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**

For the transition period from __________ to __________

Commission File Number: 001-38383

Quintana Energy Services Inc.

(Exact name of registrant as specified in its charter)

Delaware	**82-1221944**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

1415 Louisiana Street, Suite 2900
Houston, TX 77002
(832) 518-4094
(Address, including zip code, and telephone number, including area code, of principal executive offices of registrant)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common stock, par value $0.01 per share	New York Stock Exchange

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 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 the 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 Act). Yes ☐ No ☒

The aggregate market value of the Registrant's Common Stock held by non-affiliates of the Registrant on 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 on June 30, 2018) was $65.0 million.

The number of shares of the registrant's common stock, par value $0.01 per share, outstanding at March 1, 2019, was 33,907,414.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the Registrant's proxy statement for its annual meeting of stockholders to be held on May 14, 2019, which proxy statement will be filed with the Securities Exchange Commission within 120 days of December 31, 2018, are incorporated by reference in Part III.

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PART I

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K for the year ended December 31, 2018 (this "Annual Report”) contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this Annual Report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report, the words “could,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “project” and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under the heading “Risk Factors” included in this Annual Report. These forward-looking statements are based on management’s current beliefs, based on currently available information, as to the outcome and timing of future events.

Forward-looking statements may include statements about:

- our business strategy;
- our operating cash flows, the availability of capital and our liquidity;
- our future revenue, income and operating performance;
- uncertainty regarding our future operating results;
- our ability to sustain and improve our utilization, revenue and margins;
- our ability to maintain acceptable pricing for our services;
- our future capital expenditures;
- our ability to finance equipment, working capital and capital expenditures;
- competition and government regulations;
- our ability to obtain permits and governmental approvals;
- pending legal or environmental matters;
- loss or corruption of our information in a cyberattack on our computer systems;
- the supply and demand for oil and natural gas;
- the ability of our customers to obtain capital or financing needed for exploration and production (“E&P”) operations;
- business acquisitions;
- general economic conditions;
- credit markets;
- the occurrence of a significant event or adverse claim in excess of the insurance we maintain;
- seasonal and adverse weather conditions that can affect oil and natural gas operations;
- our ability to successfully develop our research and technology capabilities and implement technological developments and enhancements; and

- plans, objectives, expectations and intentions contained in this Annual Report that are not historical.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control. These risks include, but are not limited to, decline in demand for our services, the cyclical nature and volatility of the oil and natural gas industry, a decline in, or substantial volatility of, crude oil and natural gas commodity prices, environmental risks, regulatory changes, the inability to comply with the financial and other covenants and metrics in our New ABL Facility (as defined below), cash flow and access to capital, the timing of development expenditures and the other risks described under "Risk Factors" in this Annual Report. For more information on our New ABL Facility, please see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Our Credit Facility section."

Should one or more of the risks or uncertainties described in this Annual Report or any other risks or uncertainties of which we are currently unaware occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, expressed or implied, included in this Annual Report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this Annual Report.

GLOSSARY OF SELECTED TERMS

Basin. A large geography of oil and gas deposits generally understood in the industry.

Bbl. Stock tank barrel, or 42 U.S. gallons liquid volume, used in this Annual Report in reference to crude oil or other liquid hydrocarbons.

British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Cementing. To prepare and pump cement into place in a wellbore.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Crude oil. Liquid hydrocarbons retrieved from geological structures underground to be refined into fuel sources.

Directional drilling. The intentional deviation of a wellbore from the path it would naturally take. This is accomplished through the use of whipstocks, bottomhole assembly ("BHA") configurations, instruments to measure the path of the wellbore in three-dimensional space, data links to communicate measurements taken downhole to the surface, mud motors and special BHA components and drill bits, including rotary steerable systems, and drill bits. The directional driller also exploits drilling parameters such as weight on bit and rotary speed to deflect the bit away from the axis of the existing wellbore. In some cases, such as drilling steeply dipping formations or unpredictable deviation in conventional drilling operations, directional-drilling techniques may be employed to ensure that the hole is drilled vertically. While many techniques can accomplish this, the general concept is simple: point the bit in the direction that one wants to drill. The most common way is through the use of a bend near the bit in a downhole steerable mud motor. The bend points the bit in a direction different from the axis of the wellbore when the entire drillstring is not rotating. By pumping mud through the mud motor, the bit turns while the drillstring does not rotate, allowing the bit to drill in the direction it points. When a particular wellbore direction is achieved, that direction may be maintained by rotating the entire drillstring (including the bent section) so that the bit does not drill in a single direction off the wellbore axis, but instead sweeps around and its net direction coincides with the existing wellbore. Rotary steerable tools allow steering while rotating, usually with higher rates of penetration and ultimately smoother boreholes.

Drillstring. The combination of the drillpipe, the BHA and any other tools used to make the drill bit turn at the bottom of the wellbore.

EM. Electromagnetic navigational systems used in directional drilling.

E&P. Exploration and production of oil and natural gas.

Field. An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

HHP. Hydraulic horsepower.

Horizontal drilling. A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at approximately a right angle with a specified interval.

Horizontal wells. Wells drilled directionally horizontal to allow for development of structures not reachable through traditional vertical drilling mechanisms.

Hydraulic fracturing. A stimulation treatment routinely performed on oil and natural gas wells in low permeability reservoirs. Specially engineered fluids are pumped at high pressure and rate into the reservoir interval to be treated, causing a vertical fracture to open. The wings of the fracture extend away from the wellbore in opposing directions according to the natural stresses within the formation. Proppant, such as grains of sand of a particular size, is mixed with the treatment fluid to keep the fracture open when the treatment is complete. Hydraulic fracturing creates high-conductivity communication with a large area of formation and bypasses any damage that may exist in the near-wellbore area.

Hydrocarbon. A naturally occurring organic compound comprising hydrogen and carbon. Hydrocarbons can be as simple as methane, but many are highly complex molecules, and can occur as gases, liquids or solids. Petroleum is a complex mixture of hydrocarbons. The most common hydrocarbons are natural gas, oil and coal.

Large Diameter. A coiled tubing unit or coil tubing with a capacity of 2.38 inch units or larger.

Mcf. Thousand cubic feet of natural gas.

MMBtu. Million British thermal units.

MWD. Measurement-while-drilling.

Mud motors. A positive displacement drilling motor that uses hydraulic horsepower of the drilling fluid to drive the drill bit. Mud motors are used extensively in directional drilling operations.

Proppant. Sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment. In addition to naturally occurring sand grains, man-made or specially engineered proppants, such as resin-coated sand or high-strength ceramic materials like sintered bauxite, may also be used. Proppant materials are carefully sorted for size and sphericity to provide an efficient conduit for production of fluid from the reservoir to the wellbore.

Reserves. Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to the market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

Resource play. A set of discovered or prospective oil and/or natural gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, reservoir structure, timing, trapping mechanism and hydrocarbon type.

Shale. A fine-grained, fissile, sedimentary rock formed by consolidation of clay- and silt-sized particles into thin, relatively impermeable layers.

Unconventional resource. An umbrella term for oil and natural gas that is produced by means that do not meet the criteria for conventional production. What has qualified as "unconventional" at any particular time is a complex function of resource characteristics, the available E&P technologies, the economic environment, and the scale, frequency and duration of production from the resource. Perceptions of these factors inevitably change over time and often differ among users of the term. At present, the term is used in reference to oil and gas resources whose porosity, permeability, fluid trapping mechanism or other characteristics differ from conventional sandstone and carbonate reservoirs. Coalbed methane, gas hydrates, shale gas, fractured reservoirs and tight gas sands are considered unconventional resources.

Wellbore. The physical conduit from surface into the hydrocarbon reservoir.

Wireline. A general term used to describe well-intervention operations conducted using single-strand or multi-strand wire or cable for intervention in oil or gas wells. Although applied inconsistently, the term commonly is used in association with electric logging and cables incorporating electrical conductors.

Workover. The process of performing major maintenance or remedial treatments on an oil or gas well. In many cases, workover implies the removal and replacement of the production tubing string after the well has been killed and a workover rig has been placed on location. Through-tubing workover operations, using coiled tubing, snubbing or slickline equipment, are routinely conducted to complete treatments or well service activities that avoid a full workover where the tubing is removed. This operation saves considerable time and expense.

WTI. West Texas Intermediate Spot Oil Price.

Item 1. Business

Overview

Quintana Energy Services Inc. (either individually or together with its subsidiaries, as the context requires, the “Company,” “QES,” “we,” “us,” and “our”) is a Delaware corporation that was incorporated on April 13, 2017. Our accounting predecessor, Quintana Energy Services LP (“QES LP” and “Predecessor”), was formed as a Delaware partnership on November 3, 2014. In connection with our initial public offering (the “IPO”) which closed on February 13, 2018, the existing investors in QES LP and QES Holdco LLC contributed all of their direct and indirect equity interests to QES in exchange for shares of common stock in QES, and we became the holding company for the reorganized QES LP and its subsidiaries.

We are a growth-oriented provider of diversified oilfield services to leading onshore oil and natural gas E&P companies operating in conventional and unconventional plays in all of the active major basins throughout the United States. We classify the services we provide into four reportable segments: (1) Directional Drilling, (2) Pressure Pumping, (3) Pressure Control and (4) Wireline. Our Directional Drilling segment enables efficient drilling and guidance of the horizontal section of a wellbore using our technologically-advanced fleet of downhole motors and 115 MWD kits. Our Pressure Pumping segment includes hydraulic fracturing, cementing and acidizing services, and such services are supported by a high-quality pressure pumping fleet of approximately 267,500 HHP as of December 31, 2018. Our primary pressure pumping focus is on large hydraulic fracturing jobs. Our Pressure Control segment provides various forms of well control, completions and workover applications through our 24 coiled tubing units (10 of which are Large Diameter units), 36 rig-assisted snubbing units and ancillary equipment. As of December 31, 2018, our wireline services included 41 wireline units providing a full range of pump-down services in support of unconventional completions, and cased-hole wireline services enabling reservoir characterization.

Our operations are diversified by our broad customer base and expansive geographical reach. We currently operate throughout all active major onshore oil and gas basins in the United States and we served approximately 1,100 customers as of December 31, 2018. We have cultivated and maintain strong relationships with our E&P company customers, including leading companies such as EOG Resources, Parsley Energy, Matador Resources, Pioneer Natural Resources, Seneca Energy, Triumph Energy Partners and XTO Energy.

Our core businesses depend on our customers’ willingness to make expenditures to produce, develop and explore for oil and natural gas in the United States. Industry conditions are influenced by numerous factors, such as the supply of and demand for oil and natural gas, domestic and worldwide economic conditions, political stability in oil producing countries, merger and divestiture activity among oil and gas producers and changes in oil and natural gas prices. The volatility of the oil and natural gas industry and the consequent impact on E&P activity could adversely impact the level of drilling, completion and workover activity by some of our customers. This volatility affects the demand for our services and the price of our services.

We derive a majority of our revenues from services supporting oil and natural gas operations. As oil and natural gas prices fluctuate significantly, demand for our services correspondingly changes as our customers must balance expenditures for drilling and completion services against their available cash flows. Because our services are required to support drilling and completions activities, we are also subject to changes in spending by our customers as oil and natural gas prices fluctuate.

During the fourth quarter of 2018, the price of crude oil fell approximately 38.6%, with WTI closing at $45.15 per barrel on December 28, 2018. This precipitous decline in crude oil prices had a moderate negative impact on our fourth quarter 2018 consolidated results of operations. We expect further customer-driven activity declines in early 2019 as customers reassess their budgets and plans in light of lower commodity prices. If the current pricing environment for crude oil does not improve, or declines further, our customers may be required to further reduce their capital expenditures, causing additional declines in the demand for, and prices of, our products and services, which would adversely affect our future results of operations, cash flows and financial position. Despite the recent decline in oil prices, demand for our services has improved since May 2016. From the second quarter of 2016 through the fourth quarter of 2018, our Directional Drilling segment increased the number of days we provided services to rigs and earned revenues during the period, including days that standby revenues were earned (“rig days”) by 311.4%, while day rates have improved from the lows we experienced during the second quarter of 2016. We reactivated our second and third pressure pumping hydraulic fracturing fleets in February and October 2017, and placed our fourth hydraulic fracturing fleet into service during June 2018. Utilization of our Pressure Control assets has also continued to improve since the second quarter of 2016.

Since 2016, we have worked to optimize our cost structure and increase efficiency to better serve our customers. As part of these cost control initiatives, we closed unprofitable locations serving non-key regions, renegotiated supplier contracts and certain equipment leases to improve profitability and reduced general and administrative expenses. To improve operational efficiencies, we streamlined our internal processes and further improved customer focus.

Our Services

We classify the services we provide into four reportable segments: (1) Directional Drilling, (2) Pressure Pumping, (3) Pressure Control and (4) Wireline. We describe each of these segments below.

Directional Drilling

Our Directional Drilling segment is comprised of directional drilling services, downhole navigational and rental tools businesses and support services, including well planning and site supervision, which assists customers in the drilling and placement of complex directional and horizontal wellbores. This segment utilizes its fleet of in-house positive pulse MWD navigational tools, mud motors and ancillary downhole tools, as well as EM navigational systems. The demand for these services tends to be influenced primarily by customer drilling-related activity levels. We provide directional drilling and associated services to E&P companies in many of the most active areas of onshore oil and natural gas development in the United States, including the Permian Basin, Eagle Ford Shale, Mid-Continent region (including the SCOOP/STACK), Marcellus/Utica Shale and DJ/Powder River Basin.

Our Directional Drilling segment provides the highly technical and essential services of guiding horizontal and directional drilling operations for E&P companies. We offer premium drilling services including directional drilling, horizontal drilling, under balanced drilling, MWD and logging tools. Our package also offers various technologies, including our positive pulse MWD navigational tool asset fleet, Q-Series Mud Motors and ancillary downhole tools, as well as EM navigational systems. We also provide a suite of integrated and related services, including rotational gamma, pressure-while-drilling, continuous inclination and continuous azimuth.

Although we do not typically enter into long-term contracts for our services in this segment, we have long standing relationships with our customers in this segment and believe they will continue to utilize our services. As of the quarter ended December 31, 2018, 90.2% of our directional drilling activity is tied to “follow-me rigs,” which involve non-contractual, generally recurring services as our Directional Drilling team members follow a drilling rig from well-to-well or pad-to-pad for multiple wells or pads, and in some cases, multiple years. With increasing use of pad drilling and reactivation of rigs, through 2018 we have increased the number of “follow me rigs” from approximately 32 in January of 2016 to 74 as of the month ended December 31, 2018. We intend to continue to re-deploy additional MWD kits into 2019, as market conditions warrant.

Our Directional Drilling segment accounted for approximately 31.9%, 33.2% and 35.8% of our revenues for the years ended December 31, 2018, 2017 and 2016, respectively.

Pressure Pumping

Our Pressure Pumping segment provides hydraulic fracturing stimulation services, cementing services and acidizing services. The majority of the revenues generated in this segment are derived from pressure pumping services focused on fracturing, cementing and acidizing services in the Mid-Continent and Rocky Mountains regions. These pressure pumping and stimulation services are primarily used in the completion, production and maintenance of oil and gas wells. Customers for this segment include major E&P operators as well as independent oil and gas producers. Our personnel have extensive technical expertise and customer relationships, which we believe enables us to maintain and further expand our presence in these regions. Additionally, we believe these regions will continue to benefit from E&P companies’ increasing design of more complex wells, with higher service intensity that increases demand for our services.

We focus on providing services for larger hydraulic fracturing jobs, but have the capability to provide a customized range of hydraulic fracturing services to meet the particular needs of our customers. We believe our technical capabilities, depth of talent and operational flexibility allow us to accommodate the increasing requirements of our customers’ hydraulic fracturing jobs and such strengths provide us with access to a large number of customers. In addition, many of these jobs require logistically intensive service and mobility capabilities for which we are well suited as a result of our basin-specific experience. We believe such operational flexibility allows us to be responsive to our customers’ needs, increasing the utilization of our assets and strengthening our existing customer relationships.

As of December 31, 2018, our Pressure Pumping fleet had a capacity of 267,500 HHP, of which 241,500 HHP was dedicated to hydraulic fracturing, 14,500 HHP was dedicated to cementing and 11,500 HHP was dedicated to acidizing and other. As of December 31, 2018, we had 214,600 total hydraulic fracturing HHP deployed in the Mid-Continent region. Of our total deployed HHP dedicated to hydraulic fracturing, approximately 92% is dedicated to unconventional hydraulic fracturing services in the Mid-Continent, approximately 7% is dedicated to hydraulic fracturing services in the Rockies, and approximately 1% is dedicated to vertical fracturing services. We have successfully grown our Pressure Pumping segment through organic growth and acquisitions. From January 1, 2007 to December 31, 2018, we increased from 15,500 HHP to 267,500 HHP.

In addition, we have multi-year proppant supply contracts for approximately 143,000 average annual tons through 2020. We also have 13,250 tons of flat sand storage in Enid, Oklahoma in our facility located on the BNSF Railway, which provides access to the materials needed to ensure consistently reliable operations. Our Pressure Pumping segment accounted for approximately 35.4%, 35.0% and 21.5% of our revenues for the years ended December 31, 2018, 2017 and 2016, respectively.

Pressure Control

Our Pressure Control segment supplies a wide variety of equipment, services and expertise in support of completion and workover operations throughout the United States. Its capabilities include coiled tubing, snubbing, fluid pumping, nitrogen, well control and other pressure control related services. Our pressure control equipment is tailored to the unconventional resources market with the ability to operate under high pressures without having to delay or cease production during completion or workover operations. Our pressure control services help E&P companies minimize the risk of such damage during completion activities. We provide our pressure control services primarily in the Mid-Continent region (including the SCOOP/STACK), Eagle Ford Shale, Permian Basin, Marcellus/Utica Shale, DJ/Powder River Basin, Haynesville Shale, Fayetteville Shale and Williston Basins (including the Bakken Shale).

Our coiled tubing units are used in the provision of unconventional completion services or in support of well-servicing and workover applications. Our rig-assisted snubbing units are used in conjunction with a workover rig to insert or remove downhole tools or in support of other well services while maintaining pressure in the well, or in support of unconventional completions. Our nitrogen pumping units provide a non-combustible environment downhole and are used in support of other pressure control or well-servicing applications. We also offer highly-technical and specialized well control services, which are typically required in response to emergencies at the well, requiring a variety of solutions including freezing, hot tapping and gate valve drilling services, as well as critical well control and containment operations. Our team is comprised of oilfield services veterans with extensive domestic and international experience in well control operations dating back to the 1980s.

As of December 31, 2018, we provided our services through our fleet of 24 coiled tubing units (10 of which are Large Diameter units, allowing us to service extended reach laterals), 36 rig-assisted snubbing units and 24 nitrogen pumping units. We accepted delivery of two new larger diameter coil units during the month of December 2018. One of the new Large Diameter units was deployed immediately.

Our Pressure Control segment accounted for approximately 20.3%, 20.5% and 24.9% of our revenues for the years ended December 31, 2018, 2017 and 2016, respectively.

Wireline

Our Wireline segment provides new well wireline conveyed tight-shale reservoir perforating services across many of the major U.S. shale basins and also offers a range of services such as cased-hole investigation and production logging services, conventional wireline and tubing conveyed perforating services, mechanical services and pipe recovery services. These services are offered in both new well completions and for remedial work. The majority of the revenues generated in our Wireline segment are derived from the Permian Basin, Eagle Ford Shale, Mid-Continent region (including the SCOOP/STACK), Haynesville Shale and East Texas Basin as well as in industrial and petrochemical facilities. Our Wireline segment principally works in connection with hydraulic fracturing services in the form of pump-down services for setting plugs between hydraulic fracturing stages, as well as with the deployment of perforation equipment in connection with "plug-and-perf" operations.

As of December 31, 2018, we operated 41 wireline units of which 21 are suited for unconventional activity, and operated from seven facilities throughout the Permian Basin, Eagle Ford Shale, Mid-Continent, South Texas and Gulf Coast regions. Of the 21 wireline units suited for unconventional activity, 10 units are crewed and the remaining 11 are available to deploy as conditions warrant. We offer our wireline services in most markets in which we provide pressure pumping services. From January 2017 to December 31, 2018, we completed approximately 19,195 stages in the United States with an overall run efficiency of approximately 97.9%.

Our Wireline segment accounted for approximately 12.4%, 11.4% and 17.8% of our revenues for the years ended December 31, 2018, 2017 and 2016, respectively.

Geographic Areas of Operation

Our Directional Drilling segment operates in the Permian Basin, Eagle Ford Shale, Mid-Continent region (including the SCOOP/STACK), Marcellus/Utica Shale and DJ/Powder River Basin. Our Pressure Pumping segment has historically operated in the Mid-Continent region (including the SCOOP/STACK) where we have a leading market position, as well as the Rocky Mountain region (including the Williston Basin). Our Pressure Control segment operates in the Mid-Continent region (including the SCOOP/STACK), Eagle Ford Shale, Permian Basin, Marcellus/Utica Shale, DJ/Powder River Basin, Haynesville Shale, Fayetteville Shale and Williston Basin (including the Bakken Shale), providing access across the continental United States. Lastly, our Wireline segment provides services throughout the Permian Basin, Eagle Ford Shale, Mid-Continent region (including the SCOOP/STACK), Gulf Coast region and East Texas/Haynesville Shale. These expansive operating areas provide us with access to a number of nearby unconventional crude oil and natural gas basins, both with existing customers expanding their production footprint and third parties acquiring new acreage. Our proximity to existing and prospective customer activities allows us to anticipate or respond quickly to such customers' needs and efficiently deploy our assets.

We believe that our strategic geographic positioning will benefit us as activity increases in our core operating areas. Our broad geographic footprint provides us with exposure to the ongoing recovery in drilling and completion activity and will allow us to opportunistically pursue new business in basins with the most active drilling environments.

Seasonality

Our operations are located in different regions of the United States. Some of these areas are adversely affected by seasonal weather conditions, primarily in the winter and spring. During periods of heavy snow, ice or rain, we may be unable to move our equipment between locations, thereby reducing our ability to provide services and generate revenues. The exploration activities of our customers may also be affected during such periods of adverse weather conditions. Weather conditions also affect the demand for, and prices of, oil and natural gas and, as a result, demand for our services.

Marketing and Customers

We operate in a highly competitive industry. Our competition includes many large and small oilfield service companies. As such, we price our services and products to remain competitive in the markets in which we operate, adjusting our rates to reflect current market conditions as necessary. We examine the rate of utilization of our equipment as a measure of our ability to compete in the current market environment.

We have also established over time a diverse and balanced mix of customers, including large, midsize and small E&P companies. We served approximately 1,100 customers in 2018. For the year ended December 31, 2018, EOG Resources represented approximately 11.9% of the Company's consolidated revenues. For the years ended December 31, 2018 and 2017, no customer individually accounted for more than 10.3% of our consolidated revenues. The loss of a material customer could have an adverse effect on our business until the equipment is redeployed at similar utilization and pricing levels.

Competition

The markets in which we operate are highly competitive. To be successful, a company must provide services and products that meet the specific needs of oil and natural gas E&P companies and drilling services contractors at competitive prices. We provide our services and products across the United States and we compete against different companies in each service and product line we offer. Our competition includes many large and small oilfield service companies, including some of the largest integrated oilfield services companies.

Our major competitors in Directional Drilling include Schlumberger, Baker Hughes, Halliburton, Phoenix Technology Services, ProDirectional, Scientific Drilling International, LEAM Drilling Systems and Nabors Industries. Our major competitors for Pressure Pumping, Pressure Control and Wireline include Halliburton, Schlumberger, RPC, C&J Energy Services, Keane Group, Basic Energy Services, Nine Energy Services, Superior Energy Services, Key Energy Services, Forbes Energy Services, STEP Energy Services and KLX.

We believe that the principal competitive factors in the market areas that we serve are quality of service and products, reputation for safety and technical proficiency, availability and price. While we must be competitive in our pricing, we believe our customers select our services and products based on the local leadership and basin-expertise that our field management and operating personnel use to deliver quality services and products.

Suppliers

We have dedicated supply chain teams that manage sourcing and logistics to ensure flexibility and continuity of our supply chain in a cost effective manner across our geographic areas of operation. We have fostered long-term relationships with numerous industry leading suppliers of proppant, chemicals, coil tubing and select directional drilling, pressure pumping, pressure control and wireline equipment. In addition, we have multi-year proppant supply contracts for approximately 143,000 average annual tons through 2020.

We purchase a wide variety of raw materials, parts and components that are manufactured and supplied for our operations. We are not dependent on any single source of supply for those parts, supplies or materials. To date, we have generally been able to obtain the equipment, parts and supplies necessary to support our operations on a timely basis. While we believe that we will be able to make satisfactory alternative arrangements in the event of any interruption in the supply of these materials and/or products by one of our suppliers, we may not always be able to do so. In addition, certain materials for which we do not currently have long-term supply agreements could experience shortages and significant price increases in the future. As a result, we may be unable to mitigate any future supply shortages and our results of operations, prospects and financial condition could be adversely affected.

Intellectual Property

We have pending applications and registered trademarks for various names under which our entities conduct business or provide products or services. Except for the foregoing, we do not own or license any patents, trademarks or other intellectual property that we believe to be material to the success of our business. In addition, we rely to a great extent on the technical expertise and know-how of our personnel to maintain our competitive position, and we take commercially reasonable measures to protect trade secrets and other confidential and/or proprietary information relating to the technologies we develop.

Risk Management and Insurance

Our operations are subject to hazards inherent in the oilfield services industry, such as accidents, blowouts, explosions, fires and spills and releases that can cause:

- personal injury or loss of life;
- damage or destruction of property, equipment, natural resources and the environment; and
- suspension of operations.

In addition, claims for loss of oil and natural gas production and damage to formations can occur in the oilfield services industry. If a serious accident were to occur at a location where our equipment and services are being used, it could result in us being named as a defendant in lawsuits asserting large claims.

Because our business involves the transportation of heavy equipment and materials, we may also experience traffic accidents which may result in spills, property damage and personal injury.

Despite our efforts to maintain safety standards, we from time to time have suffered accidents in the past and anticipate that we could experience accidents in the future. In addition to the property damage, personal injury and other losses from these accidents, the frequency and severity of these incidents affect our operating costs and insurability and our relationships with customers, employees, regulatory agencies and other parties.

Any significant increase in the frequency or severity of these incidents, or the general level of compensation awards, could adversely affect the cost of, or our ability to obtain, workers' compensation and other forms of insurance, and could have other material adverse effects on our financial condition and results of operations.

Although we maintain insurance coverage of types and amounts that we believe to be customary in the industry, we are not fully insured against all risks, either because insurance is not available or because of the high premium costs relative to perceived risk. Further, insurance rates have in the past been subject to wide fluctuation and changes in coverage could result in less coverage, increases in cost or higher deductibles and retentions. Liabilities for which we are not insured, or which exceed the policy limits of our applicable insurance, could have a material adverse effect on us.

Employees

As of December 31, 2018, we had approximately 1,500 full time employees and our overall personnel count increased approximately 13.3% from the year ended December 31, 2017. None of our employees are represented by labor unions or covered by any collective bargaining agreements. We also hire independent contractors and consultants as needed.

Safety and Remediation Program

In the oilfield services industry, an important competitive factor in establishing and maintaining long term E&P customer relationships is having an experienced and skilled workforce. Recently, many of our large customers have placed an emphasis not only on pricing, but also on safety records and quality management systems of contractors. We believe these factors will gain further importance in the future. We have dedicated safety personnel and training facilities for each of our four segments. We have committed resources toward employee safety and quality management training programs. Our field employees are required to complete both technical and safety training programs.

As part of our safety procedures, we also have the capability to shut down our pressure pumping and fracturing operations both at the lines and in our data van. In addition, we maintain spill kits on location for containment of pollutants that may be spilled in the process of providing our hydraulic fracturing services. The spill kits are generally comprised of pads and booms for absorption and containment of spills, as well as soda ash for neutralizing acid. Fire extinguishers are also in place on job sites at each pump.

We have used third-party contractors to provide remediation and spill response services when necessary to address spills that travel beyond our containment capabilities. Historically, these prior spills have not had a material adverse effect on our hydraulic fracturing services. To the extent our hydraulic fracturing or other oilfield services operations result in a future spill or release, we will engage the services of a remediation company or an alternative company, as necessary, to assist us with clean-up and remediation.

Government Regulations and Environmental, Health and Safety Matters

We operate under the jurisdiction of a number of regulatory bodies that regulate worker safety standards, the handling of hazardous materials, the storage and transportation of explosives, the protection of human health and the environment and standards of operation. Regulations concerning equipment certification create an ongoing need for regular maintenance that is incorporated into our daily operating procedures. Moreover, the oil and natural gas industry is subject to environmental regulation pursuant to local, state and federal legislation and regulatory initiatives.

Transportation Matters

In connection with our transportation and relocation of our oilfield service equipment and shipment of hydraulic fracturing sand, we operate trucks and other heavy equipment. As such, we operate as a commercial motor carrier in providing certain of our services and therefore are subject to regulation by the U.S. Department of Transportation ("DOT") and analogous state agencies. These regulatory authorities exercise broad powers, governing activities such as the authorization to engage in motor carrier operations and regulatory safety, driver licensing and insurance requirements, financial reporting and review of certain mergers, consolidations and acquisitions and hazardous materials labeling, placarding and marking. There are additional regulations specifically related to the trucking industry, including testing and specification of equipment and product handling requirements. In addition, our trucking operations are subject to possible regulatory and legislative changes that may increase our costs 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 or work in any specific period, onboard electronic logging device ("ELD") requirements or limits on vehicle weight and size.

Interstate motor carrier operations are subject to safety requirements prescribed by the DOT. To a large degree, intrastate motor carrier operations are subject to state safety regulations that mirror federal regulations but may be more stringent. Such matters as weight and dimension of equipment are also subject to federal and state regulations.

Finally, 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 contracted drivers. We cannot predict whether, or in what form, any increase in such taxes applicable to us would be enacted.

Environmental Matters and Regulation

General. Our operations and the operations of our oil and natural gas E&P customers are subject to stringent federal, tribal, regional, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous federal, state and local governmental agencies, such as the U.S. Environmental Protection Agency ("EPA") and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions. These laws and regulations may require the acquisition of a permit before conducting regulated activities, restrict the types, quantities and concentrations of various substances that may be released into the environment, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically sensitive and other protected areas, require action to prevent or remediate pollution from current or former operations, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from our operations or relating to our owned or operated facilities. Any failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties, the imposition of investigatory, remedial or corrective action obligations or the incurrence of capital expenditures; the occurrence of restrictions, delays or cancellations in the permitting or performance of projects; and the issuance of orders enjoining performance of some or all of our operations in a particular area.

The trend in environmental regulation is to place more restrictions and limitations on activities that may adversely affect the environment, and thus any new laws and regulations, amendment of existing laws and regulations, reinterpretation of legal requirements or increased governmental enforcement that result in more stringent and costly completion activities, or waste handling, storage transport, disposal or remediation requirements could have a material adverse effect on our financial position and results of operations. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for personal injury to persons and damage to properties or natural resources. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on our business and operating results. Additionally, our customers may also incur increased costs or delays, restrictions or cancellations in permitting or operating activities as a result of more stringent environmental laws and regulations, which may result in a curtailment of exploration, development or production activities that would reduce the demand for our services.

The following is a summary of the more significant existing environmental laws, as amended from time to time, to which our business is subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Waste Handling. The Resource Conservation and Recovery Act ("RCRA"), and comparable state statutes, regulate the generation, treatment, storage, transportation, disposal and clean-up of hazardous and nonhazardous wastes. Pursuant to rules issued by the EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more requirements, which may be more stringent. In the course of our operations, we generate some amounts of ordinary industrial wastes that may be regulated as hazardous wastes. Additionally, drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of oil or natural gas, if properly handled, are currently exempt from regulation as hazardous waste under RCRA and, instead, are regulated under RCRA's less stringent non-hazardous waste provisions, state laws or other federal laws. However, it is possible that certain oil and natural gas drilling and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. For example, in response to a consent decree issued by the U.S. District Court for the District of Columbia in 2016, the EPA is required to propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D criteria regulations that could result in oil and natural gas wastes being regulated as hazardous wastes, or sign a determination that revision of the regulations is unnecessary. If the EPA proposes a rulemaking for revised oil and natural gas waste regulations, the consent decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. A loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in an increase in our, as well as the oil and natural gas E&P industry's, costs to manage and dispose of generated wastes, which could have a material adverse effect on the industry as well as on our business.

Remediation of Hazardous Substances. The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the "Superfund" law, and comparable state statutes impose liability, without regard to fault or legality of the original conduct, on classes of persons that are considered to have contributed to the release of a hazardous substance into the environment. Such classes of persons include the current and past owners or operators of sites where a hazardous substance was released, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, these persons may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property or natural resources damage allegedly caused by the hazardous substances released into the environment. We currently own, lease or operate upon numerous properties and facilities that for many years have been used for industrial activities, including oil and natural gas-related operations. Hazardous substances, wastes or hydrocarbons may have been released on or under the properties owned, leased or operated upon by us, or on or under other locations where such substances have been taken for recycling or disposal. In addition, some of these properties have been operated by third parties or by previous owners whose treatment and disposal or release of hazardous substances, wastes or hydrocarbons, were not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes and remediate contaminated property (including groundwater contamination), including instances where the prior owner or operator caused the contamination, or perform remedial activities to prevent future contamination.

Handling and Exposure to Radioactive Materials. In the course of our operations, some of our equipment may be exposed to naturally occurring radioactive materials ("NORM") associated with oil and natural gas deposits and, accordingly may result in the generation of wastes and other materials containing NORM. Any NORM exhibiting levels of naturally occurring radiation in excess of established state standards are subject to special handling and disposal requirements, and any storage vessels, piping and work area affected by NORM may be subject to remediation or restoration requirements. Because certain of the properties presently or previously owned, operated or occupied by us may have been used for oil and natural gas production operations, it is possible that we may incur costs or liabilities associated with NORM.

In addition, some of our operations utilize equipment that contains sealed, low-grade radioactive sources. Our activities involving the use of radioactive materials are regulated by the U.S. Nuclear Regulatory Commission ("NRC") and also by state regulatory agencies under agreement with the NRC. Standards implemented by these regulatory agencies require us to obtain licenses or other approvals for the use of such radioactive materials. These regulatory agencies have adopted regulations implementing and enforcing these laws, for which compliance is often costly and difficult.

Water Discharges and Discharges into Belowground Formations. The Federal Water Pollution Control Act (the "Clean Water Act") and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and hazardous substances, into state waters and waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Spill prevention, control and countermeasure plan requirements imposed under the Clean Water Act require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. The Clean Water Act and analogous state laws also may impose substantial civil and criminal penalties for non-compliance including spills and other non-authorized discharges. In 2015, the EPA and the U.S. Army Corps of Engineers ("Corps") published a final rule outlining their position on the federal jurisdictional reach over waters of the United States, including wetlands, but legal challenges to this rule followed. Beginning in the first quarter of 2017, the EPA and the Corps agreed to reconsider the 2015 rule and, thereafter, the agencies have (i) published a proposed rule in 2017 to rescind the 2015 rule and recodify the regulatory text that governed waters of the United States prior to promulgation of the 2015 rule, (ii) published a final rule in February 2018 adding a February 6, 2020 applicable date to the 2015 rule, and (iii) published a proposed rule in December 2018 re-defining the Clean Water Act's jurisdiction over waters of the United States for which the agencies will seek public comment. The 2015 and February 2018 final rules are being challenged by various factions in federal district court and implementation of the 2015 rule has been enjoined in twenty-eight states pending resolution of the various federal district court challenges. As a result of these legal developments, future implementation of the 2015 rule is uncertain at this time. Any expansion of the Clean Water Act's jurisdiction in areas where we or our oil and natural gas E&P customers operate could impose additional permitting obligations on us and our customers.

The Oil Pollution Act of 1990 ("OPA") amends the Clean Water Act and sets minimum standards for prevention, containment and cleanup of oil spills. The OPA applies to vessels, offshore facilities and onshore facilities, including E&P facilities that may affect waters of the United States. Under OPA, responsible parties including owners and operators of onshore facilities may be held strictly liable for oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills. The OPA also requires owners or operators of certain onshore facilities to prepare Facility Response Plans for responding to a worst case discharge of oil into waters of the United States.

Our oil and natural gas E&P customers dispose of flowback and produced water or certain other oilfield fluids gathered from oil and natural gas producing operations in accordance with permits issued by government authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change based on concerns of the public or governmental authorities regarding such disposal activities. One such concern relates to recent seismic events near underground disposal wells used for the disposal by injection of flowback and produced water or certain other oilfield fluids resulting from oil and natural gas activities. Developing research suggests that the link between seismic activity and wastewater disposal may vary by region, and that only a very small fraction of the tens of thousands of injection wells have been suspected to be, or may have been, the likely cause of induced seismicity. In 2016, the United States Geological Survey identified six states with the most significant hazards from induced seismicity, including Oklahoma, Kansas, Texas, Colorado, New Mexico and Arkansas. In response to concerns regarding induced seismicity, regulators in some states have imposed, or are considering imposing, additional requirements in the permitting of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, Texas and Oklahoma have issued rules for wastewater disposal wells that imposed certain permitting restrictions, operating restrictions and/or reporting requirements on disposal wells in proximity to faults. States may, from time to time, develop and implement plans directing certain wells where seismic incidents have occurred to restrict or suspend disposal well operations. In Oklahoma, the Oklahoma Corporation Commission's ("OCC") Oil and Gas Conservation Division and the Oklahoma Geological Survey released well completion seismicity guidance in late 2016, which requires operators to take certain prescriptive actions, including an operator's planned mitigation practices, following certain unusual seismic activity within 1.25 miles of hydraulic fracturing operations. In recent years, including during 2018, the OCC's Oil and Gas Conservation Division has issued orders limiting future increases in the volume of oil and natural gas wastewater injected belowground into the Arbuckle formation in an effort to reduce the number of earthquakes in the state. Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal.

These developments could result in additional regulation and restrictions on the use of injection wells by our customers to dispose of flowback and produced water and certain other oilfield fluids. Increased regulation and attention given to induced seismicity also could lead to greater opposition to, and litigation concerning, oil and natural gas activities utilizing injection wells for waste disposal. Any one or more of these developments may result in our customers having to limit disposal well volumes, disposal rates or locations, or require our customers or third party disposal well operators that are used to dispose of customer wastewater to shut down disposal wells, which developments could adversely affect our customers' business and result in a corresponding decrease in the need for our services, which would could have a material adverse effect on our business, financial condition and results of operations.

Air Emissions. Certain of our operations also result in emissions of regulated air pollutants. The federal Clean Air Act (the "CAA") and analogous state laws require permits for certain facilities that have the potential to emit substances into the atmosphere that could adversely affect environmental quality. These laws and their implementing regulations also impose generally applicable limitations on air emissions and require adherence to maintenance, work practice, reporting and record keeping, and other requirements. Failure to obtain a permit or to comply with permit or other regulatory requirements could result in the imposition of sanctions, including administrative, civil and criminal penalties. In addition, we or our oil and natural gas E&P customers could be required to shut down or retrofit existing equipment, leading to additional expenses and operational delays.

Many of these regulatory requirements, including new source performance standards ("NSPS") and Maximum Achievable Control Technology standards are expected to be made more stringent over time as a result of stricter ambient air quality standards and other air quality protection goals adopted by the EPA. Compliance with these or other new regulations could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs, which could adversely impact on our business. For example, in 2015, the EPA lowered the National Ambient Air Quality Standard ("NAAQs"), for ground-level ozone from 75 to 70 parts per billion for both the eight-hour primary and secondary standards. In 2017 and 2018, the EPA issued area designations with respect to ground-level ozone as either "attainment/unclassifiable," unclassifiable" or "non-attainment." Additionally, in November 2018, the EPA issued final requirements that apply to state, local, and tribal air agencies for implementing the 2015 NAAQS for ground-level ozone. States are also expected to implement requirements as a result of this NAAQs final rule, which could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of oil and natural gas projects and increase costs for us and our customers. Moreover, our business could be materially affected if our E&P customers' operations are significantly affected by these or other similar requirements. These requirements could increase the cost of doing business for us and our customers and reduce the demand for the oil and natural gas our customers produce, and thus have an adverse effect on the demand for our services.

Climate Change. The U.S. Congress and the EPA, in addition to some state and regional efforts, have in recent years considered legislation or regulations to reduce emissions of greenhouse gases ("GHGs"). These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. In the absence of federal GHG-limiting legislations, the EPA has determined that GHG emissions present a danger to public health and the environment and has adopted regulations that, among other things, restrict emissions of GHGs under existing provisions of the CAA and may require the installation of "best available control technology" to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future if they would otherwise emit large volumes of GHGs together with other criteria pollutants. Also, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from oil and natural gas production, processing, transmission and storage facilities in the United States. In 2015, the EPA amended and expanded the GHG reporting requirements to all segments of the oil and natural gas industry, including gathering and boosting stations as well as completions and workovers from hydraulically fractured oil wells.

The EPA has also taken steps to limit methane emissions, a GHG, from certain new modified or reconstructed facilities in the oil and natural gas sector through the adoption of a final rule in 2016 establishing Subpart OOOOa standards for methane emissions. However, in 2017, the EPA published a proposed rule to stay certain portions of these Subpart OOOOa standards for two years but the rule was not finalized. Rather, in February 2018, the EPA finalized amendments to certain requirements of the 2016 final rule, and in September 2018 the EPA proposed additional amendments, including rescission of certain requirements and revisions to other requirements, such as fugitive emission monitoring frequency. Furthermore, in late 2016, the federal Bureau of Land Management ("BLM") published a final rule to reduce methane emissions by regulating venting, flaring and leaks from oil and natural gas production activities on onshore federal and Native American lands. However, in September 2018, the BLM published a final rule that rescinds most of the new requirements of the 2016 final rule and codifies the BLM's prior approach to venting and flaring but the rule rescinding the 2016 final rule has been challenged in federal court and remains pending. In the event that the EPA's 2016 or the BLM's 2016 rules should remain or be placed in effect, or should any other new methane emission standards be imposed on the oil and natural gas sector, such requirements could result in increased costs to our or our oil and natural gas E&P customers' operations as well as result in restrictions, delays or cancellations in such operations, which costs, restrictions, delays or cancellations could adversely affect our business.

Internationally, in April 2016, the United States joined other countries in entering into a United Nations-sponsored non-binding agreement negotiated in Paris, France ("Paris Agreement") for nations to limit their GHG emissions through individually determined reduction goals every five years beginning in 2020. However, in August 2017, the U.S. State Department informed the United Nations of the intent of the United States to withdraw from the Paris Agreement, which provides for a four-year exit process beginning when it took effect in November 2016. The United States' adherence to the exit process and/or the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time. Substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas our E&P customers produce and lower the value of their reserves, which developments could reduce demand for our services and have a corresponding material adverse effect on our results of operations and financial position. Moreover, recent activism directed at shifting investments away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector

Endangered Species. The federal Endangered Species Act ("ESA") and analogous state laws regulate activities that could have an adverse effect on threatened and endangered species or their habitats. Similar protections are offered to migratory birds under the federal Migratory Bird Treaty Act ("MBTA"). The U.S. Fish and Wildlife Service ("FWS") may designate critical habitat and suitable habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal and private land use and could delay or prohibit land access or oil and gas development. If harm to species or damages to habitat occur, government entities or, at times, private parties may act to prevent oil and gas exploration or development activities or seek damages for harm to species, habitat or natural resources resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and, in some cases, may seek criminal penalties. Permanent restrictions imposed to protect these species or their habitat could delay, restrict or prohibit drilling in certain areas by our oil and natural gas E&P customers, which could reduce demand for our services.

In addition, as a result of one or more settlements entered into by the FWS, the agency is required to consider listing numerous species as endangered or threatened under the ESA pursuant to specific time lines. The designation of previously unprotected species as threatened or endangered in areas where our oil and natural gas customers operate could cause certain of our customers to incur increased costs arising from species protection measures or could result in limitations on their E&P activities that could have an adverse effect on our ability to provide products and services to those customers.

Regulation of Hydraulic Fracturing

We perform hydraulic fracturing services for our oil and natural gas E&P customers. Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand or other proppant and chemical additives under pressure into the formation to fracture the surrounding rock and stimulate production.

Hydraulic fracturing typically is regulated by state oil and natural gas commissions or similar agencies, but the EPA has asserted federal regulatory authority and performed investigations over aspects of the process. For example, the EPA has asserted regulatory authority pursuant to the federal Safe Drinking Water Act ("SDWA") Underground Injection Control ("UIC") program over hydraulic fracturing activities involving the use of diesel and issued guidance covering such activities as well as published an Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Additionally, the EPA issued final CAA regulations in 2012 and in 2016 governing performance standards, including standards for the capture of emissions of methane and volatile organic compounds ("VOCs") released during hydraulic fracturing. The EPA also published an effluent limit guideline final rule in 2016 prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plant. The BLM published a final rule in 2015 that established new or more stringent standards for performing hydraulic fracturing on federal and Indian lands but the BLM rescinded the 2015 rule in late 2017; however, litigation challenging the BLM's decision to rescind the 2015 rule is pending in federal district court. Also, in late 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances.

Additionally, various state and local governments have implemented, or are considering, increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions, disclosure requirements, well construction and temporary or permanent bans on hydraulic fracturing in certain areas. For example, Texas, Colorado and North Dakota, among others, have adopted regulations that impose new or more stringent permitting, disclosure, disposal and well construction requirements on hydraulic fracturing operations. States could also elect to prohibit high volume hydraulic fracturing altogether, following the approach taken by the State of New York. In addition to state laws, local land use restrictions, such as city ordinances, may restrict drilling in general and/or hydraulic fracturing in particular. Moreover, non-governmental organizations may seek to restrict hydraulic fracturing, as has been the case in Colorado in recent years, when certain interest groups therein have unsuccessfully pursued ballot initiatives in recent general election cycles that, had they been successful, would have revised the state constitution or state statutes in a manner that would have made exploration and production activities in the state more difficult or costly in the future including, for example, by increasing mandatory setback distances of oil and natural gas operations, including hydraulic fracturing, from specific occupied structures and/or certain environmentally sensitive or recreational areas. If new federal, state or local laws, regulations or ballot initiatives that significantly restrict hydraulic fracturing are adopted, such legal requirements could result in delays, eliminate certain drilling and injection activities and make it more difficult or costly to perform hydraulic fracturing. Any such regulations limiting or prohibiting hydraulic fracturing could result in decreased oil and natural gas E&P activities and, therefore, adversely affect demand for our services and our business. Such laws or regulations could also materially increase our costs of compliance and doing business.

Historically, our hydraulic fracturing compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future. It is possible, however, that substantial costs for compliance or penalties for non-compliance may be incurred in the future. Moreover, it is possible that other developments, such as the adoption of stricter environmental laws, regulations, ballot initiatives and enforcement policies, could result in additional costs or liabilities that we cannot currently quantify.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations that are binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although changes to the regulatory burden on the oil and natural gas industry could affect the demand for our services, we would not expect to be affected any differently or to any greater or lesser extent than other companies in the industry with similar operations.

Drilling. Our customers' operations are subject to various types of regulation at the federal, state and local level. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. The state and some counties and municipalities in which our customers are located also regulate one or more of the following:

- the location of wells;

- the method of drilling and casing wells;

- the timing of construction or drilling activities, including seasonal wildlife closures;

- the surface use and restoration of properties upon which wells are drilled; and

- notice to, and consultation with, surface owners and other third parties.

State Regulation. States regulate the drilling for oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and natural gas resources. States do not regulate wellhead prices or engage in other similar direct economic regulation, but we cannot assure you that they will not do so in the future. The oil and natural gas industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us. To the extent that such regulations result in the curtailment of our customers' operations or production, we may incur decreased demand for our services, which may have an adverse effect on our financial condition and results of operations.

Storage and Handling of Explosive Materials.

Our operations involve the handling of explosive materials for our wireline services provided to our oil and natural gas E&P customers. Despite our use of specialized facilities to store explosive materials and intensive employee training programs, the handling of explosive materials could result in incidents that temporarily shut down or otherwise disrupt our or our customers' operations or could cause restrictions, delays or cancellations in the delivery of our services. It is possible that an explosion could result in death or significant injuries to employees and other persons. Material property damage to us, our customers and other third parties could also occur. Any explosive incident could expose us to adverse publicity or liability for damages, including environmental natural resource damages, or cause production restrictions, delays or cancellations, any of which developments could have a material adverse effect on our business, financial condition and results of operations.

Occupational Safety and Health Matters

We are subject to the requirements of the federal Occupational Safety and Health Act which is administered and enforced by the Occupational Safety and Health Administration, commonly referred to as OSHA, and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and the public. We believe that our operations are in substantial compliance with the OSHA requirements, including general industry standards, record keeping requirements and monitoring of occupational exposure to regulated substances. OSHA continues to evaluate worker safety and to propose new regulations, such as but not limited to, the proposed new rule regarding respirable silica sand. Although it is not possible to estimate the financial and compliance impact of the proposed respirable silica sand rule or any other proposed rule, the imposition of more stringent requirements could have a material adverse effect on our business, financial condition and results of operations.

Corporate Information

We were formed in Delaware in 2017 and maintain our principal corporate offices at 1415 Louisiana Street, Suite 2900, Houston, Texas 77002. Our common stock is listed on the New York Stock Exchange and is traded under the symbol "QES." Our telephone number is 832-518-4094 and our internet address is www.quintanaenergyservices.com. We will make available free of charge through our website our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the United States Securities and Exchange Commission ("SEC").

In addition to the reports filed or furnished with the SEC, we publicly disclose information from time to time in our press releases, at annual meetings of stockholders, in publicly accessible conferences and investor presentations, and through our website (principally on our "Investors" page). References to our website in this Annual Report on Form 10-K are provided as a convenience and do not constitute, and should not be deemed, an incorporation by reference of the information contained on, or available through, the website, and such information should not be considered part of this Annual Report .

Item 1A. Risk Factors

Investing in our common stock involves a high degree of risk. You should carefully consider the information in this Annual Report, including the matters addressed under "Cautionary Note Regarding Forward-Looking Statements" and the following risks before making an investment decision. If any of the following risks or uncertainties or any other risks or uncertainties of which we are *currently unaware actually occur, our business, financial condition and results of operations could be materially adversely effected. The trading price of our common stock could decline due to any of these risks, and you may lose all or part of your investment.*

Risks Related to Our Business and Industry

Our business depends on domestic capital spending by the oil and natural gas industry, and reductions in capital spending could have a material adverse effect on our business, financial condition and results of operations.

Our business is cyclical and directly affected by our customers' capital spending to explore for, develop and produce oil and natural gas in the United States. The significant decline in oil and natural gas prices that began in late 2014 has caused a reduction in the exploration, development and production activities of most of our customers and their spending on our services. These cuts in spending have curtailed drilling programs, which has resulted in a reduction in the demand for our services as compared to activity levels in late 2014, as well as the prices we can charge. Although a recovery began in late 2016 and continued through 2017 and early 2018, the recovery has been marked by periods of volatility, most recently in the fourth quarter of 2018, and the outlook for 2019 remains unclear. If oil and natural gas prices decline below current levels for an extended period of time, certain of our customers may be unable to pay their vendors and service providers, including us, as a result of the decline in commodity prices. Reduced discovery rates of new oil and natural gas reserves in our areas of operation as a result of decreased capital spending may also have a negative long-term impact on our business, even in an environment of stronger oil and natural gas prices. Any of these conditions or events could adversely affect our operating results. If the recent recovery does not continue or our customers fail to further increase their capital spending, it could have a material adverse effect on our business, financial condition and results of operations.

Industry conditions are influenced by numerous factors over which we have no control, including:

- expected economic returns to E&P companies of new well completions;
- domestic and foreign economic conditions and supply of and demand for oil and natural gas;
- the level of prices, and expectations about future prices, of oil and natural gas;
- the cost of exploring for, developing, producing and delivering oil and natural gas;
- the level of global oil and natural gas E&P;
- the level of domestic and global oil and natural gas inventories;
- federal, state and local regulation of hydraulic fracturing activities, as well as oil and natural gas E&P activities, including public pressure on governmental bodies and regulatory agencies to regulate our industry;
- U.S. federal, state and local and non-U.S. governmental taxes and regulations, including the policies of governments regarding the exploration for and production and development of their oil and natural gas reserves;
- political and economic conditions in oil and natural gas producing countries;
- actions by the members of the Organization of Petroleum Exporting Countries ("OPEC") and certain non-OPEC producers, including Russia, with respect to oil production levels and announcements of potential changes in such levels;
- moratoriums on drilling activity resulting in a cessation of operation or a failure to expand operations;
- global weather conditions and natural disasters;
- worldwide political, military and economic conditions;
- lead times associated with acquiring equipment and products and availability of qualified personnel;
- the discovery rates of new oil and natural gas reserves;
- stockholder activism or activities by non-governmental organizations to limit certain sources of funding for the energy sector or restrict the exploration, development and production of oil and natural gas;

- the availability of water resources, suitable proppant and chemical additives in sufficient quantities for use in hydraulic fracturing fluids;
- advances in exploration, development and production technologies or in technologies affecting energy consumption;
- the potential acceleration of development of alternative fuels;
- the price and availability of alternative fuels;
- merger and divestiture activity among oil and natural gas producers and drilling contractors;
- uncertainty in capital and commodities markets and the ability of oil and natural gas companies to raise equity capital and debt financing;
- any prolonged reduction in the overall level of oil and natural gas E&P activities, whether resulting from changes in oil and natural gas prices or otherwise, could adversely impact us in many ways by negatively affecting;
- our utilization, revenues, cash flows and profitability;
- our ability to maintain or increase borrowing capacity;
- our ability to obtain additional capital to finance our business and the cost of that capital; and
- our ability to attract and retain skilled personnel.

The volatility of oil and natural gas prices may adversely affect the demand for our services and negatively impact our results of operations.

The demand for our services is primarily determined by current and anticipated oil and natural gas prices and the related levels of capital spending and drilling activity in the areas in which we have operations. Volatility or weakness in oil prices or natural gas prices (or the perception that oil prices or natural gas prices will decrease) affects the spending patterns of our customers and may result in the drilling of fewer new wells. This, in turn, could lead to lower demand for our services and may cause lower utilization of our assets. We have, and may in the future, experience significant fluctuations in operating results as a result of the reactions of our customers to changes in oil and natural gas prices. For example, prolonged low commodity prices experienced by the oil and natural gas industry beginning in late 2014 and uncertainty about future prices even when prices increased, combined with adverse changes in the capital and credit markets, caused many E&P companies to significantly reduce their capital budgets and drilling activity. This resulted in a significant decline in demand for oilfield services and adversely impacted the prices oilfield services companies could charge for their services.

Prices for oil and natural gas historically have been extremely volatile and are expected to continue to be volatile. During the past five years, WTI has ranged from a low of $26.21 per Bbl in February 2016 to a high of $107.26 per Bbl in June 2014. As of December 28, 2018 WTI closed at $45.15 per Bbl, a 25.3% decrease compared to WTI on December 31, 2017. As of March 1, 2019, WTI closed at $55.76 per Bbl. If the prices of oil and natural gas continue to be volatile, reverse their recent increases or decline, our business, financial condition and results of operations may be materially and adversely affected.

We have operated at a loss in the past, and there is no assurance of our profitability in the future.

Historically, we have experienced periods of low demand for our services and have incurred operating losses. For example, in 2016 we had a net loss of $154.7 million, in 2017 we had a net loss of $21.2 million and in 2018 we had a net loss of $18.2 million. In the future, we may not be able to reduce our costs, increase our revenues or reduce our debt service obligations sufficient to achieve or maintain profitability and generate positive operating income. Under such circumstances, we may incur further operating losses and experience negative operating cash flow.

Restrictions in our New ABL Facility could limit our growth and our ability to engage in certain activities.

Concurrently with the closing of our IPO, we entered into a new asset-based revolving credit facility, which we refer to as our "New ABL Facility," borrowing $13.0 million. The operating and financial restrictions and covenants in our New ABL Facility and any future financing agreements may restrict our ability to finance future operations or capital needs or to expand or pursue our business activities. For example, our New ABL Facility restricts or limits our ability to:

- pay dividends and move cash;

- incur additional liens;
- incur additional indebtedness;
- hedge interest rates;
- engage in a merger, consolidation or dissolution;
- enter into transactions with affiliates;
- sell or otherwise dispose of assets, businesses and operations;
- materially alter the character of our business as conducted at the closing of our IPO; and
- make acquisitions, investments and capital expenditures.

Furthermore, our New ABL Facility contains a minimum fixed charge coverage ratio financial covenant tested from time to time. Our ability to comply with the covenants and restrictions contained in our New ABL Facility may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, our ability to comply with such covenants may be impaired. Any violation of the restrictions, covenants, ratios or tests in our New ABL Facility could result in an event of default, which may cause indebtedness under our New ABL Facility to become immediately due and payable, and our lender's commitment to provide further loans to us may terminate. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. Any subsequent replacement of our New ABL Facility or any new indebtedness could have similar or more restrictive covenants and conditions. For more information about our New ABL Facility, please see “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Our New ABL Facility.”

Our operations are subject to inherent risks, some of which are beyond our control. These risks may be self-insured, or may not be fully covered under our insurance policies.

Our operations are subject to hazards inherent in the oil and natural gas industry, such as, but not limited to, accidents, blowouts, explosions, craterings, fires, natural gas leaks, oil and produced water spills and releases of gases, hydraulic fracturing fluids or wastewater into the environment. These conditions can cause:

- disruption in operations;
- substantial repair, restoration or remediation costs;
- personal injury or loss of human life;
- significant damage to or destruction of property and equipment;
- environmental pollution, including groundwater contamination;
- unusual or unexpected geological formations or pressures and industrial accidents;
- impairment or suspension of operations; and
- substantial revenue loss.

In addition, our operations are subject to, and exposed to, employee/employer liabilities and risks such as wrongful termination, discrimination, labor organizing, retaliation claims and general human resource related matters.

The occurrence of a significant event or adverse claim in excess of the insurance coverage that we maintain or that is not covered by insurance could have a material adverse effect on our business, financial condition and results of operations. Claims for loss of oil and natural gas production and damage to formations can occur in the well services industry. Litigation arising from a catastrophic occurrence at a location where our equipment and services are being used may result in our being named as a defendant in lawsuits asserting large claims.

We do not have insurance against all foreseeable risks, either because insurance is not available or because of the high premium costs. The occurrence of an event not fully insured against or the failure of an insurer to meet its insurance obligations could result in substantial losses. In addition, we may not be able to maintain adequate insurance in the future at rates we consider reasonable.

Insurance may not be available to cover any or all of the risks to which we are subject, or, even if available, it may be inadequate, or insurance premiums or other costs could rise significantly in the future so as to make such insurance prohibitively expensive.

We face intense competition that may cause us to lose market share and could negatively affect our ability to market our services and expand our operations.

The oilfield services business is highly competitive. Some of our competitors have a broader geographic scope, greater financial and other resources, or other cost efficiencies. Additionally, there may be new companies that enter our business, or re-enter our business with significantly reduced indebtedness following emergence from bankruptcy, or our existing and potential customers may develop their own service businesses. Our ability to maintain current revenue and cash flows and our ability to market our services and expand our operations could be adversely affected by the activities of our competitors and our customers. If our competitors substantially increase the resources they devote to the development and marketing of competitive services or substantially decrease the prices at which they offer their services, we may be unable to effectively compete. All of these competitive pressures could have a material adverse effect on our business, financial condition and results of operations. Some of our larger competitors provide a broader range of services on a regional, national or worldwide basis. These companies may have a greater ability to continue oilfield service activities during periods of low commodity prices and to absorb the burden of present and future federal, state, local and other laws and regulations.

We may be unable to implement price increases or maintain existing prices on our core services.

We generate revenue from our core service lines, the majority of which is provided on a spot market basis. Pressure on pricing for our core services, including due to competition and industry and/or economic conditions, may impact, among other things, our ability to implement price increases or maintain pricing on our core services. We operate in a very competitive industry and, as a result, we may not always be successful in raising or maintaining our existing prices. Additionally, during periods of increased market demand, a significant amount of new service capacity, including hydraulic fracturing equipment, may enter the market, which also puts pressure on the pricing of our services and limits our ability to increase or maintain prices. Furthermore, during periods of declining pricing for our services, we may not be able to reduce our costs accordingly, which could further adversely affect our profitability.

Even when we are able to increase our prices, we may not be able to do so at a rate that is sufficient to offset such rising costs. Also, we may not be able to successfully increase prices without adversely affecting our activity levels. The inability to maintain our prices or to increase our prices as costs increase could have a material adverse effect on our business, financial condition and results of operations.

We rely on a limited number of third parties for sand, proppant and chemicals, and delays in deliveries of such materials increases in the cost of such materials or our contractual obligations to pay for materials that we ultimately do not require could harm our business, results of operations and financial condition.

We have established relationships with a limited number of suppliers of our raw materials (such as sand, proppant and chemical additives). Should any of our current suppliers be unable to provide the necessary materials or otherwise fail to deliver the materials in a timely manner and in the quantities required, any resulting delays in the provision of services could have a material adverse effect on our business, financial condition and results of operations. Additionally, increasing costs of such materials may negatively impact demand for our services or the profitability of our business operations. In the past, our industry faced sporadic proppant shortages associated with hydraulic fracturing operations requiring work stoppages, which adversely impacted the operating results of several competitors. We may not be able to mitigate any future shortages of materials, including proppant. Furthermore, to the extent our contracts require us to purchase more materials, including proppant, than we ultimately require, we may be forced to pay for the excess amount under “take or pay” contract provisions.

We have multi-year proppant supply contracts for approximately 143,000 average annual tons through 2020. The proppant market remains highly competitive and relatively volatile. An increase in the cost of proppant as a result of increased demand or a decrease in the number of proppant providers as a result of consolidation could increase our cost of an essential raw material in hydraulic stimulation and have a material adverse effect on our business, financial condition and results of operations.

We may be adversely affected by uncertainty in the global financial markets and the deterioration of the financial condition of our customers.

Our future results may be impacted by the uncertainty caused by an economic downturn, volatility or deterioration in the debt and equity capital markets, inflation, deflation or other adverse economic conditions that may negatively affect us or parties with whom we do business resulting in a reduction in our customers’ spending and their non-payment or inability to perform obligations owed to us, such as the failure of customers to honor their commitments or the failure of major suppliers to complete orders. Additionally, during times when the natural gas or crude oil markets weaken, our customers are more likely to experience financial difficulties, including being unable to access debt or equity financing, which could result in a reduction in our customers’ spending for our services. In addition, in the course of our business we hold accounts receivable from our customers. In the event of the financial distress or bankruptcy of a customer, we could lose all or a portion of such outstanding accounts receivable associated with that customer. Further, if a customer was to enter into bankruptcy, it could also result in the cancellation of all or a portion of our service contracts with such customer at significant expense or loss of expected revenues to us.

Our assets require significant amounts of capital for maintenance, upgrades and refurbishment and may require significant capital expenditures for new equipment.

Our Pressure Pumping and Pressure Control fleets and other drilling and completion service-related equipment require significant capital investment in maintenance, upgrades and refurbishment to maintain their competitiveness. The costs of components and labor have increased in the past and may increase in the future with increases in demand, which will require us to incur additional costs to upgrade any fleets we may acquire in the future. Our fleets and other equipment typically do not generate revenue while they are undergoing maintenance, upgrades or refurbishment. Any maintenance, upgrade or refurbishment project for our assets could increase our indebtedness or reduce cash available for other opportunities. Furthermore, such projects may require proportionally greater capital investments as a percentage of total asset value, which may make such projects difficult to finance on acceptable terms. To the extent we are unable to fund such projects, we may have less equipment available for service or our equipment may not be attractive to potential or current customers. Additionally, competition or advances in technology within our industry may require us to update or replace existing fleets or build or acquire new fleets and equipment. Such demands on our capital or reductions in demand for our hydraulic fracturing fleets and the increase in cost of labor necessary for such maintenance and improvement, in each case, could have a material adverse effect on our business, financial condition and results of operations and may increase our costs.

Delays or restrictions in obtaining permits by us for our operations or by our customers for their operations could impair our business.

In most states, our operations and the operations of our oil and natural gas E&P customers require permits from one or more governmental agencies in order to perform drilling and completion activities, secure water rights, or other regulated activities. Such permits are typically issued by state agencies, but federal and local governmental permits may also be required. The requirements for such permits vary depending on the location where such regulated activities will be conducted. As with all governmental permitting processes, there is a degree of uncertainty as to whether a permit will be granted, the time it will take for a permit to be issued and the conditions that may be imposed in connection with the granting of the permit. In addition, some of our customers' drilling and completion activities may take place on federal land or Native American lands, requiring leases and other approvals from the federal government or Native American tribes to conduct such drilling and completion activities or other regulated activities. Under certain circumstances, federal agencies may cancel proposed leases for federal lands and refuse to grant or otherwise delay required approvals. Therefore, our E&P customers' operations in certain areas of the United States may be canceled or interrupted or suspended for varying lengths of time, causing a loss of revenue to us and adversely affecting our results of operations in support of those customers.

Federal or state legislative and regulatory initiatives related to induced seismicity could result in operating restrictions or delays in the drilling and completion of oil and natural gas wells that may reduce demand for our services and could have a material adverse effect on our business, financial condition and results of operations.

Our oil and natural gas E&P customers dispose of flowback and produced water or certain other oilfield fluids gathered from oil and natural gas E&P operations in accordance with permits issued by government authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change based on concerns of the public or governmental authorities regarding such disposal activities. One such concern relates to recent seismic events near underground disposal wells that are used for the disposal by injection of flowback and produced water or certain other oilfield fluids resulting from oil and natural gas activities. Developing research suggests that the link between seismic activity and wastewater disposal may vary by region, and that only a very small fraction of the tens of thousands of injection wells have been suspected to be, or may have been, the likely cause of induced seismicity. In 2016, the United States Geological Survey identified six states with the most significant hazards from induced seismicity, including Oklahoma, Kansas, Texas, Colorado, New Mexico, and Arkansas. In response to concerns regarding induced seismicity, regulators in some states have imposed, or are considering imposing, additional requirements in the use of such wells. For example, Oklahoma issued rules for wastewater disposal wells that imposed certain permitting and operating restrictions and reporting requirements on disposal wells in proximity to faults and also, from time to time, is developing and implementing plans directing certain wells where seismic incidents have occurred to restrict or suspend disposal well operations. Texas adopted similar rules. Also, in late 2016, the OCC's Oil and Gas Conservation Division and the Oklahoma Geological Survey released well completion seismicity guidance, which requires operators to take certain prescriptive actions, including an operator's planned mitigation practices, following certain unusual seismic activity within 1.25 miles of hydraulic fracturing operations. In recent years, including during 2018, the OCC's Oil and Gas Conservation Division has issued orders limiting future increases in the volume of oil and natural gas wastewater injected belowground into the Arbuckle formation in an effort to reduce the number of earthquakes in the state. Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by our customers to dispose of flowback and produced water and certain other oilfield fluids. Increased regulation and attention given to induced seismicity also could lead to greater opposition to, and litigation concerning, oil and natural gas activities utilizing injection wells for waste disposal. Any one or more of these developments may result in our customers having to limit disposal well volumes, disposal rates or locations, or require our customers or third party disposal well operators that are used to dispose of customers' wastewater to shut down disposal wells, which developments could adversely affect our customers' business and result in a corresponding decrease in the need for our services, which could have a material adverse effect on our business, financial condition and results of operations.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities may serve to limit future oil and natural gas E&P activities and could have a material adverse effect on our business, financial condition and results of operations.

We perform hydraulic fracturing services for our oil and natural gas E&P customers. The hydraulic fracturing process involves the injection of water, sand or other proppant and chemical additives under pressure into the formation to fracture the surrounding rock and stimulate production.

Hydraulic fracturing typically is regulated by state oil and natural gas commissions or similar agencies, but the EPA has asserted federal regulatory authority and performed investigations over aspects of the process. For example, the EPA has asserted regulatory authority pursuant to the SDWA's UIC program over hydraulic fracturing activities involving the use of diesel and issued guidance covering such activities, as well as published an Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Additionally, in June 2016, the EPA published an effluent limit guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants. The BLM also published a final rule in 2015 that established new or more stringent standards relating to hydraulic fracturing on federal and Native American lands but the BLM rescinded the 2015 rule in late 2017; however, litigation challenging the BLM's decision to rescind the 2015 rule is pending in federal district court. Also, in late 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances. From time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. In the event that new federal restrictions relating to the hydraulic fracturing process are adopted in areas where we or our E&P customers conduct business, we or our customers may incur additional costs or permitting requirements to comply with such federal requirements that may be significant and, in the case of our customers, also could result in added restrictions, delays or cancellations in the pursuit of exploration, development, or production activities, which would in turn reduce the demand for our services.

Moreover, some states and local governments have adopted, and other governmental entities are considering adopting, regulations that could impose more stringent permitting, disclosure and well-construction requirements on hydraulic fracturing operations, including states where we or our customers operate. For example, Texas, Colorado and North Dakota, among others, have adopted regulations that impose new or more stringent permitting, disclosure, disposal and well construction requirements on hydraulic fracturing operations. States could also elect to prohibit high volume hydraulic fracturing altogether, following the approach taken by the State of New York. In addition to state laws, local land use restrictions, such as city ordinances, may restrict drilling in general and/or hydraulic fracturing in particular. Also, non-governmental organizations may seek to restrict hydraulic fracturing, as has been the case in Colorado in recent years, when certain interest groups therein have unsuccessfully pursued ballot initiatives in recent general election cycles that, had they been successful, would have revised the state constitution or state statutes in a manner that would have made exploration and production activities in the state more difficult or costly in the future including, for example, by increasing mandatory setback distances of oil and natural gas operations, including hydraulic fracturing, from specific occupied structures and/or certain environmentally sensitive or recreational areas. Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to, and litigation concerning, oil and natural gas production activities using hydraulic fracturing techniques. Additional legislation, regulation or ballot initiatives could also lead to operational restrictions, delays or cancellations for our customers or increased operating costs in the production of oil and natural gas, including from the developing shale plays, or could make it more difficult for us and our customers to perform hydraulic fracturing. The adoption of any federal, state or local laws or ballot initiatives, or the implementation of regulations or ballot initiatives regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and natural gas wells and an associated decrease in demand for our services and increased compliance costs and time, which could have a material adverse effect on our business, financial condition and results of operations.

Changes in transportation regulations may increase our costs and negatively impact our business, financial condition and results of operations.

We are subject to various transportation regulations including as a motor carrier by the DOT and by various federal, state and tribal agencies, whose regulations include certain permit requirements of highway and safety authorities. These regulatory authorities exercise broad powers over our trucking operations, generally governing such matters as the authorization to engage in motor carrier operations, safety, equipment testing, driver requirements and specifications and insurance requirements. The trucking industry is subject to possible regulatory and legislative changes that may impact our operations, such as changes in fuel emissions limits, hours of service regulations that govern the amount of time a driver may drive or work in any specific period, onboard ELD requirements and limits on vehicle weight and size. As the federal government continues to develop and propose regulations relating to fuel quality, engine efficiency and GHG emissions, we may experience an increase in costs related to truck purchases and maintenance, impairment of equipment productivity, a decrease in the residual value of vehicles, unpredictable fluctuations in fuel prices and an increase in operating expenses. Increased truck traffic may contribute to deteriorating road conditions in some areas where our operations are performed. Our operations, including routing and weight restrictions, could be affected by road construction, road repairs, detours and state and local regulations and ordinances restricting access to certain roads. Proposals to increase federal, state or local taxes, including taxes on motor fuels, are also made from time to time, and any such increase would increase our operating costs. Also, state and local regulation of permitted routes and times on specific roadways could adversely affect our operations. We cannot predict whether, or in what form, any legislative or regulatory changes or municipal ordinances applicable to our logistics operations will be enacted and to what extent any such legislation or regulations could increase our costs or otherwise have a material adverse effect on our business, financial condition and results of operations.

We are subject to environmental and occupational health and safety laws and regulations that may expose us to significant costs and liabilities.

Our operations and the operations of our oil and natural gas E&P customers are subject to numerous federal, tribal, regional, state and local laws and regulations relating to protection of the environment, including natural resources, health and safety aspects of our operations and waste management, including the transportation and disposal of waste and other materials. These laws and regulations may impose numerous obligations on our operations and the operations of our E&P customers, including the acquisition of permits to conduct regulated activities, the imposition of restrictions on the types, quantities and concentrations of various substances that can be released into the environment or injected in non-producing formations in connection with E&P activities, the incurrence of capital expenditures to mitigate or prevent releases of materials from our equipment, facilities or from customer locations where we are providing services, the imposition of substantial liabilities for pollution resulting from our operations, and the application of specific health and safety criteria addressing worker protection. Any failure on our part or the part of our E&P customers to comply with these laws and regulations could result in prohibitions or restrictions on operations, assessment of sanctions including administrative, civil and criminal penalties, issuance of corrective action orders requiring the performance of investigatory, remedial or curative activities or enjoining performance of some or all of our operations in a particular area and the occurrence of restrictions, delays or cancellations in the permitting or performance of projects.

Our business activities present risks of incurring significant environmental costs and liabilities, including costs and liabilities resulting from our handling of oilfield and other wastes, because of air emissions and wastewater discharges related to our operations, and due to historical oilfield industry operations and waste disposal practices. In addition, private parties, including the owners of properties upon which we perform services and facilities where our wastes are taken for reclamation or disposal, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property or environmental natural resource damages. Some environmental laws and regulations may impose strict liability, which means that in some situations we could be exposed to liability as a result of our conduct that was lawful at the time it occurred or the conduct of, or conditions caused by, prior operators or other third parties. Additionally, multiple environmental laws provide for citizen suits, which allow private parties, including environmental organizations, to act in place of the government and sue operators for alleged violations of environmental law. Remedial costs and other damages arising as a result of environmental laws and costs associated with changes in environmental laws and regulations could be substantial and could have a material adverse effect on our business, financial condition and results of operations.

Laws and regulations protecting the environment generally have become more stringent in recent years and are expected to continue to do so, which could lead to material increases in costs for future environmental compliance and remediation. New laws and regulations, amendment of existing laws and regulations, reinterpretation of legal requirements or increased governmental enforcement, could restrict, delay or cancel exploratory or developmental drilling for oil and natural gas and could limit well servicing opportunities. We may not be able to recover some or any of our costs of compliance with these laws and regulations from insurance

The occurrence of explosive incidents could disrupt our or our customers' operations and could adversely affect our business, financial condition and results of operations.

Our operations involve the storage and handling of explosive materials for our wireline services provided to our oil and natural gas E&P customers. Despite our use of specialized facilities to store explosive materials and intensive employee training programs, the handling of explosive materials could result in incidents that temporarily shut down or otherwise disrupt our or our E&P customers’ operations or could cause restrictions, delays or cancellations in the delivery of our services. It is possible that an explosion could result in death or significant injuries to employees and other persons. Material property damage to us, our E&P customers and other third parties could also occur. Any explosive incident could expose us to adverse publicity or liability for damages or cause production restrictions, delays or cancellations, any of which developments could have a material adverse effect on our business, financial condition and results of operations.

Silica-related legislation, health issues and litigation could have a material adverse effect on our business, financial condition, results of operation and reputation.

We are subject to laws and regulations relating to human exposure to crystalline silica. For example, in 2016, OSHA published a final rule that established a more stringent permissible exposure limit for exposure to respirable crystalline silica and provided other provisions to protect employees, such as requirements for exposure assessments, methods for controlling exposure, respiratory protection, medical surveillance, hazard communication, and recording. Compliance with most aspects of the 2016 rule relating to hydraulic fracturing was required by June 2018, and the 2016 rule further requires compliance with engineering control obligations to limit exposures to respirable crystalline silica in connection with hydraulic fracturing activities by June 2021. Federal regulatory authorities, including OSHA and analogous state agencies may continue to propose changes in their regulations regarding workplace exposure to crystalline silica. We may not be able to comply with any new laws and regulations that are adopted, and any new laws and regulations could have a material adverse effect on our operating results by requiring us to modify or cease our operations.

In addition, the inhalation of respirable crystalline silica is associated with the lung disease silicosis. There is evidence of an association between crystalline silica exposure or silicosis and lung cancer and a possible association with other diseases, including immune system disorders such as scleroderma. These health risks have been, and may continue to be, a significant issue confronting the hydraulic fracturing industry. Concerns over silicosis and other potential adverse health effects, as well as concerns regarding potential liability from the use of hydraulic fracture sand, may have the effect of discouraging our oil and natural gas E&P customers' use of hydraulic fracture sand. The actual or perceived health risks of handling hydraulic fracture sand could materially and adversely affect hydraulic fracturing service providers, including us, through reduced use of hydraulic fracture sand, the threat of product liability or employee or third-party lawsuits, increased scrutiny by federal, state and local regulatory authorities of us and our E&P customers or reduced financing sources available to the hydraulic fracturing industry.

We are exposed to potential liabilities arising from our business operations and, if realized, such liabilities will affect our business, financial condition, results of operations and reputation.

Our operations are subject to equipment malfunctions and failures, equipment misuse and defects, explosions and uncontrollable flows of oil, natural gas or well fluids and natural disasters that can cause personal injury, loss of life, damage to property, equipment, the environment or facilities and the suspension of operations. Any fluctuations in operating efficiencies affect our ability to deliver services to our customers on a timely basis, which could have a material adverse effect on our financial condition and results of operations. Despite our quality assurance measures, errors, defects or other performance problems could result in financial, reputational or other losses, including personal injury liability, costs of repair and clean-up and potential criminal and civil penalties and damages. The frequency and severity of such incidents will affect operating costs, insurability and relationships with customers, employees and regulators. Any errors, defects or other performance problems could adversely affect our reputation.

Generally, our oil and natural gas E&P customers agree to indemnify us against claims arising from their employees' personal injury or death to the extent that, in the case of our well site services, their employees are injured or their properties are damaged by such operations, unless, in most instances, resulting from our gross negligence or willful misconduct. Similarly, we generally agree to indemnify our E&P customers for liabilities arising from personal injury to or death of any of our employees, unless, in most instances, resulting from gross negligence or willful misconduct of the E&P customer. In addition, our E&P customers generally agree to indemnify us for loss or destruction of customer-owned property or equipment and in turn, we agree to indemnify our customers for loss or destruction of property or equipment we own. Losses due to catastrophic events, such as blowouts, are generally the responsibility of the E&P customer. However, despite this general allocation of risk, we might not succeed in enforcing such contractual allocation, might incur an unforeseen liability falling outside the scope of such allocation or may be required to enter into a service agreement with terms that vary from the above allocations of risk. As a result, we may incur substantial losses which could materially and adversely affect our business, financial condition and results of operations.

Although either we or our affiliates expect to maintain insurance at a level that we believe is consistent with that of similarly situated companies in our industry, we cannot guarantee that this insurance will be adequate to cover all liabilities. Further, insurance may not be generally available in the future or, if available, insurance premiums may make such insurance commercially unjustifiable.

Anti-indemnity provisions enacted by many states may restrict or prohibit a party's indemnification of us.

We typically enter into agreements with our customers governing the provision of our services, which agreements usually include certain indemnification provisions for losses resulting from operations (see the preceding risk factor). Such agreements may require each party to indemnify the other against certain claims regardless of the negligence or other fault of the indemnified party; however, many states place limitations on contractual indemnity agreements, particularly agreements that indemnify a party against the consequences of its own negligence. Furthermore, certain states, including Texas, Louisiana, New Mexico and Wyoming, have enacted statutes generally referred to as "oilfield anti-indemnity acts" expressly prohibiting certain indemnity agreements contained in or related to oilfield services agreements. Such anti-indemnity acts may restrict or void a party's indemnification of us, which could have a material adverse effect on our business, financial condition and results of operations.

Oil and natural gas companies' operations using hydraulic fracturing are substantially dependent on the availability of water. Restrictions on the ability to obtain water for E&P activities and the disposal of flowback and produced water may impact their operations and have a corresponding adverse effect on our business, financial condition and results of operations.

Water is an essential component of shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Our oil and natural gas E&P customers' access to water to be used in these processes may be adversely affected due to reasons such as periods of extended drought, private, third-party competition for water in localized areas or the implementation of local or state governmental programs to monitor or restrict the beneficial use of water subject to their jurisdiction for hydraulic fracturing to assure adequate local water supplies. The occurrence of these or similar developments may result in limitations being placed on allocations of water due to needs by third-party businesses with more senior contractual or permitting rights to the water. Our customers' inability to locate or contractually acquire and sustain the receipt of sufficient amounts of water could adversely impact their E&P operations and have a corresponding adverse effect on our business, financial condition and results of operations.

Moreover, the imposition of new environmental regulations and other regulatory initiatives could include increased restrictions on our E&P customers' ability to dispose of flowback and produced water generated in hydraulic fracturing or other fluids resulting from E&P activities. Applicable laws, including the Clean Water Act, impose restrictions and strict controls regarding the discharge of pollutants into waters of the United States and require that permits or other approvals be obtained to discharge pollutants to such waters. In 2015, the EPA and the Corps published a final rule outlining their position on the federal jurisdictional reach over waters of the United States, including wetlands, but legal challenges to this rule followed. Beginning in the first quarter of 2017, the EPA and the Corps agreed to reconsider the 2015 rule and, thereafter, the agencies have (i) published a proposed rule in 2017 to rescind the 2015 rule and recodify the regulatory text that governed waters of the United States prior to promulgation of the 2015 rule, (ii) published a final rule in February 2018 adding a February 6, 2020 applicable date to the 2015 rule, and (iii) published a proposed rule in December 2018 re-defining the Clean Water Act's jurisdiction over waters of the United States for which the agencies will seek public comment. The 2015 and February 2018 final rules are being challenged by various factions in federal district court and implementation of the 2015 rule has been enjoined in twenty-eight states pending resolution of the various federal district court challenges. Also, in 2016, the EPA published final regulations prohibiting wastewater discharges from hydraulic fracturing and certain other natural gas operations to publicly-owned wastewater treatment plants. The Clean Water Act and analogous state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and hazardous substances. Compliance with current and future environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells and any inability to secure transportation and access to disposal wells with sufficient capacity to accept all of the flowback and produced water on economic terms may increase our customers' operating costs and cause restrictions, delays, interruptions or termination of our E&P customers' operations, the extent of which cannot be predicted.

Any future indebtedness could restrict our operations and adversely affect our financial condition.

We may incur indebtedness to fund capital expenditures and for working capital needs. Our level of indebtedness may adversely affect our operations and limit our growth, and we may have difficulty making debt service payments on our indebtedness as such payments become due. Our indebtedness may affect our operations in several ways, including the following:

- our indebtedness may increase our vulnerability to general adverse economic and industry conditions;
- the covenants contained in the agreements that will govern our indebtedness limit our ability to borrow funds, dispose of assets, pay dividends and make certain investments;
- our debt covenants will also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- any failure to comply with the financial or other covenants of our indebtedness could result in an event of default, which could result in some or all of our indebtedness becoming immediately due and payable;
- our indebtedness could impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions or other general corporate purposes; and
- our business may not generate sufficient cash flows from operations to enable us to meet our obligations under our indebtedness. If our cash flows and capital resources are insufficient to fund any debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance indebtedness.

Increases in interest rates could adversely impact the price of our shares, our ability to issue equity or incur debt for acquisitions or other purposes.

Interest rates on future borrowings, credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. A rising interest rate environment could have an adverse impact on the price of our shares, our ability to issue equity or incur debt for acquisitions or other purposes.

We rely on a few key employees whose absence or loss could adversely affect our business.

Many key responsibilities within our business have been assigned to a small number of employees. The loss of their services could adversely affect our business. In particular, the loss of the services of one or more members of our management team, including our Chief Executive Officer, Chief Financial Officer, Chief Operating Officer, Chief Compliance Officer, Chief Accounting Officer, Divisional Presidents, and certain of our Vice Presidents, could disrupt our operations. We do not maintain "key person" life insurance policies on any of our employees. As a result, we are not insured against any losses resulting from the death of our key employees.

Our industry overall has experienced a high rate of employee turnover. Any difficulty we experience replacing or adding personnel could have a material adverse effect on our business, financial condition and results of operations.

We are dependent upon the available labor pool of skilled employees and may not be able to find enough skilled labor to meet our needs, which could have a negative effect on our growth. We are also subject to the Fair Labor Standards Act, which governs such matters as minimum wage, overtime and other working conditions. Our services require skilled workers who can perform physically demanding work. As a result of our industry volatility, including the recent and pronounced decline in drilling activity, as well as the demanding nature of the work, many workers have left the hydraulic fracturing industry to pursue employment in different fields. If we are unable to retain or meet growing demand for skilled technical personnel, our operating results and our ability to execute our growth strategies may be adversely affected.

The growth of our business through acquisitions may expose us to various risks, including those relating to difficulties in identifying suitable, accretive acquisition opportunities, as well as difficulties in obtaining financing for targeted acquisitions and the potential for increased leverage or debt service requirements.

As a component of our business strategy, we intend to pursue selected, accretive acquisitions of complementary assets, businesses and technologies. Acquisitions involve a number of risks, including:

- unanticipated costs and assumption of liabilities and exposure to unforeseen liabilities of acquired businesses, including environmental liabilities;
- limitations on our ability to properly assess and maintain an effective internal control environment over an acquired business, in order to comply with public reporting requirements;
- potential losses of key employees and customers of the acquired business;
- inability to commercially develop acquired technologies;
- risks of entering markets in which we have limited prior experience; and
- increases in our expenses and working capital requirements.

In addition, we may not have sufficient capital resources to complete additional acquisitions. We may incur substantial indebtedness to finance future acquisitions and also may issue equity or debt 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 stockholders. Furthermore, we may not be able to obtain additional financing on satisfactory terms. Even if we have access to the necessary capital, we may be unable to continue to identify suitable acquisition opportunities, negotiate acceptable terms or successfully acquire identified targets. There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause use to refrain from, completing acquisitions.

Our ability to grow through acquisitions and manage growth will require us to continue to invest in operational, financial and management information systems to attract, retain, motivate and effectively manage our employees. Our business, financial condition and results of operations may fluctuate significantly from quarter to quarter, based on whether or not significant acquisitions are completed in particular quarters.

Integrating acquisitions may be time-consuming and create costs that could reduce our net income and cash flows.

Part of our strategy includes pursuing acquisitions that we believe will be accretive to our business. If we consummate an acquisition, the process of integrating the acquired business may be complex and time consuming, may be disruptive to the business and may cause an interruption of, or a distraction of management's attention from, the business as a result of a number of obstacles, including, but not limited to:

- a failure of our due diligence process to identify significant risks or issues;
- the loss of customers of the acquired company or our company;
- negative impact on the brands or banners of the acquired company or our company;
- a failure to maintain or improve the quality of customer service;
- difficulties assimilating the operations and personnel of the acquired company;
- our inability to retain key personnel of the acquired company;
- the incurrence of unexpected expenses and working capital requirements;
- our inability to achieve the financial and strategic goals, including synergies, for the combined businesses;
- difficulty in maintaining internal controls, procedures and policies;
- mistaken assumptions about the overall costs of equity or debt; and
- unforeseen difficulties operating in new product areas or new geographic areas.

Any of the foregoing obstacles, or a combination of them, could decrease gross profit margins or increase selling, general and administrative expenses in absolute terms and/or as a percentage of net sales, which could in turn negatively impact our financial condition.

We may not be able to consummate acquisitions in the future on terms acceptable to us, or at all. In addition, future acquisitions are accompanied by the risk that the obligations and liabilities of an acquired company may not be adequately reflected in the historical financial statements of that company and the risk that those historical financial statements may be based on assumptions which are incorrect or inconsistent with our assumptions or approach to accounting policies. Any of these material obligations, liabilities or incorrect or inconsistent assumptions could adversely impact our business, financial condition and results of operations.

If our intended expansion of our business is not successful, our business, financial condition and results of operations could be materially adversely affected, and we may not achieve the increases in revenue and profitability that we hope to realize.

A key element of our business strategy involves the expansion of our services, geographic presence and customer base. These aspects of our strategy are subject to numerous tasks and uncertainties, including:

- an inability to retain or hire experienced crews and other personnel;
- a lack of customer demand for the services we intend to provide;
- an inability to secure necessary equipment, raw materials or technology to successfully execute our expansion objective;
- shortages of water used in our hydraulic fracturing operations;
- unanticipated delays that could limit or defer the provision of services by us and jeopardize our relationships with existing customers and adversely affect our ability to obtain new customers for such services; and
- competition from new and existing service providers.

Encountering any of these or any unforeseen problems in implementing our planned expansion could have a material adverse impact on our business, financial condition and results of operations, and could prevent us from achieving the increases in revenues and profitability that we hope to realize.

Fuel conservation measures could reduce demand for oil and natural gas which would in turn reduce the demand for our services.

Fuel conservation measures, alternative fuel requirements and increasing consumer demand for alternatives to oil and natural gas could reduce demand for oil and natural gas. The impact of the changing demand for oil and natural gas may have a material adverse effect on our business, financial condition, prospects, results of operations and cash flows. Additionally, the increased competitiveness of alternative energy sources (such as wind, solar geothermal, tidal and biofuels) could reduce demand for hydrocarbons and therefore for our services, which would lead to a reduction in our revenues.

Unsatisfactory safety performance may negatively affect our customer relationships and, to the extent we fail to retain existing customers or attract new customers, adversely impact our revenues.

Our ability to retain existing customers and attract new business is dependent on many factors, including our ability to demonstrate that we can reliably and safely operate our business in a manner that is consistent with applicable laws, rules and permits, which legal requirements are subject to change. Existing and potential customers consider the safety record of their third-party service providers to be of high importance in their decision to engage such providers. If one or more accidents were to occur at one of our operating sites, the affected customer may seek to terminate or cancel its use of our facilities or services and may be less likely to continue to use our services, which could cause us to lose substantial revenues. Furthermore, our ability to attract new customers may be impaired if they elect not to engage us because they view our safety record as unacceptable. In addition, it is possible that we will experience multiple or particularly severe accidents in the future, causing our safety record to deteriorate. This may be more likely as we continue to grow, if we experience high employee turnover or labor shortage, or hire inexperienced personnel to bolster our staffing needs.

Climate change legislation and regulations restricting or regulating emissions of GHGs could result in increased operating and capital costs and reduced demand for our hydraulic fracturing services.

Climate change continues to attract considerable public, governmental and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs and regulations that directly limit GHG emissions from certain sources.

At the federal level, no comprehensive climate change legislation has been implemented to date. The EPA has, however, adopted rules under authority of the CAA that, among other things, establish Potential for Significant Deterioration ("PSD") construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that are also potential major sources of certain principal, or criteria, pollutant emissions, which reviews could require securing PSD permits at covered facilities emitting GHGs and meeting "best available control technology" standards for those GHG emissions. Additionally, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, including, among others, onshore and offshore production facilities, which include certain of our E&P customers' operations. The EPA has expanded the GHG reporting requirements to all segments of the oil and natural gas industry, including gathering and boosting facilities as well as completions and workovers from hydraulically fractured oil wells.

Federal agencies also have begun directly regulating emissions of methane, a GHG, from oil and natural gas operations. In 2016, the EPA published NSPS, known as Subpart OOOOa, which requires certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and VOC emissions. These Subpart OOOOa standards expand previously issued NSPS published by the EPA in 2012 and known as Subpart OOOOa, by using certain equipment-specific emissions control practices. However, in 2017, the EPA published a proposed rule to stay certain portions of these Subpart OOOOa standards for two years but the rule was not finalized. Rather, in February 2018, the EPA finalized amendments to certain requirements of the 2016 final rule, and in September 2018 the EPA proposed additional amendments, including rescission of certain requirements and revisions to other requirements, such as fugitive emission monitoring frequency. Furthermore, in 2016, the BLM published a final rule that established, among other things, requirements to reduce methane emissions by regulating venting, flaring and leaks from oil and natural gas production activities on onshore federal and Native American lands. However, in September 2018, the BLM published a final rule that rescinds most of the new requirements of the 2016 final rule and codifies the BLM's prior approach to venting and flaring but the rule rescinding the 2016 final rule has been challenged in federal court and remains pending.

Internationally, in late 2015, the United States joined other countries in entering into a United Nations-sponsored non-binding agreement negotiated in Paris, France ("Paris Agreement") for nations to limit their GHG emissions through individually determined reduction goals every five years beginning in 2020. However, in August 2017, the U.S. State Department informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016. The United States' adherence to the exit process and/or the terms on which the United States may reenter the Paris Agreement or separately negotiated agreement are unclear at this time. The adoption and implementation of any international, federal or state legislation or regulations that require reporting of GHGs or otherwise restrict emissions of GHGs could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial condition, demand for our services and results of operations. Moreover, recent activism directed at shifting funds away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector.

Finally, some scientists have concluded that increasing concentrations of GHG in the atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climate events that could have an adverse effect on our operations and the operations of our customers.

The ESA and MBTA laws and other restrictions intended to protect certain species of wildlife govern our and our customers' operations and additional restrictions may be imposed in the future, which constraints could have an adverse impact on our ability to expand some of our existing operations or limit our customers' ability to develop new oil and natural gas wells.

Oil and natural gas E&P operations in our operating areas can be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife, which may limit our ability to operate in protected areas. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures.

For example, the ESA restricts activities that may affect endangered or threatened species or their habitats. Similar protections are offered to migratory birds under the MBTA. To the extent species that are listed under the ESA or similar state laws, or are protected under the MBTA, live in the areas where we or our oil and natural gas E&P customers operate, our and our customers' abilities to conduct or expand operations and construct facilities could be limited or be forced to incur material additional costs. Moreover, our customer's drilling activities may be delayed, restricted or precluded in protected habitat areas or during certain seasons, such as breeding and nesting seasons. Some of our operations and the operations of our customers are located in areas that are designated as habitats for protected species.

Moreover, as a result of one or more settlements approved by the federal government, FWS must make determinations on the listing of numerous species as endangered or threatened under the ESA pursuant to specific timelines. The designation of previously unidentified endangered or threatened species could indirectly cause us to incur additional costs, cause our or our customers' operations to become subject to operating restrictions or bans, and limit future development activity in affected areas. The FWS and similar state agencies may designate critical or suitable habitat areas that they believe are necessary for the survival of threatened or endangered species. Such a designation could materially restrict use of or access to federal, state and private lands.

Technology advancements in drilling and well service technologies, including those involving hydraulic fracturing, could have a material adverse effect on our business, financial condition and results of operations.

The hydraulic fracturing and completions tool industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As competitors and others use or develop new technologies or technologies comparable to ours in the future, we may lose market share or be placed at a competitive disadvantage. Further, we may face competitive pressure to implement or acquire certain new technologies at a substantial cost. Some of our competitors may have greater financial, technical and personnel resources than we do, which may allow them to gain technological advantages or implement new technologies before we can. Additionally, we may be unable to implement new technologies or services at all, on a timely basis or at an acceptable cost. New technology could also make it easier for our oil and natural gas E&P customers to vertically integrate their operations, thereby reducing or eliminating the need for our services. Limits on our ability to effectively use or implement new technologies may have a material adverse effect on our business, financial condition and results of operations.

Seasonal weather conditions and natural disasters could severely disrupt normal operations and harm our business.

Our operations are located in different regions of the United States. Some of these areas are adversely affected by seasonal weather conditions, primarily in the winter and spring. During periods of heavy snow, ice or rain, we may be unable to move our equipment between locations, thereby reducing our ability to provide services and generate revenues. The exploration activities of our customers may also be affected during such periods of adverse weather conditions. Additionally, extended drought conditions in our operating regions could impact our ability or our customers' ability to source sufficient water or increase the cost for such water. As a result, a natural disaster or inclement weather conditions could severely disrupt the normal operation of our business and adversely impact our financial condition and results of operations.

Certain of our segments may be concentrated in particular geographic regions, which could exacerbate any negative performance of those companies to the extent those companies perform poorly.

We have historically focused our Pressure Pumping services in the Mid-Continent and Rocky Mountain regions. During periods of adverse weather, difficult market conditions or slowdowns in oil and natural gas exploration in these geographic regions, the decreased revenues, difficulty in obtaining access to financing and increased funding costs we experience may be exacerbated by the geographic concentration of our completion and production operations. We could experience any of these conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have more geographically diversified operations. Such delays or interruptions could have a material adverse effect on our business, financial condition and results of operations.

We may be subject to interruptions or failures in our information technology systems.

We rely on sophisticated information technology systems and infrastructure to support our business, including process control technology. Any of these systems may be susceptible to outages due to fire, floods, power loss, telecommunication failures, usage errors by employees, computer viruses, cyberattacks or other security breaches or similar events. The failure of any of our information technology systems may cause disruptions in our operations, which could adversely affect our sales and profitability.

We are subject to cyber security risks. A cyber incident could occur and result in information theft, data corruption, operational disruption and/or financial loss.

The oil and natural gas industry has become increasingly dependent on digital technologies to conduct certain processing activities. For example, we depend on digital technologies to perform many of our services and to process and record financial and operating data. At the same time, cyber incidents, including deliberate attacks, have increased. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. Our technologies, systems and networks, and those of our vendors, suppliers and other business partners, may become the target of cyberattacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. Our systems and insurance coverage for protecting against cyber security risks may not be sufficient. As cyber incidents continue to evolve, we will likely be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents. Our insurance coverage for cyberattacks may not be sufficient to cover all the losses we may experience as a result of such cyberattacks.

If we are unable to fully protect our intellectual property rights, we may suffer a loss in our competitive advantage or market share.

We do not have patents or patent applications relating to many of our key processes and technology. If we are not able to maintain the confidentiality of our trade secrets, or if our competitors are able to replicate our technology or services, our competitive advantage would be diminished. We also cannot assure you that any patents we may obtain in the future would provide us with any significant commercial benefit or would allow us to prevent our competitors from employing comparable technologies or processes.

We may be adversely affected by disputes regarding intellectual property rights of third parties.

Third parties from time to time may initiate litigation against us by asserting that the conduct of our business infringes, misappropriates or otherwise violates intellectual property rights. We may not prevail in any such legal proceedings related to such claims, and our products and services may be found to infringe, impair, misappropriate, dilute or otherwise violate the intellectual property rights of others. If we are sued for infringement and lose, we could be required to pay substantial damages and/or be enjoined from using or selling the infringing products or technology. Any legal proceeding concerning intellectual property could be protracted and costly regardless of the merits of any claim and is inherently unpredictable and could have a material adverse effect on our financial condition, regardless of its outcome.

If we were to discover that our technologies or products infringe valid intellectual property rights of third parties, we may need to obtain licenses from these parties or substantially re-engineer our products in order to avoid infringement. We may not be able to obtain the necessary licenses on acceptable terms, or at all, or be able to re-engineer our products successfully. If our inability to obtain required licenses for our technologies or products prevents us from selling our products, our business, financial condition and results of operations could be materially adversely impacted.

A terrorist attack or armed conflict could harm our business.

The occurrence or threat of terrorist attacks in the United States or other countries, anti-terrorist efforts and other armed conflicts involving the United States or other countries, including continued hostilities in the Middle East, may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. Additionally, destructive forms of protest and opposition by activists and other disruptions, including acts of sabotage or eco-terrorism against oil and natural gas development and production activities could potentially result in personal injury to persons, damages to property, natural resources or the environment or lead to extended interruptions of our or our customers' operations. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our services and causing a reduction in our revenues. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if infrastructure integral to our customers' operations is destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

We engage in transactions with related parties and such transactions present possible conflicts of interest that could have an adverse effect on us.

We have entered into a significant number of transactions with related parties. The details of certain of these transactions are set forth in the section "Certain Relationships and Related Transactions, and Director Independence." Related party transactions create the possibility of conflicts of interest with regard to our management, including that:

- we may enter into contracts between us, on the one hand, and related parties, on the other, that are not as a result of arm's-length transactions;
- our executive officers and directors that hold positions of responsibility with related parties may be aware of certain business opportunities that are appropriate for presentation to us as well as to such other related parties and may present such business opportunities to such other parties; and
- our executive officers and directors that hold positions of responsibility with related parties may have significant duties with, and spend significant time serving, other entities and may have conflicts of interest in allocating time.

Such conflicts could cause an individual in our management to seek to advance his or her economic interests or the economic interests of certain related parties above ours. Further, the appearance of conflicts of interest created by related party transactions could impair the confidence of our investors. Our Board of Directors (the "Board of Directors" or "Board") regularly reviews these transactions. Notwithstanding this, it is possible that a conflict of interest could have a material adverse effect on our business, financial condition and results of operations.

We may record losses or impairment charges related to idle assets or assets that we sell.

Prolonged periods of low utilization, changes in technology or the sale of assets below their carrying value may cause us to experience losses. These events could result in the recognition of impairment charges that negatively impact our financial results. Significant impairment charges as a result of a decline in market conditions or otherwise could have a material adverse effect on our results of operations in future periods.

We may be required to take write-downs of the carrying values of our long-lived assets.

We evaluate our long-lived assets, such as property and equipment, for impairment whenever events or changes in circumstances indicate that their carrying value may not be recoverable. Recoverability is measured by a comparison of their carrying amount to the estimated undiscounted cash flows to be generated by those assets. Based on specific market factors and circumstances at the time of prospective impairment reviews and the continuing evaluation of development plans, economics and other factors, we may be required to write down the carrying value of our long-lived and other intangible assets. There was no impairment on our long-lived assets for the years ended December 31, 2018 and 2017.

The requirements of being a public company, including compliance with the reporting requirements of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and the requirements of the Sarbanes-Oxley Act of 2002 ("Sarbanes-Oxley"), may strain our resources, increase our costs and distract management, and we may be unable to comply with these requirements in a timely or cost-effective manner.

As a public company, we are required to comply with new laws, regulations and requirements, certain corporate governance provisions of Sarbanes-Oxley, related regulations of the SEC and the requirements of the New York Stock Exchange (the "NYSE"), with which we were not required to comply as a private company. Complying with these statutes, regulations and requirements occupies a significant amount of time of our Board of Directors and management and significantly increases our costs and expenses. We are required to:

- institute a more comprehensive compliance function;
- comply with rules promulgated by the NYSE;
- continue to prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;
- establish new internal policies, such as those relating to insider trading; and
- involve and retain to a greater degree outside counsel and accountants in the above activities.

Specifically, Sarbanes-Oxley requires that we maintain effective disclosure controls and procedures and internal control over financial reporting. We are continuing to develop and refine our disclosure controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports that we file with the SEC, is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms, and that information required to be disclosed in reports under the Exchange Act, is accumulated and communicated to our principal executive and financial officers. Any failure to develop or maintain effective controls could adversely affect the results of periodic management evaluations. In the event that we are not able to demonstrate compliance with Sarbanes-Oxley, that our internal control over financial reporting is perceived as inadequate, or that we are unable to produce timely or accurate financial statements, investors may lose confidence in our operating results and the price of our common stock could decline.

Sarbanes-Oxley requires, among other things, that we assess the effectiveness of our internal control over financial reporting annually and disclosure controls and procedures quarterly. In particular, we must perform system and process evaluation and testing of our internal control over financial reporting to allow management to report on the effectiveness of our internal control over financial reporting, as required by Section 404 of Sarbanes-Oxley. This assessment includes the disclosure of any material weaknesses in our internal control over financial reporting identified by our management or our independent registered public accounting firm. To achieve compliance with Section 404 within the prescribed period, we continue to dedicate internal resources and utilize outside consultants and continue to execute a detailed work plan to assess and document the adequacy of internal control over financial reporting, continue steps to improve control processes as appropriate, validate through testing that controls are functioning as documented, and implement a continuous reporting and improvement process for internal control over financial reporting. If material weaknesses are identified in the future or we are not able to comply with the requirements of Section 404 in a timely manner, our reported financial results could be materially misstated, we could receive an adverse opinion regarding our internal controls over financial reporting from our accounting firm, if and when required, and we could be subject to investigations or sanctions by regulatory authorities, which would require additional financial and management resources, which could result in an adverse reaction in the financial markets due to a loss of confidence in the reliability of our financial statements. We cannot assure you that there will not be material weaknesses or significant deficiencies in our disclosure controls or our internal controls over financial reporting in the future. For so long as we remain as an emerging growth company, our accounting firm will not be required to provide an opinion regarding our internal controls over financial reporting.

In addition, we expect that being a public company subject to these rules and regulations may make it more difficult and more expensive for us to obtain director and officer liability insurance and we may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for us to attract and retain qualified individuals to serve on our Board of Directors or as executive officers.

Our stock price may be volatile.

The market price of our common stock could vary significantly as a result of a number of factors, some of which are beyond our control. In the event of a drop in the market price of our common stock, you could lose a substantial part or all of your investment in our common stock. The following factors could affect our stock price:

- quarterly variations in our financial and operating results;
- the public reaction to our press releases, our other public announcements and our filings with the SEC;
- strategic actions by our competitors;
- changes in revenue or earnings estimates, or changes in recommendations or withdrawal of research coverage, by equity research analysts;
- speculation in the press or investment community;
- the failure of research analysts to cover our common stock;
- sales of our common stock by us, our Principal Stockholders (as defined below) or other stockholders, or the perception that such sales may occur;
- changes in accounting principles, policies, guidance, interpretations or standards;
- additions or departures of key management personnel;
- actions by our stockholders;
- general market conditions, including fluctuations in commodity prices;
- domestic and international economic, legal and regulatory factors unrelated to our performance; and
- the realization of any risks described under this "Risk Factors" section.

The stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock. Securities class action litigation has often been instituted against companies following periods of volatility in the overall market and in the market price of a company's securities. Such litigation, if instituted against us, could result in very substantial costs, divert our management's attention and resources and harm our business, financial condition and results of operations.

The Principal Stockholders have the ability to direct the voting of a majority of our voting stock, and their interests may conflict with those of our other stockholders.

Upon completion of our IPO, investment funds managed by Quintana Capital Group ("Quintana"), Archer Well Company Inc. ("Archer"), Geveran Investments Limited and its affiliates ("Geveran"), Robertson QES Investment LLC ("Robertson QES") and Corbin J. Robertson, Jr. ("Mr. Robertson" and, together with Quintana, Archer, Geveran, and Robertson QES, the "Principal Stockholders"), own, on a combined basis, approximately 75.7% of our voting stock as of March 1, 2019. As a result, on a combined basis, the Principal Stockholders are able to control matters requiring stockholder approval, including the election of directors, changes to our organizational documents and significant corporate transactions. This concentration of ownership makes it unlikely that any other holder or group of holders of our common stock will be able to affect the way we are managed or the direction of our business. The interests of the Principal Stockholders with respect to matters potentially or actually involving or affecting us, such as future acquisitions, financings and other corporate opportunities and attempts to acquire us, may conflict with the interests of our other stockholders.

Given this concentrated ownership, the Principal Stockholders would have to approve any potential acquisition of us. The existence of significant stockholders may have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in the best interests of our company. Moreover, the Principal Stockholders' concentration of stock ownership may adversely affect the trading price of our common stock to the extent investors perceive a disadvantage in owning stock of a company with significant stockholders.

In addition, our second amended and restated equity rights agreement (the "Equity Rights Agreement"), provides Quintana with the right to appoint two directors to our Board of Directors, provides Archer with the right to appoint two directors to our Board of Directors and provides Geveran with the right to appoint one director to our Board of Directors. Pursuant to the Equity Rights Agreement, the Principal Stockholders are also deemed a "group" for purposes of certain rules and regulations of the SEC. As a result, we are a controlled company within the meaning of the NYSE corporate governance standards. See "Management—Status as a Controlled Company."

Certain of our directors have significant duties with, and spend significant time serving, entities that may compete with us in seeking acquisitions and business opportunities and, accordingly, may have conflicts of interest in allocating time or pursuing business opportunities. Certain of our directors, who are responsible for managing the direction of our operations, hold positions of responsibility with other entities (including affiliated entities) that are in the oil and natural gas industry. These directors may become aware of business opportunities that may be appropriate for presentation to us as well as to the other entities with which they are or may become affiliated. Due to these existing and potential future affiliations, they may present potential business opportunities to other entities prior to presenting them to us, which could cause additional conflicts of interest. They may also decide that certain opportunities are more appropriate for other entities with which they are affiliated, and as a result, they may elect not to present those opportunities to us. These conflicts may not be resolved in our favor. For additional discussion of our directors' business affiliations and the potential conflicts of interest of which our stockholders should be aware, see "Certain Relationships and Related Transactions, and Director Independence."

Quintana, Archer and their respective affiliates are not limited in their ability to compete with us, and the corporate opportunity provisions in our amended and restated certificate of incorporation could enable Quintana or Archer to benefit from corporate opportunities that might otherwise be available to us.

Our governing documents provide (a) that we renounce any interest and expectancy in any business opportunity that may be from time to time presented to Quintana or Archer or their respective affiliates, and (b) that Quintana and Archer and their respective affiliates (including their portfolio investments) are not restricted from owning assets or engaging in businesses that compete directly or indirectly with us. In particular, subject to the limitations of applicable law, our amended and restated certificate of incorporation does, among other things:

- permit Quintana and Archer, and their respective affiliates to conduct business that competes with us and to make investments in any kind of property in which we may make investments; and
- provide that if Quintana or Archer or their respective affiliates, or any employee, partner, member, manager, officer or director of Quintana or Archer or their respective affiliates who is also one of our directors or officers, becomes aware of a potential business opportunity, transaction or other matter, they will have no duty to communicate or offer that opportunity to us.

Quintana or Archer or their respective affiliates may become aware, from time to time, of certain business opportunities (such as acquisition opportunities) and may direct such opportunities to other businesses in which they have invested, in which case we may not become aware of or otherwise have the ability to pursue such opportunity. Furthermore, such businesses may choose to compete with us for these opportunities, possibly causing these opportunities to not be available to us or causing them to be more expensive for us to pursue. In addition, Quintana and Archer and their respective affiliates may dispose of oil and natural gas properties or other assets in the future, without any obligation to offer us the opportunity to purchase any of those assets. As a result, our renouncing our interest and expectancy in any business opportunity that may be from time to time presented to Quintana and Archer and their respective affiliates could adversely impact our business or prospects if attractive business opportunities are procured by such parties for their own benefit rather than for ours.

A significant reduction by any of the Principal Stockholders of their respective ownership interests in us could adversely affect us.

We believe that the Principal Stockholders' ownership interests in us provide each of them with an economic incentive to assist us to be successful. None of the Principal Stockholders are subject to any obligation to maintain their respective ownership interest in us and may elect at any time to sell all or a substantial portion of or otherwise reduce their respective ownership interest in us. If any of the Principal Stockholders sell all or a substantial portion of their respective ownership interest in us, such Principal Stockholder may have less incentive to assist in our success and such Principal Stockholders' affiliate(s) that are expected to serve as members of our Board of Directors may resign. Such actions could adversely affect our ability to successfully implement our business strategies which could adversely affect our business, financial condition and results of operations.

Our amended and restated certificate of incorporation and amended and restated bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock and could deprive our investors of the opportunity to receive a premium for their shares.

Our amended and restated certificate of incorporation authorizes our Board of Directors to issue preferred stock without stockholder approval in one or more series, designate the number of shares constituting any series, and fix the rights, preferences, privileges and restrictions thereof, including dividend rights, voting rights, rights and terms of redemption, redemption price or prices and liquidation preferences of such series. If our Board of Directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our amended and restated certificate of incorporation and amended and restated bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders. These provisions include:

- after we cease to be a controlled company, dividing our Board of Directors into three classes of directors, with each class serving staggered three-year terms, other than directors which may be elected by holders of our preferred stock, if any;

- after we cease to be a controlled company, providing that all vacancies, including newly created directorships, may, except as otherwise required by law or, if applicable, the rights of holders of one or more series of our preferred stock, be filled only by the affirmative vote of a majority of directors then in office, even if less than a quorum (prior to such time, vacancies may also be filled by stockholders holding a majority of the outstanding shares);

- providing that, after we cease to be a controlled company, any action required or permitted to be taken by the stockholders must be effected at a duly called annual or special meeting of stockholders and may not be effected by any consent in writing in lieu of a meeting of such stockholders, subject to the rights of the holders of any series of our preferred stock with respect to such series;

- providing that, after we cease to be a controlled company, our certificate of incorporation and bylaws may be amended by the affirmative vote of the holders of not less than 66% of our then outstanding common stock;

- providing that, after we cease to be a controlled company, permitting special meetings of our stockholders to be called only by our Board of Directors pursuant to a resolution adopted by the affirmative vote of a majority of the members of the board of directors serving at the time of such vote (prior to such time, a special meeting may also be called at the request of stockholders holding a majority of the then outstanding shares entitled to vote);

- providing that, after we cease to be a controlled company, the affirmative vote of the holders of not less than 66% in voting power of all then outstanding common stock entitled to vote generally in the election of directors, voting together as a single class, is required to remove any or all of the directors from office at any time, and directors will be removable only for “cause”;

- prohibiting cumulative voting by our stockholders on all matters;

- establishing advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders;

- providing that our Board of Directors has the ability to authorize undesignated preferred stock;

- providing that the authorized number of directors constituting our Board of Directors may be changed only by a resolution of the board of directors; and
- providing that our Board of Directors is expressly authorized to adopt, alter or repeal our bylaws.

Our amended and restated certificate of incorporation also contains a provision that provides us with protections similar to Section 203 of the Delaware General Corporation Law (the "DGCL"), and prevents us from engaging in a business combination, such as a merger, with a person or group who acquires at least 15% of our voting stock for a period of three years from the date such person became an interested stockholder, unless (with certain exceptions) the business combination or the transaction in which the person became an interested stockholder is approved as prescribed in our amended and restated certificate of incorporation. However, our amended and restated certificate of incorporation also provides that our Principal Stockholders and any persons to whom our Principal Stockholders sell their common stock will be excluded from the definition of "interested stockholder".

Our amended and restated certificate of incorporation designates the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, employees or agents.

Our amended and restated certificate of incorporation provides that, unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware will, to the fullest extent permitted by applicable law, be the sole and exclusive forum for (i) any derivative action or proceeding brought on our behalf, (ii) any action asserting a claim of breach of a fiduciary duty owed by any of our directors, officers, employees or agents to us or our stockholders, (iii) any action asserting a claim arising pursuant to any provision of the DGCL, our amended and restated certificate of incorporation or our amended and restated bylaws or (iv) any action asserting a claim against us that is governed by the internal affairs doctrine, in each such case subject to such Court of Chancery having personal jurisdiction over the indispensable parties named as defendants therein. Any person or entity purchasing or otherwise acquiring any interest in shares of our capital stock will be deemed to have notice of, and consented to, the provisions of our amended and restated certificate of incorporation described in the preceding sentence. This choice of forum provision may limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with us or our directors, officers, employees or agents, which may discourage such lawsuits against us and such persons. Alternatively, if a court were to find these provisions of our amended and restated certificate of incorporation inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition or results of operations.

We do not intend to pay cash dividends on our common stock. Consequently, your only opportunity to achieve a return on your investment is if the price of our common stock appreciates.

We do not plan to declare cash dividends on shares of our common stock in the foreseeable future. Additionally, our New ABL Facility places certain restrictions on our ability to pay cash dividends. Consequently, your only opportunity to achieve a return on your investment in us may be if you sell your common stock at a price greater than you paid for it. There is no guarantee that the price of our common stock that will prevail in the market will ever exceed the price at which you purchased your shares of common stock.

Future sales of our common stock in the public market, or the perception that such sales may occur, could reduce our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.

We may sell additional shares of common stock in subsequent public offerings or may issue additional shares of common stock or convertible securities. We have 33,907,414 shares of our common stock outstanding as of March 1, 2019.

In connection with our IPO, on February 14, 2018, we filed a registration statement with the SEC on Form S-8 providing for the registration of 5,257,215 shares of our common stock issued or reserved for issuance under our equity incentive plan. Subject to the satisfaction of vesting conditions and the requirements of Rule 144, shares registered under the registration statement on Form S-8 may be made available for resale immediately in the public market without restriction.

Additionally, on December 21, 2018, pursuant to our contractual obligations under the Registration Rights Agreement, dated February 13, 2018, by and among the Company and certain of the Principal Stockholders, the Company filed a selling stockholder shelf registration statement on Form S-1 with the SEC and registered 25,654,384 shares of our common stock, par value $0.01 per share, which may be offered for sale from time to time by the selling stockholders named therein (the "December 2018 Form S-1"). The shares of our common stock covered by the December 2018 Form S-1 were issued by us to the selling stockholders in the corporate reorganization connected to our IPO or were purchased by the selling stockholders in our IPO, which closed on February 13, 2018. We are not selling any shares of common stock pursuant to the December 2018 Form S-1 and will not receive any proceeds from the sale of any shares of common stock by the selling stockholders. We cannot predict the size of future issuances of our common stock or securities convertible into common stock or the effect, if any, that future issuances and/or sales of shares of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our common stock.

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

Our amended and restated certificate of incorporation authorizes our Board of Directors to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our Board of Directors may determine. The terms of one or more classes or series of our preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of a class or series of our 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 our common stock.

We are a "controlled company" within the meaning of the NYSE rules and, as a result, qualify for and intend to rely on exemptions from certain corporate governance requirements.

The Principal Stockholders own, on a combined basis, a majority of the combined voting power of all classes of our outstanding voting stock. Additionally, the Principal Stockholders are deemed a group for purposes of certain rules and regulations of the SEC as a result of the Equity Rights Agreement. As a result, we are a controlled company within the meaning of the NYSE corporate governance standards. Under the NYSE rules, a company of which more than 50% of the voting power is held by another person or group of persons acting together is a controlled company and may elect not to comply with certain NYSE corporate governance requirements, including the requirements that:

- a majority of the board of directors consist of independent directors as defined under the rules of the NYSE;
- the nominating and governance committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and
- the compensation committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities.

These requirements will not apply to us as long as we remain a controlled company. We intend to utilize some or all of these exemptions. For example, while not currently mandatory given our controlled company status, we have voluntarily established a compensation committee as of the closing of our IPO. Accordingly, you may not have the same protections afforded to stockholders of companies that are subject to all of the corporate governance requirements of the NYSE. See "Management—Status as a Controlled Company."

For as long as we are an emerging growth company, we will not be required to comply with certain reporting requirements, including those relating to accounting standards and disclosure about our executive compensation, that apply to other public companies.

We are classified as an emerging growth company under the JOBS Act. For as long as we are an emerging growth company, which may be up to five full fiscal years, unlike other public companies, we will not be required to, among other things: (i) provide an auditor's attestation report on management's assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of Sarbanes-Oxley; (ii) comply with any new requirements adopted by the Public Company Accounting Oversight Board ("PCAOB") requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer; (iii) provide certain disclosures regarding executive compensation required of larger public companies; or (iv) hold nonbinding advisory votes on executive compensation. We will remain an emerging growth company for up to five years, although we will lose that status sooner if we have more than $1.07 billion of revenues in a fiscal year, have more than $700.0 million in market value of our common stock held by non-affiliates, or issue more than $1.07 billion of non-convertible debt over a three-year period.

To the extent that we rely on any of the exemptions available to emerging growth companies, you will receive less information about our executive compensation and internal control over financial reporting than issuers that are not emerging growth companies. If some investors find our common stock to be less attractive as a result, there may be a less active trading market for our common stock and our stock price may be more volatile.

As a smaller reporting company, we cannot be certain if such reduced disclosure will make our common stock less attractive to investors.

We are currently a "smaller reporting company" as defined in the Exchange Act, and are thus allowed to provide simplified executive compensation disclosures in our filings, are exempt from the provisions of Section 404(b) of Sarbanes-Oxley requiring that an independent registered public accounting firm provide an attestation report on the effectiveness of internal control over financial reporting and have certain other reduced disclosure obligations with respect to our SEC filings. We will remain a "smaller reporting company" until the aggregate market value of our outstanding common stock held by non-affiliates as of the last business day our recently completed second fiscal quarter is over $250 million. We cannot predict whether investors will find our common stock less attractive because of our reliance on any of these exemptions. If some investors find our common stock less attractive as a result, there may be a less active trading market for our common stock and our stock price may be more volatile.

If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our common stock or if our operating results do not meet their expectations, our stock price could decline.

The trading market for our common stock is influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrades our common stock or if our operating results do not meet their expectations, our stock price could decline.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

We currently lease our corporate headquarters, which are located at 1415 Louisiana Street, Suite 2900, Houston, Texas 77002. We currently own or lease the following additional material facilities:

	Leased or Owned	Expiration of Lease
Directional Drilling		
Midland, TX	Leased	6/30/2022
Midland, TX	Leased	12/31/2021
Oklahoma City, OK	Leased	6/30/2026
Willis, TX	Owned	N/A
Willis, TX	Leased	Month-to-Month
Mills, WY	Leased	10/31/2026
Morgantown, WV	Leased	Month-to-Month
Pressure Pumping		
Gillette, WY	Leased	11/30/2021
Ponca City, OK	Owned	N/A
Union City, OK	Owned	N/A
Oakley, KS	Owned	N/A
Chanute, KS	Owned	N/A
Thayer, KS	Owned	N/A
El Dorado, KS	Owned	N/A
Ottawa, KS	Owned	N/A
Pressure Control		
Williston, ND	Owned	N/A
Greeley, CO	Owned	N/A
Odessa, TX	Leased	3/31/2021
Victoria, TX	Owned	N/A
Longview, TX	Owned	N/A
Arnett, OK	Owned	N/A
Elk City, OK	Leased	4/30/2027
Oklahoma City, OK	Leased	12/12/2026
Kensett, AR	Leased	Month-to-Month
Lore City, OH	Leased	4/14/2020
Wireline		
Guthrie, OK	Owned	N/A
Levelland, TX	Owned	N/A
Odessa, TX	Leased	3/31/2021
Alice, TX	Leased	12/31/2021
Rosharon, TX	Leased	7/31/2019
Longview, TX	Leased	3/8/2021
Cresson, TX	Owned	N/A
Fort Worth, TX	Leased	12/31/2020

We believe that our facilities are adequate for our current operations.

Item 3. Legal Proceedings

Due to the nature of our business, we are, from time to time, involved in other 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, if decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations.

Item 4. Mine Safety Disclosures

Not applicable.

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

Market Information

In connection with our IPO, our common stock began trading on the NYSE under the symbol "QES" on February 9, 2018.

As of March 1, 2019, we had approximately 33,907,414 shares of common stock outstanding and 46 stockholders of record. The number of record holders does not include persons who held shares of our common stock in nominee or "street name" accounts through brokers.

Dividend Policy

We do not anticipate declaring or paying cash dividends to holders of our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the growth of our business. Our future dividend policy is within the discretion of our Board of Directors and will depend upon then existing conditions, including our results of operations, financial condition, capital requirements, investment opportunities, statutory restrictions on our ability to pay dividends and other factors our Board of Directors may deem relevant. In addition, our New ABL Facility places restrictions on our ability to pay cash dividends to holders of our common stock. For more information on our New ABL Facility, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations-New ABL Facility" below.

Securities Authorized for Issuance under Equity Compensation Plans

Information covering securities authorized for issuance under equity compensation plans is incorporated by reference to our definitive proxy statement for our 2019 Annual Meeting of Stockholders pursuant to Regulation 14A under the Exchange Act, which we expect to file with the SEC within 120 days after the close of the year ended December 31, 2018.

Recent Sales of Unregistered Securities

The Company has had no unregistered sales of equity securities not previously reported.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Under our common stock repurchase program, repurchases are being made from time to time in the open market or privately negotiated transactions based on market conditions, securities law limitations and other factors. The following table includes repurchases made under these programs during the fourth quarter of 2018.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (*in thousands*)
October 2018	5,667	$ 6.40	5,667	$ 5,964
November 2018	47,112	$ 6.26	47,112	$ 5,669
December 2018 (1)	43,528	$ 4.72	43,528	$ 5,463
October to December 31, 2018 Total	**96,307**		**96,307**	

(1) On August 8, 2018, our Board of Directors approved a $6.0 million stock repurchase program authorizing us to repurchase common stock in the open market. The timing and amount of stock repurchases will depend on market conditions and corporate, regulatory and other relevant considerations. Repurchases may be commenced or suspended at any time without notice. The program does not obligate

QES to purchase any particular number of shares of common stock during any period or at all, and the program may be modified or suspended at any time, subject to the Company's insider trading policy, at the Company's discretion.

During the quarter ended December 31, 2018, approximately 2,033 shares were withheld from certain executives and employees under the terms of our share-based compensation agreements to provide funds for the payment of payroll and income taxes due at vesting of restricted stock awards.

Item 6. Selected Financial Data

As a smaller reporting company, we are not required to provide the disclosure required by this Item.

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

The following discussion and analysis should be read in conjunction with the historical consolidated financial statements and related notes included elsewhere in this Annual Report on Form 10-K ("Annual Report"). This discussion contains forward-looking statements reflecting our current expectations and estimates and assumptions concerning events and financial trends that may affect our future operating results or financial position. Actual results and the timing of events may differ materially from those contained in these forward-looking statements due to a number of factors, including those discussed in the sections entitled "Risk Factors" and "Cautionary Note Regarding Forward-Looking Statements" appearing elsewhere in this Annual Report.

Overview

We are a growth-oriented provider of diversified oilfield services to leading onshore oil and natural gas exploration and production ("E&P") companies operating in conventional and unconventional plays in all of the active major basins throughout the United States. We classify the services we provide into four reportable segments: (1) Directional Drilling, (2) Pressure Pumping, (3) Pressure Control and (4) Wireline. Our Directional Drilling segment enables efficient drilling and guidance of the horizontal section of a wellbore using our technologically-advanced fleet of downhole motors and 115 MWD kits. Our Pressure Pumping segment includes hydraulic fracturing, cementing and acidizing services, and such services are supported by a high-quality pressure pumping fleet of approximately 267,500 hydraulic horsepower ("HHP") as of December 31, 2018. Our primary pressure pumping focus is on large hydraulic fracturing jobs. Our Pressure Control segment provides various forms of well control, completions and workover applications through our 24 coiled tubing units (10 of which are Large Diameter), 36 rig-assisted snubbing units and ancillary equipment. As of December 31, 2018, our wireline services included 41 wireline units providing a full range of pump-down services in support of unconventional completions, and cased-hole wireline services enabling reservoir characterization.

The Company was incorporated on April 13, 2017 and this Annual Report includes the results of our accounting Predecessor, Quintana Energy Services LP ("QES LP" or our "Predecessor"), which was formed as a Delaware partnership on November 3, 2014. In connection with our initial public offering (the "IPO"), we became the holding company for QES LP and its subsidiaries.

How We Generate Revenue and the Costs of Conducting Our Business

Our core businesses depend on our customers' willingness to make expenditures to produce, develop and explore for oil and natural gas in the United States. Industry conditions are influenced by numerous factors, such as the supply of and demand for oil and natural gas, domestic and worldwide economic conditions, political instability in oil producing countries and merger and divestiture activity among oil and natural gas producers. The volatility of the oil and natural gas industry and the consequent impact on E&P activity could adversely impact the level of drilling, completion and workover activity by some of our customers. This volatility affects the demand for our services and the price of our services.

We derive a majority of our revenues from services supporting oil and natural gas operations. As oil and natural gas prices fluctuate significantly, demand for our services correspondingly change as our customers must balance expenditures for drilling and completion services against their available cash flows. Because our services are required to support drilling and completions activities, we are also subject to changes in spending by our customers as oil and natural gas prices fluctuate.

During the fourth quarter of 2018, the price of crude oil fell approximately 38.6%, with WTI closing at $45.15 per barrel on December 28, 2018. This precipitous decline in crude oil prices had a moderately negative impact on our fourth quarter 2018 consolidated results of operations, particularly those tied to activity in the U.S. shale play regions. If the current pricing environment for crude oil does not improve, or declines further, our customers may be required to further reduce their capital expenditures, causing additional declines in the demand for, and prices of, our products and services, which would adversely affect our future results of operations, cash flows and financial position.

Demand for our services has continued to improve since May 2016 as oil and natural gas prices have increased from previous levels and as the Baker Hughes Incorporated ("Baker Hughes") lower 48 U.S. states land rig count has increased from 375 rigs on May 27, 2016 to 1,052 rigs as of December 31, 2018. Although our industry experienced a significant downturn beginning in late 2014 and remained depressed for a prolonged period, which materially adversely affected our results in 2015 and 2016, the rebound in demand and increasing rig count beginning in May 2016 has improved both activity levels and pricing for our services.

Despite the recent decline in oil prices, demand for our services has improved since May 2016. From the second quarter of 2016 through the fourth quarter of 2018, our Directional Drilling segment increased the number of days we provided services to rigs and earned revenues during the period, including days that standby revenues were earned ("rig days") by 311.4%, while day rates have improved from the lows we experienced during the second quarter of 2016. We reactivated our second and third pressure pumping hydraulic fracturing fleets in February and October 2017, and placed our fourth hydraulic fracturing fleet into service during June 2018. Utilization of our Pressure Control assets has also continued to improve since the second quarter of 2016.

Directional Drilling: Our Directional Drilling segment provides the highly technical and essential services of guiding horizontal and directional drilling operations for E&P companies. We offer premium drilling services including directional drilling, horizontal drilling, under balanced drilling, MWD and rental tools. Our package also offers various technologies, including our positive pulse MWD navigational tool asset fleet, mud motors and ancillary downhole tools, as well as electromagnetic navigational systems. We also provide a suite of integrated and related services, including downhole rental tools. We generally provide directional drilling services on a day rate or hourly basis. We charge prevailing market prices for the services provided in this segment, and we may also charge fees for set up and mobilization of equipment depending on the job. Generally, these fees and other charges vary by location and depend on the equipment and personnel required for the job and the market conditions in the region in which the services are performed. In addition to fees that are charged during periods of active directional drilling, a stand-by fee is typically agreed upon in advance and charged on an hourly basis during periods when drilling must be temporarily ceased while other on-site activity is conducted at the direction of the operator or another service provider. We will also charge customers for the additional cost of oilfield downhole tools and rental equipment that is involuntarily damaged or lost-in-hole. Proceeds from customers for the cost of oilfield downhole tools and other equipment that is involuntarily damaged or lost-in-hole are reflected as product revenues.

Although we do not typically enter into long-term contracts for our services in this segment, we have long standing relationships with our customers in this segment and believe they will continue to utilize our services. As of December 31, 2018, 90.2% of our directional drilling activity is tied to "follow-me rigs," which involve non-contractual, generally recurring services as our Directional Drilling team members follow a drilling rig from well-to-well or pad-to-pad for multiple wells or pads, and in some cases, multiple years. With increasing use of pad drilling and reactivation of rigs, during the year ended December 31, 2018 we have increased the number of "follow me rigs" from approximately 32 in January of 2016 to 74 as of December 31, 2018. We intend to continue to re-deploy additional MWD kits over the course of the fourth quarter and into 2019, as market conditions warrant.

Our Directional Drilling segment accounted for approximately 31.9%, 33.2% and 35.8% of our revenues for the years ended December 31, 2018, 2017 and 2016, respectively.

Pressure Pumping: Our Pressure Pumping segment provides Pressure Pumping services including hydraulic fracturing stimulation, cementing and acidizing services. The majority of the revenues generated in this segment are derived from Pressure Pumping services in the Mid-Continent and Rocky Mountain regions.

Our Pressure Pumping services are based upon a purchase order, contract or on a spot market basis. Services are bid on a stage rate or job basis (for fracturing services) or job basis (for cementing and acidizing services), contracted or hourly basis. Jobs for these services are typically short-term in nature and range from a few hours to multiple days. Customers are charged for the services performed on location and mobilization of the equipment to the location. Additional revenue can be generated through product sales of some materials that are delivered as part of the service being performed.

Our Pressure Pumping segment accounted for approximately 35.4%, 35.0% and 21.5% of our revenues for the years ended December 31, 2018, 2017 and 2016, respectively.

Pressure Control: Our Pressure Control segment provides a wide scope of Pressure Control services, including coiled tubing, rig assisted snubbing, nitrogen, fluid pumping and well control services.

Our coiled tubing units are used in the provision of unconventional completion services or in support of well-servicing and workover applications. Our rig-assisted snubbing units are used in conjunction with a workover rig to insert or remove downhole tools or in support of other well services while maintaining pressure in the well, or in support of unconventional completions. Our nitrogen pumping units provide a non-combustible environment downhole and are used in support of other pressure control or well-servicing applications.

Jobs for our Pressure Control services are typically short-term in nature and range from a few hours to multiple days. Customers are charged for the services performed and any related materials (such as friction reducers and nitrogen materials) used during the course of the services, which are reported as product sales. We may also charge for the mobilization and set-up of equipment, the personnel on the job, any additional equipment used on the job and other miscellaneous materials.

Our Pressure Control segment accounted for approximately 20.3%, 20.5% and 24.9% of our revenues for the years ended December 31, 2018, 2017 and 2016, respectively.

Wireline: Our Wireline segment principally works in connection with hydraulic fracturing services in the form of pump-down services for setting plugs between hydraulic fracturing stages, as well as with the deployment of perforation equipment in connection with "plug-and-perf" operations. We offer a full range of other pump-down and cased-hole wireline services. We also provide cased-hole production logging services, injection profiling, stimulation performance evaluation and water break-through identification via this segment. In addition, we provide industrial logging services for cavern, storage and injection wells.

We provide our wireline services on a spot market basis or subject to a negotiated pricing agreement. Jobs for these services are typically short-term in nature, lasting anywhere from a few hours to a few weeks. We typically charge the customer for these services on a per job basis at agreed-upon spot market rates.

Our Wireline segment accounted for approximately 12.4%, 11.4% and 17.8% of our revenues for the years ended December 31, 2018, 2017 and 2016, respectively.

How We Evaluate Our Operations

Our management team utilizes a number of measures to evaluate the results of operations and efficiently allocate personnel, equipment and capital resources. We evaluate our segments primarily by asset utilization, revenue and Adjusted EBITDA.

For each of our business services segments, we measure our utilization levels primarily by the total number of days that our asset base works on a monthly basis, based on the available working days per month. We generally consider an asset to be working such days that it is at or in transit to a job location. Undue reliance should not be placed on utilization as an indicator of our financial or operating performance because depending on the type of service performed, requirements of the job as well as competitive factors, revenue and profitability can vary from job to job.

Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. Adjusted EBITDA is not a measure of net income or cash flows as determined by U.S. generally accepted accounting principles ("GAAP"). We define Adjusted EBITDA as net income (loss) plus income taxes, net interest expense, depreciation and amortization, impairment charges, net (gain)/loss on disposition of assets, stock based compensation, transaction expenses, rebranding expenses, settlement expenses, severance expenses and equipment stand-up expense.

We believe Adjusted EBITDA is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods, book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDA should not be considered as an alternative to, or more meaningful than, net income as determined by GAAP, or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDA. Our computations of Adjusted EBITDA may not be comparable to other similarly titled measures of other companies. For a definition and description of Adjusted EBITDA and reconciliations of Adjusted EBITDA to net income, the most directly comparable financial measure calculated and presented in accordance with GAAP, please see "Adjusted EBITDA" below.

Items Affecting the Comparability of our Future Results of Operations to our Historical Results of Operations

The historical financial results of our Predecessor discussed below may not be comparable to our future financial results for the reasons described below.

- During 2017, we sold select pressure pumping and wireline assets for aggregate sale proceeds of $27.6 million. During 2018 we completed strategic investments of approximately $30.0 million to expand our hydraulic fracturing fleet and our fleet of Large Diameter coiled tubing units. While we expect continued growth, expansions and strategic divestitures in the future, it is likely such growth, expansions and divestitures will be economically different from the acquisitions and divestitures discussed above, and such differences in economics will impact the comparability of our future results of operations to our historical results.

- QES is subject to U.S. federal and state income taxes as a corporation. Our Predecessor was treated as a flow-through entity for U.S. federal income tax purposes, and as such, was generally not subject to U.S. federal income tax at the entity level. Rather, the tax liability with respect to its taxable income was passed through to its partners. Accordingly, the financial data attributable to our Predecessor contains no expense for U.S. federal income taxes or income taxes in any state or locality (other than franchise tax in the State of Texas).
- Our IPO served as a vesting event under the phantom unit awards granted under our Predecessor's 2015 and 2017 LTIP Plans. As a result, certain of our Predecessor's phantom unit awards fully vested and were settled in connection with the IPO and additional phantom unit awards will fully vest and be settled according to their vesting schedules. We recognized $17.9 million of stock-based compensation expense for the year ended December 31, 2018. Stock-based compensation expense of approximately $10.0 million associated with these phantom unit awards was recognized for the year ended December 31, 2018. See "Note 1 - Organization and Nature of Operations" for additional details on our IPO and related phantom unit awards.
- As we continue to implement controls, processes and infrastructure applicable to companies with publicly traded equity securities, it is likely that we will incur additional selling, general and administrative (“G&A”), expenses relative to historical periods.

Our future results will depend on our ability to efficiently manage our combined operations and execute our business strategy and other factors we may not have the ability to control in addition to those explained above.

Recent Trends and Outlook

Demand for our services is predominantly influenced by the level of drilling and completion activity by E&P companies (“operators”), which is driven largely by the current and anticipated profitability of developing oil and natural gas reserves. WTI has increased from its low of $26.21 per Bbl in early 2016 to $45.15 per Bbl as of December 28, 2018. Natural gas prices have increased from their lows of $1.64 per MMBtu in early 2016 to $3.26 per MMBtu as of December 31, 2018. Drilling and completion activity in the United States has increased significantly as commodity prices have generally increased, which corresponds with increased demand for our services. Despite the significant increase in demand from the lows of 2016, there remains opportunity for growth in 2019 and beyond.

Commodity price volatility remains present in the market and WTI dropped over 38.6% in the fourth quarter of 2018. This price volatility created headwinds for the industry in late 2018 and into early 2019. However, oil prices have climbed since the beginning of 2019, and we believe supply and demand fundamentals for multi-year industry growth are still intact. The shale revolution in the United States continues to evolve with both operators and service companies introducing significant efficiencies to drive cost from exploration and production work. Both public and private operators appear to have shifted their strategies from production growth to operating within cash flow and generating returns. While it may create some near term budget constraints, we believe this is a positive sign for the long-term prospects of our industry. If widely implemented, this strategic shift may moderate volatility in demand for our services, which over time will drive improved results.

The drop in oil prices in late 2018 appears to have contributed to the moderation of 2019 budgets for operators. We believe the mix of moderated 2019 budgets, a shifting strategy for operators to remain within cash flow, and the takeaway constraints in the Permian Basin may reduce overall completions activity levels during the beginning of 2019. While we do not provide hydraulic fracturing services in the Permian Basin, we have seen the impact of the slowdown in that region in the Mid-Continent and other regions as hydraulic fracturing fleets migrate from the Permian Basin to other basins, placing pressure on pricing. We believe, however, that in the second half of 2019, there are several catalysts that could increase demand for our services from their current levels, including reloaded operator budgets, a supportive commodity price environment, improvements to takeaway capacity constraints in the Permian Basin and a material inventory of drilled but uncompleted wells. We will continue to refine our cost structure, adjust headcount and reposition our assets with high utilization customers as market conditions evolve.

Our industry remains fragmented and there are ample opportunities for consolidation amongst service companies. For 2019, we intend to continue to strengthen our operating divisions through a combination of organic growth and to pursue strategic acquisition opportunities.

Results of Operations

The following tables provide selected operating data for the periods indicated. (*in thousands except Other Operational Data*).

	Year Ended		
	December 31, 2018	December 31, 2017	December 31, 2016
Revenues:	$ 604,354	$ 438,033	$ 210,428
Costs and expenses:			
Direct operating costs	468,502	335,609	182,928
General and administrative	97,280	69,856	73,600
Depreciation and amortization	46,683	45,687	78,661
Fixed asset impairment	—	—	1,380
Goodwill impairment	—	—	15,051
(Gain) loss on disposition of assets	(2,375)	(2,639)	5,375
Operating loss	(5,736)	(10,480)	(146,567)
Non-operating income (expense):			
Interest expense	(11,825)	(11,251)	(8,015)
Other income	—	666	—
Loss before income tax	(17,561)	(21,065)	(154,582)
Income tax expense	(621)	(91)	(167)
Net loss	$ (18,182)	$ (21,156)	$ (154,749)

	Year Ended		
	December 31, 2018	December 31, 2017	December 31, 2016
Segment Adjusted EBITDA:			
Directional Drilling	$ 23,694	$ 17,498	$ (76)
Pressure Pumping	28,700	27,784	(19,372)
Pressure Control	18,389	6,539	(5,804)
Wireline	1,362	(1,794)	(6,161)
Adjusted EBITDA [(1)]	$ 60,232	$ 41,226	$ (36,679)
Other Operational Data:			
Directional Drilling rig days [(2)]	18,252	14,407	7,001
Average monthly Directional Drilling rigs on revenue [(3)]	69	58	31
Total hydraulic fracturing stages	4,179	2,993	1,567
Average hydraulic fracturing revenue per stage	$ 47,897	$ 47,189	$ 23,338

(1) Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. For a definition and description of Adjusted EBITDA and reconciliations of Adjusted EBITDA to net income, the most directly comparable financial measure calculated and presented in accordance with GAAP, please read "Adjusted EBITDA" below.

(2) Rig days represent the number of days we are providing services to rigs and are earning revenues during the period, including days that standby revenues are earned.

(3) Rigs on revenue represents the number of rigs earning revenues during a time period, including days that standby revenues are earned.

Adjusted EBITDA

The following table presents a reconciliation of the non-GAAP financial measures of Adjusted EBITDA to the most directly comparable GAAP financial measure for the year ended December 31, 2018, 2017 and 2016 (*in thousands of dollars*):

	Year Ended		
	December 31, 2018	**December 31, 2017**	**December 31, 2016**
Adjustments to reconcile Adjusted EBITDA to net loss:			
Net loss	$ (18,182)	$ (21,156)	$ (154,749)
Income tax expense	621	91	167
Interest expense	11,825	11,251	8,015
Other income	—	(666)	—
Depreciation and amortization expense	46,683	45,687	78,661
Fixed asset impairment	—	—	1,380
Goodwill impairment (1)	—	—	15,051
(Gain) loss on disposition of assets, net (2)	(2,375)	(2,639)	5,375
Non-cash stock based compensation	17,898	—	—
Transaction expense (3)	—	977	4,358
Rebranding expense (4)	322	9	2,237
Settlement expense (5)	825	3,680	1,740
Severance expense (6)	235	243	1,075
Equipment and stand-up expense (7)	2,380	3,749	11
Adjusted EBITDA	$ 60,232	$ 41,226	$ (36,679)

1. For the year ended December 31, 2016, represents a non-cash goodwill impairment charge related to Directional Drilling and the continual decline in commodity pricing and historical low rig activity in 2015, which continued in 2016.
2. Excludes gains on disposition of assets lost in hole of $5.4 million, $7.9 million and $4.1 million for the years ended December 31, 2018, 2017 and 2016, respectively.
3. For the years ended December 31, 2017 and 2016, represents professional fees related to investment banking, accounting and legal services associated with entering into the Former Term Loan (as defined in Item 7 - Liquidity and Capital Resources), of which $1.0 million and $4.4 million was recorded in general and administrative expenses.
4. Relates to expenses incurred in connection with rebranding our segments.
5. For the year ended December 31, 2018, represents lease buyouts, legal fees for FLSA claims, expenses associated with facility closures and other non-recurring expenses that were recorded in general and administrative expenses. For the years ended December 31, 2017 and 2016 relates to the non-recurring settlement of lease termination costs associated with the 2016 market downturn, and sales tax audit accrual and retention payments in the years ended December 31, 2017 and 2016 associated with the acquisition of the U.S. pressure pumping, directional drilling. wireline and pressure control businesses of Archer. In our performance for the year ended December 31, 2017 and the year ended December 31, 2016, $0.5 million and $0.5 million was recorded in direct operating expenses, respectively, and $3.1 million and $1.2 million was recorded in general and administrative expenses, respectively.
6. Relates to severance expenses in the years ended December 31, 2017 and 2016 incurred in connection with a program implemented to reduce headcount in connection with the industry downturn, of which $0.2 million and $0.8 million was recorded to direct operating expenses, respectively and a nominal amount was recorded to general and administrative expenses. In our performance for the year ended December 31, 2018, $0.2 million was recorded in general and administrative expenses.
7. Relates to equipment stand-up costs incurred in connection with the mobilization and redeployment of assets. In our performance for the year ended December 31, 2018, approximately $2.2 million was recorded in direct operating expenses and approximately $0.2 million was recorded in general and administrative expenses for the deployment of our fourth hydraulic fracturing fleet and upgrades of coiled tubing units to large diameter specification For the year ended December 31, 2017, this primarily represents costs related to the deployment of our third hydraulic fracturing fleet, of which $2.2 million was recorded in direct operating expenses and $0.2 million was recorded in general and administrative expenses. For the year ended December 31, 2016, approximately $0.01 million was recorded in direct operating expenses

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

Revenue. *The following table provides revenues by segment for the periods indicated (in thousands of dollars)*:

	Year Ended	
	December 31, 2018	December 31, 2017
Revenue:		
Directional Drilling	$ 192,491	$ 145,230
Pressure Pumping	214,154	153,118
Pressure Control	122,620	89,912
Wireline	75,089	49,773
Total revenue	$ 604,354	$ 438,033

Revenue for the year ended December 31, 2018 increased by $166.4 million, or 38.0%, to $604.4 million from $438.0 million for the year ended December 31, 2017. The increase in revenue by segment was as follows:

Directional Drilling revenue increased by $47.3 million, or 32.6%, to $192.5 million for the year ended December 31, 2018, from $145.2 million for the year ended December 31, 2017. This increase was primarily attributable to a 28.2% increase in utilization and a 7.1% increase in pricing. Approximately 93.0% of our Directional Drilling segment revenue was derived from directional drilling and MWD activities for the year ended December 31, 2018 compared to 94.0% for the year ended December 31, 2017. The change in utilization and pricing accounted for 74.9% and 25.1% of the Directional Drilling revenue increase, respectively.

Pressure Pumping revenue increased by $61.1 million, or 39.9%, to $214.2 million for the year ended December 31, 2018, from $153.1 million for year ended December 31, 2017. This increase was primarily attributable to the mobilization of additional hydraulic fracturing fleets in February 2017, October 2017 and June 2018, which drove a 39.6% increase in stages pumped for the year ended December 31, 2018. Additionally, we experienced a 1.5% increase in average revenue per stage for the year ended December 31, 2018, due to a shift in the job types completed. Approximately 93.5% of our Pressure Pumping segment revenue was derived from hydraulic fracturing services for the year ended December 31, 2018, compared to 92.2% for the year ended December 31, 2017.

Pressure Control revenue increased by $32.7 million, or 36.4%, to $122.6 million for the year ended December 31, 2018, from $89.9 million for the year ended December 31, 2017. This increase was primarily attributable to a 3.5% increase in weighted average utilization and a 48.6% increase in weighted average revenue per day for the year ended December 31, 2018. The addition of new Large Diameter coiled tubing units deployed and higher well control activities positively impacted both Pressure Control revenue and weighted average revenue per day during the year ended December 31, 2018.

Wireline revenue increased by $25.3 million, or 50.8%, to $75.1 million for the year ended December 31, 2018, from $49.8 million for the year ended December 31, 2017. The increase was primarily attributable to a 24.8% increase in utilization and a 38.0% increase in revenue per day for the year ended December 31, 2018. Approximately 78.0% of our Wireline segment revenue was derived from unconventional services for the year ended December 31, 2018, compared to 71.4% for the year ended December 31, 2017. The change in utilization and pricing accounted for 23.4% and 76.6% of the Wireline revenue change, respectively.

Direct operating expenses*. The following table provides our direct operating expenses by segment for the periods indicated (in thousands of dollars):*

	Year Ended	
	December 31, 2018	December 31, 2017
Direct operating expenses:		
Directional Drilling	$ 148,272	$ 111,978
Pressure Pumping	171,974	115,526
Pressure Control	88,717	69,483
Wireline	59,539	38,622
Total direct operating expenses	$ 468,502	$ 335,609

Direct operating expenses for the year ended December 31, 2018 increased by $132.9 million, or 39.6%, to $468.5 million, from $335.6 million for the year ended December 31, 2017. The increase in direct operating expense was attributable to our segments as follows:

Directional Drilling direct operating expenses increased by $36.3 million, or 32.4%, to $148.3 million for the year ended December 31, 2018, from $112.0 million for the year ended December 31, 2017. This increase was primarily attributable to a 26.7% increase in rig days over the same period, which in turn resulted in increased direct operating expenses for personnel, equipment, and repair and maintenance.

Pressure Pumping direct operating expenses increased by $56.5 million, or 48.9%, to $172.0 million for the year ended December 31, 2018, from $115.5 million for the year ended December 31, 2017. This increase was primarily attributable to increased activity driven by a 39.6% increase in stages pumped compared to the prior period, which resulted in direct operating expense increases in materials, equipment and personnel costs. Additionally, Pressure Pumping placed incremental hydraulic fracturing fleets in service in February 2017, October 2017 and June 2018 driving direct operating expenses higher.

Pressure Control direct operating expenses increased by $19.2 million, or 27.6%, to $88.7 million for the year ended December 31, 2018, from $69.5 million for the year ended December 31, 2017. This increase was primarily attributable to increased market activity, including a 3.5% increase in weighted average utilization, which resulted in increased direct operating expenses associated with personnel, equipment and materials.

Wireline direct operating expenses increased by $20.9 million, or 54.1%, to $59.5 million for the year ended December 31, 2018, from $38.6 million for the year ended December 31, 2017. This increase was primarily attributable to increased market activity, including a 24.8% increase in utilization which resulted in increased direct operating expenses associated with personnel, equipment and consumables.

General and administrative expenses. G&A expenses represent the costs associated with managing and supporting our operations. These expenses increased by $27.4 million, or 39.2%, to $97.3 million for the year ended December 31, 2018, from $69.9 million for the year ended December 31, 2017. The increase in G&A expenses was primarily driven by stock based compensation expense of $17.9 million recognized in 2018. No stock expense was recognized in 2017. The increase in G&A expenses was also driven by additional administrative expenses related to being a publicly traded company and outsourced services for internal controls and tax consultancy compliance. Increases in headcount also contributed to the increase in G&A expenses during the year ended December 31, 2018.

Depreciation and amortization. Depreciation and amortization expense increased $1.0 million, or approximately 2.2% to $46.7 million for the year ended December 31, 2018. The slight increase in depreciation and amortization expense was primarily attributable to the fourth hydraulic fracturing fleet, Large Diameter coiled tubing units and additional equipment and machinery placed into service during the year ended December 31, 2018.

Gain on disposition of assets, net. Net gain on disposition of assets for year ended December 31, 2018 was $2.4 million, primarily attributable to gains on idle equipment disposals in our Wireline segment, offset by losses in other segments, compared to a $2.6 million net gain on disposition of assets, primarily attributable to the disposition of Pressure Pumping and Wireline assets for the year ended December 31, 2017.

Interest expense. Interest expense increased by $0.5 million, or approximately 4.4%, to $11.8 million for the year ended December 31, 2018, compared to $11.3 million for the year ended December 31, 2017. Upon closing of the IPO, the proceeds were used to pay off the Former Revolving Credit Facility and Former Term Loan, which resulted in the write-off of additional deferred financing costs of $1.9 million, discounts on the Former Term Loan of $5.3 million, a repayment premium of $1.3 million and interest on the New ABL Facility. The increase was partially offset by lower borrowings on the New ABL Facility during the year ended December 31, 2018.

Adjusted EBITDA. Adjusted EBITDA for year ended December 31, 2018 increased by $19.0 million, or 46.1% to $60.2 million from $41.2 million for the year ended December 31, 2017. The change in Adjusted EBITDA by segment was as follows:

Directional Drilling Adjusted EBITDA increased by $6.2 million, or 35.4%, to $23.7 million in the year ended December 31, 2018, compared to $17.5 million in the year ended December 31, 2017. The increase was primarily attributable to a 32.6% increase in revenue as a result of higher utilization and pricing partially driven by greater use of specialized technology and tools, which was offset by a 32.4% increase in direct operating costs and a 37.0% increase in G&A expenses due to increased activity levels.

Pressure Pumping Adjusted EBITDA increased by $0.9 million, or 3.2% to $28.7 million in the year ended December 31, 2018, compared to $27.8 million in the year ended December 31, 2017. The increase was primarily attributable to a 39.9% increase in revenue driven by increased hydraulic fracturing activity, which was partially offset by a 48.9% increase in direct operating expenses and a 20.0% increase in G&A expenses incurred as the business deployed additional equipment, including the third and fourth hydraulic fracturing fleets.

Pressure Control Adjusted EBITDA increased by $11.9 million, or 183.1% to $18.4 million in the year ended December 31, 2018, compared to $6.5 million in the year ended December 31, 2017. The increase was primarily attributable to a 36.4% increase in revenue driven by increased completions and well control activity, which was offset by a 27.6% and 18.9% increase in direct operating and G&A expenses driven by increased personnel, materials and overhead costs.

Wireline Adjusted EBITDA increased by $3.2 million to $1.4 million in the year ended December 31, 2018, compared to $(1.8) million in the year ended December 31, 2017. The increase was primarily attributable to a 50.8% increase in revenue driven by increased pricing and utilization, partially offset by a 54.1% increase in direct operating expenses and a 14.8% increase in G&A expense driven by increased personnel, consumables and overhead costs resulting from increased utilization.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Revenue. *The following table provides our revenues by segment for the periods indicated (in thousands of dollars):*

	Year Ended	
	December 31, 2017	December 31, 2016
Revenue:		
Directional Drilling	$ 145,230	$ 75,326
Pressure Pumping	153,118	45,165
Pressure Control	89,912	52,388
Wireline	49,773	37,549
Total revenue	$ 438,033	$ 210,428

Revenue for the year ended December 31, 2017 increased by $227.6 million, or 108.2%, to $438.0 million from $210.4 million for the year ended December 31, 2016. The increase in revenue by segment was as follows:

Directional Drilling revenue increased by $69.9 million, or 92.8%, to $145.2 million for the year ended December 31, 2017, from $75.3 million for the year ended December 31, 2016. This increase was primarily attributable to a 101.9% increase in utilization for the year ended December 31, 2017. The utilization increase was offset by a (4.0)% decline in dayrate for the year ended December 31, 2017 as a result of a shift in geographic revenue mix as rig count expanded in 2017. Approximately 94.0% of our Directional Drilling segment revenue was derived from directional drilling and MWD activities for the year ended December 31, 2017 compared to 91.0% for the year ended December 31, 2016. The change in utilization and pricing accounted for 108.4% and (8.4)% of the Directional Drilling revenue change, respectively.

Pressure Pumping revenue increased by $107.9 million, or 238.7%, to $153.1 million for the year ended December 31, 2017, from $45.2 million for year ended December 31, 2016. This increase was primarily attributable to the mobilization of additional hydraulic fracturing fleets in February 2017 and October 2017, which drove a 91.0% increase in stages for the year ended December 31, 2017. Additionally we experienced a 102.2% increase in average revenue per stage for year ended December 31, 2017, due to improving market conditions and shift in the job types completed. Approximately 92.2% of our Pressure Pumping segment revenue was derived from hydraulic fracturing services for the year ended December 31, 2017, compared to 81.0% for the year ended December 31, 2016.

Pressure Control revenue increased by $37.5 million, or 71.6%, to $89.9 million for the year ended December 31, 2017, from $52.4 million for the year ended December 31, 2016. This increase was primarily attributable to a 34.6% increase in weighted average utilization and a 28.0% increase in weighted average pricing for the year ended December 31, 2017. The number of days for which we generated revenue ("revenue days") increased 33.7% for the year ended December 31, 2017. The change in utilization and pricing accounted for 56.4% and 43.6% of the pressure control revenue change, respectively.

Wireline revenue increased by $12.3 million, or 32.8%, to $49.8 million for the year ended December 31, 2017, from $37.5 million for the year ended December 31, 2016. During the year ended December 31, 2017, revenue per day was up 28.2%. Utilization during the year ended December 31, 2017 was up 31.8% driven by a reduction in equipment fleet, while revenue days increased 3.5% for the year ended December 31, 2016. Approximately 71.4% of our Wireline segment revenue was derived from unconventional services for the year ended December 31, 2017, compared to 53.0% for the year ended December 31, 2016. The change in pricing, as measured by revenue per day, and the increased activity accounted for 3.0% and 10.7% of the Wireline revenue change, respectively.

Direct operating expenses. The following table provides our direct operating expenses by segment for the periods indicated:

	Year Ended	
	December 31, 2017	December 31, 2016
Direct operating expenses:		
Directional Drilling	$ 111,978	$ 58,834
Pressure Pumping	115,526	50,828
Pressure Control	69,483	47,926
Wireline	38,622	25,340
Total direct operating expenses	$ 335,609	$ 182,928

Direct operating expenses for the year ended December 31, 2017 increased by $152.7 million, or 83.5%, to $335.6 million, from $182.9 million for the year ended December 31, 2016. The increase in direct operating expense was attributable to our segments as follows:

Directional Drilling direct operating expenses increased by $53.1 million, or 90.2%, to $112.0 million for the year ended December 31, 2017, from $58.9 million for the year ended December 31, 2016. This increase was primarily attributable to a 105.8% increase in rig days over the same period, which in turn resulted in higher direct operating expenses associated with both personnel and equipment.

Pressure Pumping direct operating expenses increased by $64.7 million, or 127.4%, to $115.5 million for the year ended December 31, 2017, from $50.8 million for the year ended December 31, 2016. This increase was primarily attributable to increased activity driven by a 91.0% increase in hydraulic fracturing stages completed, which resulted in an increase in consumables, equipment and personnel costs.

Pressure Control direct operating expenses increased by $21.6 million or 45.1%, to $69.5 million for the year ended December 31, 2017, from $47.9 million for the year ended December 31, 2016. This increase was primarily attributable to increased market activity, including a 34.6% increase in weighted average utilization and a 33.6% increase in revenue days, which resulted in increased direct operating expenses associated with personnel, equipment and consumables.

Wireline direct operating expenses increased by $13.3 million, or 52.6%, to $38.6 million for the year ended December 31, 2017, from $25.3 million for the year ended December 31, 2016. This increase was primarily attributable to increased market activity in our unconventional plug-and-perf business, which resulted in increased direct operating expenses associated with personnel, equipment and consumables.

General and administrative. G&A expenses represent the costs associated with managing and supporting our operations. These expenses decreased by $3.7 million, or 5.0%, to $69.9 million for the year ended December 31, 2017, from $73.6 million for the year ended December 31, 2016. The decrease in G&A expenses was primarily driven by reduction in overhead across our segments due to the Archer integration that occurred over the course of 2016.

Depreciation and amortization. Depreciation and amortization decreased by $33.0 million, or 41.9%, to $45.7 million for the year ended December 31, 2017, from $78.7 million for the year ended December 31, 2016. The decrease in depreciation and amortization was attributable to a $27.3 million disposition of assets in January 2017, which resulted in a reduction in depreciation expense of $6.7 million, a reduction in impairment expense of $1.4 million recognized in 2016, and the remainder due to the retirement of aging assets and fully depreciated assets.

Gain on disposition of assets, net. Net gain on disposition of assets for year ended December 31, 2017 was $2.6 million, primarily attributable to the disposition of Pressure Pumping and Wireline assets, compared to a $5.4 million net loss primarily attributable to a $5.8 million loss on disposition of Pressure Pumping segment assets, $0.1 million gain on disposition of Pressure Control segment assets and $0.3 million gain on disposal of Wireline segment assets for the year ended December 31, 2016.

Interest expense. Net interest expense increased by $3.3 million, or approximately 41.3%, to $11.3 million for the year ended December 31, 2017, compared to $8.0 million for the year ended December 31, 2016. The increase in interest expense was attributable to a combination of higher interest on the Term Loan and the deferred financing cost associated with the Term Loan.

Income tax expense. For the year ended December 31, 2017, we recognized $0.1 million of income tax benefit compared to $0.2 million of income tax expense for the year ended December 31, 2016.

Adjusted EBITDA. Adjusted EBITDA for year ended December 31, 2017 increased by $77.9 million to $41.2 million from $(36.7) million for the year ended December 31, 2016. The increase in Adjusted EBITDA by segment was as follows:

Directional Drilling Adjusted EBITDA for our Directional Drilling segment increased by $17.6 million to $17.5 million in the year ended December 31, 2017, compared to $(0.1) million in the year ended December 31, 2016. The increase was primarily attributable to a 92.8% increase in revenue associated with increased rig count and drilling capital spending by E&P operators, which was partially offset by direct operating costs increasing by 90.3% due to increased activity levels.

Pressure Pumping Adjusted EBITDA for our pressure pumping segment increased by $47.2 million to $27.8 million in the year ended December 31, 2017, compared to $(19.4) million in the year ended December 31, 2016. The increase was primarily attributable to a 238.7% increase in revenue driven by increased hydraulic fracturing activity, which was partially offset by a 127.4% increase in direct operating expenses incurred as the business increased utilization and deployed additional hydraulic fracturing fleets in February 2017 and October 2017.

Pressure Control Adjusted EBITDA for our Pressure Control segment increased by $12.3 million to $6.5 million in the year ended December 31, 2017, compared to $(5.8) million in the year ended December 31, 2016. The increase was primarily attributable to a 71.6% increase in revenue driven by increased completions and workover activity, which was offset by a 45.1% increase in direct operating expenses.

Wireline Adjusted EBITDA for our Wireline segment increased by $4.4 million, to $(1.8) million in the year ended December 31, 2017, compared to $(6.2) million in the year ended December 31, 2016. The increase was primarily attributable to a 32.8% increase in revenue driven by increased pricing, increased unconventional activity and utilization, partially offset by a 52.6% increase in direct operating expenses.

Liquidity and Capital Resources

We require capital to fund ongoing operations, including maintenance expenditures on our existing fleet and equipment, organic growth initiatives, investments and acquisitions. Our primary sources of liquidity to date have been capital contributions from our equity holders and borrowings under our former revolving credit facility (the “Former Revolving Credit Facility”), our former $40.0 million term loan (the “Former Term Loan”), the New ABL Facility (as defined below) and cash flows from operations. At December 31, 2018, we had $13.8 million of cash and cash equivalents and $60.2 million available to draw on the New ABL Facility, which resulted in a total liquidity position of $74.0 million.

As our drilling and completion activity has increased with the rise in commodity prices since 2016, our cash flow from operations has begun to improve and we expect cash flow to continue to improve if drilling and completion activity continues to increase. However, there is no certainty that cash flow will continue to improve or that we will have positive operating cash flow for a sustained period of time. Our operating cash flow is sensitive to many variables, the most significant of which are utilization and profitability, the timing of billing and customer collections, payments to our vendors, repair and maintenance costs and personnel, any of which may affect our cash available.

Our primary use of capital resources has been for investing in property and equipment used to provide our services. Our primary uses of cash are maintenance and growth capital expenditures, including acquisitions and investments in property and equipment. We regularly monitor potential capital sources, including equity and debt financings, in an effort to meet our planned capital expenditure and liquidity requirements. Our future success will be highly dependent on our ability to access outside sources of capital.

The following table sets forth our cash flows for the periods indicated (in thousands of dollars) presented below:

	Year Ended		
	December 31, 2018	December 31, 2017	December 31, 2016
Net cash provided by (used in) operating activities	$ 39,939	$ (11,540)	$ (42,835)
Net cash provided by (used in) investing activities	(54,213)	14,510	2,266
Net cash provided by (used in) financing activities	19,327	(6,438)	46,525
Net change in cash	5,053	(3,468)	5,956
Cash balance end of period	$ 13,804	$ 8,751	$ 12,219

Net cash provided by (used in) operating activities

Net cash provided by operating activities was $39.9 million for the year ended December 31, 2018, compared to net cash used in operating activities of $11.5 million for the year ended December 31, 2017. The increase in operating cash flows was primarily attributable to the faster collection of trade receivables and significant operational performance improvements of major key indicators, Directional Drilling rig days, average monthly Directional Drilling rigs on revenue, total hydraulic fracturing stages and average hydraulic fracturing revenue per stage, compared to the lower utilization and pricing experienced during the year ended December 31, 2017 as a result of prevailing market conditions.

Net cash used in operating activities was $11.5 million for the year ended December 31, 2017, compared to $42.8 million for the year ended December 31, 2016. The increase in operating cash flows was primarily attributable to a decrease in net loss.

Our operating cash flow is sensitive to many variables, the most significant of which are pricing, utilization and profitability, the timing of billing and customer collections, the timing of payments to vendors, and maintenance and personnel costs, any of which may affect our available cash.

Net cash provided by (used in) investing activities

Net cash used in investing activities was $54.2 million for the year ended December 31, 2018, compared to net cash provided by investing activities of $14.5 million for the year ended December 31, 2017. The cash flow used in investing activities for the year ended December 31, 2018 was primarily used on our existing fleet capital spending, to activate our fourth hydraulic fracturing fleet, and additional Large Diameter coiled tubing capacity, compared to the net cash provided by divestiture activities during the same period in 2017.

We used $65.0 million to purchase equipment and we received $10.7 million in exchange for selling assets for the year ended December 31, 2018, compared to $21.2 million of cash that was used to purchase equipment and the receipt of $35.8 million in exchange for selling assets during the year ended December 31, 2017.

Net cash provided by investing activities was $14.5 million for the year ended December 31, 2017, compared to $2.3 million for the year ended December 31, 2016.

We used $21.2 million to purchase equipment and we received $35.8 million in exchange for selling assets for the year ended December 31, 2017, as compared to the year ended December 31, 2016, when we used $7.3 million cash to purchase equipment and received $9.6 million in exchange for selling assets.

Net cash provided by (used in) financing activities

Net cash provided by financing activities was $19.3 million for the year ended December 31, 2018, compared to net cash provided by financing activities of $6.4 million for the year ended December 31, 2017. Net cash provided by financing activities was primarily the result of net proceeds received from draws made on our New ABL Facility and the closing of our IPO totaling $90.5 million, which was offset by the repayments under our Former Revolving Credit Facility and Former Term Loan, which totaled $92.3 million. In connection with the settlement of the Former Term Loan, a prepayment fee of 3.0%, or approximately $1.3 million was paid. Additionally, $1.3 million was paid for treasury shares in connection with the settlement of equity based compensation, net of taxes, which vested during the year ended December 31, 2018. Common stock repurchases of $0.5 million was paid for treasury shares in connection with our common stock repurchase program during the fourth quarter of 2018.

Net cash provided by (used in) financing activities was primarily the result of debt borrowings net of repayments under our Revolving Credit Facility and Term Loan. Net cash provided by (used in) financing activities was $(6.4) million for the year ended December 31, 2017, compared to $46.5 million for the year ended December 31, 2016. In the year ended December 31, 2017, we repaid $22.0 million under our Revolving Credit Facility and incurred $5.0 million under the Term Loan.

Our Credit Facility

Former Revolving Credit Facility

We had a revolving credit facility which had a maximum borrowing facility of $110.0 million that was scheduled to mature on September 19, 2018. All obligations under the credit agreement for the Former Revolving Credit Facility were collateralized by substantially all of the assets of our Predecessor. The Former Revolving Credit Facility's credit agreement contained customary restrictive covenants that required the Company not to exceed or fall below two key ratios, a maximum loan to value ratio of 70% and a minimum liquidity of $7.5 million. In connection with the closing of the IPO on February 13, 2018, we fully repaid and terminated the Former Revolving Credit Facility. No early termination fees were incurred by the Company in connection with the termination of the Former Revolving Credit Facility. A loss on extinguishment of $0.3 million relating to unamortized deferred costs was recognized in interest expense.

Former Term Loan

We also had a four-year, $40.0 million term loan agreement with a lending group, which included Geveran, Archer Holdco LLC, an affiliate of Archer, and Robertson QES, that was scheduled to mature on December 19, 2020. The Former Term Loan contained customary restrictive covenants that required our Predecessor not to exceed or fall below two key ratios, a maximum loan to value ratio of 77% and a minimum liquidity of $6.75 million. The interest rate on the unpaid principal was 10.0% interest per annum and accrued on a daily basis. At the end of each quarter all accrued and unpaid interest was paid in kind by capitalizing and adding to the outstanding principal balance. In connection with the closing of the IPO on February 13, 2018, the Former Term Loan was settled in full by cash and common shares in the Company. In connection with the settlement of the Former Term Loan, a prepayment fee of 3%, or approximately $1.2 million was paid. The prepayment fee is recorded as a loss on extinguishment of debt and included within interest expense. The Company also recognized $5.4 million of unamortized discount expense and $1.7 million of unamortized deferred financing cost in connection with the termination of the Former Term Loan.

New ABL Facility

In connection with the closing of the IPO on February 13, 2018, we entered into a new semi-secured asset-based revolving credit agreement (the "New ABL Facility") with each lender party thereto and Bank of America, N.A. as administrative agent and collateral agent. The New ABL Facility replaced the Former Revolving Credit Facility. The New ABL Facility provides for a $100.0 million revolving credit facility subject to a borrowing base. Upon closing of the New ABL Facility the borrowing capacity was $77.6 million and $13.0 million was immediately drawn. The loan interest rate on the borrowings outstanding at December 31, 2018, was 5.3% and $29.5 million was outstanding and recorded as long term debt under the New ABL Facility as of December 31, 2018. At December 31, 2018, we had $13.8 million of cash and equivalents and $60.2 million available to draw on the New ABL Facility, which resulted in a total liquidity position of $74 million.

The New ABL Facility contains various affirmative and negative covenants, including financial reporting requirements and limitations on indebtedness, liens, mergers, consolidations, liquidations and dissolutions, sales of assets, dividends and other restricted payments, investments (including acquisitions) and transactions with affiliates. Certain affirmative covenants, including certain reporting requirements and requirements to establish cash dominion accounts with the administrative agent, are triggered by failing to maintain availability under the New ABL Facility at or above specified thresholds or by the existence of an event of default under the New ABL Facility. The New ABL Facility provides for certain baskets and carve-outs from its negative covenants allowing the Company to make certain restricted payments and investments; subject to maintaining availability under the New ABL Facility at or above a specified threshold and the absence of a default thereunder.

The New ABL Facility contains a minimum fixed charge coverage ratio of 1.0 to 1.0 that is triggered when availability under the New ABL Facility falls below a specified threshold and is tested until availability exceeds a separate specified threshold for 30 consecutive days.

The New ABL Facility contains events of default customary for facilities of this nature, including, but not limited, to: (i) events of default resulting from the Borrowers' failure or the failure of any credit party to comply with covenants (including the above-referenced financial covenant during periods in which the financial covenant is tested); (ii) the occurrence of a change of control; (iii) the institution of insolvency or similar proceedings against the Borrowers or any credit party; and (iv) the occurrence of a default under any other material indebtedness the Borrowers or any guarantor may have. Upon the occurrence and during the continuation of an event of default, subject to the terms and conditions of the New ABL Facility, the lenders will be able to declare any outstanding principal balance of our New ABL Facility, together with accrued and unpaid interest, to be immediately due and payable and exercise other remedies, including remedies against the collateral, as more particularly specified in the New ABL Facility. As of December 31, 2018, we were in compliance with our debt covenants.

Capital Requirements and Sources of Liquidity

During the year ended December 31, 2018, our capital expenditures were approximately $13.0 million, $29.3 million, $20.1 million and $2.6 million in our Directional Drilling, Pressure Pumping, Pressure Control and Wireline segments, respectively, for aggregate capital expenditures of approximately $65.0 million, primarily for the activation of our fourth hydraulic fracturing fleet, the addition of a new Large Diameter coiled tubing unit, upgrades to two existing coiled tubing units to Large Diameter specification and maintenance capital expenditures on existing equipment.

For the year ended December 31, 2017, our capital expenditures, excluding acquisitions, were approximately $9.0 million, $5.3 million, $6.4 million and $0.5 million in our Directional Drilling, Pressure Pumping, Pressure Control and Wireline segments for aggregate net capital expenditures of approximately $21.2 million, primarily for purchase of new drilling motors, the redeployment of a hydraulic fracturing fleet and maintenance capital expenditures.

For the year ended December 31, 2016, our capital expenditures (net of proceeds from dispositions of equipment), excluding acquisitions, were approximately $6.5 million, $0.1 million, $0.7 million and $0.0 million in our Directional Drilling segment, Pressure Pumping segment, Pressure Control segment and Wireline segment, respectively, for aggregate net capital expenditures of approximately $7.3 million primarily for the purchase of new drilling motors and replacement of MWD kits.

We currently estimate that our capital expenditures for our existing fleets, approved capacity additions and other projects during 2019 will range from $40.0 million to $50.0 million. We expect to fund these expenditures through a combination of cash on hand, cash generated by our operations and borrowings under our New ABL Facility.

We believe that our operating cash flow and available borrowings under our New ABL Facility will be sufficient to fund our operations for the next twelve months. Our operating cash flow is sensitive to many variables, the most significant of which are pricing, utilization and profitability, the timing of billing and customer collections, the timing of payments to vendors, and maintenance and personnel costs, any of which may affect our cash available. Significant additional capital expenditures will be required to conduct our operations and there can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned or future levels of capital expenditures and make expected distributions. Further, we do not have a specific capital expenditures acquisition budget for 2019 since the timing and size of acquisitions cannot be accurately forecasted. In the event we make one or more acquisitions and the amount of capital required is greater than the amount we have available for acquisitions at that time, we could be required to reduce the expected level of capital expenditures or distributions and/or seek additional capital. If we seek additional capital for that or other reasons, we may do so through borrowings under our New ABL Facility, joint venture partnerships, asset sales, offerings of debt and equity securities or other means. We cannot assure that this additional capital will be available on acceptable terms or at all. If we are unable to obtain funds we need, we may not be able to complete acquisitions that may be favorable to us or to finance the capital expenditures necessary to conduct our operations.

On August 8, 2018, our Board of Directors approved a $6.0 million stock repurchase program authorizing us to repurchase common stock in the open market. The timing and amount of stock repurchases will depend on market conditions and corporate, regulatory and other relevant considerations. Repurchases may be commenced or suspended at any time without notice. The program does not obligate QES to purchase any particular number of shares of common stock during any period or at all, and the program may be modified or suspended at any time, subject to the Company's insider trading policy and at the Company’s discretion. As of December 31, 2018, the Company repurchased 96,307 shares under this program.

Contractual Obligations

As a smaller reporting company, we are not required to provide the disclosure required by Item 303(a)(5)(i) of Regulation S-K.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements, as defined in Item 303(a)(4)(ii) of Regulation S-K, as of December 31, 2018.

Critical Accounting Policies and Estimates

The preparation of financial statements requires the use of judgments and estimates. Our critical accounting policies are described below to provide a better understanding of how we develop our assumptions and judgments about future events and related estimations and how they can impact our financial statements. A critical accounting estimate is one that requires our most difficult, subjective or complex judgments and assessments and is fundamental to our results of operations.

We base our estimates on historical experience and on various other assumptions we believe to be reasonable according to the current facts and circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. We believe the following are the critical accounting policies used in the preparation of our consolidated financial statements, as well as the significant estimates and judgments affecting the application of these policies. This discussion and analysis should be read in conjunction with QES's consolidated financial statements and related notes included therewith.

Emerging Growth Company Status

The JOBS Act permits an emerging growth company like us to take advantage of an extended transition period to comply with new or revised accounting standards applicable to public companies. We are choosing to “opt out” of this provision and, as a result, we will comply with new or revised accounting standards as required when they are adopted. This decision to opt out of the extended transition period is irrevocable.

Allowance for bad debts

We evaluate our accounts receivable through a continuous process of assessing our portfolio on an individual customer and overall basis. This process consists of a thorough review of historical collection experience, current aging status of the customer accounts, and financial condition of our customers. We also consider the economic environment of our customers, both from a marketplace and geographic perspective, in evaluating the need for an allowance. Based on our review of these factors, we establish or adjust allowances for specific customers and the accounts receivable portfolio as a whole. This process involves a high degree of judgment and estimation, and periodically involves significant dollar amounts. Accordingly, our results of operations can be affected by adjustments to the allowance due to actual write-offs that differ from estimated amounts. Our estimates of allowances for bad debts have historically been accurate. Over the last five years, our estimates of allowances for bad debts, as a percentage of accounts receivable before the allowance, have ranged from 0.9% to 2.3%. At December 31, 2018, our allowance for bad debts totaled $1.8 million, or 1.8% of accounts receivable before the allowance. At December 31, 2017, allowance for bad debts totaled $0.8 million, or 0.9% of accounts receivable before the allowance. At December 31, 2016, allowance for bad debts totaled $0.9 million, or 2.3% of accounts receivable before allowance.

Plant, Property, and Equipment

We calculate depreciation based on estimated useful lives of our assets. When assets are placed into service, we separately identify and account for certain significant components of our directional drilling, pressure pumping, pressure control and wireline equipment and make estimates with respect to their useful lives that we believe are reasonable. However, the cyclical nature of our business, which results in fluctuations in the use of our equipment and the environments in which we operate, could cause our estimates to change, thus affecting the future calculations of depreciation.

Impairment of Long-lived assets, Including Intangible Assets

We carry a variety of long-lived assets on our balance sheet including property, plant and equipment, and intangibles. We conduct impairment tests on long-lived assets whenever events or changes in circumstances indicate that the carrying value may not be recoverable. Impairment is the condition that exists when the carrying amount of a long-lived asset exceeds its fair value, and any impairment charge that we record reduces our earnings. We review the carrying value of these assets based upon estimated undiscounted future cash flows while taking into consideration assumptions and estimates, including the future use of the asset, remaining useful life of the asset and service potential of the asset. The determination of recoverability is made based upon the estimated undiscounted future net cash flows of assets grouped at the lowest level for which there are identifiable cash flows independent of the cash flows of other groups of assets, with such cash flows to be realized over the estimated remaining useful life of the primary asset within the asset group.

The quantitative impairment test we perform for long-lived assets utilizes certain assumptions, including forecasted revenue and costs assumptions. The forecasted revenue can be affected by rig count, day rates and the number of well completions, while our cost assumptions can be impacted by the price of sand and labor rates. If the U.S. rig count and the price of crude oil remains at low levels for a sustained period of time, we could record an impairment of the carrying value of our long lived assets in the future. If rig count and crude oil prices decline further or remain at low levels, to the extent appropriate we expect to perform our impairment assessment on a more frequent basis to determine whether an impairment is required.

Insurance Accruals

We self-insure for certain losses relating to workers' compensation, general liability, automobile, and our employee health plan. We estimate the level of our liability related to the insurance and record reserves for these amounts in the consolidated financial statements. These estimates, which are actuarially determined, are based on the facts and circumstances specific to existing claims and past experience with similar claims. These loss estimates and accruals recorded in the financial statements for claims have historically been reasonable in light of the actual amount of claims paid and are actuarially supported. Although we believe our insurance coverage and reserve estimates are reasonable, a significant accident or other event that is not fully covered by insurance or contractual indemnity could occur and could materially affect our financial position and results of operations for a particular period.

Legal and Environmental Matters

As of December 31, 2018, we assessed the legal action pending against the Company and have accrued an estimate of probable and estimated costs. Our legal department monitors and manages all claims filed and potential claims against us and reviews all pending investigations. Generally, the estimate of probable costs related to these matters is developed in consultation with internal and outside legal counsel representing us. Our estimates are based upon an analysis of potential results, assuming a combination of litigation and settlement strategies. The accuracy of these estimates is impacted by, among other things, the complexity of the issues and the amount of due diligence we have been able to perform. We attempt to resolve these matters through settlements, mediation and arbitration proceedings when possible. If the actual settlement costs, final judgments or fines, after appeals, differ from our estimates, our future financial results may be adversely affected.

Income Taxes

The asset and liability method is used in accounting for income taxes. Under this method, deferred tax assets and liabilities are recognized for operating loss and tax credit carryforwards and for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the year in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the results of operations in the period that includes the enactment date. If applicable, a valuation allowance is recorded to reduce the carrying amounts of deferred tax assets unless it is more likely than not that such assets will be realized. The Company's policy is to account for interest and penalties with respect to income taxes as operating expenses.

On December 22, 2017, the President of the United States signed into law legislation informally known as the Tax Cuts and Jobs Act (the "Act"). The Act represents major tax reform legislation that, among other provisions, reduces the U.S. corporate tax rate.

As of December 31, 2018 management considers that the abovementioned Act will have an immaterial impact. However, going forward, the Company will analyze the impact based on revised circumstances.

Equity Based Compensation

We are required to value our common stock or, in the case of our predecessor QES LP, our common units, for purposes of recognizing equity based compensation. In order to determine the fair market value of our common units on the grant date of our equity based compensation issued prior to the IPO, our management utilized a combination of two valuation methodologies: (i) discounted cash flow ("DCF") analysis, and (ii) public peer trading analysis. For the grant date our equity based compensation issued after the IPO, our management utilized the quoted closing price of the common stock on the grant date for awards that had no market conditions and for awards that had a market condition we utilized a third-party valuation firm that used a Monte Carlo Simulation and Cholesky models to arrive at the fair market value.

The DCF analysis is predicated upon a five-year projection with material assumptions made for revenue, EBITDA margin, capital expenditures and tax rate. Those assumptions are used to arrive at a forecasted free cash flow ("FCF"). We then assume a terminal event at the end of the 5-year projection period and derive an implied terminal value by applying our public company peer group's EBITDA multiple to our projected terminal year EBITDA result. The terminal value and FCF are then discounted using our public company peer group's average weighted average cost of capital ("WACC"). Estimating a five-year projection and the applicable assumptions is highly complex and subjective and determining the appropriate peer group to determine our peer group EBITDA multiple and average WACC is subjective. Our management selects a group of comparable public companies in each valuation exercise whose equity market pricing reflects the market's view on key sector, geographic and service lines similar to those that drive our business.

The public peer trading analysis is predicated upon the selection of public peers described above and calculating implied trading multiples of enterprise value to EBITDA. These multiples are then applied to our forecasted EBITDA results for the selected forecast period which calculates an implied enterprise value for us. The current net debt is subtracted from the enterprise value to arrive at an equity value. As described above, both forecasting our EBITDA to apply to the market multiple and selecting our peer group involve subjective judgment by management. In addition, because we are not publicly traded, common valuation practice dictates that we apply an illiquidity discount to the implied equity value produced by the public company multiples, and there is subjective judgement in determining the illiquidity discount as well.

The equity values derived by the DCF analysis and public trading peer analysis are then weighted based on relevance and appropriateness given the current market environment at the time the valuation exercise is performed to arrive at a consolidated equity valuation. There is an element of subjectivity to each of the valuation methodologies as well as the weighting of the three methodologies in arriving at fair market value

A Monte Carlo simulation performs risk analysis by modeling numerous possible scenarios to determine a probability distribution for any variable with inherent uncertainty. The model runs 100,000 iterations to determine the earned market condition as an average of the iterations. It then calculates results over and over, each time using a different set of random values from the probability functions. Depending upon the number of uncertainties and the ranges specified for them, a Monte Carlo simulation could involve thousands or tens of thousands of recalculations before it is complete. Monte Carlo simulation produces distributions of possible outcome values

Using the results from the Monte-Carlo, the Cholesky model converts the correlation of each security into a matrix which populates relation of all companies with each other. The Monte Carlo simulation then considers the co-relation effect to arrive at a fair market value for the equity grants that have a market condition.

We recognized stock based compensation expense of $17.9 million for the year ended December 31, 2018 and approximately $10.0 million was recognized upon closing our IPO.

Recent Accounting Pronouncements

See "Note - 1 Nature of Operations, Basis of Presentation and Significant Accounting Policies" to our consolidated financial statements for a discussion of recently issued accounting pronouncements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

As a smaller reporting company, we are not required to provide the information required by this Item.

Item 8. Financial Statements and Supplementary Data

Index to Consolidated Financial Statements

QUINTANA ENERGY SERVICES INC.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Quintana Energy Services Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Quintana Energy Services Inc. and its subsidiaries (the "Company") as of December 31, 2018 and 2017, and the related consolidated statements of operations, of shareholders' equity and of cash flows for each of the three years in the period ended December 31, 2018, including the related notes (collectively referred to as 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 three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (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 of these consolidated financial statements 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

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/PricewaterhouseCoopers LLP

Houston, Texas

March 7, 2019

We have served as the Company or its predecessors' auditor since 2010, which includes periods before the Company became subject to SEC reporting requirements.

Item 1. Financial Statements

Quintana Energy Services Inc.
Consolidated Balance Sheets
(*in thousands, except per share and share amounts*)

	December 31, 2018	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 13,804	$ 8,751
Accounts receivable, net of allowance of $1,841 and $776	101,620	83,325
Unbilled receivables	13,766	9,645
Inventories (Note 2)	23,464	22,693
Prepaid expenses and other current assets	7,481	9,520
Total current assets	160,135	133,934
Property, plant and equipment, net	153,878	128,518
Intangible assets, net	9,019	10,832
Other assets	1,517	2,375
Total assets	$ 324,549	$ 275,659
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 51,568	$ 36,027
Accrued liabilities (Note 5)	37,533	33,825
Current portion of debt and capital lease obligations (Note 6)	422	79,443
Total current liabilities	89,523	149,295
Long-term debt, net of deferred financing costs of $0 and $1,709 (Note 6)	29,500	37,199
Long-term capital lease obligations (Note 6)	3,451	3,829
Deferred tax liability	130	185
Other long-term liabilities	125	183
Total liabilities	122,729	190,691
Commitments and contingencies (Note 11)		
Shareholders' and members' equity:		
Members' equity	—	212,630
Preferred shares, $0.01 par value, 10,000,000 authorized; none issued and outstanding	—	—
Common shares, $0.01 par value, 150,000,000 authorized; 33,774,053 issued; 33,541,161 outstanding	344	—
Additional paid-in-capital	349,080	—
Treasury stock, at cost, 232,892 common shares	(1,821)	—
Accumulated deficit	(145,783)	(127,662)
Total shareholders' and members' equity	201,820	84,968
Total liabilities, shareholders' and members' equity	$ 324,549	$ 275,659

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

Quintana Energy Services Inc.
Consolidated Statements of Operations
(*in thousands of dollars and shares, except per share amounts*)

	Years Ended		
	December 31, 2018	**December 31, 2017**	**December 31, 2016**
Revenues:	$ 604,354	$ 438,033	$ 210,428
Costs and expenses:			
Direct operating costs	468,502	335,609	182,928
General and administrative	97,280	69,856	73,600
Depreciation and amortization	46,683	45,687	78,661
Fixed asset impairment	—	—	1,380
Goodwill impairment	—	—	15,051
(Gain) loss on disposition of assets	(2,375)	(2,639)	5,375
Operating loss	(5,736)	(10,480)	(146,567)
Non-operating income (expense):			
Interest expense	(11,825)	(11,251)	(8,015)
Other income	—	666	—
Loss before income tax	(17,561)	(21,065)	(154,582)
Income tax expense	(621)	(91)	(167)
Net loss	(18,182)	(21,156)	(154,749)
Net loss attributable to predecessor	(1,546)	(21,156)	(154,749)
Net loss attributable to Quintana Energy Services Inc.	$ (16,636)	$ —	$ —
Net loss per common share:			
Basic	$ (0.50)	$ —	$ —
Diluted	$ (0.50)	$ —	$ —
Weighted average common shares outstanding:			
Basic	33,573	—	—
Diluted	33,573	—	—

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

Quintana Energy Services Inc.
Consolidated Statement of Shareholders' Equity
(in thousands of dollars, units and shares)

	Common Unitholders Number of Units	Members' Equity	Common Shareholders Number of Shares Outstanding	Common Stock	Additional Paid in Capital	Treasury Stock	Retained Deficit	Total Shareholders' Equity
Balance at December 31, 2016	417,441	$ 212,630	—	—	$ —	$ —	$ (106,506)	$ 106,124
Net loss	—	—	—	—	—	—	(21,156)	(21,156)
Balance at December 31, 2017	417,441	$ 212,630	—	—	$ —	$ —	$ (127,662)	$ 84,968
Effect of reorganization transactions	(417,441)	(212,630)	23,598	238	246,023	—	—	33,631
Issuance of common stock sold in initial public offering, net of offering costs	—	—	9,632	96	90,446	—	—	90,542
Net loss prior to reorganization transactions	—	—	—	—	—	—	(1,546)	(1,546)
Cost incurred for stock issuance	—	—	—	—	(5,277)	—	—	(5,277)
Equity-based compensation	—	—	544	10	17,888	—	—	17,898
Tax withholding on stock vesting	—	—	(137)	—	—	(1,284)	—	(1,284)
Stock buyback plan activity	—	—	(96)	—	—	(537)	—	(537)
Opening deferred tax adjustment	—	—	—	—	—	—	61	61
Net loss subsequent to reorganization transactions	—	—	—	—	—	—	(16,636)	(16,636)
Balance at December 31, 2018	—	$ —	33,541	$ 344	$ 349,080	$ (1,821)	$ (145,783)	$ 201,820

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

Quintana Energy Services Inc.
Consolidated Statements of Cash Flows
(*in thousands of dollars*)

	Year Ended		
	December 31, 2018	December 31, 2017	December 31, 2016
Cash flows from operating activities:			
Net loss	$ (18,182)	$ (21,156)	$ (154,749)
Adjustments to reconcile net loss to net cash used in operating activities			
Depreciation and amortization	46,683	45,687	78,661
(Gain) loss on disposition of assets	(7,785)	(10,500)	1,268
Non-cash interest expense	1,032	5,960	845
Fixed asset impairment	—	—	1,380
Goodwill impairment	—	—	15,051
Loss on debt extinguishment	8,594	—	—
Provision for doubtful accounts	1,103	289	142
Deferred income tax expense	92	50	(42)
Stock-based compensation	17,898	—	—
Changes in operating assets and liabilities:			
Accounts receivable	(19,398)	(46,869)	9,688
Unbilled receivables	(4,121)	(1,953)	(4,213)
Inventories	(770)	(3,144)	1,559
Prepaid expenses and other current assets	1,442	1,812	3,894
Other noncurrent assets	(3)	(1,439)	632
Accounts payable	10,647	6,969	8,842
Accrued liabilities	2,767	12,810	(5,778)
Other long-term liabilities	(60)	(56)	(15)
Net cash provided by (used in) operating activities	39,939	(11,540)	(42,835)
Cash flows from investing activities:			
Purchases of property, plant and equipment	(64,957)	(21,244)	(7,340)
Proceeds from sale of property, plant and equipment	10,744	35,754	9,606
Net cash (used in) provided by investing activities	(54,213)	14,510	2,266
Cash flows from financing activities:			
Proceeds from revolving debt	41,500	11,035	35,159
Payments on revolving debt	(91,071)	(21,964)	(22,000)
Proceeds from term loans	—	5,000	28,600
Proceeds from warrants, net of issuance costs	—	—	5,961
Payments on term loans	(11,225)	—	—
Payments on capital lease obligations	(380)	(315)	(317)
Payments on financed payables	(2,139)	—	—
Issuance of units	—	—	1,000
Payment of deferred financing costs	(1,564)	(194)	(1,878)
Prepayment premiums on early debt extinguishment	(1,346)	—	—
Payments for treasury shares	(1,816)	—	—
Proceeds from new shares issuance, net of underwriting commissions	90,542	—	—
Costs incurred for stock issuance	(3,174)	—	—
Net cash provided by (used in) financing activities	19,327	(6,438)	46,525
Net increase (decrease) in cash and cash equivalents	5,053	(3,468)	5,956
Cash and cash equivalents beginning of period	8,751	12,219	6,263
Cash and cash equivalents end of period	$ 13,804	$ 8,751	$ 12,219

Supplemental cash flow information			
Cash paid for interest	$ 2,087	$ 5,755	$ 5,935
Income taxes paid, net of refund	105	77	198
Supplemental non-cash investing and financing activities			
Non-cash proceeds from sale of assets held for sale	—	3,990	—
Fixed asset purchases in accounts payable and accrued liabilities	4,900	934	93
Financed payables	2,994	1,666	950
Non-cash capital lease additions	53	70	—
Non-cash payment for property, plant and equipment	3,279	711	—
Equity issued as payment for professional services	—	—	2,000
Debt conversion of Former Term Loan to equity	33,631	—	—
Conversion of accrued interest to debt	—	4,202	126
Issuance of common shares for members' equity	$ 212,630	$ —	$ —

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

NOTE 1 - Nature of Operations, Basis of Presentation and Significant Accounting Policies

Organization and Nature of Operations

Quintana Energy Services Inc. (either individually or together with its subsidiaries, as the context requires, the "Company," "QES," "we," "us," and "our") is a Delaware corporation that was incorporated on April 13, 2017. Our accounting predecessor, Quintana Energy Services LP ("QES LP" and "Predecessor"), was formed as a Delaware partnership on November 3, 2014. In connection with our initial public offering (the "IPO") which closed on February 13, 2018, the existing investors in QES LP and QES Holdco LLC contributed all of their direct and indirect equity interests to QES in exchange for shares of common stock in QES, and we became the holding company for the reorganized QES LP and its subsidiaries.

We are a growth-oriented provider of diversified oilfield services to leading onshore oil and natural gas exploration and production ("E&P") companies operating in both conventional and unconventional plays in all of the active major basins throughout the United States. The Company operates through four reporting segments which are Directional Drilling, Pressure Pumping, Pressure Control and Wireline.

Initial Public Offering

As of December 31, 2017, our Predecessor had approximately 417,441,074 common units outstanding and 227,885,579 warrants to purchase common units outstanding. Immediately prior to the IPO on February 13, 2018, the warrants were net settled for 223,394,762 common units, and immediately thereafter our Predecessor and affiliated entities were reorganized through mergers and related transactions and 20,235,193 shares of our common stock were issued to the holders of equity in our Predecessor at a ratio of 1 share of our common stock for 31.669363 common units of our Predecessor (with elimination of fractional shares) (the "Merger Transactions"). On February 13, 2018, immediately after the Merger Transactions, but prior to our IPO, our Predecessor's Former Term Loan (as defined below) was extinguished and in partial consideration therefore 3,363,208 shares were issued to our Predecessor's Former Term Loan lenders based on the price to the public of our IPO (representing 1 share of common stock for each $10.00 in Former Term Loan obligations converted) (together with the "Merger Transactions", the "Reorganization Transactions").

The gross proceeds of the IPO to the Company, at the public offering price of $10.00 per share, were $92.6 million, which resulted in net proceeds to the Company of approximately $87.0 million, after deducting $5.6 million of underwriting discounts and commissions associated with the shares sold by the Company, excluding approximately $5.3 million in offering expenses payable by the Company. Taking together the Reorganization Transactions and the issuance of 9,259,259 shares of our common stock to the public in our IPO, as of February 13, 2018, we had 32,857,660 shares outstanding immediately following our IPO. Subsequent to our IPO, we issued 139,921 shares in connection with the vesting of awards under our Predecessor's 2015 LTIP Plan on February 22, 2018, and 260,529 shares of our common stock were issued on March 8, 2018 in consideration of vesting of awards under our Predecessor's 2017 LTIP which we assumed. In connection with both awards, certain shares were withheld to satisfy tax obligations of the holder of the award, which shares are currently treasury shares totaling 136,585 shares of common stock. Also in connection with the consummation of the IPO, on March 9, 2018, the underwriters exercised their overallotment option to purchase an additional 372,824 shares of common stock of QES, which resulted in additional net proceeds of approximately $3.5 million (the "Option Exercise"), net of underwriter's discounts and commission of $0.1 million. Upon the completion of the Reorganization Transactions, the IPO and the Option Exercise, QES had 33,630,934 shares of common stock outstanding.

The net proceeds received from the IPO and a $13.0 million drawdown on the New ABL Facility (described below) were used to fully repay the Company's revolving credit facility balance of $81.1 million and repay $12.6 million of the Company's $40.0 million, 10% Former Term Loan due 2020, as described in "Note 6 - Long-Term Debt and Capital Lease Obligations." The remaining proceeds from the IPO were used for general corporate purposes.

Basis of Presentation and Principles of Consolidation

The accompanying interim consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP"). The consolidated financial accounts include all QES accounts and all of our subsidiaries where we exercise control. All inter-company transactions and account balances have been eliminated upon consolidation.

Certain reclassifications have been made to the prior year financial statements to conform to the current period financial statement presentation.

Segment Reporting

The Company's reportable segments are: (1) Pressure Pumping, (2) Directional Drilling, (3) Pressure Control, and (4) Wireline.

The Company routinely evaluates whether its separate operating and reportable segments continue to reflect the way its Chief Operating Decision Maker ("CODM") evaluates the business. The determination is based on the following factors: (1) how the Company's CODM is currently managing each operating segment as a separate business and evaluating the performance of each segment and making resource allocation decisions distinctly and expects to do so for the foreseeable future, and (2) whether discrete financial information for each operating segment is available. The Company considers its Chief Executive Officer to be its CODM.

The current structure in place continues to reflect the financial information and reports used by the Company's management, specifically its CODM, to make decisions regarding the Company's business, including resource allocations and performance assessments. See "Note 12 - Segment Information" for further discussion regarding the Company's reportable segments.

Use of Estimates

The preparation of consolidated financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ materially from those estimates.

Revenue Recognition

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-09, Revenue from Contracts with Customers. This ASU amended the existing accounting standards for revenue recognition and requires companies to recognize revenue when control of the promised goods or services is transferred to a customer at an amount that reflects the consideration a company expects to receive in exchange for those goods or services. QES adopted this ASU on January 1, 2018 using the modified retrospective transition method applied to those contracts which were not completed as of January 1, 2018. Prior to the adoption of ASU No. 2014-09, Revenue from Contracts with Customers ("ASC 606"), on January 1, 2018, the revenue was recognized when persuasive evidence of an arrangement existed, services are performed, the sales price was fixed or determinable and collectability was reasonably assured.

QES recognizes revenue upon the transfer of control of promised products or services to customers at an amount that reflects the consideration it expects to receive in exchange for these products or services. The vast majority of our services and product offerings are short-term in nature, generally between 30 to 60 days. Services are sold without warranty and QES generates revenue from multiple sources within its four operating segments outlined as follows:

Pressure Pumping revenue. Through its Pressure Pumping segment, the Company provides completion and production services based upon a purchase order, contract or on a spot market basis. Services are provided based on the price book and bid on a stage rate (for hydraulic fracturing services) or job basis (for cementing and acidizing services), contracted or hourly basis, and revenue is recognized when the stage or job is completed. Jobs for these services are typically short-term in nature and range from a few hours to multiple days. Revenue is recognized upon the completion of each day's work (or job, if longer than a day) based upon a completed field ticket, which includes the charges for the services performed, mobilization of the equipment to the location and the personnel involved in such services or mobilization. Additional revenue is generated through labor charges and reimbursable consumable supplies that are incidental to the service being performed. Labor charges and the use of consumable supplies are included on completed field tickets.

Directional Drilling revenue. Through its directional drilling segment, the Company provides directional drilling services on a day rate or hourly basis, and recognizes the revenue as the services are provided. QES recognizes mobilization revenue and costs for day-work over the days of actual drilling. Included in revenue are proceeds from customers for the cost of oilfield downhole tools and other equipment that are involuntarily damaged or lost-in-hole.

Pressure Control revenue. Through its Pressure Control segment, the Company provides a range of coiled tubing, snubbing, well control and other well completion and production-related services, including nitrogen and fluid pumping services, on both a contract and spot market basis. Jobs for these services are typically short-term in nature and range from a few hours to multiple days. Revenue is recognized upon completion of each day's work based upon a completed field ticket. The field ticket includes charges for the services performed and any related consumables (such as friction reducers and nitrogen materials) used during the course of the services, which are reported as product sales. The field ticket may also include charges for the mobilization and set-up of equipment, the personnel on the job, any additional equipment used on the job, and other miscellaneous consumables.

Wireline revenue. Through its Wireline segment, the Company provides cased-hole production logging, casing evaluation logging, through tubing and casing perforating, pressure control, pipe recovery, plug setting, dump-bailing, and other complementary services, on a spot market basis or subject to a negotiated pricing agreement. Jobs for these services are typically short-term in nature, lasting anywhere from a few hours to a few weeks. The Company typically charges the customer for these services on a per job basis at agreed-upon spot market rates. Revenue is normally recognized based on a field ticket issued upon the completion of the job. However, for large stage jobs that starts in one period and finishes in another, revenue is recognized on the stages completed for which a field ticket is issued.

The timing of revenue recognition may differ from contract billing or payment schedules, resulting in revenues that have been earned but not billed ("unbilled revenue") or amounts that have been collected, but not earned.

Typical Contractual Arrangements

The Company typically provides the services based upon a combination of a Master Service Agreement ("MSA") or its General Terms & Conditions (T&Cs") and a purchase order or other similar forms of work requests that primarily operate on a spot market basis for a defined work scope on a particular well or well pad. Services are provided based on a price book and bid on a day rate, stage rate or job basis. QES may also charge for the mobilization and set-up of equipment and for materials and consumables used in the services. Contracts generally are short-term in nature, ranging from a few hours to multiple weeks. Contracts typically do not stipulate substantive early termination penalties for either party. As such, the Company determined that its contracts are day to day, even though parties typically do not terminate the contract early during the normal course of business. In cases where the customer terminates the contract early, the Company has an enforceable right to payment for services performed to date. Under day rate contracts, we generally receive a contractual day rate for each day we are performing services. The contractual day rate may vary based on the status of the operations and generally includes a full operating rate and a standby rate. Other fees may be stipulated in the contract related to mobilization and setup of equipment and reimbursements for consumables and cost of tools and equipment, that are involuntarily damaged or lost-in-hole.

Performance Obligations and Transaction Price

Customers generally contract with us to provide an integrated service of personnel and equipment for directional drilling, pressure pumping, pressure control or wireline services. The Company is seen by the operator as the overseer of its services and is compensated to provide an entire suite for its scope of services. QES determined that each service contract contains a single performance obligation, which is each day's service. In addition, each day's service is within the scope of the series guidance as both criteria of series guidance are met: 1) each distinct increment of service (i.e. days available to supervise or number of stages determined at contract inception) that the Company agrees to transfer represents a performance obligation that meets the criteria for recognizing revenue over time, and 2) the Company would use the same method for measuring progress toward satisfaction of the performance obligation for each distinct increment of service in the series. Therefore, the Company has determined that each service contract contains one single performance obligation, which is the series of each distinct stage or day's service.

The transaction price for the Company's service contracts is based on the amount of consideration the Company expects to receive for providing the services over the specified term and includes both fixed amounts and unconstrained variable amounts. In addition, the contract term may impact the determination and allocation of the transaction price and recognition of revenue. As the Company's contracts do not stipulate substantive termination penalties, the contract is treated as day to day. Typically, the only fixed or known consideration at contract inception is initial mobilization and demobilization (where it is contractually guaranteed). In cases where the demobilization fee is not fixed, the Company estimates the variable consideration using the expected value method and includes this in the transaction price to the extent it is not constrained. Variable consideration is generally constrained if it is probable that a significant reversal in the amount of cumulative revenue recognized will occur when the uncertainty associated with the variable consideration is subsequently resolved. As the contracts are not enforceable, the contract price should not include any estimation for the day rate or stage rate charges.

Recognition of Revenue

Directional drilling, pressure pumping, pressure control and wireline services are consumed as the services are performed and generally enhances the customer or operators well site. Work performed on a well site does not create an asset with an alternative use to the contractor since the well/asset being worked on is owned by the customer. Therefore, the Company's measure of progress for our contracts are hours available to provide the services over the contracted duration. This unit of measure is representative of an output method as described in ASC 606.

The following chart details the types of fees found in a typical service contract and the related recognition method under ASC 606:

Fee type	Revenue Recognition
Day rate	Revenue is recognized based on the day rates earned as it relates to the level of service provided for each day throughout the contract.
Initial mobilization	Revenue is estimated at contract inception and included in the transaction price to be recognized ratably over contract term.
Demobilization	Unconstrained demobilization revenue is estimated at contract inception, included in the transaction price, and recognized ratably over the contract term.
Reimbursement	Recognized (gross of costs incurred) at the amount billed to the customer.

Disaggregation of Revenue

The Company discloses a reconciliation of the disaggregated revenue with the reported results in "Note 12 - Segment Information."

Future Performance Obligations and Financing Arrangements

As our contracts are day to day and short-term in nature, the Company determined that it does not have material future performance obligations or financing arrangements under its service contracts. Payments are typically due within 30 days after the services are rendered. The timing between the recognition of revenue and receipt of payment is not significant.

No contract assets or liabilities were recognized related to contracts with our customers.

The Company has also exercised the following practical expedients and accounting policy elections provided by ASC 606 for all its service contracts.

1) QES occasionally pays commissions to its sales staff for successfully obtaining a contract. The commission payment is incremental costs of obtaining a contract and should be capitalized and amortized over the contract period. However, ASC 340-40-25-4 provides a practical expedient, which states that "an entity may recognize the incremental costs of obtaining a contract as an expense when incurred if the amortization period of the asset that the entity otherwise would have recognized is one year or less." Management has elected to use this practical expedient as most of the Company's service contracts are less than a month. Accordingly, the Company expenses the commission expense as incurred.

2) In May 2016, the FASB issued ASU 2016-12 that allows an entity to make an accounting policy election to exclude from the transaction price certain types of taxes collected from a customer (i.e. present revenue net of these taxes), including sales, use, value-added and some excise taxes.

Cash and Cash Equivalents

For purposes of reporting cash flows, cash and cash equivalents consist of cash on hand, and certificates of deposits. QES considers all highly liquid investments with a maturity of three months or less when purchased to be cash equivalents.

The Company maintains its cash and cash equivalents in various financial institutions, which at times may exceed federally insured amounts. Management believes that this risk is not significant.

Accounts Receivable and Allowance for Doubtful Accounts

QES grants credit to qualified customers, which potentially subjects the Company to credit risk resulting from, among other factors, adverse changes in the industry in which the Company operates and the financial condition of its customers. Estimated losses on accounts receivable are provided through an allowance for doubtful accounts. The level of allowance is determined by specifically evaluating customers deemed to be an elevated credit risk, as well as a general analysis of the overall aging of our accounts. As the financial condition of any party changes, circumstances develop or additional information becomes available, adjustments to the allowance for doubtful accounts may be required. As of December 31, 2018 and 2017, the allowance for doubtful accounts was approximately $1.8 million and $0.8 million, respectively. Bad debt expense of $1.1 million, $0.3 million and $0.1 million was included in selling, general and administration expenses on the consolidated statement of operations for the years ended December 31, 2018, 2017 and 2016, respectively.

Activity in our allowance for doubtful accounts during the years ended December 31, 2018, 2017 and 2016 is set forth in the table below (*in thousands of dollars*):

	Balance at beginning of period	Charged to costs and expenses	Deductions [(1)]	Balance at end of period
2018				
Allowance for doubtful accounts	$ 776	$ 1,103	$ (38)	$ 1,841
2017				
Allowance for doubtful accounts	880	289	(393)	776
2016				
Allowance for doubtful accounts	$ 994	$ 142	$ (256)	$ 880

(1) Accounts receivable balances written off during the period, net of recoveries.

Unbilled Receivables

Unbilled receivables are the amounts of recoverable revenue that have been earned and not billed at the balance sheet date. Unbilled receivables relate principally to revenue that is billed in the month after services are performed. These items are expected to be collected in the normal course of business.

Inventories

Inventories consisting primarily of cement mix, sand, fuel, chemicals, proppants, and downhole tool spare parts are stated at the lower of cost or net realizable value. The average cost method is used for inventory held by all segments.

Property, Plant, and Equipment

Property, plant, and equipment ("PP&E") are stated at cost less accumulated depreciation. Maintenance and repairs are charged to expense as incurred while the cost of additions and improvements that substantially extend the useful life and/or the functionality of a particular asset are capitalized. The cost and related accumulated depreciation of assets retired or otherwise disposed of are eliminated from the accounts, and any resulting gains or losses are recognized in operations in the period of disposal.

PP&E are evaluated on an annual basis to identify events or changes in circumstances ("triggering events") that indicate that the carrying value of certain PP&E may not be recoverable. PP&E are reviewed for impairment upon the occurrence of a triggering event. An impairment loss is recorded in the period in which it is determined that the carrying amount of PP&E is not recoverable. The determination of recoverability is made based upon the estimated undiscounted future net cash flows of assets grouped at the lowest level for which there are identifiable cash flows independent of the cash flows of other groups of assets with such cash flows to be realized over the estimated remaining useful life of the primary asset within the asset group. If the estimated undiscounted future net cash flows for a given asset group is less than the carrying amount of the related assets, an impairment loss is determined by comparing the estimated fair value with the carrying value of the related assets. The impairment loss is then allocated across the asset group's major classifications.

Based on management's assessment and consideration of the current business environment, the financial performance of the business, and the current outlook, it was determined there has been no impairment the current period. As such, no impairment of PP&E was recorded for the years ended December 31, 2018 and 2017. The company reported an impairment of PP&E of approximately $1.4 million for the year ended December 31, 2016.

Goodwill and Definite-Lived Intangible Assets

Goodwill represents the excess of the purchase price over the fair value of identifiable tangible and intangible assets acquired. In accordance with U.S. GAAP, goodwill is not amortized since it has an indefinite life. Instead, the Company's Goodwill balance, if any, it is tested at least annually for impairment; impairment losses, if any, are recorded in the statement of operations as part of income from operations. The Company tests goodwill for impairment at the reporting unit level on an annual basis as of September 30, or when events or changes in circumstances, referred to as triggering events, indicate the carrying value of goodwill may not be recoverable and that a potential impairment exists. The quantitative impairment test for goodwill requires a two-step approach, which is performed at a reporting unit level. Step one of the test identifies potential impairments by comparing the fair value of the reporting unit to its carrying amount. Step two, which is performed if the fair value of a reporting unit is less than its carrying value, calculates the impairment loss as the difference between the carrying amount of the reporting unit's goodwill and the implied fair value of that goodwill.

The Company uses the income and market approach to estimate the fair value of its reporting units. The income approach is based on a discounted cash flow model, which utilizes present values of estimated cash flows to estimate fair value. The future cash flows are projected based on estimates of projected revenue growth, fleet and rig count, utilization, gross profit rates, SG&A rates, working capital fluctuations and capital expenditures. Management's anticipated business outlook, which has been impacted by the sustained decline in commodity prices, falling Company stock prices, and negative cash flows, is taken into consideration. The future cash flows are discounted using a market-participant risk-adjusted weighted average cost of capital. These assumptions are derived from unobservable Level 3 inputs, as described below, and reflect management's judgments and assumptions.

The market approach is based upon selected public companies operating within the same industry as the reporting unit. Based on this set of comparable competitor data, enterprise value-to-earnings multiples are derived and applied to the estimated earnings of the reporting unit to determine an estimated fair value. Earnings estimates are derived from unobservable inputs that require significant estimates, judgments and assumptions as described in the income approach.

Definite-lived intangible assets are amortized over their estimated useful lives. When events or changes in circumstances (a triggering event) indicate that the asset may have a net book value in excess of their recoverable value, the Company performs a recoverability test on its definite-lived intangible assets by comparing the estimated future net undiscounted cash flows expected to be generated from the use of the asset to the carrying amount of the asset. If the estimated undiscounted cash flows exceed the carrying amount of the asset, an impairment does not exist, and a loss will not be recognized. If the undiscounted cash flows are less than the carrying amount of the asset, the asset is deemed to not be recoverable, and the amount of impairment must be determined by fair valuing the asset.

Deferred Financing Costs

Costs incurred to obtain financing are capitalized and amortized over the term of the loan using the effective interest method. These costs are classified within interest expense on the consolidated statements of operations.

Income Taxes

The asset and liability method is used in accounting for income taxes. Under this method, deferred tax assets and liabilities are recognized for operating loss and tax credit carryforwards and for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the year in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the results of operations in the period that includes the enactment date. If applicable, a valuation allowance is recorded to reduce the carrying amounts of deferred tax assets unless it is more likely than not that such assets will be realized. The Company's policy is to account for interest and penalties with respect to income taxes as operating expenses.

On December 22, 2017, the President of the United States signed into law legislation informally known as the Tax Cuts and Jobs Act (the "Act"). The Act represents major tax reform legislation that, among other provisions, reduces the U.S. corporate tax rate.

Comprehensive Income (loss)

Any comprehensive income (loss) and its components are displayed in our financial statements. When they arise, we classify items of comprehensive income by their nature in the financial statements and display the accumulated balance and other comprehensive income in members' equity. Comprehensive income equals net income for all periods presented in the accompanying consolidated financial statements.

Fair Value of Financial Instruments

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. A hierarchy has been established for inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability, and are developed based on market data obtained from sources independent of QES. Unobservable inputs are inputs that reflect QES' assumptions of what market participants would use in pricing the asset or liability based on the *best* information available in the circumstances. The financial and nonfinancial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The hierarchy is broken down into three levels based on the reliability of the inputs.

Level 1 Quoted prices are available in active markets for identical assets or liabilities;

Level 2	Quoted prices in active markets for similar assets and liabilities that are observable for the asset or liability; or
Level 3	Unobservable pricing inputs that are generally less observable from objective sources, such as discounted cash flow models or valuations.

Stock-based compensation

The Company records compensation relating to stock-based compensation transactions and includes such costs in general and administrative expenses in the consolidated statement of operations. The cost is measured at the grant date and based on the calculated fair value of the award. See “Note 13 - Stock-Based Compensation” for additional information related to stock-based compensation.

<u>Recent Accounting Pronouncements</u>

Adopted in 2018

In May 2014, the FASB issued ASU No. 2014-9, *Revenue from Contracts with Customers (Topic 606)*, a comprehensive new revenue recognition standard that supersedes most existing industry-specific guidance. ASC 606 creates a framework by which an entity allocates the transaction price to separate performance obligations and recognizes revenue when each performance obligation is satisfied. Under the new standard, entities are required to use judgment and make estimates, including identifying performance obligations in a contract, estimating the amount of variable consideration to include in the transaction price, allocating the transaction price to each separate performance obligation and determining when an entity satisfies its performance obligations. The standard allows for either “full retrospective” adoption, meaning that the standard is applied to all of the periods presented with a cumulative catch-up in the earliest period presented, or “modified retrospective” adoption, meaning the standard is applied only to the most current period presented in the financial statements with a cumulative catch-up in the current period. In July and December 2016, the FASB issued various additional authoritative guidance for the new revenue recognition standard. The accounting standard is effective for reporting periods beginning after December 15, 2017 and did not have a material impact on the Company’s 2018 first quarter interim condensed consolidated financial position, results of operations and cash flows. The Company adopted ASC 606, effective January 1, 2018, utilizing the modified retrospective method of adoption.

In January 2017, FASB issued ASU No. 2017-1, *Business Combinations (Topic 805): Clarifying the Definition of a Business*. The amendments provide a more robust framework to use in determining when a set of assets and activities constitutes a business. The new standard was effective for the Company beginning on January 1, 2018. The standard did not have a material impact on the Company’s interim condensed consolidated financial position, results of operations and cash flows as it did not have any business combinations transactions.

In May 2017, the FASB issued ASU 2017-9, *Compensation (Topic 718): Scope of Modification Accounting*, which clarifies what constitutes a modification of a stock-based payment award. The new standard was effective for the Company beginning on January 1, 2018. The standard did not have a material impact on the Company’s interim condensed consolidated financial position, results of operations and cash flows because there has been no modification to our equity-based payment awards.

In August 2016, the FASB issued ASU 2016-15, *Classification of Certain Cash Receipts and Cash Payments* providing new guidance on the classification of certain cash receipts and payments including debt extinguishment costs, debt prepayment costs, settlement of zero-coupon debt instruments, contingent consideration payments, proceeds from the settlement of insurance claims and life insurance policies and distributions received from equity method investees in the statement of cash flows. This update is required to be applied using the retrospective transition method to each period presented unless it is impracticable to be applied retrospectively. In such situation, this guidance is to be applied prospectively. The new standard was effective for the Company beginning on January 1, 2018, which did not impact 2017 results, but resulted in a $1.3 million prepayment premium cost being reported under financing activities relating to the debt extinguishment of the Company’s $40.0 million term loan at the closing of the IPO.

Accounting Standards not yet adopted

In June 2018, the FASB issued ASU No. 2018-07, *Compensation - Stock Compensation (Topic 718), Improvements to Nonemployee Share-Based Payment Accounting*. This ASU is intended to simplify aspects of stock-based compensation issued to non-employees by making the guidance consistent with the accounting for employee stock-based compensation. The guidance is effective for the Company for the fiscal year beginning January 1, 2020. While the exact impact of this standard is not known, the guidance is not expected to have a material impact on the Company's consolidated financial statements, as non-employee stock compensation is nominal relative to the Company's total expenses as of December 31, 2018.

In February 2016, the FASB issued ASU No. 2016-2, *Leases,* to provide guidance for the accounting for leasing transactions. The standard requires the lessee to recognize a lease liability along with a right-of-use asset for all leases with a term longer than one year. A lessee is permitted to make an accounting policy election by class of underlying asset to not recognize the lease liability and related right-of-use asset for leases with a term of one year or less. The provisions of this standard also apply to situations where the Company is the lessor. The requirements in this update are effective during interim and annual periods beginning after December 15, 2018. The Company adopted this new guidance effective January 1, 2019. ASC 842 requires a modified retrospective approach to each lease that existed at the date of initial application as well as leases entered into after that date. The Company has elected to report all leases at the beginning of the period of adoption and not restate its comparative periods. Based on the Company's lease portfolio, the Company anticipates recognizing a right-of-use asset and a related lease liability of approximately $33.0 million on its balance sheet, with an immaterial impact on the Company's consolidated statement of operations compared to the previous lease accounting guidance.

Practical Expedients Adopted with Topic 842

The Company has elected to adopt the following practical expedients upon the transition date to Topic 842 on January 1, 2019:

- Transitional practical expedients package: An entity may elect to apply the listed practical expedients as a package to all the leases that commenced before the effective date. The practical expedients are:
    - The entity need not reassess whether any expired or existing contracts are or contains leases;
    - The entity need not reassess the lease classification for expired or existing contracts;
    - The entity need not reassess initial direct costs for any existing leases.

- Use of portfolio approach: An entity can apply this guidance to a portfolio of leases with similar characteristics if the entity reasonably expects that the application of the lease model to the portfolio would not differ materially from the application of the lease model to the individual leases in that portfolio. This approach can also be applied to other aspects of the leases guidance for which lessees/lessors need to make judgments and estimates, such as determining the discount rate and determining and reassessing the lease term.

- Lease and non-lease components: As a practical expedient, a lessor may combine lease and non-lease components where the revenue recognition pattern is the same and where the lease component, when accounted for separately, would be considered an operating lease.

NOTE 2 - Inventories

Inventories consisted of the following (*in thousands of dollars*):

	December 31, 2018	December 31, 2017	December 31, 2016
Consumables and materials	$ 7,566	$ 7,085	6,056
Spare parts	15,898	15,608	13,493
Inventories	$ 23,464	$ 22,693	19,549

NOTE 3 - Property, Plant and Equipment

Depreciation of assets is computed using the straight-line method over the lesser of the estimated useful lives of the respective assets or the lease term, if shorter. Depreciation expense and capital lease amortization expense for the years ended December 31, 2018, 2017 and 2016 was $44.9 million, $43.3 million and $76.3 million, respectively. A substantial portion of the Company's tools are designed for specific applications in oil and gas exploration. Changes in industry drilling processes or technology could impact the estimated useful lives of the Company's equipment. Gains recorded for assets lost in hole for the years ended December 31, 2018, 2017 and 2016 were $5.4 million, $7.9 million and $4.1 million, respectively. Gain/(loss) related to the sale of PP&E for the years ended December 31, 2018, 2017 and 2016 were $2.4 million, $2.6 million and ($5.4) million, respectively.

Major classifications of PP&E and their respective useful lives were as follows (in thousands of dollars):

	Estimated Useful Lives	As of December 31, 2018	2017	2016
Land	Indefinite	$ 3,740	$ 3,999	$ 4,050
Service equipment	3-10 years	298,782	262,795	250,435
Machinery and equipment	7-15 years	70,749	51,333	55,897
Buildings and leasehold improvements	5-39 years	24,648	27,061	27,290
Software	3-5 years	2,348	2,012	1,123
Office furniture and equipment	3-10 years	2,792	2,376	3,098
		403,059	349,576	341,893
Less: Accumulated depreciation		(255,843)	(224,764)	(193,985)
		147,216	124,812	147,908
Construction in progress		6,662	3,706	2,798
Property, plant and equipment, net		$ 153,878	$ 128,518	$ 150,706

Property, plant and equipment under capital leases included in the above are as follows:

	Estimated Useful Lives	As of December 31, 2018	2017	2016
Machinery and equipment	3 Years	$ 233	$ 181	$ —
Buildings and leasehold improvements	20 Years	2,252	2,252	2,252
		2,485	2,433	2,252
Less: Accumulated amortization		(676)	(415)	(193)
		$ 1,809	$ 2,018	$ 2,059

NOTE 4 - Intangible Assets

Definite-Lived Intangible Assets

There were no impairment triggering events during 2018, 2017 and 2016. The changes in the carrying amounts of other intangible assets for the year ended December 31, 2018, 2017 and 2016 are as follows (*in thousands of dollars*):

	Trademarks	Customer Relationships	Non-compete Agreement	Total
Estimated useful life (years)	3	13	5	
Gross Amount as of December 31, 2016	$ 1,750	$ 11,710	$ 4,560	$ 18,020
Accumulated Amortization	(1,166)	(1,802)	(1,824)	(4,792)
Net Balance as of December 31, 2016	584	9,908	2,736	13,228
Gross Amount as of December 31, 2017	$ 1,750	$ 11,710	$ 4,560	$ 18,020
Accumulated Amortization	(1,750)	(2,702)	(2,736)	(7,188)
Net Balance as of December 31, 2017	—	9,008	1,824	10,832
Gross Amount as of December 31, 2018	$ 1,750	$ 11,710	$ 4,560	$ 18,020
Accumulated Amortization	(1,750)	(3,603)	(3,648)	(9,001)
Net Balance as of December 31, 2018	—	8,107	912	9,019

Amortization expense for the years ended December 31, 2018, 2017 and 2016 were $1.8 million, $2.4 million and $2.4 million, respectively.

Amortization expense of these intangibles for each of the subsequent five fiscal years is expected to be as follows (*in thousands of dollars*):

Year Ending December 31,	Total
2019	$ 1,813
2020	901
2021	901
2022	901
Thereafter	4,503
	$ 9,019

NOTE 5 - Accrued Liabilities

Accrued liabilities consist of the following (*in thousands of dollars*):

	December 31, 2018	December 31, 2017
Current accrued liabilities		
Accrued payables	$ 12,943	$ 11,905
Payroll and payroll taxes	7,051	6,089
Bonus	6,117	6,019
Workers compensation insurance premiums	1,532	1,760
Sales tax	2,599	2,923
Ad valorem tax	581	728
Health insurance claims	921	913
Other accrued liabilities	5,789	3,488
Total accrued liabilities	$ 37,533	$ 33,825

NOTE 6 - Long-Term Debt and Capital Lease Obligations

Long-term debt consisted of the following (*in thousands of dollars*):

	December 31, 2018	December 31, 2017
New ABL revolving credit facility due February 2023	$ 29,500	$ —
Revolving credit facility	—	79,071
2017 term loan facility	—	44,328
Less: deferred financing costs	—	(1,709)
Less: discount on term loan	—	(5,420)
Total debt obligations, net of discounts and deferred financing	29,500	116,270
Capital leases	3,873	4,200
Less: current portion of debt and capital lease obligation	(422)	(79,443)
Long-term debt and capital lease obligations	$ 32,951	$ 41,027

Long-Term Debt

Former Revolving Credit Facility

The Company had a revolving credit facility ("the Former Revolving Credit Facility"), which had a maximum borrowing facility of $110.0 million that was scheduled to mature on September 19, 2018. All obligations under the credit agreement for the Former Revolving Credit Facility were collateralized by substantially all of the assets of the Company. The Revolving Credit Facility's credit agreement contained customary restrictive covenants that required the Company not to exceed or fall below two key ratios, a maximum loan to value ratio of 70% and a minimum liquidity of $7.5 million. In connection with the closing of the IPO on February 13, 2018, we fully repaid and terminated the Former Revolving Credit Facility. No early termination fees were incurred by the Company in connection with the termination of the Former Revolving Credit Facility. A loss on extinguishment of $0.3 million relating to unamortized deferred costs was recognized in interest expense, during the first quarter of 2018.

Former Term Loan

The Company also had a four-year, $40.0 million term loan agreement with a lending group, which included Geveran Investments Limited, Archer Holdco LLC and Robertson QES Investment LLC, an affiliate of Quintana Capital Group, L.P., that was scheduled to mature on December 19, 2020. The Former Term Loan agreement contained customary restrictive covenants that required the

Company not to exceed or fall below two key ratios, a maximum loan to value ratio of 77% and a minimum liquidity of $6.8 million. The interest rate on the unpaid principal was 10.0% interest per annum and accrued on a daily basis. At the end of each quarter all accrued and unpaid interest was paid in kind by capitalizing and adding to the outstanding principal balance. In connection with the closing of the IPO on February 13, 2018, the Former Term Loan was settled in full by cash and common shares in the Company. In connection with the settlement of the Former Term Loan, a prepayment fee of 3%, or approximately $1.3 million was paid. The prepayment fee is recorded as a loss on extinguishment and included within interest expense. The Company also recognized within interest expense $5.4 million of unamortized discount expense and $1.7 million of unamortized deferred financing cost in interest expense, during the first quarter of 2018.

New ABL Facility

In connection with the closing of the IPO on February 13, 2018, we entered into a new asset-based revolving credit agreement (the "New ABL Facility") with each lender party thereto and Bank of America, N.A. as administrative agent and collateral agent. The New ABL Facility replaced the Former Revolving Credit Facility, which was terminated in conjunction with the effectiveness of the New ABL Facility. The New ABL Facility provides for a $100.0 million revolving credit facility subject to a borrowing base. Upon closing of the New ABL Facility, the borrowing capacity was $77.6 million and $13.0 million was immediately drawn. The loan interest rate on the borrowings outstanding at December 31, 2018, was 5.3% and $29.5 million was outstanding and recorded as long term debt under the New ABL Facility as of December 31, 2018. At December 31, 2018, we had $13.8 million of cash and cash equivalents and $60.2 million available to draw on the New ABL Facility, which resulted in a total liquidity position of $74.0 million.

The New ABL Facility contains various affirmative and negative covenants, including financial reporting requirements and limitations on indebtedness, liens, mergers, consolidations, liquidations and dissolutions, sales of assets, dividends and other restricted payments, investments (including acquisitions) and transactions with affiliates. Certain affirmative covenants, including certain reporting requirements and requirements to establish cash dominion accounts with the administrative agent, are triggered by failing to maintain availability under the New ABL Facility at or above specified thresholds or by the existence of an event of default under the New ABL Facility. The New ABL Facility provides for some exemptions to its negative covenants allowing the Company to make certain restricted payments and investments; subject to maintaining availability under the New ABL Facility at or above a specified threshold and the absence of a default.

The New ABL Facility contains a minimum fixed charge coverage ratio of 1.0 to 1.0 that is triggered when availability under the New ABL Facility falls below a specified threshold and is tested until availability exceeds a separate specified threshold for 30 consecutive days.

The New ABL Facility contains events of default customary for facilities of this nature, including, but not limited, to: (i) events of default resulting from the Borrowers' failure or the failure of any credit party to comply with covenants (including the above-referenced financial covenant during periods in which the financial covenant is tested); (ii) the occurrence of a change of control; (iii) the institution of insolvency or similar proceedings against the Borrowers or any credit party; and (iv) the occurrence of a default under any other material indebtedness the Borrowers or any guarantor may have. Upon the occurrence and during the continuation of an event of default, subject to the terms and conditions of the New ABL Facility, the lenders will be able to declare any outstanding principal balance of our New ABL Facility, together with accrued and unpaid interest, to be immediately due and payable and exercise other remedies, including remedies against the collateral, as more particularly specified in the New ABL Facility. As of December 31, 2018 the Company was in compliance with debt covenants.

Capital Lease Obligations

The Company has long-term lease agreements for a manufacturing and office facility for the operations of its Pressure Control segment in Oklahoma City, Oklahoma and Elk City, Oklahoma. Each lease is accounted for as a capital lease. The lease for the facility in Oklahoma City, Oklahoma commenced in December 2006, creating a lease obligation of $3.3 million as of March 2007. The lease is payable monthly in amounts ranging from $28,000 to $31,000 over the lease term. The lease for the facility in Elk City, Oklahoma commenced in April 2007, creating a lease obligation of $2.9 million as of May 2008. The lease is payable monthly in amounts ranging from $25,000 to $27,000 over the lease term.

The Company leases certain machinery and equipment, and service equipment under capital leases that were entered into during the year and expire in 2020. The capital lease obligation for the assets have a lease term of 36 months and an interest rate of 5.5%.

As of December 31, 2018, the future minimum lease payments acquired under the Company's capital leases are as follows (in thousands of dollars):

Years Ending December 31,	
2019	$ 721
2020	687
2021	640
2022	630
2023	630
Thereafter	1,937
	$ 5,245

The interest expense associated with the lease payments during the year ended December 31, 2018, 2017 and 2016, under the Company's capital leases totaled $0.3 million, $0.3 million and $0.4 million respectively.

NOTE 7 - Stockholders' Equity

The Company is authorized to issue 150,000,000 shares of common stock, par value $0.01 per share, of which 33,541,161 shares were outstanding on December 31, 2018. As of December 31, 2017 approximately 417,441,074 common units and 227,885,579 warrants to purchase common units were outstanding on December 31, 2018 and 2017, respectively. See "Note 1 - Nature of Operations, Basis of Presentation and Significant Accounting Policies" for more details on how the IPO, conversion and stock split impacted the Predecessor units and warrants. We are also authorized to issue 10,000,000 shares of preferred stock, par value $0.01 per share, which may be issued in series with terms and conditions determined by our Board of Directors. All common units and warrants for common units have been converted to shares of common stock. No shares of preferred stock have been issued.

NOTE 8 - Income Taxes

Quintana Energy Services LP was originally organized as a limited partnership and treated as a flow-through entity for federal and most state income tax purposes. As such, taxable income and any related tax credits were passed through to its members and included in their respective tax returns. As a result of the IPO and related Organizational Transactions, Quintana Energy Services, Inc. was formed as a corporation to hold all of the operational assets of Quintana Energy Services Inc. Due to the fact that Quintana Energy Services, Inc. is a taxable entity, the Company established a provision for deferred income taxes as of February 8, 2018. Accordingly, a provision for federal and state corporate income taxes has been made only for the operations of Quintana Energy Services, Inc. from February 8, 2018 through December 31, 2018 in the accompanying consolidated and combined financial statements.

As the Company does not operate internationally, income from continuing operations is sourced exclusively from the United States.

The provision for income taxes consisted of the following (*in thousands of dollars*):

	Year Ended December 31,		
	2018	**2017**	**2016**
Current income tax (expense) benefit			
Federal	$ (22)	$ (40)	$ (244)
State	(507)	(1)	35
Total current income tax (expense)	(529)	(41)	(209)
Deferred income tax (expense) benefit			
Federal	—	(45)	37
State	(92)	(5)	5
Total deferred income tax (expense) benefit	(92)	(50)	42
	$ (621)	$ (91)	$ (167)

The following table presents the reconciliation of our income taxes calculated at the statutory federal tax rate, currently 21.0%, to the income tax provision in our financial statements. The Company's effective tax rate for 2018 of (3.9)% differs from the statutory rate, primarily due to nondeductible expenses, state taxes and a valuation allowance. The Company's effective tax rate for 2017 and 2016 was (0.4)% and (0.1)%, respectively.

	Year Ended December 31,		
	2018	2017	2016
Income tax provision computed at the statutory federal rate	21.0 %	34.0 %	34.0 %
State income taxes, net of federal tax benefit	(3.7)	—	—
Non-deductible wages	(4.1)	—	—
Non-deductible meals and entertainment	(4.1)	—	—
Stock based compensation	(6.5)	—	—
Valuation allowance	(6.3)	—	—
Flow through income not taxable	—	(34.4)	(34.2)
Other differences	(0.2)	—	0.1
Effective tax rate	(3.9)%	(0.4)%	(0.1)%

On December 22, 2017, the US enacted the Tax Cuts and Jobs Act of 2017 (“US Tax Reform”), a comprehensive U.S. tax reform package that, effective January 1, 2018, among other things, lowered the corporate income tax rate from 35% to 21% and moved the country toward a territorial tax system. Under ASC 740 “Income Taxes,” companies are required to recognize the effects of changes in tax laws and tax rates on deferred tax assets and liabilities in the period in which the new legislation is enacted. As a result, all deferred tax assets and liabilities were appropriately measured at the effective rate. Our 2018 provision for income taxes includes the new provisions of US Tax Reform as enacted on January 1, 2018, based on authoritative and proposed guidance, issued by the Internal Revenue Service.

Deferred income taxes are provided to reflect the future tax consequences or benefits of differences between the tax basis of assets and liabilities and their reported amounts in the financial statements using enacted tax rates. Deferred tax assets and liabilities were classified in the consolidated balance sheet as follows (in thousands of dollars):

	Year Ended December 31,		
	2018	2017	2016
Deferred tax assets:			
Reserves & accruals	$ 1,698	$ —	$ —
Stock based compensation	1,844	—	—
Intangible assets	60,978	—	—
Net operating loss carryforwards	40,987	—	—
Other	56	—	—
Total deferred tax assets	105,563	—	—
Valuation allowance	(90,027)	—	—
Net deferred tax assets	15,536	—	—
Deferred tax liability:			
Prepaid expenses	(180)	—	—
Property plant and equipment	(15,486)	(185)	(135)
Total deferred tax liabilities	(15,666)	(185)	(135)
Net deferred tax liability	$ (130)	$ (185)	$ (135)

As of December 31, 2018, the Company had total U.S. federal tax net operating loss (“NOL”) carryforwards of $93.5 million and state NOL carryforwards of $472.9 million. Of these amounts, for U.S. federal purposes, $77.9 million related to the Company’s current year federal tax loss, and the remaining $15.6 million was generated prior to the IPO transaction. In regard to the state NOL carryforwards, $472.3 million is related to the Company’s current year state tax losses and less than $0.6 million is related to periods prior to the IPO. As a result of the US Tax Reform enacted in January 2018, federal net operating losses generated after December 31, 2017 can be carried forward indefinitely. As such, the Company’s federal carryforwards of $15.6 million will begin to expire in 2029 and the remaining carryforwards have no expiration. The Company’s state NOL carryforwards will begin to expire in 2019.

ASC 740, "Income Taxes", requires the Company to reduce its deferred tax assets by a valuation allowance if, based on the weight of the available evidence, it is more likely than not that all or a portion of a deferred tax asset 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 are deductible. As a result of the Company's evaluation of both the positive and negative evidence, the Company determined it does not believe it is more likely than not that its deferred tax assets will be utilized in the foreseeable future and has recorded a valuation allowance. The valuation allowance as of December 31, 2018 fully offsets the impact of the initial benefit recorded related to the formation of Quintana Energy Services, Inc. This initial deferred impact was recorded as an adjustment to equity due to a transaction between entities under common control.

Changes in the valuation allowance for deferred tax assets were as follows (*in thousands of dollars*):

Valuation allowance as of the beginning of January 1, 2018	$	(379)
Charged to equity		(68,908)
Charged to income tax provision for current year activity		(20,740)
Valuation allowance as of December 31, 2018	$	(90,027)

There were no unrecognized tax positions or unrecognized tax benefits nor any accrued interest or penalties associated with unrecognized tax positions during the years ended December 31, 2018, 2017 and 2016. The Company believes it has appropriate support for the income tax positions taken and to be taken on the Company's tax returns and its accruals for tax liabilities are adequate for all open years based on our assessment of many factors including past experience and interpretations of tax law applied to the facts of each matter. The Company's tax returns are open to audit under the statute of limitations for the years ended December 31, 2015 through February 8, 2018 for federal tax purposes and for the years ended December 31, 2015 through December 31, 2017 for state tax purposes.

NOTE 9 - Related Party Transactions

The Company utilizes some Quintana Capital Group affiliate employees for certain corporate functions, such as accounting and risk management. These amounts are reimbursed by the Company on a monthly basis.

At December 31, 2018, 2017 and 2016, QES had the following transactions with related parties (*in thousands of dollars*):

	December 31, 2018		December 31, 2017	
Accounts payable to affiliates of Quintana Capital Group	$	—	$	81
Accounts payable to affiliates of Archer Well Company Inc.	$	40	$	9

	Year Ended December 31,					
	2018		2017		2016	
Operating expenses from affiliates of Quintana Capital Group	$	384	$	529	$	1,628
Operating expenses from affiliates of Archer Well Company Inc.	$	81	$	10	$	2,095

NOTE 10 - Business Concentration

Financial instruments that potentially subject the Company to concentrations of credit risk consist primarily of cash and cash equivalents and accounts receivable. Concentrations of credit risk with respect to accounts receivable are limited because the Company performs credit evaluations, sets credit limits, and monitors the payment patterns of its customers. Cash balances on deposits with financial institutions, at times, may exceed federally insured limits. The Company regularly monitors the institutions' financial condition.

The majority of the Company's business is conducted with large, midsized, small, and independent oil and gas operators and exploration and production ("E&P") companies. The Company evaluates the financial strength of customers and provide allowances for probable credit losses when deemed necessary. The market for the Company's services is the oil and gas industry in the United States. This market has historically experienced significant volatility.

As of December 31, 2018 and 2017 one customer revenue represented 11.9% and 10.3% respectively, of the Company's consolidated revenue. There were no customers whose revenue exceeded 10.0% of consolidated revenue for the year ended December 31, 2016.

As of December 31, 2018, 2017 and 2016, one customer had a balance due that represented 10.7%, 18.3% and 11.2% respectively, of the Company's consolidated accounts receivable.

NOTE 11 - Commitments and Contingencies

Environmental Regulations & Liabilities

The Company is subject to various federal, state and local environmental laws and regulations that establish standards and requirements for the protection of the environment. The Company continues to monitor the status of these laws and regulations. However, the Company cannot predict the future impact of such standards and requirements on its business, which are subject to change and can have retroactive effectiveness.

Currently, the Company has not been fined, cited or notified of any environmental violations or liabilities that would have a material adverse effect upon its consolidated financial position, results of operations, liquidity or capital resources. However, management does recognize that by the very nature of its business, material costs could be incurred in the near term to maintain compliance. The amount of such future expenditures is not determinable due to several factors, including the unknown magnitude of possible regulation or liabilities, the unknown timing and extent of the corrective actions which may be required, the determination of the Company's liability in proportion to other responsible parties and the extent to which such expenditures are recoverable from insurance or indemnification.

Litigation

The Company is a defendant or otherwise involved in a number of lawsuits in the ordinary course of business. Estimates of the range of liability related to pending litigation are made when the Company believes the amount and range of loss can be estimated and records its best estimate of a loss when the loss is considered probable. When a liability is probable, and there is a range of estimated loss with no best estimate in the range, the minimum estimated liability related to the lawsuits or claims is recorded. As additional information becomes available, the potential liability related to pending litigation and claims is assessed and the estimate is revised. Due to uncertainties related to the resolution of lawsuits and claims, the ultimate outcome may differ from estimates. The Company's ultimate exposure with respect to pending lawsuits and claims is not expected to have a material adverse effect on our financial position, results of operations or cash flows.

A class action has been filed against one of the Company's subsidiaries alleging violations of state based wage and hour laws and the Fair Labor Standards Act ("FLSA") relating to non-payment of overtime pay. The Company believes its pay practices comply with the FLSA. The case is working its way through the various stages of the legal process, however, management believes the Company's exposure is not material.

The Company is not aware of any other matters that may have a material effect on its financial position or results of operations.

NOTE 12 - Segment Information

QES currently has four reportable segments: Directional Drilling, Pressure Pumping, Pressure Control and Wireline. These segments have been selected based on the Company's CODM assessment of resource allocation and performance. The Company considers its Chief Executive Officer to be its CODM. The CODM evaluates the performance of our segments based on revenue and income measures, which include non-GAAP measures.

Directional Drilling

Our Directional Drilling segment is comprised of directional drilling services, downhole navigational and rental tools businesses and support services, including well planning and site supervision, which assists customers in the drilling and placement of complex directional and horizontal wellbores. This segment utilizes its fleet of in-house positive pulse measurement-while-drilling navigational tools, mud motors and ancillary downhole tools, as well as electromagnetic navigational systems. The demand for these services tends to be influenced primarily by customer drilling-related activity levels. We provide directional drilling and associated services to E&P companies in many of the most active areas of onshore oil and natural gas development in the United States, including the Permian Basin, Eagle Ford Shale, Mid-Continent region (including the SCOOP/STACK), Marcellus/Utica Shale and DJ/Powder River Basin.

Pressure Pumping

Our Pressure Pumping segment provides hydraulic fracturing stimulation services, cementing services and acidizing services. The majority of the revenues generated in this segment are derived from pressure pumping services focused on fracturing, cementing and acidizing services in the Mid-Continent and Rocky Mountains regions. These pressure pumping and stimulation services are primarily used in the completion, production and maintenance of oil and gas wells. Customers for this segment include major E&P operators as well as independent oil and gas producers.

Pressure Control

Our Pressure Control segment supplies a wide variety of equipment, services and expertise in support of completion and workover operations throughout the United States. Its capabilities include coiled tubing, snubbing, fluid pumping, nitrogen, well control and other pressure control related services. Our Pressure Control equipment is tailored to the unconventional resources market with the ability to operate under high pressures without having to delay or cease production during completion operations. We provide our pressure control services primarily in the Mid-Continent region (including the SCOOP/STACK), Eagle Ford Shale, Permian Basin, Marcellus/Utica Shale, DJ/Powder River Basin, Haynesville Shale, Fayetteville Shale and Williston Basins (including the Bakken Shale).

Wireline

Our Wireline segment provides new well wireline conveyed tight-shale reservoir perforating services across many of the major U.S. shale basins and also offers a range of services such as cased-hole investigation and production logging services, conventional wireline and tubing conveyed perforating services, mechanical services and pipe recovery services. These services are offered in both new well completions and for remedial work. The majority of the revenues generated in our Wireline segment are derived from the Permian Basin, Eagle Ford Shale, Mid-Continent region (including the SCOOP/STACK), Haynesville Shale and East Texas Basin as well as in industrial and petrochemical facilities.

Segment Adjusted EBITDA

The Company views Adjusted EBITDA as an important indicator of segment performance. The Company defines Segment Adjusted EBITDA as net income (loss) plus income taxes, net interest expense, depreciation and amortization, impairment charges, net (gain) loss on disposition of assets - excluding (gain) loss of lost in hole assets, stock based compensation, transaction expenses, rebranding expenses, settlement expenses, severance expenses and equipment stand-up expense. The CODM uses Segment Adjusted EBITDA as the primary measure of segment operating performance.

The following table presents a reconciliation of Segment Adjusted EBITDA to net loss (*in thousands of dollars*):

	Year Ended December 31,		
	2018	2017	2016
Directional Drilling	$ 23,694	$ 17,498	$ (76)
Pressure Pumping	28,700	27,784	(19,372)
Pressure Control	18,389	6,539	(5,804)
Wireline	1,362	(1,794)	(6,161)
Corporate and Other	(33,573)	(17,459)	(14,687)
Income tax expense	(621)	(91)	(167)
Interest expense	(11,825)	(11,251)	(8,015)
Depreciation and amortization	(46,683)	(45,687)	(78,661)
Fixed asset impairment	—	—	(1,380)
Goodwill impairment	—	—	(15,051)
Gain on disposition of assets, net	2,375	2,639	(5,375)
Other income	—	666	—
Net loss	$ (18,182)	$ (21,156)	$ (154,749)

Financial information related to the Company's total assets position as of December 31, 2018 and December 31, 2017, by segment, is as follow (*in thousands of dollars*):

	December 31, 2018	December 31, 2017
Directional Drilling	$ 105,942	$ 82,789
Pressure Pumping	121,824	111,322
Pressure Control	70,401	52,884
Wireline	28,039	28,988
Total	$ 326,206	$ 275,983
Corporate & Other	7,344	7,695
Eliminations	(9,001)	(8,019)
Total assets	$ 324,549	$ 275,659

The following tables set forth certain financial information with respect to QES' reportable segments (*in thousands of dollars):*

	Year Ended December 31, 2018				
	Directional Drilling	Pressure Pumping	Pressure Control	Wireline	Total
Revenues	$ 192,491	$ 214,154	$ 122,620	$ 75,089	$ 604,354
Depreciation and amortization	10,849	22,571	9,207	4,056	46,683
Capital expenditures	$ 13,003	$ 29,235	$ 20,125	$ 2,594	$ 64,957

	Year Ended December 31, 2017				
	Directional Drilling	Pressure Pumping	Pressure Control	Wireline	Total
Revenues	$ 145,230	$ 153,118	$ 89,912	$ 49,773	$ 438,033
Depreciation and amortization	11,994	22,867	6,560	4,266	45,687
Capital expenditures	$ 9,038	$ 5,268	$ 6,446	$ 492	$ 21,244

	Year Ended December 31, 2016				
	Directional Drilling	Pressure Pumping	Pressure Control	Wireline	Total
Revenues	$ 75,326	$ 45,165	$ 52,388	$ 37,549	$ 210,428
Depreciation and amortization	21,585	37,876	11,391	7,809	78,661
Capital expenditures	$ 6,465	$ 101	$ 741	$ 33	$ 7,340

NOTE 13 - Stock-Based Compensation

As of December 31, 2018, the Company had three types of stock-based compensation under the Company's 2018 Long-Term Incentive Plan (i) restricted stock awards ("RSA") issued to directors (ii) restricted stock units (“RSU”) issued to executive officers and other key employees and (iii) performance stock units (“PSU”), which are RSUs with performance requirements, issued to executive officers and other senior management. Stock-based compensation issued prior to the Company’s IPO was subject to a dual component, one of which was the consummation of a specified transaction, which included a public offering. As the public offering occurred on February 7, 2018, there was no stock-based compensation expense recognized in periods prior to the IPO.

The following table summarizes stock-based compensation costs for the years ended December 31, 2018, 2017 and 2016 *(in thousands of dollars):*

	Years Ended December 31,		
	2018	2017	2016
Restricted stock awards	$ 438	$ —	$ —
Restricted stock units	16,293	—	—
Performance stock units	1,167	—	—
Stock-based compensation expense	$ 17,898	$ —	$ —

i. Restricted Stock Awards

In March 2018, the Company's Compensation Committee of the Board of Directors approved the issuance of RSAs to the Company's non-executive directors. During the second quarter 2018, we granted 57,145 RSAs, which had a grant date fair value of $8.75 per share. The stock awards fully vest on the anniversary date of the Company's IPO. RSAs were not granted in the first, third or fourth quarter of 2018.

For the years ended December 31, 2018 and 2017, the Company recognized $0.4 million and zero of non-cash stock compensation expense into earnings, respectively, which is presented within selling, general and administration expense in the consolidated statement of operations.

As of December 31, 2018, the total unamortized compensation costs related to the non-executive RSAs was $0.1 million, which the Company expects to recognize over the remaining vesting period of 0.1 years.

ii. Restricted Stock Units

During the second quarter 2018, executive officers and key employees were granted a total of 476,042 RSUs under the 2018 Long-Term Incentive Plan. These RSUs vest ratably over a three-year service condition with one-third vesting on each anniversary of the Company's IPO provided that the employee remains employed by the Company at the applicable vesting date. RSUs were not granted in the first, third or fourth quarter of 2018.

The Company recognized these RSUs at fair value based on the closing price of the Company's common stock on the date of grant. The compensation expense associated with these RSUs will be amortized into income on a straight-line basis over the vesting period.

Total RSU non-cash stock based compensation expense for the years ended December 31, 2018 and 2017, was $16.3 million and zero, which is presented within selling, general and administrative expense in the consolidated statements of operations.

As of December 31, 2018 and 2017 total unamortized compensation cost related to unvested restricted stock units were $16.9 million and $28.9 million, respectively.
A summary of the status and changes during the year ended December 31, 2018 of the Company's shares of non-vested RSUs is as follows:

	Number of Shares (in thousands)	Grant Date Fair Value per Share	Weighted Average Remaining Life (in years)
Outstanding at December 31, 2017	1,627	17.73	3.46
Granted	476	8.92	2.11
Forfeited	(8)	—	—
Vested	(544)	—	—
Outstanding at December 31, 2018	1,551	15.74	2.36

iii. Performance Stock Units

During the second quarter 2018, executive officers and senior management were granted a total of 425,083 PSUs under the 2018 Long-Term Incentive Plan. The PSUs are subject to both a performance and time vesting requirement. The PSUs require the achievement of a certain performance as measured on December 31, 2018, based on (i) the Company's performance with respect to relative total stockholder return and (ii) the Company's performance with respect to absolute total stockholder return. Any PSUs that have not been earned at the end of a performance period are forfeited. Should the grantee satisfy the service requirement applicable to such earned performance share unit, vesting shall occur in equal installments on the first three anniversaries of the Company's IPO.

The Company recognized these PSUs at the fair value determined using the Monte Carlo simulation model. The compensation expense associated with these PSUs will be amortized into income on a straight-line basis over the vesting period. For the year ended December 31, 2018 and 2017, the Company recognized $1.2 million and zero of non-cash stock compensation expense into income, which is presented within selling, general and administrative expense in the consolidated statements of operations. PSUs were not granted during the first, third or fourth quarter of 2018.

As of December 31, 2018, total unamortized compensation cost related to unvested PSUs was $1.2 million, which the Company expects to recognize over the remaining weighted-average period of 2.11 years.

A summary of the outstanding PSUs as of December 31, 2018 is as follows:

	Number of Shares (in thousands)	Grant Date Fair Value per Share	Weighted Average Remaining Life (in years)
Outstanding at December 31, 2017	—	—	—
Granted	425	$ 5.49	2.11
Forfeited	—	—	—
Vested	—	—	—
Outstanding at December 31, 2018	425	$ 5.49	2.11

NOTE 14 - Loss Per Share

Basic loss per share (“EPS”) is based on the weighted average number of common shares outstanding during the period. A reconciliation of the number of shares used for the basic EPS computation is as follows (*in thousands, except per share amounts*):

	Year Ended December 31, 2018
Numerator:	
Net loss attributed to common share holders	$ (16,636)
Denominator:	
Weighted average common shares outstanding - basic	33,573
Weighted average common shares outstanding - diluted	33,573
Net loss per common share:	
Basic	$ (0.50)
Diluted	$ (0.50)

The Company granted 2.1 million potentially dilutive RSAs, RSUs and PSUs as of the year ended December 31, 2018.

NOTE 15 - Selected Quarterly Financial Data

The following tables sets forth certain unaudited financial and operating information for each quarter in the years ended December 31, 2018, 2017 and 2016. The unaudited quarterly information includes all adjustments that, in the opinion of management, are necessary for the fair presentation of the information presented. Operating results for interim periods are not necessarily indicative of the results that may be expected for a full fiscal year.

	Year Ended December 31, 2018			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenue	$ 141,268	$ 152,536	$ 150,897	$ 159,653
Cost and Expenses:				
Direct operating Expenses	106,492	116,581	118,525	126,904
General and administrative expenses	29,917	22,500	22,540	22,323
Depreciation and amortization	11,078	11,155	12,033	12,417
Gain on disposition of assets, net	(106)	(594)	(629)	(1,046)
Operating (loss) income	(6,113)	2,894	(1,572)	(945)
Interest expense, net	(10,192)	(433)	(574)	(626)
(Loss) income before income taxes	(16,305)	2,461	(2,146)	(1,571)
Income tax (expense) benefit	(51)	(326)	(207)	(37)
Net (loss) income	(16,356)	2,135	(2,353)	(1,608)
Net loss attributable to Predecessor	(1,546)	—	—	—
Net (loss) income attributable to Quintana Energy Services Inc.	$ (14,810)	$ 2,135	$ (2,353)	$ (1,608)

	Year Ended December 31, 2017			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenue	$ 85,439	$ 108,457	$ 113,274	$ 130,863
Cost and Expenses:				
Direct operating Expenses	67,429	81,667	89,910	96,603
General and administrative expenses	17,150	16,025	18,613	18,068
Depreciation and amortization	11,594	11,432	11,238	11,423
Gain on disposition of assets, net	(1,657)	(332)	(310)	(340)
Operating (loss) income	(9,077)	(335)	(6,177)	5,109
Interest expense, net	(2,601)	(2,788)	(2,901)	(2,961)
Other income (expense), net	—	—	724	(58)
(Loss) income before income taxes	(11,678)	(3,123)	(8,354)	2,090
Income tax (expense) benefit	6	9	(84)	(22)
Net (loss) income	$ (11,672)	$ (3,114)	$ (8,438)	$ 2,068

	Year Ended December 31, 2016			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenue	$ 61,786	$ 40,771	$ 49,619	$ 58,252
Cost and Expenses:				
Direct operating Expenses	58,902	35,722	42,047	46,257
General and administrative expenses	20,673	17,387	16,502	19,038
Depreciation and amortization	21,269	18,603	19,565	19,224
Fixed asset impairment	—	—	—	1,380
Goodwill impairment	—	—	15,051	—
Loss (gain) on disposition of assets, net	(210)	(63)	53	5,595
Operating loss	(38,848)	(30,878)	(43,599)	(33,242)
Interest expense, net	(1,460)	(1,674)	(2,405)	(2,476)
Loss before income taxes	(40,308)	(32,552)	(46,004)	(35,718)
Income tax (expense) benefit	34	(81)	20	(140)
Net loss	$ (40,274)	$ (32,633)	$ (45,984)	$ (35,858)

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures that are designed to ensure that the information required to be disclosed by the Company in the reports that it files or submits under the Securities Exchange Act of 1934, as amended (the "Exchange Act") is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms and that such information is accumulated and communicated to management, including our principal executive officer and principal financial officer (who are our Chief Executive Officer and Chief Financial Officer, respectively) as appropriate to allow timely decisions regarding required disclosure. In designing and evaluating our disclosure controls and procedures, management recognized that disclosure controls and procedures can provide only reasonable, not absolute, assurance that the objectives of the disclosure controls and procedures are met.

In connection with the preparation of this Annual Report on Form 10-K for the year ended December 31, 2018, an evaluation was performed under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the Company's disclosure controls and procedures. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company's disclosure controls and procedures as defined in Rules 13a-15(c) and 15d-15(e) of the Exchange Act of were effective as of December 31, 2018 to provide reasonable assurance that information required to be disclosed by the Company in reports that it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms and (ii) accumulated and communicated to the Company's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f).

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2018 using the criteria established in *Internal Control- Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment and those criteria, management concluded that our internal control over financial reporting was effective at a reasonable assurance level as of December 31, 2018.

This Annual Report on Form 10-K does not include an attestation report of our independent registered public accounting firm regarding internal control over financial reporting due to a transition period established by the JOBS Act for emerging growth companies.

Changes in Internal Control over Financial Reporting

No changes in our internal control over financial reporting occurred during the quarter ended December 31, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated by reference to our definitive proxy statement for our 2019 Annual Meeting of Stockholders pursuant to Regulation 14A under the Exchange Act, which we expect to file with the SEC within 120 days after the close of the year ended December 31, 2018.

Item 11. Executive Compensation

The information required by this item is incorporated by reference to our definitive proxy statement for our 2019 Annual Meeting of Stockholders pursuant to Regulation 14A under the Exchange Act, which we expect to file with the SEC within 120 days after the close of the year ended December 31, 2018.

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

The information required by this item is incorporated by reference to our definitive proxy statement for our 2019 Annual Meeting of Stockholders pursuant to Regulation 14A under the Exchange Act, which we expect to file with the SEC within 120 days after the close of the year ended December 31, 2018.

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

The information required by this item is incorporated by reference to our definitive proxy statement for our 2019 Annual Meeting of Stockholders pursuant to Regulation 14A under the Exchange Act, which we expect to file with the SEC within 120 days after the close of the year ended December 31, 2018.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated by reference to our definitive proxy statement for our 2019 Annual Meeting of Stockholders pursuant to Regulation 14A under the Exchange Act, which we expect to file with the SEC within 120 days after the close of the year ended December 31, 2018.

Item 15. Exhibits and Financial Statement Schedules

Index to Exhibits

2.1†	Master Reorganization Agreement, dated as of February 8, 2018, by and among the Quintana Energy Services Inc., Quintana Energy Services LP, QES Holdco LLC and the other parties named therein (Incorporated by reference to Exhibit 2.1 of Quintana Energy Services Inc.'s Current Report on Form 8-K filed on February 14, 2018).
2.2†	Letter Agreement re: Reorganization Document Correction, dated November 5, 2018, between the Company and the entities party thereto (Incorporated by reference to Exhibit 2.1 of Quintana Energy Services, Inc.'s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2018).
3.1	Amended and Restated Certificate of Incorporation of Quintana Energy Services Inc. (Incorporated by reference to Exhibit 3.1 of Quintana Energy Services Inc.'s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2018).
3.2	Amended and Restated Bylaws of Quintana Energy Services Inc. (Incorporated by reference to Exhibit 3.3 of Quintana Energy Services Inc.'s Current Report on Form 8-K filed on February 14, 2018).
4.1	Second Amended and Restated Equity Rights Agreement, dated February 13, 2018, by and among Quintana Energy Services Inc. and the other parties named therein (Incorporated by reference to Exhibit 4.1 of Quintana Energy Services Inc.'s Current Report on Form 8-K filed on February 14, 2018).
4.2	Registration Rights Agreement, dated February 13, 2018, by and among Quintana Energy Services Inc. and the other parties named therein (Incorporated by reference to Exhibit 4.2 of Quintana Energy Services Inc.'s Current Report on Form 8-K filed on February 14, 2018).
10.1	Credit Agreement, dated as of September 9, 2014, among QES Holdco LLC, as Borrower, certain of the subsidiaries of Borrower party thereto, as Guarantors, the lenders from time to time party thereto, as Lenders, and Amegy Bank National Association, as Administrative Agent, Issuing Bank and Swing Line Lender (Incorporated by reference to Exhibit 10.1 of Quintana Energy Services Inc.'s Registration Statement on Form S-1 filed on August 9, 2017).
10.2	Assignment, Release, Consent and First Amendment to Credit Agreement, dated January 9, 2015, by and among Quintana Energy Services LP, as Borrower, certain subsidiaries of Borrower party thereto, as Guarantors, the lenders from time to time party thereto, as Lenders and ZA, N.A. DBA Amegy Bank, as Administrative Agent, Issuing Bank and Swing Line Lender (Incorporated by reference to Exhibit 10.2 of Quintana Energy Services Inc.'s Registration Statement on Form S-1 filed on August 9, 2017).
10.3	Second Amendment to Credit Agreement, dated December 31, 2015, by and among Quintana Energy Services LP, as Borrower, certain subsidiaries of Borrower party thereto, as Guarantors, the lenders from time to time party thereto, as Lenders and ZA, N.A. DBA Amegy Bank, as Administrative Agent, Issuing Bank and Swing Line Lender (Incorporated by reference to Exhibit 10.3 of Quintana Energy Services Inc.'s Registration Statement on Form S-1 filed on August 9, 2017).
10.4	Third Amendment and Waiver to Credit Agreement, dated December 19, 2016, by and among Quintana Energy Services LP, as Borrower, certain subsidiaries of Borrower party thereto, as Guarantors, the lenders from time to time party thereto, as Lenders and ZA, N.A. DBA Amegy Bank, as Administrative Agent, Issuing Bank and Swing Line Lender (Incorporated by reference to Exhibit 10.4 of Quintana Energy Services Inc.'s Form S-1 Registration Statement (File No. 333-219837) filed with the Commission on August 9, 2017).
10.5	Second Lien Credit Agreement, dated December 19, 2016, by and among Quintana Energy Services LP, as Borrower, certain subsidiaries of Borrower party thereto, as Guarantors, the lenders from time to time party thereto, as Lenders and Cortland Capital Market Services LLC, as Administrative Agent (Incorporated by reference to Exhibit 10.5 of Quintana Energy Services Inc.'s Form S-1 Registration Statement (File No. 333-219837) filed with the Commission on August 9, 2017).
10.6	Pledge Agreement, dated December 19, 2016, by and among Quintana Energy Services LP, as Borrower, certain subsidiaries of the Borrower party thereto, as Guarantors, and together with Borrower, the Pledgors, and Cortland Capital Market Services, LLC, as Administrative Agent (Incorporated by reference to Exhibit 10.6 of Quintana Energy Services Inc.'s Form S-1 Registration Statement (File No. 333-219837) filed with the Commission on August 9, 2017).
10.7	Warrant Agreement, dated December 19, 2016, by and among Quintana Energy Services LP, Archer Holdco LLC, Robertson QES Investment LLC and Geveran Investments Limited (Incorporated by reference to Exhibit 10.7 of Quintana Energy Services Inc. Form S-1 Registration Statement (File No. 333-219837) filed with the Commission on August 9, 2017).
10.8	Loan, Security and Guaranty Agreement, dated February 13, 2018, by and among Quintana Energy Services Inc., Quintana Energy Services LP, the various borrowers thereto, Bank of America, N.A., as agent, joint lead arranger and sole bookrunner, ZB, N.A. DBA Amegy Bank, as joint lead arranger, and Citibank, N.A., as joint lead arranger (Incorporated by reference to Exhibit 10.3 of Quintana Energy Services Inc.'s Current Report on Form 8-K filed on February 14, 2018).
10.9+	Quintana Energy Services Inc. 2018 Long Term Incentive Plan (Incorporated by reference to Exhibit 10.1 of Quintana Energy Services Inc.'s Current Report on Form 8-K filed on February 14, 2018).
10.10+	Quintana Energy Services Inc. Amended and Restated Long-Term Incentive Plan (also referred to as the QES Legacy Long-Term Incentive Plan) (Incorporated by reference to Exhibit 10.2 of Quintana Energy Services Inc.'s Current Report on Form 8-K filed on February 14, 2018).
10.11+	Form of Phantom Unit Agreement under the Quintana Energy Services Inc. Amended and Restated Long-Term Incentive Plan (Incorporated by reference to Exhibit 4.10 of Quintana Energy Services Inc.'s Registration Statement on Form S-8 filed on February 14, 2018).
10.12+	Form of Phantom Unit Agreement (Corporate Executives) under the Quintana Energy Services Inc. Amended and Restated Long-Term Incentive Plan (Incorporated by reference to Exhibit 4.11 of Quintana Energy Services Inc.'s Registration Statement on Form S-8 filed on February 14, 2018).
10.13+	Indemnification Agreement (D. Rogers Herndon) (Incorporated by reference to Exhibit 10.4 of Quintana Energy Services Inc.'s Current Report on Form 8-K filed on February 14, 2018).

10.14+	Indemnification Agreement (Christopher J. Baker) (Incorporated by reference to Exhibit 10.5 of Quintana Energy Services Inc.'s Current Report on Form 8-K filed on February 14, 2018).
10.15+	Indemnification Agreement (Keefer M. Lehner) (Incorporated by reference to Exhibit 10.6 of Quintana Energy Services Inc.'s Current Report on Form 8-K filed on February 14, 2018).
10.16+	Indemnification Agreement (Max L. Bouthillette) (Incorporated by reference to Exhibit 10.7 of Quintana Energy Services Inc.'s Current Report on Form 8-K filed on February 14, 2018).
10.17+	Indemnification Agreement (Dag Skindlo) (Incorporated by reference to Exhibit 10.8 of Quintana Energy Services Inc.'s Current Report on Form 8-K filed on February 14, 2018).
10.18+	Indemnification Agreement (Gunnar Eliassen) (Incorporated by reference to Exhibit 10.9 of Quintana Energy Services Inc.'s Current Report on Form 8-K filed on February 14, 2018).
10.19+	Indemnification Agreement (Rocky L. Duckworth) (Incorporated by reference to Exhibit 10.10 of Quintana Energy Services Inc.'s Current Report on Form 8-K filed on February 14, 2018).
10.20+	Indemnification Agreement (Dalton Boutté, Jr.) (Incorporated by reference to Exhibit 10.11 of Quintana Energy Services Inc.'s Current Report on Form 8-K filed on February 14, 2018).
10.21+	Indemnification Agreement (Corbin J. Robertson, Jr.) (Incorporated by reference to Exhibit 10.12 of Quintana Energy Services Inc.'s Current Report on Form 8-K filed on February 14, 2018).
10.22†**	Indemnification Agreement (Bobby S. Shackouls)
10.23+	Executive Employment Agreement, dated July 1, 2017, by and between Quintana Energy Services Inc. and Rogers Herndon (Incorporated by reference to Exhibit 10.14 of Quintana Energy Services Inc.'s Form S-1 Registration Statement (File No. 333-219837) filed with the Commission on August 9, 2017).
10.24+	Executive Employment Agreement, dated July 1, 2017, by and between Quintana Energy Services Inc. and Christopher Baker (Incorporated by reference to Exhibit 10.15 of Quintana Energy Services Inc.'s Form S-1 Registration Statement (File No. 333-219837) filed with the Commission on August 9, 2017).
10.25+	Executive Employment Agreement, dated July 1, 2017, by and between Quintana Energy Services Inc. and Keefer M. Lehner (Incorporated by reference to Exhibit 10.16 of Quintana Energy Services Inc.'s Form S-1 Registration Statement (File No. 333-219837) filed with the Commission on August 9, 2017).
10.26†*	Form of Performance Share Unit Agreement (Executive Officers - 2018 Form) under the Quintana Energy Services Inc. 2018 Long-Term Incentive Plan.
10.27†*	Form of Performance Share Unit Agreement (Employees - 2018 Form) under the Quintana Energy Services Inc. 2018 Long-Term Incentive Plan.
10.28†*	Form of Performance Share Unit Agreement (Executive Officers - 2019 Form) under the Quintana Energy Services Inc. 2018 Long-Term Incentive Plan.
10.29†*	Form of Restricted Stock Unit Agreement (Executive Officers) under the Quintana Energy Services Inc. 2018 Long-Term Incentive Plan.
10.30†*	Form of Restricted Stock Unit Agreement (Employees) under the Quintana Energy Services Inc. 2018 Long-Term Incentive Plan.
10.31†*	Form of Restricted Stock Unit Agreement (Directors) under the Quintana Energy Services Inc. 2018 Long-Term Incentive Plan.
21.1	List of Subsidiaries of Quintana Energy Services Inc. (Incorporated by reference to Exhibit 21.1 of Quintana Energy Services Inc.'s Annual Report on Form 10-K for the fiscal year ended December 31, 2017).
23.1**	Consent of PricewaterhouseCoopers LLP
31.1*	Certification of Principal Executive Officer Pursuant to Rules 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Principal Financial Officer Pursuant to Rules 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.

** Furnished herewith.

† The schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K and will be provided to the Securities and Exchange Commission upon request.

\+ Management contract or compensatory plan or arrangement

Item 16. Form 10-K Summary

None.

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.

QUINTANA ENERGY SERVICES INC.

By: /s/ D. Rogers Herndon

D. Rogers Herndon

President, Chief Executive Officer and Director

Date: March 7, 2019

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 indicated on March 7, 2019.

Signature	Title
/s/ D. Rogers Herndon D. Rogers Herndon	President, Chief Executive Officer, and Director (Principal Executive Officer)
/s/ Keefer M. Lehner Keefer M. Lehner	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ Geoffrey C. Stanford Geoffrey C. Stanford	Vice President and Chief Accounting Officer (Principal Accounting Officer)
/s/ Corbin J. Robertson, Jr. Corbin J. Robertson, Jr.	Chairman of the Board of Directors
/s/ Dalton Boutté, Jr. Dalton Boutté, Jr.	Director and Chairman of the Compensation Committee
/s/ Rocky L. Duckworth Rocky L. Duckworth	Director and Chairman of the Audit Committee
/s/ Gunnar Eliassen Gunnar Eliassen	Director
/s/ Bobby S. Shackouls Bobby S. Shackouls	Director
/s/ Dag Skindlo Dag Skindlo	Director