require completion services to prepare the well for production. 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, replacing defective tubing in a gas well, cleaning a live well, and servicing mechanical issues. 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. 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. 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.

At the end of the well life cycle, a process is required to permanently close oil and gas wells that are 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.

As of December 31, 2018, the fleet count for each of our production services business segments are as follows:

	550 HP	600 HP	Total
Well servicing rigs, by horsepower (HP) rating	113	12	125

	Total
Wireline services units	105
Coiled tubing services units	9

- *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.

  Well servicing rigs are frequently used to complete newly drilled wells to minimize the use of higher cost drilling rigs in the completion process. 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. 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. We also perform plugging and abandonment work throughout our core areas of operation in conjunction with equipment provided by other service companies.

  We believe that our well servicing fleet is among the newest in the industry, consisting entirely of tall-masted rigs with at least 550 horsepower, capable of working at depths of over 20,000 feet. These specifications allow us to operate in areas with deeper well depths and perform jobs that rigs with lesser capabilities cannot. In 2017, we traded in 20 of our older 550 horsepower well servicing rigs for 20 new-model rigs, further improving the quality of our rig fleet, enhancing our ability to recruit crew talent and competitively positioning us for new service opportunities as the market continues to improve.

Our well servicing operations are deployed through 10 locations, mostly in the Gulf Coast states, as well as in North Dakota and Colorado.

- *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 13 operating locations in the Gulf Coast, Mid-Continent and Rocky Mountain states.

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

  Our coiled tubing operations are deployed through two operating locations that provide services in Texas, Wyoming and surrounding areas.

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. While 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 oil and gas exploration and production companies. 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
Year ended December 31, 2018	
Gran Tierra Energy, Inc.	8.1%
Apache Corporation	5.9%
QEP Energy Company	5.8%
Year ended December 31, 2017	
Apache Corporation	7.5%
Extraction Oil & Gas, LLC	6.4%
Whiting Petroleum Corporation	6.3%
Year ended December 31, 2016	
Apache Corporation	11.9%
Whiting Petroleum Corporation	10.1%
PDC Energy, Inc.	4.4%

Competition

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

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

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

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

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

The following is an overview of the market for each of our services:

- *Domestic and International Drilling.* Our principal domestic drilling competitors are Helmerich & Payne, Inc., Precision Drilling Corporation, Patterson-UTI Energy, Inc. and Nabors Industries Ltd. In Colombia, we primarily compete with Helmerich & Payne, Inc., Nabors Industries Ltd., Weatherford International plc, Petrex S.A., Tuscany International Drilling, and Estrella International Energy Services Ltd. Our current drilling rig fleet is 100% pad-capable and offers the latest advancements in pad drilling, which we believe positions us well to compete and expand our presence in predominant shale regions.

- *Well Servicing.* The largest well servicing providers that we compete with are Key Energy Services, Basic Energy Services, C&J Energy Services, Superior Energy Services and Forbes Energy Services. 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.

- *Wireline.* 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, Nine Energy Services, and Quintana Energy Services. 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.

- *Coiled Tubing.* The market for coiled tubing has expanded within the oilfield services market over recent years due to technological advances that increased the variety of applications for the coiled tubing unit and due to 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, Schlumberger Ltd., Halliburton Company, Quintana Energy Services and RPC, Inc.

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

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

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

Raw Materials

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

Operating Risks and Insurance

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

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

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

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

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

Our current insurance coverage includes property insurance on our rigs, drilling equipment, production services equipment and real property. Our insurance coverage for property damage to our rigs, drilling equipment and production services equipment is based on our estimates of the cost of comparable used equipment to replace the insured property. The policy provides for a deductible of no more than $750,000 per drilling rig and a deductible on production services equipment of $100,000 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 and an additional $250,000 annual aggregate deductible. 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.

Employees

We currently have approximately 2,400 employees, the majority of which work in our drilling and production services operations 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 results. As a result, our operations depend, to a considerable extent, on the continuing availability of such personnel. From time to time, 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 29 regional offices throughout the United States in Texas, Oklahoma, Colorado, Montana, North Dakota, Pennsylvania, Wyoming, Mississippi, Louisiana and Kansas, and internationally in Colombia. These operating locations typically include leased real estate properties which are used for regional offices, storage and maintenance yards and personnel housing sufficient to support our operations in the area. We own 12 real estate properties associated with our regional operations.

Governmental Regulation

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

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

Environment Protection. 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 the laws, rules and regulations applicable to our industry 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 wastes and/or hazardous substances. Planning, implementation and maintenance of protective measures are required to prevent accidental discharges. Spills of oil, natural gas liquids, drilling fluids and other substances may subject us to penalties and cleanup requirements. Handling, storage and disposal of both hazardous and non-hazardous wastes are also subject to these regulatory requirements. In addition, our operations are often conducted in or near ecologically sensitive areas, such as wetlands, which are subject to special protective measures and which may expose us to additional operating costs and liabilities for accidental discharges of oil, gas, drilling fluids, contaminated water or other substances, or for noncompliance with other aspects of applicable laws and regulations.

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

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

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

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

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

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

Transportation. 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; Rules of Conduct Applicable to All Employees; Corporate Governance Guidelines; and Company Contact Information. Information on our website is not incorporated into this report or otherwise made part of this report.

ITEM 1A. RISK FACTORS

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

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

Risks Relating to the Oil and Gas Industry

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

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

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

  - the worldwide supply and demand for oil and gas;
  - the cost of exploring for, producing and delivering oil and gas;
  - the discovery rate of new oil and gas reserves;
  - the rate of decline of existing and new oil and gas reserves;

- available pipeline and other oil and gas transportation capacity;
- the levels of oil and gas storage;
- the ability of oil and gas exploration and production companies to raise capital;
- economic conditions in the United States and elsewhere;
- actions by the Organization of Petroleum Exporting Countries, which we refer to as OPEC;
- political instability in 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, or their investments in oil and gas reserves located in other countries; and
- the price of foreign imports of oil and gas.

Additionally, the above factors can also be affected by technological advances affecting energy consumption and the supply and demand within the market for renewable energy resources.

- *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.*

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.

In late 2014, oil prices worldwide began to drop significantly and as a result, our clients significantly reduced both their operating and capital expenditures during 2015 and 2016, which adversely affected our business. In 2017 and 2018, our clients modestly increased their spending as compared to 2016 levels, and our business trended upward as a result. However, in late 2018, oil prices again began to decline and as a result, oil and gas exploration and production companies may cancel or curtail their drilling programs and reduce production spending on existing wells, thereby reducing demand for our services. If the reduction in the overall level of exploration and development activities, whether resulting from changes in oil and gas prices or otherwise, continues or worsens, it could materially and adversely affect us further by negatively impacting:

- our revenues, cash flows and profitability;
- the fair market value of our drilling and production services fleets;
- 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.

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. Likewise, an increase or oversupply of well servicing rigs, wireline units and coiled tubing units, without increased demand, could further decrease the pricing and utilization rates of our production services and adversely affect our revenues and profitability.

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

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

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

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

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

- *We face competition from many competitors with greater resources.*

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

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

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

  Technological advancements and trends in our industry also affect the demand for certain types of equipment, and can affect the overall demand for the services our industry provides. Enhanced directional and horizontal drilling techniques have allowed exploration and production operators to drill increasingly longer lateral wellbores which enable higher hydrocarbon production per well, and reduce the overall number of wells needed to achieve the desired production. This trend toward longer lateral wellbores also increases demand for the more specialized equipment, such as high-spec drilling rigs, higher horsepower well servicing rigs equipped with taller masts, larger diameter coiled tubing units, and other higher power ancillary equipment, which is needed in order to drill, complete and provide services to the full length of the wellbore.

  Our domestic drilling and production services fleets are highly capable and designed for operation in today's long lateral, pad-oriented environment. 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, 2018, 2017 and 2016, our drilling and production services to our top three clients accounted for approximately 20%, 20%, and 26%, 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. For a detail of our three largest clients as a percentage of our total revenues during the last three fiscal years, see Item 1—"Business" in Part I of this Annual Report on Form 10-K.

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

  Our indebtedness is primarily a result of the acquisitions of the well servicing and wireline services businesses which we acquired in 2008 and the coiled tubing business that we acquired in 2011, as well as organic growth investments. At December 31, 2018, our total debt consists of $300 million outstanding under our Senior Notes and $175 million outstanding under our Term Loan, with additional borrowing availability under our ABL Facility.

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

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

  We currently expect that cash and cash equivalents, cash generated from operations, proceeds from sales of assets, and available borrowings under our ABL Facility are adequate to cover our liquidity requirements for at least the next 12 months. However, our ability to make payments on our indebtedness, and to fund planned capital expenditures, will depend on our ability to generate cash in the future. This, to a certain extent, is subject to:

  - conditions in the oil and gas industry;
  - general economic and financial conditions;
  - competition in the markets where we operate;
  - the impact of legislative and regulatory actions on how we conduct our business; and
  - other factors, all of which are beyond our control.

  If our business does not generate sufficient cash flow from operations to service our outstanding indebtedness, we may have to undertake alternative financing plans, subject to the limitations imposed by our Term Loan, ABL Facility and Senior Notes, 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; and/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 Term Loan, ABL Facility, and Senior Notes, we could be in default under the terms of such instruments. In the event of a default, our lenders could elect to declare all the loans made under our Term Loan, ABL Facility, and Senior Notes 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 Term Loan, ABL Facility, and Senior Notes impose significant covenants on us that may affect our ability to successfully operate our business.*

  Our Term Loan contains customary restrictions that, among other things, and subject to certain exceptions, limit our ability to:

  - incur additional debt;
  - incur or permit liens on assets;
  - make investments and acquisitions;
  - consolidate or merge with another company;
  - engage in asset sales; and
  - pay dividends or make distributions.

  In addition, our Term Loan 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.

  Our ABL Facility contains restrictive covenants that, among other things, and subject to certain exceptions, limit our ability to:

  - declare dividends and make other distributions;
  - issue or sell certain equity interests;
  - optionally prepay, redeem or repurchase certain of our subordinated indebtedness;
  - make loans or investments (including acquisitions);
  - incur additional indebtedness or modify the terms of permitted indebtedness;
  - grant liens;
  - change our business or the business of our subsidiaries;
  - merge, consolidate, reorganize, recapitalize, or reclassify our equity interests;
  - sell our assets, and
  - enter into certain types of transactions with affiliates.

  The Indenture governing our Senior Notes, among other things, limits us and certain of our subsidiaries, subject to certain exceptions, in our ability to:

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

  The failure to comply with any of these covenants would cause an event of default under our Term Loan, ABL Facility, or 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 Term Loan, ABL Facility, and Senior Notes.

- *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. Additionally, trade and economic sanctions or other restrictions imposed by the United States or other countries could also affect the supply of equipment and supplies which are needed in our operations. Shortages could result in increased prices for equipment or supplies that we may be unable to pass on to clients and could substantially lengthen the delivery times for equipment and supplies. Any significant delays in our obtaining equipment or supplies could limit our operations and jeopardize our relations with clients and could delay and adversely affect our ability to obtain new contracts for our rigs. Any of the above 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 provide 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 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 long-term strategy for growth through acquisitions could expose 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, subject to the limitations imposed by our Term Loan, ABL Facility, and Senior Notes. This acquisition strategy in general involves numerous inherent risks, including:

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

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

  In addition, we may not have sufficient capital resources to complete additional acquisitions. Historically, we have funded business acquisitions and the growth of our fleets 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 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 or more of the financial institutions with which we deposit fails or is subject to other adverse conditions in the financial or credit markets and bank regulators elect to impose losses on uninsured depositors. To date, we have experienced no loss or lack of access to our invested cash or cash equivalents. However, in the future, our invested cash and cash equivalents could be adversely affected by adverse conditions in the financial and credit markets.

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

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

  - risks of war, terrorism, civil unrest and kidnapping of employees;
  - employee strikes, work stoppages, labor disputes and other slowdowns;
  - expropriation, confiscation or nationalization of our assets;
  - renegotiation or nullification of contracts;
  - foreign taxation, such as the tax for equality and the net-worth tax in Colombia;

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

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

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

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

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

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

Environment Protection. 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 the laws, rules and regulations applicable to our industry 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 wastes and/or hazardous substances. Planning, implementation and maintenance of protective measures are required to prevent accidental discharges. Spills of oil, natural gas liquids, drilling fluids and other substances may subject us to penalties and cleanup requirements. Handling, storage and disposal of both hazardous and non-hazardous wastes are also subject to these regulatory requirements. In addition, our operations are often conducted in or near ecologically sensitive areas, such as wetlands, which are subject to special protective measures and which may expose us to additional operating costs and liabilities for accidental discharges of oil, gas, drilling fluids, contaminated water or other substances, or for noncompliance with other aspects of applicable laws and regulations.

The federal Clean Water Act; the Oil Pollution Act; the federal Clean Air Act; the federal Resource Conservation and Recovery Act; the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA); the Safe Drinking Water Act (SDWA); the federal Outer Continental Shelf Lands Act; the Occupational Safety and Health Act (OSHA); regulations implementing these federal statutes (such as the 2015 Waters of the United States rule, which may be rescinded pursuant to a proposal issued in June 2017); 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 (EPA) "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 certain hazardous substances into the environment. These persons generally include the current owner or operator of a facility where a release has occurred, the owner or operator of a facility at the time a release occurred, and companies that disposed of or arranged for the disposal of hazardous substances found at a particular site. This liability may be joint and several. Such liability, which may be imposed for the conduct of others and for conditions others have caused, includes the cost of removal and remedial action as well as damages to natural resources. Few defenses exist to the liability imposed by many environmental laws and regulations. It is also common for third parties to file claims for personal injury and property damage caused by substances released into the environment.

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

There are a variety of regulatory developments, proposals or requirements and legislative initiatives that have been introduced in the United States and international regions in which we operate that are focused on restricting the emission of carbon dioxide, methane and other greenhouse gases. Among these developments at the international level is the United Nations Framework Convention on Climate Change, which produced the "Kyoto Protocol" (an internationally applied protocol, which has been ratified in Colombia, which is a location where we provide drilling services) in 1992. More recently, in December 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 (36°F). The Paris Agreement does not establish enforceable emissions reduction targets, but countries may establish greenhouse gas reduction measures pursuant to the agreement. The agreement went into effect in November 2016. The United States ratified the Paris Agreement in September 2016. It has since notified the United Nations of its intent to withdraw from the Paris Agreement, but under the terms of the agreement the U.S. will remain a party until approximately August 2020.

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 (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 allowance trading is now limited to only California 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. In December 2009, the EPA responded to this 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. Subsequently, the EPA has a number of climate change regulations, including greenhouse gas control and permitting requirements for certain large stationary sources, fuel economy standards for vehicles and emissions standards for power plants. In August 2016, the EPA then adopted "Phase 2" standards for medium and heavy-duty vehicles through model year 2017.

Specific to the oil and gas industry, in April 2012, the EPA issued regulations 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. In May 2016, the EPA issued a rule to reduce methane (a greenhouse gas) and VOC emissions from additional oil and gas operations. Among other requirements, the rules impose standards for hydraulically fractured oil wells and equipment leaks at oil and gas production sites and extend certain existing standards to downstream oil and gas operations. In April 2017, the EPA granted reconsideration of aspects of this rule.

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.

Oil and gas development restrictions are also possible due to voter initiatives. For example, in 2018, Colorado voted on Proposition 112, which would have increased drilling location setbacks from 500 feet to 2,500 feet, severely limiting access to oil and gas minerals. Although Proposition 112 was defeated, future voter initiatives are possible in certain jurisdictions. Further, state legislators and regulators could seek to impose similar restrictions.

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.

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

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

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

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

Hydraulic fracturing is a commonly used process that involves injection of water, sand, and a minor amount of certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore. Federal agencies have adopted new rules, such as the Bureau of Land Management's (BLM) hydraulic fracturing rule finalized in March 2015, that impose additional requirements on the practice of hydraulic fracturing. In December 2017, the BLM rescinded this rule, but litigation is pending to reinstate the rule. In October 2016, the BLM updated its rules to restrict flaring associated with the development of oil and natural gas on public lands, including through hydraulic fracturing. The BLM has since proposed rescinding portions of the rule and portions of the rule have been suspended pending the outcome of litigation concerning the rule. Additional federal regulations may also be developed. Several states are considering legislation to regulate hydraulic fracturing practices that could impose more stringent permitting, transparency, and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. Hydraulic fracturing of wells and subsurface water disposal are also under public and governmental scrutiny due to concerns regarding potential environmental and physical impacts, including groundwater and drinking water impacts, as well as whether such activities may cause earthquakes.

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

Although the ANPR did not result in a new rule, scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having completed a multi-year study of the potential environmental impacts of hydraulic fracturing. The Final Report issued by the EPA in December 2016 concluded that hydraulic fracturing activities can impact drinking water resources under some circumstances and identified conditions under which impacts can be more frequent or severe. In addition, in April 2012, the EPA issued the first federal air standards for natural gas wells that are hydraulically fractured, which 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 or reduced emission (or "green") completions. 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. The EPA has amended these rules several times. In May 2016, the EPA finalized a rule to reduce methane (a greenhouse gas) and VOC emissions from oil and gas operations. It is also possible that the EPA will further amend its oil and gas regulations. These rules may require a number of modifications to our clients' and our own operations, including the installation of new equipment to control emissions. Compliance with such rules could result in additional costs for us and our clients, including increased capital expenditures and operating costs, which may adversely impact our cash flows and results of operations.

The EPA has also developed effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities to publicly owned treatment works (POTW). The agency's final regulations, published on June 28, 2016, prohibited any discharge of wastewater pollutants from onshore unconventional oil and gas extraction facilities to a POTW. The EPA will also be assessing whether oil and gas wastes should continue to be exempt from being considered hazardous waste under the federal Resource Conservation and Recovery Act, pursuant to a Consent Decree with environmental groups approved in federal court in December 2016, with a court-imposed deadline of March 2019. 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 finalized, in October 2016, a rule to reduce flaring and venting associated with oil and gas operations on public lands. The BLM rules have since been partially or wholly rescinded or delayed, but it is possible that they will be reinstated through litigation.

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.

In June 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 and/or setback 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 cybersecurity risks.*

Our operations are increasingly dependent on information technologies and services. Threats to information technology systems associated with cybersecurity risks and cyber incidents or attacks continue to grow, and include, among other things, storms and natural disasters, terrorist attacks, utility outages, theft, viruses, malware, design defects, human error, or complications encountered as existing systems are maintained, repaired, replaced, or upgraded. Risks associated with these threats include, among other things:

- loss, corruption, or misappropriation of intellectual property, or other proprietary or confidential information (including client, supplier, or employee data);
- disruption or impairment of our and our customers' business operations and safety procedures;
- loss or damage to our worksite data delivery systems; and
- increased costs to prevent, respond to or mitigate cybersecurity events.

Although we utilize various procedures and controls to mitigate our exposure to such risk, cybersecurity attacks and other cyber events are evolving and unpredictable. Moreover, we do not have control over the information technology systems of our clients, suppliers, and others with which our systems may connect and communicate. As a result, the occurrence of a cyber incident could go unnoticed for a period time. Any such incident could have a material adverse effect on our business, financial condition and results of operations.

- *Our ability to use our net operating loss and tax credit carryforwards might be limited.*

  Section 382 of the U.S. Internal Revenue Code contains rules that limit the ability of a company that undergoes an ownership change to utilize its net operating losses and tax credit carryforwards existing as of the date of such ownership change. Under the rules, such an ownership change is generally any change in ownership of more than 50% of a company's stock within a rolling three-year period. The rules generally operate by focusing on changes in ownership among shareholders owning, directly or indirectly, 5% or more of the stock of a company and any change in ownership arising from new issuances of stock by the company.

  If we were to undergo one or more "ownership changes" as defined by Section 382, our net operating losses and certain of our tax credits existing as of the date of each ownership change may be unavailable, in whole or in part, to offset U.S. federal income tax resulting from our operations or any gains from the disposition of any of our assets and/or business, which could result in increased U.S. federal income tax liability.

- *If we implement an enterprise resource planning system, such implementation could expose us to certain risks commonly associated with the conversion of existing data and processes to a new system.*

  We are currently in the selection and evaluation phase of implementing a company-wide enterprise resource planning (ERP) system to upgrade, replace and integrate certain existing business, operational and financial processes and systems, upon which we rely. ERP implementations are complex and time-consuming projects that require transformations of business and finance processes in order to reap the benefits of an integrated ERP system. Any such project involves certain risks inherent in the conversion, including loss of information and potential disruption to normal operations and finance functions. Additionally, if the ERP system is not effectively implemented as planned, or the system does not operate as intended, the effectiveness of our internal control over financial reporting could be adversely affected or our ability to assess those controls adequately could be delayed. In addition, if we experience interruptions in service or operational difficulties and are unable to effectively manage our business during or following the implementation of the ERP system, our business and results of operations could be adversely impacted.

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 Term Loan, ABL 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; however, our issuance of preferred stock is subject to the limitations imposed on us by our ABL Facility and Senior Notes. 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—Company Overview" 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 and adequate 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

Our common stock trades on the New York Stock Exchange under the symbol "PES." As of January 31, 2019, 78,454,853 shares of our common stock were outstanding, held by 291 shareholders of record. The number of record holders does not necessarily bear any relationship to the number of beneficial owners of our common stock.

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 Term Loan, ABL Facility, and Senior Notes. Our debt arrangements include provisions that generally prohibit us from paying dividends on our capital stock.

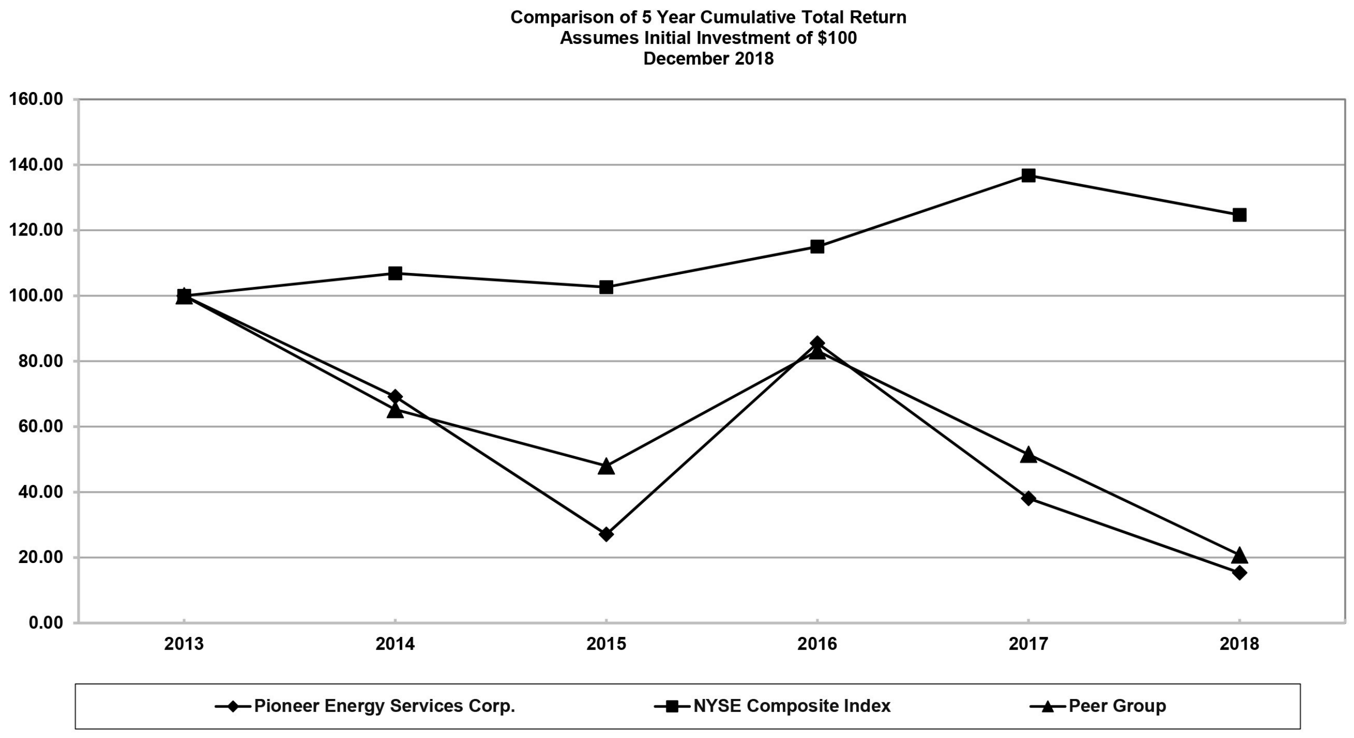
We did not make any unregistered sales of equity securities during the quarter ended December 31, 2018. No shares of our common stock were purchased by or on behalf of our company or any affiliated purchaser during the quarter ended December 31, 2018.

Performance Graph

The following graph compares, for the periods from December 31, 2013 to December 31, 2018, 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., Key Energy Services and Precision Drilling Corporation, and have been weighted according to each company's stock market capitalization. Two of the companies in the peer group, Basic Energy Services, Inc. and Key Energy Services, filed for bankruptcy protection in 2016 under Chapter 11 of the United States Bankruptcy Code, which significantly decreased the market capitalization of these peers, as well as their impact on the total return calculated for the peer group.

The comparison assumes that $100 was invested on December 31, 2013 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,				
	2018	2017	2016	2015	2014
	(In thousands, except per share amounts)				
Statement of Operations Data [(1)]					
Revenues	$ 590,097	$ 446,455	$ 277,076	$ 540,778	$1,055,223
Income (loss) from operations	(9,059)	(51,230)	(113,448)	(166,700)	23,984
Loss before income taxes	(47,103)	(79,321)	(139,123)	(192,719)	(49,322)
Loss applicable to common shareholders	(49,011)	(75,118)	(128,391)	(155,140)	(38,018)
Loss per common share-basic	$ (0.63)	$ (0.97)	$ (1.96)	$ (2.41)	$ (0.60)
Loss per common share-diluted	$ (0.63)	$ (0.97)	$ (1.96)	$ (2.41)	$ (0.60)
Other Financial Data [(1)]					
Net cash provided by (used in) operating activities	$ 39,656	$ (5,817)	$ 5,131	$ 142,719	$ 233,041
Net cash used in investing activities	(60,202)	(47,364)	(24,767)	(101,656)	(151,918)
Net cash provided by (used in) financing activities	(538)	118,635	15,670	(61,827)	(73,584)
Capital expenditures	72,854	61,447	32,556	142,907	188,121

	As of December 31,				
	2018	2017	2016	2015	2014
	(In thousands)				
Balance Sheet Data:					
Working capital	$ 110,266	$ 130,645	$ 47,944	$ 45,226	$ 121,882
Property and equipment, net	524,858	549,623	584,080	702,585	856,541
Long-term debt, excluding current portion, debt issuance costs and discount	475,000	475,000	346,000	395,000	455,053
Shareholders' equity	165,058	210,096	281,398	342,643	495,064
Total assets	741,550	766,869	700,102	821,975	1,171,589

(1) The statement of operations and other financial data reflect the impact of impairment charges as follows:

	Year ended December 31,				
	2018	2017	2016	2015	2014
	(In thousands)				
Property and equipment	$ 4,422	$ 1,902	$ 12,815	$ 114,813	$ 73,025
Intangible assets	—	—	—	14,339	—

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 made in good faith 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 debt agreements, including our senior secured term loan, our senior secured revolving asset-based credit facility, and our senior notes, operating hazards inherent in our operations, the supply of marketable drilling rigs, well servicing rigs, coiled tubing units and wireline units within the industry, the continued availability of new components for drilling rigs, well servicing rigs, coiled tubing units and wireline units, the continued availability of qualified personnel, the success or failure of our acquisition strategy, the occurrence of cybersecurity incidents, 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 and, 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 oil and gas exploration and production companies in the United States and internationally in Colombia. 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.

Business Segments

Our business is comprised of two business lines — Drilling Services and Production Services. We report our Drilling Services business as two reportable segments: (i) Domestic Drilling and (ii) International Drilling. We report our Production Services business as three reportable segments: (i) Well Servicing, (ii) Wireline Services, and (iii) Coiled Tubing Services. 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*— Our current drilling rig fleet is 100% pad-capable and offers the latest advancements in pad drilling. We have 16 AC rigs in the US and eight SCR rigs in Colombia, all of which have 1,500 horsepower or greater drawworks. We provide a comprehensive service offering which includes the drilling rig, crews, supplies and most of the ancillary equipment needed to operate our drilling rigs which are deployed through our division offices in the following regions:

	Rig Count
Domestic drilling:	
Marcellus/Utica	6
Permian Basin and Eagle Ford	8
Bakken	2
International drilling	8
	24

- *Production Services*— Our production services business segments provide a range of well, wireline and coiled tubing services to a diverse group of exploration and production companies, with our operations concentrated in the major domestic onshore oil and gas producing regions in the Gulf Coast, Mid-Continent and Rocky Mountain states. As of December 31, 2018, the fleet count for each of our production services business segments are as follows:

	550 HP	600 HP	Total
Well servicing rigs, by horsepower (HP) rating	113	12	125

	Total
Wireline services units	105
Coiled tubing services units	9

Market Conditions in Our Industry

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

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

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

However, in a severe downturn that is prolonged, both operating and capital expenditures are significantly reduced, and the demand for all our service offerings is significantly impacted. After a prolonged downturn, among the production services, the demand for completion-oriented services generally improves first, as exploration and production companies begin to complete wells that were previously drilled but not completed during the downturn, and to complete newly drilled wells as the demand for drilling services improves during recovery.

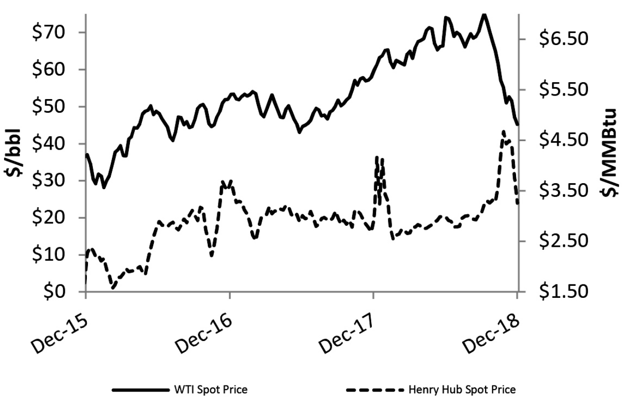
From time to time, temporary regional slowdowns or constraints occur in our industry due to a variety of factors, including, among others, infrastructure or takeaway capacity limitations, labor shortages, increased regulatory or environmental pressures, or an influx of competitors in a particular region. Any of these factors can influence the profitability of operations in the affected region. However, term contract coverage for our drilling services business and the mobility of all our equipment between regions limits our exposure to the impact of regional constraints and fluctuations in demand.

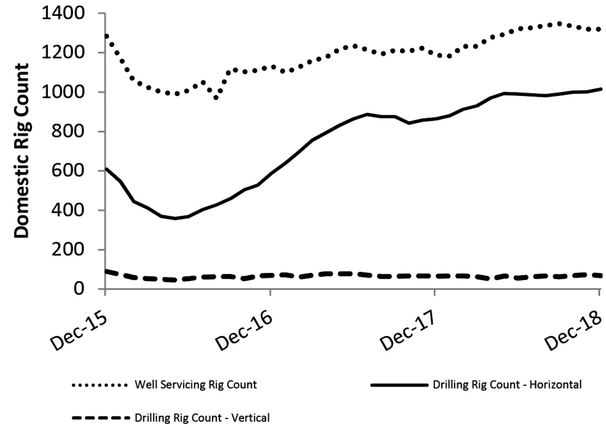
Technological advancements and trends in our industry also affect the demand for certain types of equipment, and can affect the overall demand for the services our industry provides. Enhanced directional and horizontal drilling techniques have allowed exploration and production operators to drill increasingly longer lateral wellbores which enable higher hydrocarbon production per well, and reduce the overall number of wells needed to achieve the desired production. This trend toward longer lateral wellbores also increases demand for the more specialized equipment, such as high-spec drilling rigs, higher horsepower well servicing rigs equipped with taller masts, larger diameter coiled tubing units, and other higher power ancillary equipment, which is needed in order to drill, complete and provide services to the full length of the wellbore. Our domestic drilling and production services fleets are highly capable and designed for operation in today's long lateral, pad-oriented environment.

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

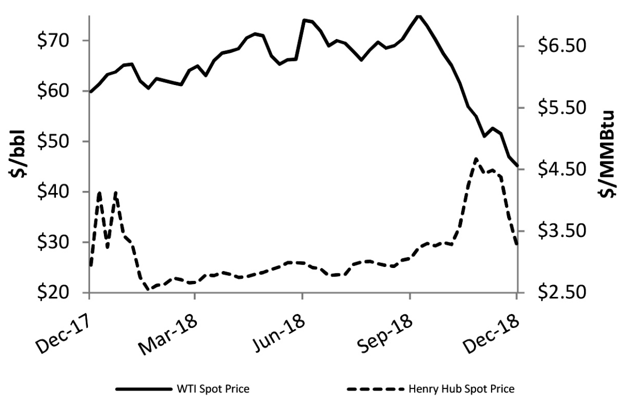
Market Conditions — Our industry experienced a severe down cycle from late 2014 through 2016, during which WTI oil prices dipped below $30 per barrel in early 2016. A modest recovery in commodity prices began in the latter half of 2016 with WTI oil prices steadily increasing from just under $50 per barrel at the end of June 2016 to approximately $60 per barrel at the end of 2017. In 2018, WTI oil prices continued to increase to a high of $75 per barrel in October, but then decreased to $45 per barrel at the end of 2018, and averaged approximately $50 per barrel during January 2019.

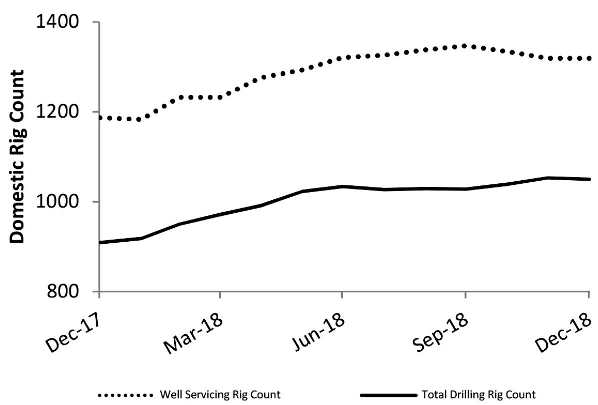
The trends in spot prices of WTI crude oil and Henry Hub natural gas, and the resulting trends in domestic land rig counts (per Baker Hughes) and domestic well servicing rig counts (per Guiberson/Association of Energy Service Companies) over the last three years are illustrated in the graphs below.





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





We began 2017 with utilization of our domestic fleet at 81% and four rigs working in Colombia. By mid- 2018, utilization of our domestic fleet increased to 100%, and seven of our eight international rigs are currently earning revenues under term contracts. In July 2018, we entered into a three-year term contract for the construction of a new 1,500 horsepower, AC pad-optimal rig, which we expect to deploy in early 2019 to the Permian Basin.

As of December 31, 2018, 23 of our 24 drilling rigs are earning revenues, 19 of which are under term contracts, which if not canceled or renewed prior to the end of their terms, will expire as follows:

			Term Contract Expiration by Period				
	Spot Market Contracts	Total Term Contracts	Within 6 Months	6 Months to 1 Year	1 Year to 18 Months	18 Months to 2 Years	2 to 4 Years
Domestic rigs	3	13	2	9	1	1	—
International rigs	1	6	2	1	2	—	1
	4	19	4	10	3	1	1

Our international drilling contracts are cancelable by our clients without penalty, although the contracts require 15 to 30 days notice and payment for demobilization services. We are actively marketing our idle rig in Colombia, and we also continue to evaluate the possibility of selling some or all of our assets in Colombia.

During the quarter ended December 31, 2018, our well servicing rig hours were steady with the previous quarter, while the number of wireline jobs completed and revenue days for our coiled tubing services decreased by 10% and 4%, respectively, as compared to the third quarter of 2018. Average revenue rates for our well servicing and coiled tubing services provided during this same period increased by 3% and 6% (on a per hour and per day basis, respectively), while average revenues per job for our wireline services decreased by 6%. The decrease in wireline services revenue was primarily due to reduced completion activity which has been a significant portion of our wireline segment's overall activity. The modest increase in coiled tubing revenues is primarily attributable to an increase in the proportion of work performed by our large-diameter coiled tubing units, which generally earn higher revenue rates as compared to smaller diameter coiled tubing units, while the modest increase in well servicing revenues corresponds with improved pricing, partially due to an increase in the completion work performed by our well servicing business.

The level of exploration and production activity within a region can fluctuate due to a variety of factors which may directly or indirectly impact our operations in the region. Despite the recovery of demand experienced in onshore markets, offshore activity remained depressed, and as a result, we exited the offshore wireline and coiled tubing market in the second quarter of 2018. In the Permian Basin, limited takeaway capacity has led to price discounts on crude oil that could continue to impact activity and near term growth in the region; however, our exposure to any decreases in activity is limited because we have term contract coverage for six of our seven drilling rigs currently operating in this region.

Although we expect a highly competitive environment to continue, we believe our high-quality equipment and services and our excellent safety record make us well positioned to compete.

Liquidity and Capital Resources

Sources of Capital Resources

Our principal sources of liquidity currently consist of:

- total cash and cash equivalents ($54.6 million as of December 31, 2018);
- cash generated from operations ($39.7 million during the year ended December 31, 2018);
- proceeds from sales of assets ($5.9 million during the year ended December 31, 2018); and
- the availability under our asset-based lending facility ($49.0 million as of December 31, 2018).

Senior Secured Term Loan — Our senior secured term loan (the "Term Loan") entered into on November 8, 2017 provided for one drawing in the amount of $175 million, net of a 2% original issue discount. Proceeds from the issuance of the Term Loan were used to repay the entire outstanding balance under our previous credit facility, plus fees and accrued and unpaid interest, as well as the fees and expenses associated with entering into the Term Loan and ABL Facility, which is further described below. The remainder of the proceeds are available to be used for other general corporate purposes. The Term Loan is set to mature on November 8, 2022, or earlier, subject to certain circumstances as described in the agreement, and including an earlier maturity date if the outstanding balance of the Senior Notes exceeds $15.0 million on December 14, 2021, at which time the Term Loan would then mature. The Term Loan contains certain covenants which are described in more detail in the *Debt Compliance Requirements* section below.

Asset-based Lending Facility — In addition to entering into the Term Loan, on November 8, 2017, we also entered into a senior secured revolving asset-based credit facility (the "ABL Facility") providing for borrowings in the aggregate principal amount of up to $75 million, subject to a borrowing base and including a $30 million sub-limit for letters of credit. The ABL Facility bears interest, at our option, at the LIBOR rate or the base rate as defined in the ABL Facility, plus an applicable margin ranging from 1.75% to 3.25%, based on average availability on the ABL Facility. The ABL Facility is generally set to mature 90 days prior to the maturity of the Term Loan, subject to certain circumstances, including the future repayment, extinguishment or refinancing of our Term Loan and/or Senior Notes prior to their respective maturity dates. We have not drawn upon the ABL Facility to date. As of December 31, 2018, we had $9.7 million in committed letters of credit, which, after borrowing base limitations, resulted in borrowing availability of $49.0 million. Borrowings available under the ABL Facility are available for general corporate purposes, and there are no limitations on our ability to access the borrowing capacity provided there is no default and compliance with the covenants under the ABL Facility is maintained. Additional information regarding these covenants is provided in the *Debt Compliance Requirements* section below.

Shelf Registration Statement — In the future, we may also consider equity and/or debt offerings, as appropriate, to meet our liquidity needs. On May 22, 2018, 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, 2018, the entire $300.0 million under the shelf registration statement is available for equity or debt offerings, subject to the limitations imposed by our Term Loan, ABL Facility and Senior Notes.

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

Uses of Capital Resources

Our principal liquidity requirements are currently for:

- capital expenditures;
- debt service; and
- working capital needs.

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

Capital Expenditures — For the year ended December 31, 2018 and 2017, our primary uses of capital resources were for property and equipment additions, which consisted of the following (amounts in thousands):

	Year ended December 31,	
	2018	**2017**
Drilling services business:		
Routine	$ 12,738	$ 16,793
Discretionary	7,723	4,010
Fleet additions and major components	5,345	7,337
	25,806	28,140
Production services business:		
Routine	18,723	13,185
Discretionary	9,442	7,826
Fleet additions	13,177	14,126
	41,342	35,137
Net cash used for purchases of property and equipment	67,148	63,277
Net impact of accruals	5,706	(1,830)
Total capital expenditures	$ 72,854	$ 61,447

In 2017 and 2018, we limited our capital spending to primarily routine expenditures and select asset acquisitions to optimize our fleets. Routine and discretionary capital expenditures during 2018 primarily related to routine expenditures to maintain our fleets, as well as the purchase of new support equipment and vehicle fleet upgrades in all domestic business segments. Capital expenditures for fleet additions in 2018 included the purchase of a coiled tubing unit, the remaining installments on another coiled tubing and three wireline units which were ordered in 2017, and the construction of one new drilling rig, which we expect to deploy in early 2019. Capital expenditures for fleet additions in 2017 included the exchange of 20 older well servicing rigs for 20 new-model rigs, the purchase of four new wireline units, and deposits on one coiled tubing unit and three wireline units which were delivered in 2018. Routine expenditures in 2017 primarily included refurbishments and start-up costs to redeploy assets that had been idle, including two drilling rigs in Colombia.

Currently, we expect to spend approximately $55 million to $60 million on capital expenditures during 2019, which includes approximately $7 million for final payments on the construction of the new-build drilling rig that is expected to begin operations in the first quarter, and previous commitments on high-pressure pump packages for coiled tubing completion operations. Actual capital expenditures may vary depending on the climate of our industry and any resulting increase or decrease in activity levels, the timing of commitments and payments, and the level of rig build and other expansion opportunities that meet our strategic and return on capital employed criteria. We expect to fund the capital expenditures in 2019 from operating cash flow in excess of our working capital requirements, although proceeds from sales of assets, remaining proceeds from our Term Loan issuance, and available borrowings under our ABL Facility are also available, if necessary.

Working Capital — Our working capital was \$110.3 million at December 31, 2018, compared to \$130.6 million at December 31, 2017. Our current ratio, which we calculate by dividing current assets by current liabilities, was 2.1 at December 31, 2018, as compared to 2.5 at December 31, 2017. The changes in the components of our working capital were as follows (amounts in thousands), and as described below:

	December 31, 2018	December 31, 2017	Change
Cash and cash equivalents	\$ 53,566	\$ 73,640	\$ (20,074)
Restricted cash	998	2,008	(1,010)
Receivables:			
Trade, net of allowance for doubtful accounts	76,924	79,592	(2,668)
Unbilled receivables	24,822	16,029	8,793
Insurance recoveries	23,656	13,874	9,782
Other receivables	5,479	3,510	1,969
Inventory	18,898	14,057	4,841
Assets held for sale	3,582	6,620	(3,038)
Prepaid expenses and other current assets	7,109	6,229	880
Current assets	215,034	215,559	(525)
Accounts payable	34,134	29,538	4,596
Deferred revenues	1,722	905	817
Accrued expenses:			
Payroll and related employee costs	24,598	21,023	3,575
Insurance premiums and deductibles	5,482	6,742	(1,260)
Insurance claims and settlements	23,593	13,289	10,304
Interest	6,148	6,624	(476)
Other	9,091	6,793	2,298
Current liabilities	104,768	84,914	19,854
Working capital	\$ 110,266	\$ 130,645	\$ (20,379)

- *Cash and cash equivalents* — The change in cash and cash equivalents during 2018 is primarily due to \$67.1 million of cash used for the purchase of property and equipment, partially offset by \$39.7 million of cash from operating activities, \$5.9 million of proceeds from the sale of property and equipment, and \$1.1 million of proceeds from insurance recoveries. Cash provided by operations during 2018 was primarily from the recent increase in activity.
- *Restricted cash* — Our restricted cash balance reflects the portion of net proceeds from the issuance of our Term Loan, which are currently held in a restricted account until the completion of certain administrative tasks related to providing access rights to certain of our real property. During 2018, a portion of these restricted funds were released and made available for general corporate use.
- *Trade and Unbilled receivables* — The net increase in our total trade and unbilled receivables during 2018 is primarily due to the 12% increase in our revenues during the quarter ended December 31, 2018, as compared to the quarter ended December 31, 2017, as well as the timing of billing and collection cycles for long-term drilling contracts in Colombia. Our domestic trade receivables generally turn over within 60 days, and our Colombian trade receivables generally turn over within 120 days.
- *Insurance recoveries and Insurance claims and settlements* — The increase during 2018 in both our insurance recoveries receivables and our accrued liability for insurance claims and settlements is primarily due to very high costs incurred on one significant workers' compensation claim in excess of our \$500,000 deductible, which are covered by our workers compensation insurance policy.
- *Other receivables* — The increase in other receivables during 2018 is primarily due to an increase in recoverable income tax receivables attributable to the increase in activity for our international operations, partially offset by the collection of a short-term note receivable from the sales of two mechanical drilling rigs that were sold during the third quarter of 2017.
- *Inventory* — The increase in inventory during 2018 is primarily associated with the increase in activity for our international drilling operations and an increase in large diameter pipe inventory for our coiled tubing operations.

- *Assets held for sale* — As of December 31, 2018, our consolidated balance sheet reflects assets held for sale of $3.6 million, which primarily represents the fair value of two domestic SCR drilling rigs, spare drilling equipment that would support these rigs and three coiled tubing units. As of December 31, 2017, our consolidated balance sheet reflects assets held for sale of $6.6 million, which primarily represents the fair value of three domestic SCR drilling rigs, one domestic mechanical drilling rig, spare drilling equipment that would support these rigs, two wireline units, one coiled tubing unit and other spare equipment. For additional information, see Note 3, *Property and Equipment* of the Notes to Consolidated Financial Statements, included in Part II, Item 8, *Financial Statements and Supplementary Data*, of this Annual Report on Form 10-K.
- *Prepaid expenses and other current assets* — The increase in prepaid expenses and other current assets during 2018 is primarily due to an increase in software subscription renewals and partially due to the increase in international deferred mobilization costs associated with the deployment of five international rigs during 2018. For additional information about rig mobilization revenue and cost recognition, see Note 2, *Revenue from Contracts with Customers* 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.
- *Accounts payable* — Our accounts payable generally turn over within 90 days. The increase in accounts payable during 2018 is primarily due to the 13% increase in our operating costs for the quarter ended December 31, 2018 as compared to the quarter ended December 31, 2017, resulting from an increase in activity, as well as an increase of $5.7 million in our accruals for capital expenditures.
- *Accrued payroll and related employee costs* — The increase in accrued payroll and related employee costs during 2018 is primarily due to the movement of the $3.2 million accrued liability for our 2016 phantom stock unit awards from noncurrent to current, as these awards are scheduled to vest in April 2019.
- *Accrued insurance premiums and deductibles* — The decrease in insurance premiums and deductibles during 2018 is primarily due to the decrease in our accrual for workers compensation and automobile liability costs resulting from a decrease in the estimated liability for the deductibles under these policies.
- *Other accrued expenses* — The increase in other accrued expenses during 2018 is primarily related to an increase in our accrued liability for sales tax obligations, as well as an increase in accrued taxes associated with the increase in revenues for our international drilling operations.

Debt and Other Contractual Obligations — The following table includes information about the amount and timing of our contractual obligations at December 31, 2018 (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	$ 475,000	$ —	$ 175,000	$ 300,000	$ —
Interest on debt	127,050	36,225	72,450	18,375	—
Purchase commitments	10,278	10,278	—	—	—
Operating leases	11,326	3,318	3,753	2,517	1,738
Incentive compensation	14,301	8,296	6,005	—	—
	$ 637,955	$ 58,117	$ 257,208	$ 320,892	$ 1,738

- *Debt* — Debt obligations at December 31, 2018 consisted of $300 million of principal amount outstanding under our Senior Notes which mature on March 15, 2022 and $175 million of principal amount outstanding under our Term Loan, which is expected to mature on December 14, 2021. As of December 31, 2018, we had no debt outstanding under our ABL Facility.
- *Interest on debt* — Interest payment obligations on our Senior Notes are calculated based on the coupon interest rate of 6.125% due semi-annually in arrears on March 15 and September 15 of each year until maturity on March 15, 2022. Interest payment obligations on our Term Loan were estimated based on (1) the 10.2% interest rate that was in effect at December 31, 2018, and (2) the principal balance of $175 million at December 31, 2018, and assuming repayment of the outstanding balance occurs at December 14, 2021.
- *Purchase commitments* — Purchase commitments generally relate to capital projects for the repair, upgrade and maintenance of our equipment, the construction or purchase of new equipment, and purchase orders for various job

and inventory supplies. At December 31, 2018, our purchase commitments primarily pertain to $2.4 million of service equipment and vehicles for our coiled tubing operations, $2.3 million of inventory and job supplies for our wireline and coiled tubing operations, and $1.4 million of remaining obligations for the construction of the new-build drilling rig which we expect to complete in early 2019. Other purchase commitments include drilling equipment on order as well as various refurbishments and upgrades to our drilling and production services fleets.

- *Operating leases* — Our operating leases consist of lease agreements for office space, operating facilities, field personnel housing, and office equipment.
- *Incentive compensation* — Incentive compensation is payable to our employees, generally contingent upon their continued employment through the date of each respective award's payout. A portion of our long-term incentive compensation is performance-based and therefore the final amount will be determined based on our actual performance relative to a pre-determined peer group over the performance period.

Debt Compliance Requirements — The following is a summary of our debt compliance requirements including covenants, restrictions and guarantees, all of which are described in more detail in Note 4, *Debt*, and Note 14, *Guarantor/Non-Guarantor Condensed Consolidating Financial Statements*, of the Notes to Consolidated Financial Statements, included in Part II, Item 8, *Financial Statements and Supplementary Data*, of this Annual Report on Form 10-K.

The Term Loan contains a financial covenant requiring the ratio of (i) the net orderly liquidation value of our fixed assets (based on appraisals obtained as required by our lenders), on a consolidated basis, in which the lenders under the Term Loan maintain a first priority security interest, plus proceeds of asset dispositions not required to be used to effect a prepayment of the Term Loan to (ii) the outstanding principal amount of the Term Loan, to be at least equal to 1.50 to 1.00 as of any June 30 or December 31 of any calendar year through maturity. As of December 31, 2018, the asset coverage ratio, as calculated under the Term Loan, was 2.36 to 1.00.

The Term Loan contains customary mandatory prepayments from the proceeds of certain transactions including certain asset dispositions and debt issuances, and has additional customary restrictions that limit our ability to enter into various transactions. In addition, the Term Loan contains customary events of default, upon the occurrence and during the continuation of any of which the applicable margin would increase by 2% per year. Our obligations under the Term Loan are guaranteed by our wholly-owned domestic subsidiaries, and are secured by substantially all of our domestic assets, in each case, subject to certain exceptions and permitted liens.

The ABL Facility also contains customary restrictive covenants which, subject to certain exceptions, limit, among other things, our ability to enter into certain transactions. Additionally, if our availability under the ABL Facility is less than 15% of the maximum amount (or $11.25 million), we are required to maintain a minimum fixed charge coverage ratio, as defined in the ABL Facility, of at least 1.00 to 1.00, measured on a trailing 12 month basis.

Our obligations under the ABL Facility are guaranteed by us and our domestic subsidiaries, subject to certain exceptions, and are secured by (i) a first-priority perfected security interest in all inventory and cash, and (ii) a second-priority perfected security in substantially all of our tangible and intangible assets, in each case, subject to certain exceptions and permitted liens.

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. The subsidiaries that generally operate our non-U.S. business concentrated in Colombia do not guarantee our Senior Notes. Our Senior Notes are not subject to any sinking fund requirements. The Indenture governing our Senior Notes contains additional restrictive covenants that limit our ability to enter into various transactions.

As of December 31, 2018, we were in compliance with all covenants required by our Term Loan, ABL Facility and Senior Notes.

Results of Operations

Statements of Operations Analysis - Year Ended December 31, 2018 Compared with Year Ended December 31, 2017

The following table provides certain information about our operations, including a detail of each of our business segments' revenues, operating costs and gross margin, and the percentage of the consolidated amount of each which is attributable to each business segment, for the years ended December 31, 2018 and 2017 (amounts in thousands, except percentages):

	Year ended December 31,			
	2018		2017	
Revenues:				
Domestic drilling	$ 145,676	25%	$ 129,276	29%
International drilling	84,161	14%	41,349	9%
Drilling services	229,837	39%	170,625	38%
Well servicing	93,800	16%	77,257	17%
Wireline services	215,858	36%	163,716	37%
Coiled tubing services	50,602	9%	34,857	8%
Production services	360,260	61%	275,830	62%
Consolidated revenues	$ 590,097	100%	$ 446,455	100%
Operating costs:				
Domestic drilling	$ 86,910	20%	$ 83,122	25%
International drilling	64,074	15%	31,994	10%
Drilling services	150,984	35%	115,116	35%
Well servicing	67,554	16%	56,379	17%
Wireline services	167,337	39%	128,137	39%
Coiled tubing services	44,038	10%	31,248	9%
Production services	278,929	65%	215,764	65%
Consolidated operating costs	$ 429,913	100%	$ 330,880	100%
Gross margin:				
Domestic drilling	$ 58,766	37%	$ 46,154	40%
International drilling	20,087	13%	9,355	8%
Drilling services	78,853	50%	55,509	48%
Well servicing	26,246	16%	20,878	18%
Wireline services	48,521	30%	35,579	31%
Coiled tubing services	6,564	4%	3,609	3%
Production services	81,331	50%	60,066	52%
Consolidated gross margin	$ 160,184	100%	$ 115,575	100%
Consolidated:				
Net loss	$ (49,011)		$ (75,118)	
Adjusted EBITDA [(1)]	$ 89,655		$ 49,873	

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

A reconciliation of net loss, as reported, to Adjusted EBITDA, and to consolidated gross margin, are set forth in the following table:

	Year ended December 31, 2018	Year ended December 31, 2017
	(amounts in thousands)	
Net loss	$ (49,011)	$ (75,118)
Depreciation and amortization	93,554	98,777
Impairment	4,422	1,902
Interest expense	38,782	27,039
Loss on extinguishment of debt	—	1,476
Income tax expense (benefit)	1,908	(4,203)
Adjusted EBITDA	89,655	49,873
General and administrative	74,117	69,681
Bad debt expense	271	53
Gain on dispositions of property and equipment, net	(3,121)	(3,608)
Other income	(738)	(424)
Consolidated gross margin	$ 160,184	$ 115,575

Consolidated gross margin — Our consolidated gross margin increased by $44.6 million, or 39%, during 2018 as compared to 2017, which reflects increased revenue rates for all of our service offerings, and increased activity, particularly for our domestic and international drilling services. All of our business segments contributed to the increase in margin. Of the $44.6 million increase in consolidated gross margin for the year ended December 31, 2018, as compared to the corresponding period in 2017, 52% is attributable to our drilling services segments, with improved demand and higher dayrates for both our domestic and international drilling services, while the increase in our production services segments was led by increased demand for our wireline services, driven by increased completion activity, and to a lesser extent, well servicing activity and pricing.

- *Drilling Services* — Our drilling services revenues increased by $59.2 million, or 35%, during 2018 as compared to 2017, while operating costs increased by $35.9 million, or 31%. The increases in our drilling services revenues and operating costs primarily resulted from a 17% increase in revenue days during 2018 as compared to 2017, primarily attributable to a 67% increase in utilization of our international drilling fleet. The following table provides operating statistics for each of our drilling services segments:

	Year ended December 31, 2018	Year ended December 31, 2017
Domestic drilling:		
Average number of drilling rigs	16	16
Utilization rate	99%	95%
Revenue days	5,808	5,524
Average revenues per day	$ 25,082	$ 23,403
Average operating costs per day	14,964	15,047
Average margin per day	$ 10,118	$ 8,356
International drilling:		
Average number of drilling rigs	8	8
Utilization rate	77%	46%
Revenue days	2,258	1,345
Average revenues per day	$ 37,272	$ 30,743
Average operating costs per day	28,376	23,787
Average margin per day	$ 8,896	$ 6,956

Our domestic drilling fleet utilization has been fully utilized since mid-2017, allowing us to achieve the higher margins of a fully utilized fleet. Our domestic drilling average revenues per day during 2018 increased as compared to 2017, primarily due to increasing dayrates on term contracts for eight rigs, partially offset by reduced dayrates for four rigs that were re-priced from historically high pre-downturn rates in 2018. Our average domestic drilling operating costs per day for the year ended December 31, 2018 decreased from the corresponding period in 2017, primarily due to additional costs incurred during the first half of 2017 to deploy previously idle rigs under new contracts and to move one rig to a new region in mid-2017 under a new term contract.

Our international drilling fleet utilization has steadily improved since the beginning of 2017, with seven of eight rigs utilized at December 31, 2018, versus four rigs utilized at the beginning of 2017. This utilization improvement has been the primary reason for the increases in our international drilling average revenues, operating costs and margin per day during 2018, as compared to 2017. Our international drilling average margin per day also increased during 2018 as compared to 2017, in part due to several drilling rigs re-pricing at higher dayrates during 2018 and additional costs incurred during 2017 to redeploy drilling rigs under new term contracts.

- *Production Services* — Our revenues from production services increased by $84.4 million, or 31%, during 2018 as compared to 2017, while operating costs increased by $63.2 million, or 29%, respectively. The increases in revenues and operating costs in our production services segments are a result of the increased demand for our services, particularly those that perform completion-related activities. The following table provides operating statistics for each of our production services segments:

	Year ended December 31,	
	2018	2017
Well servicing:		
Average number of rigs	125	125
Utilization rate	49%	43%
Rig hours	171,851	150,240
Average revenue per hour	$ 546	$ 514
Wireline services:		
Average number of units	107	115
Number of jobs	10,943	11,139
Average revenue per job	$ 19,726	$ 14,698
Coiled tubing services:		
Average number of units	12	16
Revenue days	1,472	1,529
Average revenue per day	$ 34,376	$ 22,797

Increases in production services revenues and operating costs were led by our wireline services business segment, which experienced a significant increase in completion-related activity as wells that were drilled but not completed during the downturn created higher demand for completion services. Although the number of wireline jobs decreased slightly, average revenue per job increased by 34% during 2018, as compared to 2017, which is largely due to a higher percentage of the work performed being attributable to completion-related jobs which earn higher revenue rates, but also incur higher costs for the job materials consumed on these types of jobs.

Our well servicing business segment also experienced an increase in demand during 2018 as utilization increased to 49% during 2018 from 43% during 2017. This utilization improvement represents a 14% increase in well servicing rig hours, while average revenue per hour also increased by 6%.

During 2018, our coiled tubing services business segment experienced an increase in demand for services provided using our larger diameter coiled tubing units. Despite a slight decrease in revenue days during 2018, as compared to 2017, average revenue per day increased 51% primarily due to a larger proportion of the work performed with larger diameter coiled tubing units which typically earn higher revenue rates as compared to smaller diameter coiled tubing units, partially resulting from the addition of one new large diameter coiled tubing unit which we placed in service in July 2018. The expansion of our coiled tubing operations into a new market in late 2017 and the closure of under-performing locations in 2018 also contributed to the improvement in gross margin, as compared to 2017.

Depreciation expense — Our depreciation expense decreased by $5.2 million during 2018 as compared to 2017. The decrease is almost entirely attributable to our domestic drilling operations. With our reduced domestic rig fleet size and decreased utilization during 2015 and 2016, we had sufficient drill pipe and other spare equipment on hand which allowed us to defer additional capital spending on these items during recent years.

Impairment — During the years ended December 31, 2018 and 2017, we recognized impairment charges of $4.4 million and $1.9 million, respectively, to reduce the carrying values of certain assets which were classified as held for sale, to their estimated fair values based on expected sale prices. For more detail, see Note 3, *Property and Equipment,* of the Notes to Consolidated Financial Statements, included in Part II, Item 8 *Financial Statements and Supplementary Data*, of this Annual Report on Form 10-K.

Interest expense — Our interest expense increased by $11.7 million during the year ended December 31, 2018, as compared to 2017, primarily due to the issuance of our Term Loan in November 2017, from which a portion of the proceeds were used to repay and retire our previous credit facility. As a result, our total debt outstanding increased, as did the interest rate applicable to outstanding borrowings. Debt outstanding under our Term Loan was $175 million during the year ended December 31, 2018, while the weighted average debt outstanding under our previous credit facility and Term Loan during the year ended December 31, 2017 was approximately $95 million, with annualized weighted average interest rates applicable to these borrowings during these periods of approximately 9.9% and 6.9%, respectively.

Loss on extinguishment of debt — Our loss on extinguishment of debt in 2017 represents the write-off of net unamortized debt issuance costs associated with the extinguishment of our previous credit facility in November 2017.

Income tax expense (benefit) — Our effective income tax rate for the year ended December 31, 2018 was lower than the federal statutory rate in the United States, primarily due to valuation allowances, foreign currency translation, state taxes, and other permanent differences. For more detail, see Note 6, *Income Taxes*, of the Notes to Consolidated Financial Statements, included in Part II, Item 8, *Financial Statements and Supplementary Data*, of this Annual Report on Form 10-K.

General and administrative expense — Our general and administrative expense increased by $4.4 million, or 6%, during 2018, as compared to 2017, partially due to higher consulting and professional fees primarily incurred in connection with the early stages of replacing our legacy business applications, an increase in travel-related costs incurred during 2018, and an increase in compensation costs related to salary and wages, which was partially offset by a $1.5 million decrease in our phantom stock compensation expense, attributable to the decrease in fair value of our phantom stock unit awards.

Gain on dispositions of property and equipment, net — Our net gain of $3.1 million on the disposition of property and equipment during 2018 was primarily for the sale of drill pipe and collars, various coiled tubing equipment, and fleet disposals, including the sale of five coiled tubing units, twelve wireline units, and two drilling rigs which were previously held for sale. Our net gain of $3.6 million on the disposition of property and equipment during 2017 was primarily for the sale of certain coiled tubing equipment and vehicles, as well as the loss of drill pipe in operation, for which we were reimbursed by the client, and the disposal of three cranes that were damaged.

Other income — The increase in our other income during the year ended December 31, 2018, as compared to 2017, is primarily related to interest earned on the investments made during 2018 in highly-liquid money-market mutual funds, partially offset by net foreign currency losses recognized for our Colombian operations.

Statements of Operations Analysis - Year Ended December 31, 2017 Compared with Year Ended December 31, 2016

The following table provides certain information about our operations, including a detail of each of our business segments' revenues, operating costs and gross margin, and the percentage of the consolidated amount of each which is attributable to each business segment, for the years ended December 31, 2017 and 2016 (amounts in thousands, except percentages):

	Year ended December 31,			
	2017		2016	
Revenues:				
Domestic drilling	$ 129,276	29%	$ 112,399	41 %
International drilling	41,349	9%	6,808	2 %
Drilling services	170,625	38%	119,207	43 %
Well servicing	77,257	17%	71,491	26 %
Wireline services	163,716	37%	67,419	24 %
Coiled tubing services	34,857	8%	18,959	7 %
Production services	275,830	62%	157,869	57 %
Consolidated revenues	$ 446,455	100%	$ 277,076	100 %
Operating costs:				
Domestic drilling	$ 83,122	25%	$ 63,686	31 %
International drilling	31,994	10%	9,465	5 %
Drilling services	115,116	35%	73,151	36 %
Well servicing	56,379	17%	53,208	26 %
Wireline services	128,137	39%	57,634	28 %
Coiled tubing services	31,248	9%	19,956	10 %
Production services	215,764	65%	130,798	64 %
Consolidated operating costs	$ 330,880	100%	$ 203,949	100 %
Gross margin:				
Domestic drilling	$ 46,154	40%	$ 48,713	67 %
International drilling	9,355	8%	(2,657)	(4)%
Drilling services	55,509	48%	46,056	63 %
Well servicing	20,878	18%	18,283	25 %
Wireline services	35,579	31%	9,785	13 %
Coiled tubing services	3,609	3%	(997)	(1)%
Production services	60,066	52%	27,071	37 %
Consolidated gross margin	$ 115,575	100%	$ 73,127	100 %
Consolidated:				
Net loss	$ (75,118)		$ (128,391)	
Adjusted EBITDA [1]	$ 49,873		$ 14,237	

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

A reconciliation of net loss, as reported, to Adjusted EBITDA, and to consolidated gross margin are set forth in the following table:

	Year ended December 31, 2017	Year ended December 31, 2016
	(amounts in thousands)	
Net loss	$ (75,118)	$ (128,391)
Depreciation and amortization	98,777	114,312
Impairment	1,902	12,815
Interest expense	27,039	25,934
Loss on extinguishment of debt	1,476	299
Income tax expense (benefit)	(4,203)	(10,732)
Adjusted EBITDA	49,873	14,237
General and administrative	69,681	61,184
Bad debt expense (recovery)	53	156
Gain on dispositions of property and equipment, net	(3,608)	(1,892)
Other (income) expense	(424)	(558)
Consolidated gross margin	$ 115,575	$ 73,127

Consolidated gross margin — Our consolidated gross margin increased by 58% during 2017, as compared to 2016, as a result of higher activity for each of our drilling and production services business segments during the year ended December 31, 2017, as compared to 2016, as our industry continues to recover from an industry downturn. Spot prices also improved for all of our business segments throughout 2017. Of the $42.4 million increase in consolidated gross margin, 78% is attributable to our production services segments, primarily due to improved demand for our wireline services, while the remaining increase attributable to our drilling services business segments is primarily due to higher activity for our international drilling operations.

- *Drilling Services* — Our drilling services revenues increased by $51.4 million, or 43%, during 2017, as compared to 2016, while operating costs increased by $42.0 million, or 57%. The increases in our drilling services revenues and operating costs primarily resulted from a 42% increase in revenue days due to the increasing demand in our industry, especially in Colombia. The following table provides operating statistics for each of our drilling services business segments:

	Year ended December 31, 2017	Year ended December 31, 2016
Domestic drilling:		
Average number of drilling rigs	16	23
Utilization rate	95%	55%
Revenue days	5,524	4,628
Average revenues per day	$ 23,403	$ 24,287
Average operating costs per day	15,047	13,761
Average margin per day	$ 8,356	$ 10,526
International drilling:		
Average number of drilling rigs	8	8
Utilization rate	46%	7%
Revenue days	1,345	218
Average revenues per day	$ 30,743	$ 31,229
Average operating costs per day	23,787	43,417
Average margin per day	$ 6,956	$ (12,188)

Our domestic drilling fleet utilization reached 100% by mid-2017, and remained fully utilized through December 31, 2017. Our domestic drilling average revenues per day during 2017, as compared to 2016, decreased, while our average operating costs per day increased, due to the expiration of term contracts during 2016 that were entered into prior to the downturn at higher revenue rates, many of which were terminated early. Thus, there were more revenue days during

2017 attributable to daywork activity versus revenue days associated with rigs that were earning but not working and incurring minimal operating costs during 2016.

Demand for drilling rigs influences the types of drilling contracts we are able to obtain, and the type of revenues we earn under our drilling contracts. As a result of the downturn in our industry, several of our clients terminated a number of their drilling contracts with us. Drilling rigs under contracts which are terminated early earn lower standby revenue rates, as compared to daywork rates, and incur minimal operating costs. The following table provides the percentages of our consolidated drilling services revenues by contract type:

	Year ended December 31,	
	2017	2016
Daywork contracts (not terminated early)	100%	89%
Daywork contracts terminated early	—%	11%

Our international drilling fleet utilization steadily improved throughout 2017, culminating in a 75% utilization rate at the end of 2017, versus 50% utilization at December 31, 2016, which resulted in a significant increase in our average margin per day. The substantial increase in average margin per day is largely a result of the low utilization in 2016, during which time we incurred certain fixed costs, as well as additional costs during the fourth quarter of 2016 to mobilize previously stacked rigs under new contracts, which resulted in a negative average margin per day during 2016.

- *Production Services* — Our revenues from production services increased by $118.0 million, or 75%, during 2017, as compared to 2016, while operating costs increased by $85.0 million, or 65%, respectively. The increases in revenues and operating costs in our production services segments are a result of the increased demand for our services, particularly those that perform completion-related activities. The following table provides operating statistics for each of our production services business segments:

	Year ended December 31,	
	2017	2016
Well servicing:		
Average number of rigs	125	125
Utilization rate	43%	41%
Rig hours	150,240	144,151
Average revenue per hour	$ 514	$ 496
Wireline services:		
Average number of units	115	122
Number of jobs	11,139	8,169
Average revenue per job	$ 14,698	$ 8,253
Coiled tubing services:		
Average number of units	16	17
Revenue days	1,529	1,352
Average revenue per day	$ 22,797	$ 14,023

Increases in production services revenues and operating costs were led by our wireline services business segment, which experienced a significant increase in completion-related activity as wells that were drilled but not completed during the downturn created higher demand for completion services as our industry continues to recover. The number of wireline jobs we completed increased by 36% during 2017, as compared to 2016 while average revenue per job increased by 78%, which is largely due to completion-related jobs that earn higher revenue rates but also incur higher costs for the job materials consumed on these types of jobs.

Our well servicing and coiled tubing services business segments experienced a more moderate increase in demand. Well servicing utilization increased to 43% during 2017, from 41% during 2016, representing a 4% increase in well servicing rig hours, while average revenue per hour also increased by 4%. Our coiled tubing revenue days increased by 13%, while the average revenue per day increased by 63%, which was primarily due to a larger proportion of the work performed with larger diameter coiled tubing units which typically earn higher revenue rates as compared to smaller diameter coiled tubing units.

Depreciation and amortization expense — Our depreciation and amortization expense decreased by $15.5 million during 2017, as compared to 2016, primarily as a result of the impairments, dispositions of various equipment, and assets we placed as held for sale during 2016, as well as reduced capital expenditures during 2016 and 2017 due to the downturn. During the year ended December 31, 2016, we recognized $11.6 million of depreciation on drilling and well servicing rigs, wireline units, and certain other equipment which were subsequently sold or placed as held for sale, and $1.3 million of amortization expense for certain intangible assets that were fully amortized by the end of 2016.

Impairment — During the years ended December 31, 2017 and 2016, we recognized impairment charges of $1.9 million and $12.8 million, respectively, primarily to reduce the carrying values of certain assets which were classified as held for sale, to their estimated fair values based on expected sale prices. For more detail, see Note 3, *Property and Equipment,* of the Notes to Consolidated Financial Statements, included in Part II, Item 8 *Financial Statements and Supplementary Data*, of this Annual Report on Form 10-K.

Interest expense — Our interest expense increased by $1.1 million during the year ended December 31, 2017, as compared to 2016, primarily due to the increased interest rate under our Revolving Credit Facility, which was amended in June 2016, and the issuance of our Term Loan in November 2017. Proceeds from the issuance of our Term Loan were used to repay and retire the Revolving Credit Facility, and resulted in an increase in our total debt outstanding, as well as an increased rate applicable to the outstanding borrowings. Weighted average debt outstanding under our Revolving Credit Facility and/or Term Loan (beginning in November 2017) was approximately $95.4 million and $96.0 million during the years ended December 31, 2017 and 2016, respectively, while the weighted average interest rate on these borrowings during these periods was approximately 6.9% and 5.7%, respectively.

Loss on extinguishment of debt — Our loss on extinguishment of debt in 2017 represents the write-off of net unamortized debt issuance costs associated with the extinguishment of our previous credit facility in November 2017. Our 2016 loss on debt extinguishment represents the write-off of net unamortized debt issuance costs resulting from the reduction of borrowing capacity under our previous credit facility when it was amended in 2016.

Income tax benefit — Our effective income tax rate for the year ended December 31, 2017 was lower than the federal statutory rate in the United States primarily due to effects of recent tax law changes, valuation allowances, foreign currency translation, state taxes, and other permanent differences. For more detail, see Note 6, *Income Taxes*, of the Notes to Consolidated Financial Statements, included in Part II, Item 8, *Financial Statements and Supplementary Data*, of this Annual Report on Form 10-K.

General and administrative expense — Our general and administrative expense increased by approximately $8.5 million, or 14%, during 2017, as compared to 2016, primarily related to increased compensation costs. The increase in compensation cost was primarily due to a $7.1 million increase in salary, employee benefits and bonus expense during the year ended December 31, 2017, partially as a result of increased headcount to accommodate higher activity levels, as well as increased incentive compensation based on improved company performance.

Gain on dispositions of property and equipment, net — Our net gain of $3.6 million on the disposition of various property and equipment during 2017 included sales of drilling and coiled tubing equipment and vehicles, as well as the loss of drill pipe in operation, for which we were reimbursed by our client. Net gains in 2017 also included the disposal of three cranes that were damaged. Our net gain of $1.9 million on the disposition of property and equipment during 2016 was primarily related to a net gain on the sale of drilling rigs and the disposal of excess drill pipe. These gains during 2016 were partially offset by a loss on the disposition of damaged drilling equipment.

Other (income) expense — Our other income is primarily related to net foreign currency gains recognized for our Colombian operations.

Inflation

When the demand for drilling and production services increases, we may be affected by inflation, which primarily impacts:

- wage rates for our operations personnel which increase when the availability of personnel is scarce;
- materials and supplies used in our operations;
- equipment repair and maintenance costs;
- costs to upgrade existing equipment; and
- costs to construct new equipment.

With the increases in activity in our industry, we estimate that inflation had a modest impact on our operations during 2016 through 2018. Although it varies by business, we do not expect significant inflationary pressure to impact our business in 2019.

Critical Accounting Policies and Estimates

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

Revenue Recognition — In May 2014, the FASB issued ASU No. 2014-09, a comprehensive new revenue recognition standard that supersedes nearly all pre-existing revenue recognition guidance. The standard, and its related amendments, collectively referred to as ASC Topic 606, 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 adopted this standard effective January 1, 2018 using the modified retrospective method, in which the standard has been applied to all contracts existing as of the date of initial application, with the cumulative effect of applying the standard recognized in retained earnings. Accordingly, revenues for reporting periods ending after January 1, 2018 are presented under ASC Topic 606, while prior period amounts have not been adjusted and continue to be reported under the previous revenue recognition guidance. In accordance with ASC Topic 606, we also adopted ASC Subtopic 340-40, *Other Assets and Deferred Costs, Contracts with Customers*, effective January 1, 2018, which requires that the incremental costs of obtaining or fulfilling a contract with a customer be recognized as an asset if the costs are expected to be recovered.

The adoption of these standards resulted in a cumulative effect adjustment of $0.1 million after applicable income taxes, which consists of the impact of the timing difference related to recognition of mobilization revenues and costs. Mobilization costs incurred are deferred and amortized over the expected period of benefit under ASC Subtopic 340-40, but were amortized over the initial contract term under the previous accounting guidance. The recognition of both mobilization revenues and costs begins when mobilization activity is completed under ASC Topic 606, but were recognized during the period of initial mobilization under the previous accounting guidance. Additionally, the opening balances of deferred mobilization costs were reclassified in accordance with ASC Subtopic 340-40, which requires classification of the entire deferred balance according to the duration of the original contract to which it relates, rather than bifurcating the asset into current and noncurrent portions.

For more information about the accounting under ASC Topic 606, and disclosures under the new standard, see Note 2, *Revenue from Contracts with Customers*, 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.

Accounting estimates — Material estimates that are particularly susceptible to significant changes in the near term relate to our estimates of certain variable revenues and amortization periods of certain deferred revenues and costs associated with drilling daywork contacts, 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 accordance with ASC Topic 606, *Revenue from Contracts with Customers*, we estimate certain variable revenues associated with the demobilization of our drilling rigs under daywork drilling contracts. We also make estimates of the applicable amortization periods for deferred mobilization costs, and for mobilization revenues related to cancelable term contracts which represent a material right to our clients. These estimates and assumptions are described in more detail in Note 2, *Revenue from Contracts with Customers*. In order to make these estimates, management considers all the facts and circumstances pertaining to each particular contract, our past experience and knowledge of current market conditions.

- In accordance with ASC Topic 360, *Property, Plant and Equipment*, we monitor all indicators of potential impairments, and we evaluate for potential impairment of long-lived assets when indicators of impairment are present, which may include, among other things, significant adverse changes in industry trends (including revenue rates, utilization rates, oil and natural gas market prices, and industry rig counts). Due to adverse factors affecting our well servicing operations, including increased competition and labor shortages in certain well servicing markets, and lower than anticipated utilization, all of which contributed to a decline in our projected cash flows for the well servicing reporting unit, we performed an impairment analysis of this reporting unit at September 30, 2018. As a result of this analysis, we concluded that this reporting unit was not at risk of impairment because the sum of the estimated future undiscounted net cash flows for our well servicing reporting unit was significantly in excess of the carrying amount.

The most significant inputs used in our impairment analysis include the projected utilization and pricing of our services, as well as the estimated proceeds upon any future sale or disposal of the assets, all of which are classified as Level 3 inputs as defined by ASC Topic 820, *Fair Value Measurements and Disclosures*. The assumptions we use in the evaluation for impairment are inherently uncertain and require management judgment. Although we believe the assumptions and estimates used in our impairment analysis are reasonable, different assumptions and estimates could materially impact the analysis and resulting conclusions. If commodity prices remain at current levels for an extended period of time, or if the demand for any of our services decreases below what we are currently projecting, our estimated cash flows may decrease, and if any of the foregoing were to occur, we could incur impairment charges on the related assets. For more information, see Note 3, *Property and Equipment*, of the Notes to Consolidated Financial Statements, included in Part II, Item 8, *Financial Statements and Supplementary Data*, of this Annual Report on Form 10-K.

- As of December 31, 2018, we had $96.8 million and $9.6 million of deferred tax assets related to domestic and foreign net operating losses, respectively, that are available to reduce future taxable income. In assessing the realizability of our deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. As a result, we have a valuation allowance that fully offsets our foreign and domestic federal deferred tax assets as of December 31, 2018. The valuation allowance is the primary factor causing our effective tax rate to be significantly lower than the statutory rate. For more information, see Note 6, *Income Taxes*, of the Notes to Consolidated Financial Statements, included in Part II, Item 8, *Financial Statements and Supplementary Data*, of this Annual Report on Form 10-K.

- We use a combination of self-insurance and third-party insurance for various types of coverage. 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 and an additional $250,000 annual aggregate deductible under both our general liability insurance and auto liability insurance. At December 31, 2018, our accrued insurance premiums and deductibles include approximately $1.8 million of accruals for costs incurred under the self-insurance portion of our health insurance and approximately $3.0 million of accruals for costs associated with our workers' compensation 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 cost of administrative services associated with claims processing.

- Our compensation expense includes estimates for certain of our long-term incentive compensation plans which have performance-based award components dependent upon our performance over a set performance period, as compared to the performance of a pre-defined peer group. The accruals for these awards include estimates which affect our compensation expense, employee related accruals and equity. The accruals are adjusted based on actual achievement levels at the end of the pre-determined performance periods. Additionally, our phantom stock unit awards are classified as liability awards under ASC Topic 718, *Compensation—Stock Compensation*, because we expect to settle the awards in cash when they vest, and are remeasured at fair value at the end of each reporting period until they vest. The change in fair value is recognized as a current period compensation expense in our consolidated statements of operations. Therefore, changes in the inputs used to measure fair value can result in volatility in our compensation expense. This volatility increases as the phantom stock awards approach the vesting date. For more information, see Note 9, *Equity Transactions and Stock-Based Compensation Plans*, of the Notes to Consolidated Financial Statements, included in Part II, Item 8, *Financial Statements and Supplementary Data*, of this Annual Report on Form 10-K.

Recently Issued Accounting Standards

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

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

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, 2018, the principal amount under our Term Loan was $175 million, which is our only variable rate debt with an outstanding balance. 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 $1.8 million during the year ended December 31, 2018. 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, 2018.

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 net foreign currency losses of $0.3 million for the year ended December 31, 2018.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

PIONEER ENERGY SERVICES CORP.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

The shareholders and board of directors
Pioneer Energy Services Corp.:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Pioneer Energy Services Corp. and subsidiaries (the Company) as of December 31, 2018 and 2017, the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2018, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2018, 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) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, 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 19, 2019 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

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 are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ KPMG LLP

We have served as the Company's auditor since 1979.

San Antonio, Texas
February 19, 2019

Report of Independent Registered Public Accounting Firm

The shareholders and board of directors
Pioneer Energy Services Corp.:

Opinion on Internal Control Over Financial Reporting

We have audited Pioneer Energy Services Corp.'s and subsidiaries' (the Company) internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control—Integrated Framework (2013),* issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, 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) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2018 and 2017, the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2018, and the related notes (collectively, the consolidated financial statements), and our report dated February 19, 2019 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company'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 are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. 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 of internal control over financial reporting 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.

Definition and Limitations of Internal Control Over Financial Reporting

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.

/s/ KPMG LLP

San Antonio, Texas
February 19, 2019

PIONEER ENERGY SERVICES CORP. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2018	December 31, 2017
	(in thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 53,566	$ 73,640
Restricted cash	998	2,008
Receivables:		
Trade, net of allowance for doubtful accounts	76,924	79,592
Unbilled receivables	24,822	16,029
Insurance recoveries	23,656	13,874
Other receivables	5,479	3,510
Inventory	18,898	14,057
Assets held for sale	3,582	6,620
Prepaid expenses and other current assets	7,109	6,229
Total current assets	215,034	215,559
Property and equipment, at cost	1,118,215	1,093,635
Less accumulated depreciation	593,357	544,012
Net property and equipment	524,858	549,623
Other noncurrent assets	1,658	1,687
Total assets	$ 741,550	$ 766,869
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 34,134	$ 29,538
Deferred revenues	1,722	905
Accrued expenses:		
Payroll and related employee costs	24,598	21,023
Insurance claims and settlements	23,593	13,289
Insurance premiums and deductibles	5,482	6,742
Interest	6,148	6,624
Other	9,091	6,793
Total current liabilities	104,768	84,914
Long-term debt, less unamortized discount and debt issuance costs	464,552	461,665
Deferred income taxes	3,688	3,151
Other noncurrent liabilities	3,484	7,043
Total liabilities	576,492	556,773
Commitments and contingencies (Note 12)		
Shareholders' equity:		
Preferred stock, 10,000,000 shares authorized; none issued and outstanding	—	—
Common stock $.10 par value; 200,000,000 shares authorized; 78,214,550 and 77,719,021 shares outstanding at December 31, 2018 and December 31, 2017, respectively	7,900	7,835
Additional paid-in capital	550,548	546,158
Treasury stock, at cost; 789,532 and 630,688 shares at December 31, 2018 and December 31, 2017, respectively	(4,965)	(4,416)
Accumulated deficit	(388,425)	(339,481)
Total shareholders' equity	165,058	210,096
Total liabilities and shareholders' equity	$ 741,550	$ 766,869

See accompanying notes to consolidated financial statements.

PIONEER ENERGY SERVICES CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year ended December 31,		
	2018	2017	2016
	(in thousands, except per share data)		
Revenues	$ 590,097	$ 446,455	$ 277,076
Costs and expenses:			
Operating costs	429,913	330,880	203,949
Depreciation	93,554	98,777	114,312
General and administrative	74,117	69,681	61,184
Bad debt expense	271	53	156
Impairment	4,422	1,902	12,815
Gain on dispositions of property and equipment, net	(3,121)	(3,608)	(1,892)
Total costs and expenses	599,156	497,685	390,524
Loss from operations	(9,059)	(51,230)	(113,448)
Other income (expense):			
Interest expense, net of interest capitalized	(38,782)	(27,039)	(25,934)
Loss on extinguishment of debt	—	(1,476)	(299)
Other income, net	738	424	558
Total other expense, net	(38,044)	(28,091)	(25,675)
Loss before income taxes	(47,103)	(79,321)	(139,123)
Income tax (expense) benefit	(1,908)	4,203	10,732
Net loss	$ (49,011)	$ (75,118)	$ (128,391)
Loss per common share - Basic	$ (0.63)	$ (0.97)	$ (1.96)
Loss per common share - Diluted	$ (0.63)	$ (0.97)	$ (1.96)
Weighted average number of shares outstanding—Basic	77,957	77,390	65,452
Weighted average number of shares outstanding—Diluted	77,957	77,390	65,452

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 Deficit	Total Shareholders' Equity
	Common	Treasury	Common	Treasury			
				(in thousands)			
Balance as of December 31, 2015	64,956	(458)	$ 6,496	$ (3,759)	$ 475,823	$ (135,917)	$ 342,643
Net loss	—	—	—	—	—	(128,391)	(128,391)
Sale of common stock, net of offering costs	12,075	—	1,208	—	64,222	—	65,430
Exercise of options and related income tax effect	46	—	5	—	178	—	183
Purchase of treasury stock	—	(58)	—	(124)	—	—	(124)
Income tax effect of restricted stock vesting	—	—	—	—	(1,023)	—	(1,023)
Income tax effect of stock option forfeitures and expirations	—	—	—	—	(1,264)	—	(1,264)
Issuance of restricted stock	586	—	57	—	(57)	—	—
Stock-based compensation expense	—	—	—	—	3,944	—	3,944
Balance as of December 31, 2016	77,663	(516)	$ 7,766	$ (3,883)	$ 541,823	$ (264,308)	$ 281,398
Net loss	—	—	—	—	—	(75,118)	(75,118)
Purchase of treasury stock	—	(115)	—	(533)	—	—	(533)
Issuance of restricted stock	687	—	69	—	(69)	—	—
Stock-based compensation expense	—	—	—	—	4,404	(55)	4,349
Balance as of December 31, 2017	78,350	(631)	$ 7,835	$ (4,416)	$ 546,158	$ (339,481)	$ 210,096
Net loss	—	—	—	—	—	(49,011)	(49,011)
Exercise of options	4	—	—	—	11	—	11
Purchase of treasury stock	—	(159)	—	(549)	—	—	(549)
Cumulative-effect adjustment due to adoption of ASC Topic 606	—	—	—	—	—	67	67
Issuance of restricted stock	651	—	65	—	(65)	—	—
Stock-based compensation expense	—	—	—	—	4,444	—	4,444
Balance as of December 31, 2018	79,005	(790)	$ 7,900	$ (4,965)	$ 550,548	$ (388,425)	$ 165,058

See accompanying notes to consolidated financial statements.

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

	Year ended December 31,		
	2018	2017	2016
		(in thousands)	
Cash flows from operating activities:			
Net loss	$ (49,011)	$ (75,118)	$ (128,391)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Depreciation	93,554	98,777	114,312
Allowance for doubtful accounts, net of recoveries	271	53	156
Write-off of obsolete inventory	—	—	101
Gain on dispositions of property and equipment, net	(3,121)	(3,608)	(1,892)
Stock-based compensation expense	4,444	4,349	3,944
Phantom stock compensation expense	46	1,609	1,971
Amortization of debt issuance costs and discount	2,900	1,548	1,776
Loss on extinguishment of debt	—	1,476	299
Impairment	4,422	1,902	12,815
Deferred income taxes	538	(5,030)	(11,608)
Change in other noncurrent assets	565	(1)	662
Change in other noncurrent liabilities	(426)	385	(1,493)
Changes in current assets and liabilities:			
Receivables	(8,644)	(49,750)	16,341
Inventory	(4,841)	(4,397)	(630)
Prepaid expenses and other current assets	(1,139)	744	310
Accounts payable	(1,272)	12,409	1,969
Deferred revenues	420	(348)	(3,985)
Accrued expenses	950	9,183	(1,526)
Net cash provided by (used in) operating activities	39,656	(5,817)	5,131
Cash flows from investing activities:			
Purchases of property and equipment	(67,148)	(63,277)	(32,381)
Proceeds from sale of property and equipment	5,864	12,569	7,577
Proceeds from insurance recoveries	1,082	3,344	37
Net cash used in investing activities	(60,202)	(47,364)	(24,767)
Cash flows from financing activities:			
Debt repayments	—	(120,000)	(71,000)
Proceeds from issuance of debt	—	245,500	22,000
Debt issuance costs	—	(6,332)	(819)
Proceeds from exercise of options	11	—	183
Proceeds from issuance of common stock, net of offering costs of $4,001	—	—	65,430
Purchase of treasury stock	(549)	(533)	(124)
Net cash provided by (used in) financing activities	(538)	118,635	15,670
Net increase (decrease) in cash, cash equivalents and restricted cash	(21,084)	65,454	(3,966)
Beginning cash, cash equivalents and restricted cash	75,648	10,194	14,160
Ending cash, cash equivalents and restricted cash	$ 54,564	$ 75,648	$ 10,194
Supplementary disclosure:			
Interest paid	$ 36,624	$ 25,082	$ 24,516
Income tax paid	$ 3,556	$ 1,431	$ 671
Noncash investing and financing activity:			
Change in capital expenditure accruals	$ 5,706	$ (1,830)	$ 175

See accompanying notes to consolidated financial statements.

PIONEER ENERGY SERVICES CORP. AND SUBSIDIARIES
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 oil and gas exploration and production companies in the United States and internationally in Colombia.

Our drilling services business segments provide contract land drilling services through three domestic divisions which are located in the Marcellus/Utica, Permian Basin and Eagle Ford, and Bakken regions, and internationally in Colombia. We provide a comprehensive service offering which includes the drilling rig, crews, supplies and most of the ancillary equipment needed to operate our drilling rigs. Our drilling rigs are equipped with 1,500 horsepower or greater drawworks, are 100% pad-capable and offer the latest advancements in pad drilling. The following table summarizes our current rig fleet count and composition for each drilling services business segment:

	Multi-well, Pad-capable		
	AC rigs	SCR rigs	Total
Domestic drilling	16	—	16
International drilling	—	8	8
			24

In July 2018, we entered into a three-year term contract for the construction of a new 1,500 horsepower, AC pad-optimal rig, which we expect to deploy in early 2019 to the Permian Basin.

Our production services business segments provide a range of well, wireline and coiled tubing services to a diverse group of exploration and production companies, with our operations concentrated in the major domestic onshore oil and gas producing regions in the Gulf Coast, Mid-Continent and Rocky Mountain states. As of December 31, 2018, the fleet count for each of our production services business segments are as follows:

	550 HP	600 HP	Total
Well servicing rigs, by horsepower (HP) rating	113	12	125

	Total
Wireline services units	105
Coiled tubing services units	9

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.

Use of Estimates — 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 estimates of certain variable revenues and amortization periods of certain deferred revenues and costs associated with drilling daywork contacts, 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.

Subsequent Events — In preparing the accompanying consolidated financial statements, we have reviewed events that have occurred after December 31, 2018, through the filing of this Annual Report on Form 10-K, for inclusion as necessary.

Change in Accounting Principle and Recently Issued Accounting Standards

Changes to accounting principles generally accepted in the United States of America ("U.S. GAAP") are established by the Financial Accounting Standards Board (FASB) in the form of Accounting Standards Updates (ASUs) to the FASB Accounting Standards Codification (ASC). We consider the applicability and impact of all ASUs. Any ASUs not listed below were assessed and determined to be either not applicable or are expected to have an immaterial impact on our consolidated financial position and results of operations.

- *Revenue Recognition.* In May 2014, the FASB issued ASU No. 2014-09, a comprehensive new revenue recognition standard that supersedes nearly all pre-existing revenue recognition guidance. The standard, and its related amendments, collectively referred to as ASC Topic 606, 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 adopted this standard effective January 1, 2018 using the modified retrospective method, in which the standard has been applied to all contracts existing as of the date of initial application, with the cumulative effect of applying the standard recognized in retained earnings. Accordingly, revenues for reporting periods ending after January 1, 2018 are presented under ASC Topic 606, while prior period amounts have not been adjusted and continue to be reported under the previous revenue recognition guidance. In accordance with ASC Topic 606, we also adopted ASC Subtopic 340-40, *Other Assets and Deferred Costs, Contracts with Customers*, effective January 1, 2018, which requires that the incremental costs of obtaining or fulfilling a contract with a customer be recognized as an asset if the costs are expected to be recovered.

  The adoption of these standards resulted in a cumulative effect adjustment of $0.1 million after applicable income taxes, which consists of the impact of the timing difference related to recognition of mobilization revenues and costs. Mobilization costs incurred are deferred and amortized over the expected period of benefit under ASC Subtopic 340-40, but were amortized over the initial contract term under the previous accounting guidance. The recognition of both mobilization revenues and costs begins when mobilization activity is completed under ASC Topic 606, but were recognized during the period of initial mobilization under the previous accounting guidance. Additionally, the opening balances of deferred mobilization costs were reclassified in accordance with ASC Subtopic 340-40, which requires classification of the entire deferred balance according to the duration of the original contract to which it relates, rather than bifurcating the asset into current and noncurrent portions.

  For more information about the accounting under ASC Topic 606, and disclosures under the new standard, see Note 2, *Revenue from Contracts with Customers*.

- *Leases.* In February 2016, the FASB issued ASU No. 2016-02, *Leases*, which among other things, requires lessees to recognize substantially all leases on the balance sheet, with expense recognition that is similar to the current lease standard, and aligns the principles of lessor accounting with the principles of the FASB's new revenue guidance (referenced above).

  In July 2018, the FASB issued ASU No. 2018-11, *Leases: Targeted Improvements*, which provides an option to apply the guidance prospectively, and provides a practical expedient allowing lessors to combine the lease and non-lease components of revenues where the revenue recognition pattern is the same and where the lease component, when accounted for separately, would be considered an operating lease. The practical expedient also allows a lessor to account for the combined lease and non-lease components under ASC Topic 606, *Revenue from Contracts with Customers*, when the non-lease component is the predominant element of the combined component. As a lessor, we expect to apply the practical expedient which would allow us to continue to recognize our revenues (both lease and service components) under ASC Topic 606, and continue to present them as one revenue stream in our consolidated statements of operations.

  As a lessee, this standard will primarily impact our accounting for long-term real estate and office equipment leases, for which we will recognize a right-of-use asset and a corresponding lease liability on our consolidated balance sheet. We will apply this guidance prospectively, beginning January 1, 2019 and currently estimate the impact on our balance sheet to be approximately $10 million. We are nearing completion of our process to implement a lease accounting system for our leases, including the conversion of our existing lease data to the new system and implementing relevant internal controls and procedures.

Significant Accounting Policies and Detail of Account Balances

Cash and Cash Equivalents — As of December 31, 2018, we had $13.0 million of cash and $40.6 million of cash equivalents, consisting of investments in highly-liquid money-market mutual funds. We had no cash equivalents at December 31, 2017.

Restricted Cash — Our restricted cash balance reflects the portion of net proceeds from the issuance of our senior secured term loan which are currently held in a restricted account until the completion of certain administrative tasks related to providing access rights to certain of our real property.

Revenue — Production services jobs are varied in nature, but typically represent a single performance obligation, either for a particular job, a series of distinct jobs, or a period of time during which we stand ready to provide services as our client needs them. Revenue is recognized for these services over time, as the services are performed. Our drilling services business segments earn revenues by drilling oil and gas wells for our clients under daywork contracts. Daywork contracts are comprehensive agreements under which we provide a comprehensive service offering, including the drilling rig, crew, supplies and most of the ancillary equipment necessary to operate the rig. We account for our services provided under daywork contracts as a single performance obligation comprised of a series of distinct time increments which are satisfied over time. Accordingly, dayrate revenues are recognized in the period during which the services are performed. All of our revenues are recognized net of sales taxes, when applicable. For more information about the accounting under ASC Topic 606, see Note 2, *Revenue from Contracts with Customers*.

Trade and Unbilled Accounts Receivable — We record trade accounts receivable at the amount we invoice to 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. Our unbilled receivables represent revenues we have recognized in excess of amounts billed on drilling contracts and production services completed. For more information, see Note 2, *Revenue from Contracts with Customers*.

Other Receivables — Our other receivables primarily consist of recoverable taxes related to our international operations, net income tax receivables, as well as proceeds receivable from asset sales.

Inventories — Inventories primarily consist of drilling rig replacement parts and supplies held for use by our drilling operations in Colombia, and supplies held for use by our wireline and coiled tubing operations. Inventories are valued at the lower of cost (first in, first out or actual) or net realizable value.

Prepaid Expenses and Other Current Assets — Prepaid expenses and other current assets include items such as insurance, rent deposits, software subscriptions and other 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 deferred mobilization costs for short-term drilling contracts.

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 our equipment 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. For more information, see Note 3, *Property and Equipment*.

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

Other Accrued Expenses — Our other accrued expenses include accruals for items such as sales taxes, property taxes, withholding tax liability related to our international operations, and professional and other fees. We routinely expense these items in the normal course of business over the periods these expenses benefit.

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

Insurance Recoveries, Accrued Insurance Claims and Settlements, and Accrued Premiums and Deductibles — We use a combination of self-insurance and third-party insurance for various types of coverage. Our accrued premiums and deductibles include the premiums and estimated liability for the self-insured portion of costs associated with our health, workers' compensation, general liability and auto liability insurance. Our insurance recoveries receivables and our accrued liability for insurance claims and settlements represent our estimate of claims in excess of our deductible, which are covered and managed by our third-party insurance providers, some of which may ultimately be settled by the insurance provider in the long-term. These are presented in our consolidated balance sheets as current due to the uncertainty in the timing of reporting and payment of claims. For more information, see Note 10, *Employee Benefit Plans and Insurance*.

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 our stock-based compensation awards based on the fair value estimated in accordance with ASC Topic 718, *Compensation—Stock Compensation,* and we recognize forfeitures when they occur. 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. For more information, see Note 9, *Equity Transactions and Stock-Based Compensation Plans*.

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 of enactment. For more information, see Note 6, *Income Taxes*.

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.

Related-Party Transactions — During each of the years ended December 31, 2018, 2017 and 2016, the Company paid approximately \$0.2 million for trucking and equipment rental services received from Gulf Coast Lease Service, which represented arms-length transactions. Gulf Coast Lease Service is owned and operated by the two sons of our former Senior Vice President of Well Servicing, Mr. Freeman, who also served as the President of Gulf Coast Lease Service, primarily in an advisory role to his sons, and for which he did not receive compensation from Gulf Coast Lease Service. Mr. Freeman retired from his role as Senior Vice President of Well Servicing in January 2019.

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

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

2. Revenue from Contracts with Customers

Our production services business segments earn revenues for well servicing, wireline services and coiled tubing services pursuant to master services agreements based on purchase orders or other contractual arrangements with the client. Production services jobs are generally short-term (ranging in duration from several hours to less than 30 days) and are charged at current market rates for the labor, equipment and materials necessary to complete the job. Production services jobs are varied in nature, but typically represent a single performance obligation, either for a particular job, a series of distinct jobs, or a period of time during which we stand ready to provide services as our client needs them. Revenue is recognized for these services over time, as the services are performed.

Our drilling services business segments earn revenues by drilling oil and gas wells for our clients under daywork contracts. Daywork contracts are comprehensive agreements under which we provide a comprehensive service offering, including the drilling rig, crew, supplies and most of the ancillary equipment necessary to operate the rig. Contract modifications that extend the term of a dayrate contract are generally accounted for prospectively as a separate dayrate contract. We account for our services provided under daywork contracts as a single performance obligation comprised of a series of distinct time increments which are satisfied over time. Accordingly, dayrate revenues are recognized in the period during which the services are performed.

With most drilling contracts, we also receive payments contractually designated for the mobilization and demobilization of drilling rigs and other equipment to and from the client's drill site. Revenues associated with the mobilization and demobilization of our drilling rigs to and from the client's drill site do not relate to a distinct good or service and are recognized ratably over the related contract term.

The amount of demobilization revenue that we ultimately collect is dependent upon the specific contractual terms, most of which include provisions for reduced (or no) payment for demobilization when, among other things, the contract is renewed or extended with the same client, or when the rig is subsequently contracted with another client prior to the termination of the current contract. Since revenues associated with demobilization activity are typically variable, at each period end, they are estimated at the most likely amount, and constrained when the likelihood of a significant reversal is probable. Any change in the expected amount of demobilization revenue is accounted for with the net cumulative impact of the change in estimate recognized in the period during which the revenue estimate is revised.

The upfront costs that we incur to mobilize the drilling rig to our client's initial drilling site are capitalized and recognized ratably over the term of the related contract, including any contracted renewal or extension periods, which is our estimate of the period during which we expect to benefit from the cost of mobilizing the rig. Costs associated with the final demobilization at the end of the contract term are expensed when incurred, when the demobilization activity is performed.

We also act as a principal for certain reimbursable services and auxiliary equipment provided by us to our clients, for which we incur costs and earn revenues, many of which are variable, or dependent upon the activity that is actually performed each day under the related contract. Accordingly, reimbursements that we receive for out-of-pocket expenses are recorded as revenues and the out-of-pocket expenses for which they relate are recorded as operating costs during the period to which they relate within the series of distinct time increments.

All of our revenues are recognized net of sales taxes, when applicable.

Trade and Unbilled Accounts Receivable

We record trade accounts receivable at the amount we invoice to 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.

Our production services terms generally provide for payment of invoices in 30 days. Our typical drilling contract provides for payment of invoices in 30 days. We generally do not extend payment terms beyond 30 days and have not extended payment terms beyond 90 days for any of our domestic contracts in the last three fiscal years. We review our allowance for doubtful accounts on a monthly basis. 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,		
	2018	2017	2016
Balance at beginning of year	$ 1,224	$ 1,678	$ 2,254
Increase (decrease) in allowance charged to expense	271	(197)	404
Accounts charged against the allowance	(72)	(257)	(980)
Balance at end of year	$ 1,423	$ 1,224	$ 1,678

Our unbilled receivables represent revenues we have recognized in excess of amounts billed on drilling contracts and production services completed. We typically bill our clients at 15-day intervals during the performance of daywork drilling contracts and upon completion of the daywork contract. Our unbilled receivables as of December 31, 2018 and December 31, 2017 were as follows (amounts in thousands):

	December 31, 2018	December 31, 2017
Daywork drilling contracts in progress	$ 24,365	$ 15,254
Production services	457	775
	$ 24,822	$ 16,029

Though our typical drilling contract provides for payment of invoices in 30 days, the process for invoicing work performed in our international operations generally lengthens the billing cycle for those operations, which is the primary reason for the increase in unbilled revenues during 2018.

Contract Asset and Liability Balances and Contract Cost Assets

Contract asset and contract liability balances relate to demobilization and mobilization revenues, respectively. Demobilization revenue that we expect to receive is recognized ratably over the related contract term, but invoiced upon completion of the demobilization activity. Mobilization revenue, which is typically collected upon the completion of the initial mobilization activity, is deferred and recognized ratably over the related contract term. Contract asset and liability balances are netted at the contract level, with the net current and noncurrent portions separately classified in our consolidated balance sheets, and referred to herein as "deferred revenues."

Contract cost assets represent the costs associated with the initial mobilization required in order to fulfill the contract, which are deferred and recognized ratably over the period during which we expect to benefit from the mobilization, or the period during which we expect to satisfy the performance obligations of the related contract. Contract cost assets are presented as either current or noncurrent, according to the duration of the original contract to which it relates, and referred to herein as "deferred costs."

Our current and noncurrent deferred revenues and costs as of December 31, 2018 and January 1, 2018 were as follows (amounts in thousands):

	December 31, 2018	January 1, 2018
Current deferred revenues	$ 1,722	$ 1,287
Current deferred costs	1,543	1,072
Noncurrent deferred revenues	$ 437	$ 564
Noncurrent deferred costs	679	1,177

The changes in deferred revenue and cost balances during the year ended December 31, 2018 are primarily related to increased deferred mobilization revenue and cost balances for the deployment of five international rigs and one domestic rig under new term contracts in 2018, mostly offset by the amortization of deferred revenues and costs during the period. Amortization of deferred revenues and costs during the years ended December 31, 2018, 2017 and 2016 were as follows (amounts in thousands):

	Year ended December 31,		
	2018	2017	2016
Amortization of deferred revenues	$ 2,961	$ 2,400	$ 1,566
Amortization of deferred costs	2,855	4,953	2,813

As of December 31, 2018, all but one of our 24 rigs are earning under daywork contracts, 13 of which are domestic term contracts. Our international drilling contracts are cancelable by our clients without penalty, although the contracts require 15 to 30 days notice and payment for demobilization services. The spot contracts for our domestic drilling rigs are also terminable by our client with 30 days notice, but typically do not include a required payment for demobilization services. Revenues associated with the initial mobilization and/or demobilization of drilling rigs under cancelable contracts are deferred and recognized ratably over the anticipated duration of the original contract, which is the period during which we expect our client to benefit from the mobilization of the rig, and represents a separate performance obligation because the payment for mobilization and/or demobilization creates a material right to our client during the cancelable period, for which the transaction price is allocated to the optional goods and services expected to be provided.

Remaining Performance Obligations

We have elected to apply the practical expedients in ASC Topic 606 which allow entities to omit disclosure of (i) the transaction price allocated to the remaining performance obligations associated with short-term contracts, and (ii) the estimated variable consideration related to wholly unsatisfied performance obligations, or to distinct future time increments within a series of performance obligations. Therefore, we have not disclosed the remaining amount of fixed mobilization revenue (or estimated future variable demobilization revenue) associated with short-term contracts, and we have not disclosed an estimate of the amount of future variable dayrate drilling revenue. However, the amount of fixed mobilization revenue associated with remaining performance obligations is reflected in the net unamortized balance of deferred mobilization revenues, which is presented in both current and noncurrent portions in our consolidated balance sheet, and discussed in more detail in the section above entitled, *Contract Asset and Liability Balances and Contract Cost Assets*.

Disaggregation of Revenue

ASC Topic 606 requires disclosure of the disaggregation of revenue into categories that depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. We believe the disclosure of revenues by operating segment achieves the objective of this disclosure requirement. See Note 11, *Segment Information*, for the disaggregation of revenues by operating segment, which reflects the disaggregation of revenues by the type of services provided and by geography (international versus domestic).

Impact of ASC Topic 606 on Financial Statement Line Items and Disclosures

Our revenue recognition pattern under ASC Topic 606 is similar to revenue recognition under the previous accounting guidance, except for: (i) the timing of recognition of demobilization revenues which are estimated and recognized ratably over the term of the related contract under ASC Topic 606, and constrained when appropriate, but were previously not recognized until the activity was performed under previous guidance; (ii) the timing of recognition of mobilization revenues and costs which are recognized over the applicable amortization period beginning when the initial mobilization of the rig is completed, but which, under previous guidance, we recognized over the related contract term beginning when the initial mobilization activity commenced, (iii) the timing of recognition of mobilization costs which are deferred and recognized ratably over the expected period of benefit, but which, under previous guidance, we recognized ratably over the term of the initial contract; and (iv) presentation of mobilization costs which are presented as either current or noncurrent according to the duration of the original contract to which it relates under ASC Topic 606, but which we bifurcated and presented both current and noncurrent portions in separate line items under previous guidance.

These differences have not had a material impact on our consolidated financial position or results of operations as of and during 2018. Additionally, we have determined that any disclosures required by ASC Topic 606 which are not presented herein are either not applicable, or are not material.

Concentration of Clients

We derive a significant portion of our revenue from a limited number of major clients. For the years ended December 31, 2018, 2017 and 2016, our drilling and production services to our top three clients accounted for approximately 20%, 20%, and 26%, respectively, of our revenue.

3. Property and Equipment

The following table presents the estimated useful lives and costs of our assets by class:

		As of December 31,	
		2018	2017
	Lives	Cost (amounts in thousands)	
Drilling rigs and equipment	3 - 25	$ 590,148	$ 594,743
Well servicing rigs and equipment	3 - 20	252,589	244,747
Wireline units and equipment	1 - 10	144,171	142,224
Coiled tubing units and equipment	1 - 7	25,689	18,141
Vehicles	3 - 10	50,317	47,932
Office equipment	3 - 10	11,606	12,717
Buildings and improvements	3 - 40	23,610	24,013
Property and equipment not yet placed in service	—	17,718	6,751
Land	—	2,367	2,367
		$ 1,118,215	$ 1,093,635

Capital Expenditures — Our capital expenditures were $72.9 million, $61.4 million and $32.6 million during the years ended December 31, 2018, 2017, and 2016, respectively, which includes $0.4 million, $0.4 million and $0.2 million, respectively, of capitalized interest costs incurred in connection with the construction of a new domestic drilling rig which we expect to deploy in early 2019, and the expansion of our coiled tubing and well servicing fleets in 2018 and 2017, respectively.

Capital expenditures during 2018 primarily related to various routine expenditures to maintain our fleets and purchase new support equipment, expansion of our coiled tubing and wireline fleets, capital projects to upgrade and refurbish certain components of our international and domestic drilling rigs and begin construction of one new-build drilling rig, and vehicle fleet upgrades in all domestic business segments. Capital expenditures during 2017 primarily related to the acquisition of 20 well servicing rigs and expansion of our wireline fleet, upgrades to certain domestic drilling rigs, routine capital expenditures necessary to deploy assets that were previously idle, and other new drilling equipment and trucks. Capital expenditures during 2016 consisted primarily of routine expenditures to maintain our drilling and production services fleets, and expenditures for equipment ordered in 2014 before the market slowdown.

Capital expenditures incurred for property and equipment not yet placed in service as of December 31, 2018 primarily related to approximately $8.0 million of costs for the construction of a new-build drilling rig, which is partially being constructed from spare components already in our fleet, various refurbishments and upgrades of drilling and production services equipment, and the purchase of other new ancillary equipment. At December 31, 2017, property and equipment not yet placed in service primarily related to routine refurbishments on one international drilling rig in preparation for its deployment in 2018, installments on the purchase of three wireline units and one coiled tubing unit, and scheduled refurbishments on drilling and production services equipment.

Gain/Loss on Disposition of Property — We recognized a net gain during the year ended December 31, 2018 of $3.1 million on the disposition of various property and equipment, primarily from the sale of drill pipe and collars, various coiled tubing equipment and fleet disposals, including the sale of five coiled tubing units, twelve wireline units, and two drilling rigs which were designated as held for sale. During 2017, we recognized a net gain of $3.6 million on the disposition of property and equipment, including sales of certain coiled tubing equipment and vehicles, as well as the loss of drill pipe in operation, for which we were reimbursed by the client, and the disposal of three cranes that were damaged. During 2016, we recognized a net gain of $1.9 million on the disposition of property and equipment, including the sale of three SCR drilling rigs and other drilling equipment, the disposal of excess drill pipe and the disposition of damaged components from one of our AC drilling rigs.

Assets Held for Sale — As of December 31, 2018, our consolidated balance sheet reflects assets held for sale of $3.6 million, which primarily represents the fair value of two domestic SCR drilling rigs, spare drilling equipment that would support these rigs and three coiled tubing units. As of December 31, 2017, our consolidated balance sheet reflects assets held for sale of $6.6 million, which primarily represents the fair value of three domestic SCR drilling rigs, one domestic mechanical drilling rig, spare drilling equipment that would support these rigs, two wireline units, one coiled tubing unit and other spare equipment.

During the years ended December 31, 2018, 2017 and 2016, we recognized impairment charges of $4.4 million, $1.9 million, and $12.8 million, respectively, to reduce the carrying values of assets which were classified as held for sale, to their estimated fair values, based on expected sales prices which are classified as Level 3 inputs as defined by ASC Topic 820, *Fair Value Measurements and Disclosures*.

Impairments — In accordance with ASC Topic 360, *Property, Plant and Equipment*, we monitor all indicators of potential impairments, and we evaluate for potential impairment of long-lived assets when indicators of impairment are present, which may include, among other things, significant adverse changes in industry trends (including 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 the assets grouped at the lowest level that independent cash flows can be identified. We perform an impairment evaluation and estimate future undiscounted cash flows for each of our reporting units separately, which are our domestic drilling services, international drilling services, well servicing, wireline services and coiled tubing services segments. 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, and the amount of an impairment charge would be measured as the difference between the carrying amount and the fair value of the assets.

Due to lower than anticipated operating results in 2016 and 2017 and a decline in our projected cash flows for the coiled tubing reporting unit, we performed an impairment analysis of our coiled tubing long-lived assets at September 30, 2016 and again at June 30, 2017, which indicated that our projected net undiscounted cash flows associated with the coiled tubing reporting unit were in excess of the net carrying value of the assets at both dates and thus no impairment was present.

Due to adverse factors affecting our well servicing operations, including increased competition and labor shortages in certain well servicing markets, and lower than anticipated utilization, all of which contributed to a decline in our projected cash flows for the well servicing reporting unit, we performed an impairment analysis of this reporting unit at September 30, 2018. As a result of this analysis, we concluded that this reporting unit was not at risk of impairment because the sum of the estimated future undiscounted net cash flows for our well servicing reporting unit was significantly in excess of the carrying amount.

We used an income approach to estimate the fair value of our reporting units. The most significant inputs used in our impairment analysis include the projected utilization and pricing of our services, as well as the estimated proceeds upon any future sale or disposal of the assets, all of which are classified as Level 3 inputs as defined by ASC Topic 820, *Fair Value Measurements and Disclosures*.

The assumptions we use in the evaluation for impairment are inherently uncertain and require management judgment. Although we believe the assumptions and estimates used in our impairment analysis are reasonable, different assumptions and estimates could materially impact the analysis and resulting conclusions. If commodity prices remain at current levels for an extended period of time, or if the demand for any of our services decreases below what we are currently projecting, our estimated cash flows may decrease, and if any of the foregoing were to occur, we could incur impairment charges on the related assets.

4. Debt

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

	December 31, 2018	December 31, 2017
Senior secured term loan	$ 175,000	$ 175,000
Senior notes	300,000	300,000
	475,000	475,000
Less unamortized discount (based on imputed interest rate of 10.46%)	(2,668)	(3,387)
Less unamortized debt issuance costs	(7,780)	(9,948)
	$ 464,552	$ 461,665

Senior Secured Term Loan

Our senior secured term loan (the “Term Loan”) entered into on November 8, 2017 provided for one drawing in the amount of $175 million, net of a 2% original issue discount. Proceeds from the issuance of the Term Loan were used to repay the entire outstanding balance under our previous credit facility, plus fees and accrued and unpaid interest, as well as the fees and expenses associated with entering into the Term Loan and ABL Facility, which is further described below. The remainder of the proceeds are available to be used for other general corporate purposes.

The Term Loan is not subject to amortization payments of principal. Interest on the principal amount accrues at the LIBOR rate or the base rate as defined in the agreement, at our option, plus an applicable margin of 7.75% and 6.75%, respectively. The Term Loan is set to mature on November 8, 2022, or earlier, subject to certain circumstances as described in the agreement, and including an earlier maturity date if the outstanding balance of the Senior Notes exceeds $15.0 million on December 14, 2021, at which time the Term Loan would then mature. However, the Term Loan may be prepaid, at our option, at any time, in whole or in part, subject to a minimum of $5 million, and subject to a declining call premium as defined in the agreement.

The Term Loan contains a financial covenant requiring the ratio of (i) the net orderly liquidation value of our fixed assets (based on appraisals obtained as required by our lenders), on a consolidated basis, in which the lenders under the Term Loan maintain a first priority security interest, plus proceeds of asset dispositions not required to be used to effect a prepayment of the Term Loan to (ii) the outstanding principal amount of the Term Loan, to be at least equal to 1.50 to 1.00 as of any June 30 or December 31 of any calendar year through maturity.

The Term Loan contains customary mandatory prepayments from the proceeds of certain transactions including certain asset dispositions and debt issuances, and has additional customary restrictions that, among other things, and subject to certain exceptions, limit our ability to:

- incur additional debt;
- incur or permit liens on assets;
- make investments and acquisitions;
- consolidate or merge with another company;
- engage in asset sales; and
- pay dividends or make distributions.

In addition, the Term Loan contains customary events of default, upon the occurrence and during the continuation of any of which the applicable margin would increase by 2% per year, including without limitation:

- payment defaults;
- covenant defaults;
- material breaches of representations or warranties;
- event of default under, or acceleration of, other material indebtedness;
- bankruptcy or insolvency;
- material judgments against us;
- failure of any security document supporting the Term Loan; and
- change of control.

Our obligations under the Term Loan are guaranteed by our wholly-owned domestic subsidiaries, and are secured by substantially all of our domestic assets, in each case, subject to certain exceptions and permitted liens.

Asset-based Lending Facility

In addition to entering into the Term Loan, on November 8, 2017, we also entered into a senior secured revolving asset-based credit facility (the “ABL Facility”) providing for borrowings in the aggregate principal amount of up to $75 million, subject to a borrowing base and including a $30 million sub-limit for letters of credit. The ABL Facility bears interest, at our option, at the LIBOR rate or the base rate as defined in the ABL Facility, plus an applicable margin ranging from 1.75% to 3.25%, based on average availability on the ABL Facility. The ABL Facility requires a commitment fee due monthly based on the average monthly unused amount of the commitments of the lenders, a fronting fee due for each letter of credit issued, and a monthly letter of credit fee due based on the average undrawn amount of letters of credit outstanding during such period. The ABL Facility is generally set to mature 90 days prior to the maturity of the Term Loan, subject to certain circumstances, including the future repayment, extinguishment or refinancing of our Term Loan and/or Senior Notes prior to their respective maturity dates. Availability under the ABL Facility is determined by reference to a borrowing base as defined in the agreement, generally comprised of a percentage of our accounts receivable and inventory.

We have not drawn upon the ABL Facility to date. As of December 31, 2018, we had $9.7 million in committed letters of credit, which, after borrowing base limitations, resulted in borrowing availability of $49.0 million. Borrowings available under the ABL Facility are available for general corporate purposes, and there are no limitations on our ability to access the borrowing capacity provided there is no default and compliance with the covenants under the ABL Facility is maintained. Additionally, if our availability under the ABL Facility is less than 15% of the maximum amount (or $11.25 million), we are required to maintain a minimum fixed charge coverage ratio, as defined in the ABL Facility, of at least 1.00 to 1.00, measured on a trailing 12 month basis.

The ABL Facility also contains customary restrictive covenants which, subject to certain exceptions, limit, among other things, our ability to:

- declare dividends and make other distributions;
- issue or sell certain equity interests;
- optionally prepay, redeem or repurchase certain of our subordinated indebtedness;
- make loans or investments (including acquisitions);
- incur additional indebtedness or modify the terms of permitted indebtedness;
- grant liens;
- change our business or the business of our subsidiaries;
- merge, consolidate, reorganize, recapitalize, or reclassify our equity interests;
- sell our assets, and
- enter into certain types of transactions with affiliates.

Our obligations under the ABL Facility are guaranteed by us and our domestic subsidiaries, subject to certain exceptions, and are secured by (i) a first-priority perfected security interest in all inventory and cash, and (ii) a second-priority perfected security in substantially all of our tangible and intangible assets, in each case, subject to certain exceptions and permitted liens.

Senior Notes

In 2014, we issued $300 million of unregistered senior notes at face value, with a coupon interest rate of 6.125% that are due in 2022 (the "Senior Notes"). The Senior Notes will mature on March 15, 2022 with interest due semi-annually in arrears on March 15 and September 15 of each year. We have the option to redeem the Senior Notes, in whole or in part, 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.

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

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

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

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

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

Debt Issuance Costs and Original Issue Discount

Costs incurred in connection with the issuance of our Senior Notes were capitalized and are being amortized using the effective interest method over the term of the Senior Notes which mature in March 2022. The original issue discount and costs incurred in connection with the issuance of the Term Loan were capitalized and are being amortized using the effective interest method over the expected term of the agreement. Costs incurred in connection with the ABL Facility were capitalized and are being amortized using the straight-line method over the expected term of the agreement.

Loss on Extinguishment of Debt

We recognized $1.5 million of loss on extinguishment of debt during 2017 for the write off of the unamortized debt issuance costs associated with the retirement of our previous credit agreement, which provided for a senior secured revolving credit facility up to an aggregate commitment amount of $150 million and was set to mature in March 2019. In connection with our entry into the Term Loan in November 2017, all indebtedness outstanding under the previous credit facility was repaid, together with related costs and expenses, and the previous credit facility was retired. During 2016, we recognized $0.3 million of loss on extinguishment of debt associated with the amendment of our previous credit facility which resulted in reduced borrowing capacity.

5. Leases

We lease our corporate office in San Antonio, Texas, and we conduct our business operations through 29 other regional offices. Our regional operating locations typically include regional offices, storage and maintenance yards and personnel housing sufficient to support our operations in the area. We lease most of these properties, as well as office and other equipment, under non-cancelable and month to month operating leases, many of which contain renewal options and some of which contain escalation clauses. We recognize rent expense on a straight-line basis for our leases with escalating payments.

Rent expense under operating leases, including rental exit costs, was $5.4 million, $4.8 million and $5.0 million for the years ended December 31, 2018, 2017 and 2016, respectively. Future lease obligations required under non-cancelable operating leases as of December 31, 2018 were as follows (amounts in thousands):

Year ended December 31,	
2019	$ 3,318
2020	2,032
2021	1,721
2022	1,407
2023	1,110
Thereafter	1,738
	$ 11,326

6. Income Taxes

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

	Year ended December 31, 2018	2017	2016
Domestic	$ (53,230)	$ (76,078)	$ (122,277)
Foreign	6,127	(3,243)	(16,846)
Loss before income taxes	$ (47,103)	$ (79,321)	$ (139,123)

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

	Year ended December 31, 2018	2017	2016
Current:			
Federal	$ (183)	$ (81)	$ (219)
State	586	146	(95)
Foreign	967	978	1,189
	1,370	1,043	875
Deferred:			
Federal	—	(5,417)	(12,500)
State	537	143	902
Foreign	1	28	(9)
	538	(5,246)	(11,607)
Income tax expense (benefit)	$ 1,908	$ (4,203)	$ (10,732)

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

	Year ended December 31, 2018	2017	2016
Expected tax expense (benefit)	$ (9,892)	$ (27,762)	$ (48,693)
Valuation allowance:			
Valuation allowance on operations	5,885	24,265	38,324
Impact of tax law changes on valuation allowance	(1,692)	(25,564)	—
Change in tax rate	1,692	20,147	516
State income taxes	972	339	(3,033)
Foreign currency translation loss	1,038	599	838
Net tax benefits and nondeductible expenses in foreign jurisdictions	1,412	1,493	407
GILTI tax	634	—	—
Incentive stock options	757	1,297	97
Nondeductible expenses for tax purposes	829	796	386
Expiration of capital loss	—	—	641
Other, net	273	187	(215)
Income tax expense (benefit)	$ 1,908	$ (4,203)	$ (10,732)

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

	Year ended December 31, 2018	2017	2016
Continuing operations	$ 1,908	$ (4,203)	$ (10,732)
Shareholders' equity	—	—	2,287
	$ 1,908	$ (4,203)	$ (8,445)

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,	
	2018	2017
Deferred tax assets:		
Domestic net operating loss carryforward	$ 96,777	$ 94,598
Interest expense deduction limitation carryforward	2,495	—
Foreign net operating loss carryforward	9,582	11,619
Intangibles	14,875	18,058
Property and equipment	5,291	9,280
Employee benefits and insurance claims accruals	5,374	5,652
Employee stock-based compensation	3,271	3,753
Accounts receivable reserve	325	284
Inventory	236	295
Accrued expenses	190	—
Deferred revenue	560	316
	138,976	143,855
Valuation allowance	(62,639)	(59,766)
Deferred tax liabilities:		
Accrued expenses	(419)	(112)
Property and equipment	(79,606)	(87,128)
Net deferred tax liabilities	$ (3,688)	$ (3,151)

As of December 31, 2018, we had $96.8 million and $9.6 million of deferred tax assets related to domestic and foreign net operating losses, respectively, that are available to reduce future taxable income. In assessing the realizability of our deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible.

In performing this analysis as of December 31, 2018 in accordance with ASC Topic 740, *Income Taxes*, we assessed the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit the use of deferred tax assets. A significant piece of negative evidence evaluated is the cumulative loss incurred during previous years. Such negative evidence limits the ability to consider other positive evidence that is subjective, such as projections for taxable income in future years. Because we are in a net deferred tax asset position, we recognize a benefit only to the extent that reversals of deferred income tax liabilities are expected to generate taxable income in each relevant jurisdiction in future periods which would offset our deferred tax assets.

Our domestic federal net operating losses generated through 2017 have a 20 year carryforward period and can be used to offset future domestic taxable income until their expiration, beginning in 2030, with the latest expiration in 2037. Losses generated after 2017 have an unlimited carryforward period and are limited in usage to 80% of taxable income (pursuant to the Tax Reform Act mentioned below). The majority of our foreign net operating losses generated through 2016 have an indefinite carryforward period, while losses generated after 2016 have a carryforward period of 12 years. As of December 31, 2018, we have a valuation allowance that fully offsets our foreign and domestic federal deferred tax assets. We also have net operating loss carryforwards in many of the states that we operate in. Most of these are filed on a unitary or combined basis. These states have carryover periods between 5 and 20 years, with most being 15 or 20. We have determined that a valuation allowance should be recorded against some of the state benefits through December 31, 2018. The valuation allowance is the primary factor causing our effective tax rate to be significantly lower than the statutory rate. The amount of the deferred tax asset considered realizable, however, would increase if cumulative losses are no longer present and additional weight is given to subjective evidence in the form of projected future taxable income.

We have no unrecognized tax benefits relating to ASC Topic 740 and no unrecognized tax benefit activity during the year ended December 31, 2018. We record interest and penalty expense related to income taxes as interest and other expense, respectively. At December 31, 2018, no interest or penalties have been or are required to be accrued. Our open tax years are 2015 and forward for our federal and most state income tax returns in the United States and 2013 and forward for our income tax returns in Colombia. Net operating losses generated in years prior to our open years and carried forward are available for adjustment and subject to the statute of limitation provisions of such year when the net operating losses are utilized.

Recently Enacted Tax Reform

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the "Tax Reform Act") was enacted. The legislation significantly changes U.S. tax law by, among other things, permanently reducing the U.S. corporate income tax rate from a maximum of 35% to a flat rate of 21%, repealing the alternative minimum tax (AMT), implementing a territorial tax system and imposing a repatriation tax on deemed repatriated earnings of foreign subsidiaries, limiting the current deductibility of net interest expense in excess of 30% of adjusted taxable income, and limiting net operating losses generated after 2017 to 80% of taxable income.

As a result of the reduction in the U.S. corporate income tax rate, we revalued our ending net deferred tax assets at December 31, 2017 and recognized a $20.1 million tax expense in 2017, which was fully offset by a $20.1 million reduction of the valuation allowance.

Due to the repeal of the AMT, for the year ended December 31, 2017, we reduced the valuation allowance by $5.2 million to remove the effects of AMT on the realizability of our deferred tax assets in future years. In addition, we reversed the valuation allowance on the AMT credit carryforward of $0.2 million that will now be refundable through 2021 and has been reclassified from a deferred tax asset to a noncurrent receivable.

Territorial Tax System — To minimize tax base erosion with a territorial tax system, beginning in 2018, the Tax Reform Act provides for a new global intangible low-taxed income (GILTI) provision. Under the GILTI provision, certain foreign subsidiary earnings in excess of an allowable return on the foreign subsidiary's tangible assets are included in U.S. taxable income. We are now subject to GILTI, and we have elected to treat the GILTI tax as a period expense rather than to provide U.S. deferred taxes on foreign temporary differences that are expected to generate GILTI income when they reverse in future years.

Limitation on Interest Expense Deduction — The new limitation on interest expense resulted in a $11.4 million disallowance for the year ended December 31, 2018; however, this adjustment is offset fully by our net operating loss carry forwards. The disallowed interest has an indefinite carry forward period and any limitations on the utilization of this interest expense carryforward have been factored into our valuation allowance analysis.

Limitation on Future Net Operating Losses Deduction — Net operating losses generated after 2017 are carried forward indefinitely and are limited to 80% of taxable income. Net operating losses generated prior to 2018 continue to be carried forward for 20 years and have no 80% limitation on utilization.

Mandatory Repatriation — The Tax Reform Act provided for a one-time deemed mandatory repatriation of post-1986 undistributed foreign subsidiary earnings and profits through the year ended December 31, 2017. Because we had an accumulated foreign deficit at December 31, 2017, we did not record a tax liability from the mandatory repatriation provision of the Tax Reform Act. We do not intend to distribute earnings in a taxable manner, and therefore, we intend to limit any potential distributions to earnings previously taxed in the U.S., or earnings that would qualify for the 100% dividends received deduction provided for in the Tax Reform Act. As a result, we have not recognized a deferred tax liability on our investment in foreign subsidiaries.

International Tax Reform

On December 28, 2018, the Colombian government enacted a new tax reform bill that decreases the general corporate tax rate from 33% to 30% by 2022, phases out the presumptive tax system by 2021, increases withholding tax rates on payments abroad for various services, and taxes indirect transfers of Colombian assets, among other things. Deferred tax assets and liabilities were adjusted to the new tax rates; however, the adjustments to the valuation allowance fully offset the impact to tax expense.

7. Fair Value of Financial Instruments

The FASB's Accounting Standards Codification (ASC) Topic 820, *Fair Value Measurements and Disclosures*, defines fair value and provides a hierarchal framework associated with the level of subjectivity used in measuring assets and liabilities at fair value. Our financial instruments consist primarily of cash and cash equivalents, trade and other receivables, trade payables, phantom stock unit awards and long-term debt.

The carrying value of cash and cash equivalents, 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. At December 31, 2018 and December 31, 2017, the aggregate estimated fair value of our phantom stock unit awards was $5.1 million and $6.1 million, respectively, for which the vested portion recognized as a liability in our consolidated balance sheets at both period ends was $3.6 million. The phantom stock unit awards, and the measurement of fair value for these awards, are described in more detail in Note 9, *Equity Transactions and Stock-Based Compensation Plans*.

The fair value of our Senior Notes is estimated based on recent observable market prices for our debt instruments, which are defined by ASC Topic 820 as Level 2 inputs. The fair value of our Term Loan is based on estimated market pricing for our debt instrument, which is defined by ASC Topic 820 as using Level 3 inputs which are unobservable and therefore more likely to be affected by changes in assumptions. The following table presents supplemental fair value information and carrying value for our debt, net of discount and debt issuance costs (amounts in thousands):

		December 31, 2018		December 31, 2017	
	Hierarchy Level	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Senior notes	2	$ 296,988	$ 186,750	$ 296,181	$ 243,948
Senior secured term loan	3	167,564	$ 175,875	165,484	171,613
		$ 464,552	$ 362,625	$ 461,665	$ 415,561

8. Earnings (Loss) Per Common Share

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

	Year ended December 31,		
	2018	2017	2016
Numerator (both basic and diluted):			
Net loss	$ (49,011)	$ (75,118)	$ (128,391)
Denominator:			
Weighted-average shares (denominator for basic earnings (loss) per share)	77,957	77,390	65,452
Dilutive effect of outstanding stock options, restricted stock and restricted stock unit awards	—	—	—
Denominator for diluted earnings (loss) per share	77,957	77,390	65,452
Loss per common share - Basic	$ (0.63)	$ (0.97)	$ (1.96)
Loss per common share - Diluted	$ (0.63)	$ (0.97)	$ (1.96)
Potentially dilutive securities excluded as anti-dilutive	4,722	5,116	4,953

9. Equity Transactions and Stock-Based Compensation Plans

Equity Transactions

On May 22, 2018, 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, 2018, the entire $300 million under the shelf registration statement is available for equity or debt offerings, subject to the limitations imposed by our Term Loan, ABL Facility and Senior Notes.

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, 2018, the total shares available for future grants to employees and directors under existing plans were 2,390,057, which excludes awards we grant in the form of phantom stock unit awards which are expected to be paid in cash. In January 2019, our Board of Directors approved the grant of the following awards:

	Vesting Period	Number of Shares or Units
Restricted stock unit awards	3 years	870,648
Performance-based phantom stock unit awards	39 months	2,467,776
Time-based phantom stock unit awards	3 years	810,648

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. We grant phantom stock unit awards with vesting based on time of service, performance and market conditions, which are classified as liability awards under ASC Topic 718, *Compensation—Stock Compensation* since we expect to settle the awards in cash when they become vested.

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

The following table summarizes the stock-based compensation expense recognized, by award type, and the compensation expense recognized for phantom stock unit awards during the years ended December 31, 2018, 2017 and 2016 (amounts in thousands):

	Year ended December 31,		
	2018	2017	2016
Stock option awards	$ 443	$ 974	$ 766
Restricted stock awards	460	461	421
Restricted stock unit awards	3,541	2,914	2,757
	$ 4,444	$ 4,349	$ 3,944
Phantom stock unit awards	$ 46	$ 1,609	$ 1,971

The following table summarizes the unrecognized compensation cost (amounts in thousands) to be recognized and the weighted-average period remaining (in years) over which the compensation cost is expected to be recognized, by award type, as of December 31, 2018:

	Weighted-Average Period Remaining	Unrecognized Compensation Cost
Stock options	0.26	$ 156
Restricted stock awards	0.38	174
Restricted stock unit awards	1.11	3,132
Phantom stock unit awards (based on fair value as of December 31, 2018)	2.65	1,484
		$ 4,946

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. There were no stock options granted during the year ended December 31, 2018. The following table summarizes the assumptions used in the Black-Scholes option pricing model based on a weighted-average calculation for the options granted during the years ended December 31, 2017 and 2016:

	Year ended December 31,	
	2017	2016
Expected volatility	76%	70%
Risk-free interest rates	2.1%	1.5%
Expected life in years	5.86	5.70
Grant-date fair value	$4.28	$0.80

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

The following table summarizes our stock option activity from December 31, 2017 through December 31, 2018:

	Number of Shares	Weighted-Average Exercise Price Per Share	Weighted-Average Remaining Contract Term in Years	Aggregate Intrinsic Value (in thousands)(1)
Outstanding stock options as of December 31, 2017	4,269,910	$6.78		
Forfeited	(527,000)	15.43		
Exercised	(3,000)	3.84		
Outstanding stock options as of December 31, 2018	3,739,910	$5.56	4.0	$ —
Stock options exercisable as of December 31, 2018	3,259,125	$5.91	3.5	$ —

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

The following table presents the aggregate intrinsic value of stock options exercised during the years ended December 31, 2018, 2017 and 2016 (amounts in thousands):

	Year ended December 31,		
	2018	2017	2016
Aggregate intrinsic value of stock options exercised	$ 6	$ —	$ 12

The following table summarizes our nonvested stock option activity from December 31, 2017 through December 31, 2018:

	Number of Shares	Weighted-Average Grant-Date Fair Value Per Share
Nonvested stock options as of December 31, 2017	981,447	$1.91
Vested	(500,662)	1.76
Nonvested stock options as of December 31, 2018	480,785	$2.07

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 presents the weighted-average grant-date fair value per share of restricted stock awards granted and the aggregate fair value of restricted stock awards vested during the years ended December 31, 2018, 2017 and 2016:

	Year ended December 31,		
	2018	2017	2016
Grant-date fair value of awards granted (per share)	$ 5.85	$ 2.75	$ 2.76
Aggregate fair value of awards vested (in thousands)	$ 979	$ 483	$ 137

The following table summarizes our restricted stock activity from December 31, 2017 through December 31, 2018:

	Number of Shares	Weighted-Average Grant-Date Fair Value per Share
Nonvested restricted stock as of December 31, 2017	167,272	$2.75
Granted	78,632	5.85
Vested	(167,272)	2.75
Nonvested restricted stock as of December 31, 2018	78,632	$5.85

Restricted Stock Units

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

Approximately half of the performance-based RSUs outstanding are subject to a market condition based on relative total shareholder return, as compared to that of our predetermined peer group, and therefore the fair value of these awards is measured using a Monte Carlo simulation model. Compensation expense for equity awards with a market condition is reduced only for actual 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 EBITDA 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 2018, we determined that 106% of the target number of shares granted during 2015 were actually earned based on the Company's achievement of the performance measures as described above, resulting in an increase of 25,807 shares being issued. As of December 31, 2018, we estimate that the achievement level for our outstanding performance-based RSUs granted in 2017 will be approximately 100% of the predetermined performance conditions.

The following table summarizes our restricted stock unit activity from December 31, 2017 through December 31, 2018:

	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, 2017	251,886	$3.24	986,117	$6.91
Granted	788,377	3.85	—	—
Achieved performance adjustment	—	—	25,807	5.82
Vested	(124,286)	3.04	(448,455)	5.82
Forfeited	(28,508)	3.65	—	—
Nonvested restricted stock units as of December 31, 2018	887,469	$3.80	563,469	$7.73

The following table presents the weighted-average grant-date fair value per share of restricted stock units granted and the aggregate intrinsic value of restricted stock units vested (converted) during the years ended December 31, 2018, 2017 and 2016:

	Year ended December 31,		
	2018	2017	2016
Time-based RSUs:			
Grant-date fair value of awards granted (per share)	$ 3.85	$ 5.61	$ 1.47
Aggregate intrinsic value of awards vested (in thousands)	$ 424	$ 1,206	$ 314
Performance-based RSUs:			
Grant-date fair value of awards granted (per share)	$ —	$ 7.75	$ —
Aggregate intrinsic value of awards vested (in thousands)	$ 1,547	$ 969	$ 609

Phantom Stock Unit Awards

In 2016 and 2018, we granted 1,268,068 and 1,188,216 phantom stock unit awards with weighted-average grant-date fair values of $1.35 and $3.06 per share, respectively. These awards cliff-vest after 39 months from the date of grant, with vesting based on time of service, performance and market conditions. The number of units ultimately awarded will be based upon the Company's achievement in certain performance conditions, as compared to a predefined peer group, over the respective three-year performance periods, and each unit awarded will entitle the employee to a cash payment equal to the stock price of our common stock on the date of vesting, subject to a maximum of $8.08 and $9.66 (which is four and three times the grant date stock price), respectively.

The fair value of these awards is measured using inputs that are defined as Level 3 inputs under ASC Topic 820, *Fair Value Measurements and Disclosures*. Half of the 2016 phantom stock unit awards are subject to a market condition based on relative total shareholder return, and therefore the fair values of these awards are measured using a Monte Carlo simulation model, which incorporates the estimate of our relative total shareholder return achievement level. The remaining 2016 phantom stock unit awards are subject to performance conditions, based on our relative EBITDA and EBITDA return on capital employed, and the fair values of these awards are measured using a Black-Scholes pricing model. The 2018 phantom stock unit awards will vest based upon our relative total shareholder return and relative EBITDA return on capital, both of which are subject to market conditions, and therefore, the fair value of these awards is measured using a Monte Carlo simulation model which generates a fair value that incorporates the relative estimated achievement levels. As of December 31, 2018, we estimate the achievement levels for our outstanding 2016 and 2018 phantom stock unit awards to be 175% and 100%, respectively.

These awards are classified as liability awards under ASC Topic 718, *Compensation—Stock Compensation*, because we expect to settle the awards in cash when they vest, and are remeasured at fair value at the end of each reporting period until they vest. The change in fair value is recognized as a current period compensation expense in our consolidated statements of operations.Therefore, changes in the inputs used to measure fair value can result in volatility in our compensation expense. This volatility increases as the phantom stock awards approach the vesting date. We estimate that a hypothetical increase of $1 in the market price of our common stock, which was $1.23 as of December 31, 2018, if all other inputs were unchanged, would result in an increase in cumulative compensation expense of $0.4 million, which represents the hypothetical increase in fair value of the liability for the 2018 phantom stock unit awards.

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, 2018, 2017 and 2016 were \$4.6 million, \$3.1 million and \$0.3 million, respectively. In an effort to reduce costs in response to the downturn in our industry, we suspended matching contributions from February 2016 to January 2017.

We use a combination of self-insurance and third-party insurance for various types of coverage. 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 using an actuarial calculation that is based on industry and our company's historical claim development data, and we accrue the cost of administrative services associated with claims processing. 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 a maximum health insurance liability of \$200,000 per covered individual per year, while amounts in excess of this maximum are covered under a separate policy provided by an insurance company. We have provided for reported claims costs as well as incurred but not reported medical costs in the accompanying consolidated balance sheets. 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 related to our estimate of the self-insured portion of costs associated with our health, workers' compensation, general liability and auto liability insurance are as follows:

	As of December 31,	
	2018	2017
Workers' compensation	$ 2,992	$ 3,689
Health insurance	1,834	2,046
General liability and auto liability	656	1,007
	$ 5,482	$ 6,742

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.

Our insurance recoveries receivables and our accrued liability for insurance claims and settlements represent our estimate of claims in excess of our deductible, which are covered and managed by our third-party insurance providers, some of which may ultimately be settled by the insurance provider in the long-term. These are presented in our consolidated balance sheets as current due to the uncertainty in the timing of reporting and payment of claims.

11. Segment Information

We have five operating segments, comprised of two drilling services business segments (domestic and international drilling) and three production services business segments (well servicing, wireline services and coiled tubing services), which reflects the basis used by management in making decisions regarding our business for resource allocation and performance assessment, as required by ASC Topic 280, *Segment Reporting*.

Our domestic and international drilling services segments provide contract land drilling services to a diverse group of exploration and production companies through our three drilling divisions in the US and internationally in Colombia. We provide a comprehensive service offering which includes the drilling rig, crews, supplies and most of the ancillary equipment needed to operate our drilling rigs.

Our well servicing, wireline services and coiled tubing services segments provide a range of production services to a diverse group of exploration and production companies, with our operations concentrated in the major domestic onshore oil and gas producing regions in the Gulf Coast, Mid-Continent and Rocky Mountain states.

The following tables set forth certain financial information for each of our segments and corporate (amounts in thousands):

	As of and for the year ended December 31,		
	2018	2017	2016
Revenues:			
Domestic drilling	$ 145,676	$ 129,276	$ 112,399
International drilling	84,161	41,349	6,808
Drilling services	229,837	170,625	119,207
Well servicing	93,800	77,257	71,491
Wireline services	215,858	163,716	67,419
Coiled tubing services	50,602	34,857	18,959
Production services	360,260	275,830	157,869
Consolidated revenues	$ 590,097	$ 446,455	$ 277,076
Operating costs:			
Domestic drilling	$ 86,910	$ 83,122	$ 63,686
International drilling	64,074	31,994	9,465
Drilling services	150,984	115,116	73,151
Well servicing	67,554	56,379	53,208
Wireline services	167,337	128,137	57,634
Coiled tubing services	44,038	31,248	19,956
Production services	278,929	215,764	130,798
Consolidated operating costs	$ 429,913	$ 330,880	$ 203,949
Gross margin:			
Domestic drilling	$ 58,766	$ 46,154	$ 48,713
International drilling	20,087	9,355	(2,657)
Drilling services	78,853	55,509	46,056
Well servicing	26,246	20,878	18,283
Wireline services	48,521	35,579	9,785
Coiled tubing services	6,564	3,609	(997)
Production services	81,331	60,066	27,071
Consolidated gross margin	$ 160,184	$ 115,575	$ 73,127
Identifiable Assets:			
Domestic drilling [(1)]	$ 373,370	$ 404,144	$ 415,953
International drilling [(1) (2)]	43,213	36,403	36,337
Drilling services	416,583	440,547	452,290
Well servicing	118,923	125,951	126,917
Wireline services	87,912	92,081	80,502
Coiled tubing services	37,326	30,254	26,062
Production services	244,161	248,286	233,481
Corporate	80,806	78,036	14,331
Consolidated identifiable assets	$ 741,550	$ 766,869	$ 700,102
Depreciation:			
Domestic drilling	$ 41,289	$ 45,243	$ 53,900
International drilling	5,628	5,718	6,869
Drilling services	46,917	50,961	60,769
Well servicing	19,578	19,943	22,925
Wireline services	17,945	18,451	20,707
Coiled tubing services	7,987	8,181	8,661
Production services	45,510	46,575	52,293
Corporate	1,127	1,241	1,250
Consolidated depreciation	$ 93,554	$ 98,777	$ 114,312

	As of and for the year ended December 31,		
	2018	2017	2016
Capital Expenditures:			
Domestic drilling	$ 23,598	$ 19,219	$ 19,118
International drilling	6,309	6,319	678
Drilling services	29,907	25,538	19,796
Well servicing	10,002	17,776	5,274
Wireline services	15,247	11,883	3,499
Coiled tubing services	16,558	5,496	3,548
Production services	41,807	35,155	12,321
Corporate	1,140	754	439
Consolidated capital expenditures	$ 72,854	$ 61,447	$ 32,556

(1) Identifiable assets for our drilling segments include the impact of a $40.1 million, $27.0 million, and $10.8 million intercompany balance, as of December 31, 2018, 2017, and 2016, respectively, between our domestic drilling segment (intercompany receivable) and our international drilling segment (intercompany payable).

(2) Identifiable assets for our international drilling segment 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.

The following table reconciles the consolidated gross margin of our segments reported above to loss from operations as reported on the consolidated statements of operations (amounts in thousands):

	Year ended December 31,		
	2018	2017	2016
Consolidated gross margin	$ 160,184	$ 115,575	$ 73,127
Depreciation	(93,554)	(98,777)	(114,312)
General and administrative	(74,117)	(69,681)	(61,184)
Bad debt expense	(271)	(53)	(156)
Impairment	(4,422)	(1,902)	(12,815)
Gain on dispositions of property and equipment, net	3,121	3,608	1,892
Loss from operations	$ (9,059)	$ (51,230)	$ (113,448)

12. Commitments and Contingencies

In connection with our operations in Colombia, our foreign subsidiaries routinely obtain bonds for bidding on drilling contracts, performing under drilling contracts, and remitting customs and importation duties. We have guaranteed payments of $50.9 million relating to our performance under these bonds as of December 31, 2018. Based on historical experience and information currently available, we believe the likelihood of demand for payment under these bonds and guarantees is remote.

We are currently undergoing sales and use tax audits for multi-year periods. As of December 31, 2018 and December 31, 2017, our accrued liability was $1.7 million and $1.2 million, respectively, based on our estimate of the sales and use tax obligations that are expected to result from these audits. Due to the inherent uncertainty of the audit process, we believe that it is reasonably possible that we may incur additional tax assessments with respect to one or more of the audits in excess of the amount accrued. We believe that such an outcome would not have a material adverse effect on our results of operations or financial position. Because certain of these audits are in a preliminary stage, an estimate of the possible loss or range of loss from an adverse result in all or substantially all of these cases cannot reasonably be made.

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

13. Quarterly Results of Operations (unaudited)

The following table summarizes our quarterly financial data (in thousands, except per share data):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Year ended December 31, 2018					
Revenues	$ 144,478	$ 154,782	$ 149,332	$ 141,505	$ 590,097
Income (loss) from operations	(842)	(8,803)	4,338	(3,752)	(9,059)
Income tax (expense) benefit	(1,288)	249	(258)	(611)	(1,908)
Net loss	(11,139)	(18,152)	(5,233)	(14,487)	(49,011)
Loss per share:					
Basic	$ (0.14)	$ (0.23)	$ (0.07)	$ (0.19)	$ (0.63)
Diluted	$ (0.14)	$ (0.23)	$ (0.07)	$ (0.19)	$ (0.63)
Year ended December 31, 2017					
Revenues	$ 95,757	$ 107,130	$ 117,281	$ 126,287	$ 446,455
Loss from operations	(18,873)	(12,729)	(10,892)	(8,736)	(51,230)
Income tax (expense) benefit	(48)	(1,135)	(17)	5,403	4,203
Net loss	(25,124)	(20,209)	(17,227)	(12,558)	(75,118)
Loss per share:					
Basic	$ (0.33)	$ (0.26)	$ (0.22)	$ (0.16)	$ (0.97)
Diluted	$ (0.33)	$ (0.26)	$ (0.22)	$ (0.16)	$ (0.97)

14. Guarantor/Non-Guarantor Condensed Consolidating Financial Statements

Our Senior Notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by all existing 100% owned domestic subsidiaries, except for Pioneer Services Holdings, LLC. The subsidiaries that generally operate our non-U.S. business concentrated in Colombia do not guarantee our Senior Notes. The non-guarantor subsidiaries do not have any payment obligations under the Senior Notes, the guarantees or the Indenture.

In the event of a bankruptcy, liquidation or reorganization of any non-guarantor subsidiary, such non-guarantor subsidiary will pay the holders of its debt and other liabilities, including its trade creditors, before it will be able to distribute any of its assets to us. In the future, any non-U.S. subsidiaries, immaterial subsidiaries and subsidiaries that we designate as unrestricted subsidiaries under the Indenture will not guarantee the Senior Notes. As of December 31, 2018, there were no restrictions on the ability of subsidiary guarantors to transfer funds to the parent company.

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

CONDENSED CONSOLIDATING BALANCE SHEETS
(in thousands)

	December 31, 2018				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 50,350	$ —	$ 3,216	$ —	$ 53,566
Restricted cash	998	—	—	—	998
Receivables, net of allowance	436	95,030	35,219	196	130,881
Intercompany receivable (payable)	(27,245)	67,098	(39,853)	—	—
Inventory	—	9,945	8,953	—	18,898
Assets held for sale	—	3,582	—	—	3,582
Prepaid expenses and other current assets	1,743	3,197	2,169	—	7,109
Total current assets	26,282	178,852	9,704	196	215,034
Net property and equipment	2,022	494,376	28,460	—	524,858
Investment in subsidiaries	574,695	25,370	—	(600,065)	—
Deferred income taxes	42,585	—	—	(42,585)	—
Other noncurrent assets	596	511	551	—	1,658
Total assets	$ 646,180	$ 699,109	$ 38,715	$ (642,454)	$ 741,550
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 1,093	$ 26,795	$ 6,246	$ —	$ 34,134
Deferred revenues	—	95	1,627	—	1,722
Accrued expenses	14,020	49,640	5,056	196	68,912
Total current liabilities	15,113	76,530	12,929	196	104,768
Long-term debt, less unamortized discount and debt issuance costs	464,552	—	—	—	464,552
Deferred income taxes	—	46,273	—	(42,585)	3,688
Other noncurrent liabilities	1,457	1,611	416	—	3,484
Total liabilities	481,122	124,414	13,345	(42,389)	576,492
Total shareholders' equity	165,058	574,695	25,370	(600,065)	165,058
Total liabilities and shareholders' equity	$ 646,180	$ 699,109	$ 38,715	$ (642,454)	$ 741,550

	December 31, 2017				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 70,377	$ —	$ 3,263	$ —	$ 73,640
Restricted cash	2,008	—	—	—	2,008
Receivables, net of allowance	7	93,866	19,174	(42)	113,005
Intercompany receivable (payable)	(22,955)	49,651	(26,696)	—	—
Inventory	—	7,741	6,316	—	14,057
Assets held for sale	—	6,620	—	—	6,620
Prepaid expenses and other current assets	1,238	3,193	1,798	—	6,229
Total current assets	50,675	161,071	3,855	(42)	215,559
Net property and equipment	2,011	521,080	26,532	—	549,623
Investment in subsidiaries	596,927	20,095	—	(617,022)	—
Deferred income taxes	38,028	—	—	(38,028)	—
Other noncurrent assets	496	788	403	—	1,687
Total assets	$ 688,137	$ 703,034	$ 30,790	$ (655,092)	$ 766,869
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 286	$ 24,174	$ 5,078	$ —	$ 29,538
Deferred revenues	—	97	808	—	905
Accrued expenses	12,504	37,814	4,195	(42)	54,471
Total current liabilities	12,790	62,085	10,081	(42)	84,914
Long-term debt, less unamortized discount and debt issuance costs	461,665	—	—	—	461,665
Deferred income taxes	—	41,179	—	(38,028)	3,151
Other noncurrent liabilities	3,586	2,843	614	—	7,043
Total liabilities	478,041	106,107	10,695	(38,070)	556,773
Total shareholders' equity	210,096	596,927	20,095	(617,022)	210,096
Total liabilities and shareholders' equity	$ 688,137	$ 703,034	$ 30,790	$ (655,092)	$ 766,869

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(in thousands)

	Year ended December 31, 2018				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$ —	$ 505,936	$ 84,161	$ —	$ 590,097
Costs and expenses:					
Operating costs	—	365,848	64,065	—	429,913
Depreciation	1,127	86,799	5,628	—	93,554
General and administrative	22,506	49,231	2,800	(420)	74,117
Bad debt expense	—	271	—	—	271
Impairment	—	4,422	—	—	4,422
Gain (loss) on dispositions of property and equipment, net	1	(3,068)	(54)	—	(3,121)
Intercompany leasing	—	(4,860)	4,860	—	—
Total costs and expenses	23,634	498,643	77,299	(420)	599,156
Income (loss) from operations	(23,634)	7,293	6,862	420	(9,059)
Other income (expense):					
Equity in earnings of subsidiaries	8,966	5,669	—	(14,635)	—
Interest expense, net of interest capitalized	(38,765)	(16)	(1)	—	(38,782)
Other income (expense)	578	867	(287)	(420)	738
Total other income (expense)	(29,221)	6,520	(288)	(15,055)	(38,044)
Income (loss) before income taxes	(52,855)	13,813	6,574	(14,635)	(47,103)
Income tax (expense) benefit [1]	3,844	(4,847)	(905)	—	(1,908)
Net income (loss)	$ (49,011)	$ 8,966	$ 5,669	$ (14,635)	$ (49,011)

	Year ended December 31, 2017				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$ —	$ 405,106	$ 41,349	$ —	$ 446,455
Costs and expenses:					
Operating costs	—	298,898	31,982	—	330,880
Depreciation	1,242	91,817	5,718	—	98,777
General and administrative	22,869	45,387	1,922	(497)	69,681
Bad debt expense	—	53	—	—	53
Impairment	—	1,902	—	—	1,902
Gain (loss) on dispositions of property and equipment, net	2	(3,454)	(156)	—	(3,608)
Intercompany leasing	—	(4,860)	4,860	—	—
Total costs and expenses	24,113	429,743	44,326	(497)	497,685
Income (loss) from operations	(24,113)	(24,637)	(2,977)	497	(51,230)
Other income (expense):					
Equity in earnings of subsidiaries	4,317	(3,936)	—	(381)	—
Interest expense, net of interest capitalized	(27,061)	20	2	—	(27,039)
Loss on extinguishment of debt	(1,476)	—	—	—	(1,476)
Other income (expense)	54	896	(29)	(497)	424
Total other expense, net	(24,166)	(3,020)	(27)	(878)	(28,091)
Loss before income taxes	(48,279)	(27,657)	(3,004)	(381)	(79,321)
Income tax (expense) benefit [1]	(26,839)	31,974	(932)	—	4,203
Net income (loss)	$ (75,118)	$ 4,317	$ (3,936)	$ (381)	$ (75,118)

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

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

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

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

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(in thousands)

	Year ended December 31, 2018				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows from operating activities	$ (51,947)	$ 84,663	$ 6,940	$ —	$ 39,656
Cash flows from investing activities:					
Purchases of property and equipment	(1,077)	(59,478)	(6,593)	—	(67,148)
Proceeds from sale of property and equipment	—	5,826	38	—	5,864
Proceeds from insurance recoveries	—	1,066	16	—	1,082
	(1,077)	(52,586)	(6,539)	—	(60,202)
Cash flows from financing activities:					
Proceeds from exercise of options	11	—	—	—	11
Purchase of treasury stock	(549)	—	—	—	(549)
Intercompany contributions/distributions	32,525	(32,077)	(448)	—	—
	31,987	(32,077)	(448)	—	(538)
Net decrease in cash, cash equivalents and restricted cash	(21,037)	—	(47)	—	(21,084)
Beginning cash, cash equivalents and restricted cash	72,385	—	3,263	—	75,648
Ending cash, cash equivalents and restricted cash	$ 51,348	$ —	$ 3,216	$ —	$ 54,564

	Year ended December 31, 2017				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows from operating activities	$ (41,185)	$ 26,609	$ 8,759	$ —	$ (5,817)
Cash flows from investing activities:					
Purchases of property and equipment	(745)	(56,556)	(6,407)	431	(63,277)
Proceeds from sale of property and equipment	—	12,768	232	(431)	12,569
Proceeds from insurance recoveries	—	3,344	—	—	3,344
	(745)	(40,444)	(6,175)	—	(47,364)
Cash flows from financing activities:					
Debt repayments	(120,000)	—	—	—	(120,000)
Proceeds from issuance of debt	245,500	—	—	—	245,500
Debt issuance costs	(6,332)	—	—	—	(6,332)
Purchase of treasury stock	(533)	—	—	—	(533)
Intercompany contributions/distributions	(13,454)	13,835	(381)	—	—
	105,181	13,835	(381)	—	118,635
Net increase in cash, cash equivalents and restricted cash	63,251	—	2,203	—	65,454
Beginning cash, cash equivalents and restricted cash	9,134	—	1,060	—	10,194
Ending cash, cash equivalents and restricted cash	$ 72,385	$ —	$ 3,263	$ —	$ 75,648

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

	Year ended December 31, 2016				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows from operating activities	$ (34,496)	$ 40,187	$ (560)	$ —	$ 5,131
Cash flows from investing activities:					
Purchases of property and equipment	(452)	(31,049)	(880)	—	(32,381)
Proceeds from sale of property and equipment	—	7,523	54	—	7,577
Proceeds from insurance recoveries	—	37	—	—	37
	(452)	(23,489)	(826)	—	(24,767)
Cash flows from financing activities:					
Debt repayments	(71,000)	—	—	—	(71,000)
Proceeds from issuance of debt	22,000	—	—	—	22,000
Debt issuance costs	(819)	—	—	—	(819)
Proceeds from exercise of options	183	—	—	—	183
Proceeds from common stock, net of offering costs	65,430	—		—	65,430
Purchase of treasury stock	(124)	—	—	—	(124)
Intercompany contributions/distributions	16,803	(16,698)	(105)	—	—
	32,473	(16,698)	(105)	—	15,670
Net decrease in cash and cash equivalents	(2,475)	—	(1,491)	—	(3,966)
Beginning cash and cash equivalents	11,609	—	2,551	—	14,160
Ending cash and cash equivalents	$ 9,134	$ —	$ 1,060	$ —	$ 10,194

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, 2018, to ensure that information required to be disclosed in our reports filed or submitted under the Exchange Act is (1) recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms and (2) accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

In the ordinary course of business, we may make changes to our systems and processes to improve controls and increase efficiency, and make changes to our internal controls over financial reporting in order to ensure that we maintain an effective internal control environment.

We are nearing the completion of our implementation process for the adoption of ASU No. 2016-02, *Leases*, and its related amendments, which we discuss more fully in 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. During this implementation and upon adoption of the new standard, we expect certain changes to be necessary affecting our internal control over financial reporting, the most significant of which relate to the implementation of a new lease accounting system and modifications to the related payment and accounting processes.

There has been no change in our internal control over financial reporting that occurred during the three months ended December 31, 2018 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, 2018. 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, 2018, 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, 2018. 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 2019 Annual Meeting of Shareholders. We intend to file that definitive proxy statement with the SEC on or about April 16, 2019 (and, in any event, not later than 120 days after the end of the fiscal year covered by this report).

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Please see the information appearing in the proposal for the election of directors and under the headings “Executive Officers,” “Information Concerning Meetings and Committees of the Board of Directors,” “Code of Business Conduct and Ethics and Corporate Governance Guidelines” and “Section 16(a) Beneficial Ownership Reporting Compliance” in the definitive proxy statement for our 2019 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 “Compensation Committee Report” in the definitive proxy statement for our 2019 Annual Meeting of Shareholders for the information this Item 11 requires.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED SHAREHOLDER 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 2019 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 2019 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 2019 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 May 22, 2017 (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 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)).
4.3*	-	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 2003 Stock Plan (Form S-8 dated November 18, 2003 (File No. 333-110569, Exhibit 4.4)).
10.2+*	-	Pioneer Drilling Company Amended and Restated 2007 Incentive Plan (Form 10-Q dated November 3, 2011 (File No. 1-8182, Exhibit 10.1)).
10.3+*	-	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)).
10.4+*	-	Pioneer Energy Services Corp. 2007 Incentive Plan Form of Stock Option Agreement (Form 10-Q dated July 30, 2015 (File No. 1-8182, Exhibit 10.2)).
10.5+*	-	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)).
10.6+*	-	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)).
10.7+*	-	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)).
10.8+*	-	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)).
10.9+*	-	Pioneer Energy Services Corp. 2007 Incentive Plan Form of Performance Phantom Stock Unit Award Agreement (Form 10-Q dated July 28, 2016 (File No. 1-8182, Exhibit 10.3)).
10.10+*	-	Pioneer Energy Services Corp. 2007 Incentive Plan Form of Performance Phantom Stock Unit Award Agreement (Form 10-Q dated May 2, 2018 (File No. 1-8182, Exhibit 10.1)).
10.11+*	-	Pioneer Drilling Services, Ltd. Amended and Restated Key Executive Severance Plan (Form 10-Q dated August 5, 2008 (File No. 1-8182, Exhibit 10.4)).

10.12+* - Pioneer Energy Services Corp. Form of Indemnification Agreement (Form 10-Q dated July 31, 2018 (File No. 1-8182, Exhibit 10.1)).

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

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

10.15+* - 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)).

10.16+* - Employment Letter, effective May 13, 2012, from Pioneer Drilling Company to Brian L. Tucker (Form 10-Q dated April 29, 2016 (File No. 1-8182, Exhibit 10.1)).

10.17+* - Confidential Retirement Agreement and Release of Claims, dated December 5, 2018, between Pioneer Energy Services Corp. and Joe P. Freeman (Form 8-K dated December 5, 2018 (File No. 1-8182, Exhibit 10.1)).

10.18* - Credit Agreement, dated as of November 8, 2017, by and among Pioneer Energy Services Corp., Wells Fargo Bank, National Association, as administrative agent, sole lead arranger, sole bookrunner, and the other financial institutions party thereto (Form 8-K dated November 8, 2017 (File No. 1-8182, Exhibit 10.1)).

10.19* - Term Loan Credit Agreement, dated as of November 8, 2017, by and among Pioneer Energy Services, Corp., Goldman Sachs Lending Partners LLC, as syndication agent and the arranger, Wilmington Trust, National Association, as administrative agent, and the lenders party thereto (Form 8-K dated November 8, 2017 (File No. 1-8182, Exhibit 10.2)).

10.20* - Guaranty and Security Agreement, dated as of November 8, 2017 by and among Pioneer, the other grantors party thereto and Wells Fargo Bank, National Association, as administrative agent (Form 8-K dated November 8, 2017 (File No. 1-8182, Exhibit 10.3)).

10.21* - Intercreditor Agreement, dated November 8, 2017, by and among Wells Fargo, National Association, as initial ABL agent and Wilmington Trust, National Association, as initial term agent, and acknowledged and agreed to by Pioneer and the other grantors party thereto (Form 8-K dated November 8, 2017 (File No. 1-8182, Exhibit 10.4)).

10.22* - Guaranty Agreement, dated as of November 8, 2017, made by each of Pioneer and the guarantors party thereto, in favor of Wilmington Trust, National Association (Form 8-K dated November 8, 2017 (File No. 1-8182, Exhibit 10.5)).

10.23* - Security Agreement, dated as of November 8, 2017, by and among Pioneer, the other grantors party thereto and Wilmington Trust, National Association (Form 8-K dated November 8, 2017 (File No. 1-8182, Exhibit 10.6)).

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+* - Pioneer Energy Services Corp. Amended and Restated 2007 Incentive Plan (Appendix A of definitive proxy statement on Schedule 14A dated April 18, 2016 (File No. 1-8182)).

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, 2018, 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.

ITEM 16. FORM 10-K SUMMARY

Not applicable.

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 19, 2019

/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 19, 2019
/S/ WM. STACY LOCKE Wm. Stacy Locke	President, Chief Executive Officer and Director (Principal Executive Officer)	February 19, 2019
/S/ LORNE E. PHILLIPS Lorne E. Phillips	Executive Vice President and Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)	February 19, 2019
/S/ C. JOHN THOMPSON C. John Thompson	Director	February 19, 2019
/S/ JOHN MICHAEL RAUH John Michael Rauh	Director	February 19, 2019
/S/ SCOTT D. URBAN Scott D. Urban	Director	February 19, 2019

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

	Year ended December 31,				
	2018	**2017**	**2016**	**2015**	**2014**
Net loss	$ (49,011)	$ (75,118)	$ (128,391)	$ (155,140)	$ (38,018)
Depreciation and amortization	93,554	98,777	114,312	150,939	183,376
Impairment	4,422	1,902	12,815	129,152	73,025
Interest expense	38,782	27,039	25,934	21,222	38,781
Loss on extinguishment of debt	—	1,476	299	2,186	31,221
Income tax benefit	1,908	(4,203)	(10,732)	(37,579)	(11,304)
Adjusted EBITDA*	$ 89,655	$ 49,873	$ 14,237	$ 110,780	$ 277,081

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

DIRECTORS

DEAN A. BURKHARDT
Consultant to energy industry

SCOTT D. URBAN
Partner in Edgewater Energy

JOHN MICHAEL RAUH
Retired
Kerr-McGee Corporation

C. JOHN THOMPSON
President 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

CARLOS R. PEÑA
Executive Vice President and
Chief Strategy Officer

BRYCE SEKI
Vice President, General Counsel,
Secretary and Compliance Officer

LORNE E. PHILLIPS
Executive Vice President and
Chief Financial Officer

BRIAN L. TUCKER
Executive Vice President and
Chief Operating Officer

CORPORATE INFORMATION

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Promenade Two
San Antonio, Texas 78257

STOCK LISTING
The New York Stock Exchange: PES

As of March 18, 2019, the approximate number of common shareholders of record was 291.

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

2018 ANNUAL REPORT

PIONEER ENERGY SERVICES
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San Antonio, Texas 78209

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