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, 2017

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
(Address of principal executive offices)

(832) 518-4094
(Registrant's telephone number, including area code)

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

Indicate by check mark 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	☒	(Do not check if a smaller reporting company)	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 Company was not a public company as of the last business day of its most recently completed second quarter and therefore cannot calculate the aggregate market value of its voting and non-voting common equity held by non-affiliates at such date.

The number of shares of the registrant's common stock, par value $0.01 per share, outstanding at March 27, 2018, was 33,630,934.

DOCUMENTS INCORPORATED BY REFERENCE: NONE

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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, 2017 (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 Credit 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 Credit Facility, please see “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Our New Credit Facility.”

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 prospectus supplement 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.

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.

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.

Mcf. Thousand cubic feet of natural gas.

MMBtu. Million British Thermal Units.

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.

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”), 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. See “Certain Relationships and Related Transactions, and Director Independence—Master Reorganization Agreement.” We are a growth-oriented provider of diversified oilfield services to leading onshore oil and natural gas E&P companies operating in both conventional and unconventional plays in all of the active major basins throughout the United States. The following business segments comprise our primary services: (1) directional drilling services, (2) pressure pumping services, (3) pressure control services and (4) wireline services. Our directional drilling services enable efficient drilling and guidance of the horizontal section of a wellbore using our technologically-advanced fleet of downhole motors and 117 measurement while-drilling (“MWD”) kits. Our pressure pumping services include hydraulic fracturing, cementing and acidizing services, and such services are supported by a high-quality pressure pumping fleet of 245,925 hydraulic horsepower (“HHP”) as of December 31, 2017. Our primary pressure pumping focus is on large hydraulic fracturing jobs. Our pressure control services provide various forms of well control, form completions and workover applications through our 23 coiled tubing units, 36 rig-assisted snubbing units and ancillary equipment. As of December 31, 2017, our wireline services included 49 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 800 customers as of December 31, 2017. We have cultivated and maintain strong relationships with our E&P company customers, including leading companies such as EOG Resources, Pioneer Natural Resources Company, XTO Energy Inc., Parsley Energy Inc., Seneca Energy, LLC and Matador Resources Co.

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”) U.S. land rig count has increased from 374 rigs on May 27, 2016 to 979 rigs as of March 23, 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. Our revenue has increased each quarter from the quarter ended June 30, 2016 through the quarter ended December 31, 2017. From the second quarter of 2016 through the fourth quarter of 2017, our directional drilling services business 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 166.5%, while day rates have improved from the lows we experienced during the second quarter of 2016. Moreover, through the downturn, we have steadily increased our market share in our directional drilling business services segment. We reactivated our second and third pressure pumping fleets in February and October 2017, respectively, and our frac utilization is approaching full utilization for our active fleets. In addition, in January 2018 we placed initial orders for twelve incremental frac pumps and ancillary equipment to redeploy our fourth pressure pumping fleet. Utilization of our pressure control and wireline assets has also continued to improve since the second quarter of 2016.

We used the downturn as an opportunity 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 business segments: (1) directional drilling services, (2) pressure pumping services, (3) pressure control services and (4) wireline services. We describe each of these segments below.

Directional Drilling Services

Our directional drilling services business segment provides the highly-technical and essential services of guiding horizontal and directional drilling operations for E&P companies. Directional drilling services enable E&P companies to drill horizontal wells that offer greater exposure to targeted reservoir horizons than vertical wells, and have become the standard means for drilling unconventional wells. According to Baker Hughes, 87% of all active rigs operating in the United States during the week ended March 23, 2018, were drilling horizontal wells, as compared to only 27% of active rigs as of ten years ago as of the same date. As of the quarter ended December 31, 2017, approximately 96% 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, and in some cases, multiple years. With increasing use of pad drilling and reactivation of rigs, through the fourth quarter of 2017 we have increased the number of “follow-me rigs” from approximately 30 in the first quarter of 2016 to 55 as of December 31, 2017. Furthermore, increases in rig efficiency and multi-well pad drilling favor our directional drilling services business segment, which is now able to complete more jobs per year.

Our directional drilling services business segment is one of the largest independent providers of domestic onshore directional drilling services. We offer a complete package of premium drilling services, including directional drilling, horizontal drilling, underbalanced drilling, MWD, rental tools and pipe inspection services. Our equipment package also includes various technologies, including our positive pulse MWD navigational tool asset fleet, mud motors and ancillary downhole tools, as well as third-party electromagnetic navigational systems. These technologies, coupled with our services and experienced and specialized personnel, allow our customers to drill wellbores to specific target zones within narrow location parameters. Our personnel are involved in all aspects of a well, from the initial planning of a customer’s drilling program to the management and execution of the horizontal or directional drilling operations. Our directional drilling team will remain on location 24 hours per day and oversee all drilling operations, both of the vertical and lateral wellbore, until completion. In addition, our remote monitoring capabilities allow our supervisory personnel to continuously monitor the progress of each directional drilling job across multiple drilling locations. Our directional drilling services are supported by our 30,000 square foot facility in Willis, Texas that allows us to manufacture downhole motors and perform a majority of our machining, repair and testing of our directional drilling equipment in-house. We believe our vertically integrated operations, from our in-house manufacturing and repair facilities to trucking and logistics capabilities, provide operational flexibility valued by our customers and represent a competitive advantage.

We provide directional drilling 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.

We also provide a suite of integrated and related services, including downhole rental tools and third-party inspection services of drill pipe and downhole tools. The demand for these services is primarily influenced by customer drilling-related activity levels. We introduced these tool rental and inspection services in 2008 in response to customer demand and increasing third-party costs relating to tool inspections. Our tool rental and inspection business is complementary to the other services we offer and provides us with opportunities to offer our other services in addressing the drilling needs of our customers.

Pressure Pumping Services

We are a leading provider of pressure pumping services in the Mid-Continent region, primarily in our capacity as a provider of hydraulic fracturing services to E&P companies. Pressure pumping services are intended to optimize hydrocarbon flow paths during the completion phase of horizontal wells. We focus on providing services for larger frac jobs, but have the capability to provide a customized range of frac 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’ frac 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. For example, our strong operational performance is demonstrated by an exclusive contract for our third unconventional frac spread with a leading independent operator for approximately 12 months of dedicated work in the Mid-Continent region that commenced in October 2017. In addition, in January 2018, we placed initial orders for twelve incremental frac pumps and ancillary equipment to redeploy our fourth frac spread. The fourth frac spread will consist of new equipment as well as refurbished and ancillary equipment from our existing inventory.

As of December 31, 2017, our pressure pumping fleet had a capacity of 245,925 HHP, of which 218,900 HHP was dedicated to hydraulic fracturing, 14,525 HHP was dedicated to cementing and 12,500 HHP was dedicated to acidizing. As of December 31, 2017, we had 206,925 total deployed HHP, 179,900 of which was deployed to hydraulic fracturing. Of our total deployed HHP dedicated to hydraulic fracturing, approximately 93% is dedicated to unconventional hydraulic fracturing services in the Mid-Continent, approximately 5% is dedicated to hydraulic fracturing services in the Rockies, and approximately 2% is dedicated to vertical fracturing services. We have successfully grown our pressure pumping services business segment through organic growth and acquisitions. From January 1, 2007 to December 31, 2017, we have increased our total fleet from 15,450 HHP to 245,925 HHP, and in January 2018 we placed initial orders for twelve incremental pumps and ancillary equipment to redeploy our fourth pressure pumping fleet. Additionally, in early September 2017, we entered into a contract to reactivate our third unconventional frac spread in the Mid-Continent region and operations commenced in October 2017.

We have historically focused our operations in this business segment in the Mid-Continent region (including the SCOOP/STACK) and Rocky Mountain region (including the Williston Basin), with an additional presence in the Permian Basin, and believe that we are well-positioned in these regions given demand for our services continues to improve.

We believe our high-quality active pressure pumping assets, with the majority of our pressure pumping equipment built within the last five years, allows us to provide reliable services to our customers. Our pressure pumping fleet operates out of two facilities in Oklahoma, a 41,475 square foot facility in Ponca City and a 43,510 square foot facility in Union City. Through our Oklahoma City pressure control facility, we have the in-house ability to retrofit and perform maintenance on our frac pumps and blenders, allowing us to better preserve our pressure pumping equipment at a lower cost versus outsourcing to third parties. In addition, we have multi-year proppant supply contracts for approximately 167,000 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.

We also provide cementing services, including surface- and intermediate-casing and long-string cementing capabilities, as well as a full range of acid stimulation services, including CO2 foamed acid stimulation, in all of the basins in which our pressure pumping services operate.

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.

Pressure Control Services

Our pressure control services business segment consists of coiled tubing, rig-assisted snubbing, nitrogen, fluid pumping and well control services. These services provide essential support for drilling, completion and workover activities in unconventional resource plays. Our pressure control services have the ability to operate under high pressure without delay or production halts for a well that is under pressure. Ceasing or suppressing production during the completion phase of an unconventional well could result in formation damage impacting the overall recovery of reserves and ultimately resulting in reduced returns for our E&P customers. Our pressure control services help E&P companies minimize the risk of such damage during completion activities. As of December 31, 2017, we provided our pressure control services through our fleet of 23 coiled tubing units (greater than 82% of which have two-inch or larger diameter coil, allowing us to service extended reach laterals), 36 rig-assisted snubbing units and 24 nitrogen pumping units. We have an additional large-diameter capacity unit on order, with delivery expected in the second quarter of 2018, and are anticipating adding an additional large-diameter capacity unit later in 2018. We provide our pressure control services 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).

Our coiled tubing units are used in the provision of well-servicing and workover applications, or in support of unconventional completions. 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. Our fluid pumping units are used primarily in the support of our coiled tubing intervention activities.

We also offer highly-technical and specialized well control services, which are typically required in response to emergencies at the well, particularly fires and blowouts. Our team is comprised of oilfield services veterans with extensive domestic and international experience in well control operations dating back to the 1980s.

We have in-house manufacturing and repair capabilities through our 120,000 square foot facility in Oklahoma City, Oklahoma that differentiates us and provides us with the ability to create customized solutions and make efficient repairs. These capabilities provide us the flexibility to customize coiled tubing and rig-assisted snubbing equipment, which has led to improved safety designs, decreased rig-up time and overall efficiency.

Wireline Services

Our wireline services business segment principally provides “plug-and-perf” services to enable hydraulic fracturing of new and existing wells. We increase efficiencies for customers by reducing downtime between each hydraulic fracturing process, which leads to more completed stages per day and fewer days required to complete each well. The industry-preferred “plug-and-perf” method leads to better productivity of Shale wells over other methods. Additionally, we provide logging services, including industrial logging services, for cavern, storage and injection wells, and have exclusive leases to operate Archer’s POINT® proprietary detection system and the SPACE® imaging and measurement platform in the U.S. land market. The POINT® system includes seven powerful diagnostic programs that enable a proactive and systematic approach to managing well integrity. The SPACE® imaging and measurement platform utilizes ground breaking ultrasonic techniques to enable true spatial understanding of the downhole environment. A multi-element transducer, operated as a phased array, and advanced signal and image processing algorithms combine to produce high resolution 2D and 3D rendered images. Production logging, casing evaluation, perforating, mechanical services and pipe recovery round out our offering.

We established our wireline services business segment in 2014 to enter the horizontal “plug-and-perf” market which was highly complementary to our pressure pumping services. We hired experienced management personnel and ordered new, custom built, cased-hole wireline trucks and equipment. In December 2015, the acquisition of the U.S. pressure pumping, directional drilling, wireline and pressure control services businesses (the “Archer Acquisition”) from Archer Well Company Inc. (“Archer”) significantly expanded our fleet and brought additional service offerings.

As of December 31, 2017, we operated 49 wireline units, 21 of which are suited for unconventional activity, and operated from eight 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, 8 units are available to deploy as conditions warrant. We offer our wireline services in all markets in which we provide pressure pumping services. From January 2016 to December 2017, we have completed approximately 14,900 stages in the United States with a run efficiency of approximately 98.5%.

For disclosures regarding segment financial information, see Part II, Item 8, Note 14 of this Annual Report.

Geographic Areas of Operation

Our directional drilling services business 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 services business 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) and the Permian Basin. Our pressure control services business 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 services business segment provides services throughout the Permian Basin, Eagle Ford Shale and Mid-Continent region (including the SCOOP/STACK), Haynesville Shale and the DJ/Powder River Basin. 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 oil and natural gas E&P companies. We served approximately 800 customers in 2017. For the year ended December 31, 2017, EOG Resources accounted for approximately 10.3% of the Company's consolidated revenues. For the years ended December 31, 2016 and 2015, no customer individually accounted for more than 10% of our consolidated revenues. If we were to lose any material customer, we believe that in the current market environment we would be able to redeploy our equipment with limited downtime. However, 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 Sperry Drilling Services Inc., Baker Hughes, Scientific Drilling International, Inc., Patterson-UTI Energy, Inc., LEAM Drilling Systems, LLC and Nabors Industries Ltd. Our major competitors for pressure pumping include Halliburton Company, FTS International, Inc., C&J Energy Services, Inc., Keane Group, Inc., Basic Energy Services, Inc. and RPC, Inc. Our major competitors in our pressure control business services segment include Halliburton Company, C&J Energy Services, Inc., Red Zone Coil Tubing LLC, Nine Energy Service, Inc. and RPC, Inc. Our major competitors in wireline services include Baker Hughes, C&J Energy Services, Inc., Nine Energy Service, Inc. and Allied-Horizontal Wireline Services, LLC.

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 167,000 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

In connection with our wireline services business segment, we have exclusive leases to operate Archer's POINT® proprietary detection system and the SPACE® imaging and measurement platform in the U.S. land market. The agreements that govern our operation of the POINT® and SPACE® technology prohibit Archer from providing such technology to any third parties for use in the U.S. land market during the term of such agreements. The POINT® system includes diagnostic programs that enable a systematic approach to managing well integrity. The SPACE® imaging and measurement platform utilizes ultrasonic techniques to enable spatial understanding of the downhole environment. A multi-element transducer, operated as a phased array, and advanced signal and image processing algorithms combine to produce high resolution 2D and 3D rendered images.

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, 2017, we had approximately 1,324 full time employees and overall personnel count increased approximately 33.7% from the year ended December 31, 2016. None of our employees are represented by labor unions or covered by any collective bargaining agreements. We also hire independent contractors and consultants involved in land, technical, regulatory and other disciplines to assist our full time employees.

Safety and Remediation Program

In the oilfield services industry, an important competitive factor in establishing and maintaining long term oil and natural gas 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 business 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. Further, as part of our safety program and remediation procedures, we check fluid lines for any defects on a periodic basis to avoid line failure during hydraulic fracturing operations, marking such fluid lines to reflect the most recent testing date. We also regularly monitor pressure levels in the fluid lines used for fracturing and the surface casing to verify that the pressure and flow rates are consistent with the job specific model in an effort to avoid failure. 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.

As warranted, we have used a third-party contractor to provide remediation and spill response services when necessary to address spills that were beyond our containment capabilities. None of these prior spills were significant, and we have not experienced any significant incidents, citations or legal proceeding relating to our hydraulic fracturing services for environmental concerns. To the extent our hydraulic fracturing or other oilfield services operations result in a future spill, leak or other environmental impact that is beyond our ability to contain, we intend to engage the services of such remediation company or an alternative company, as required, 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 which 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 frac 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 delays 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 changes in environmental laws and regulations or reinterpretation of enforcement policies 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 damage to property, natural resources or persons. 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 or restrictions 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 stringent requirements. 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 lawsuit filed by several non-governmental environmental groups against the EPA for the agency's failure to timely assess its RCRA Subtitle D criteria regulations for oil and natural gas wastes, the EPA and the environmental groups entered into an agreement that was finalized in a Consent Decree issued by the U.S. District Court for the District of Columbia on December 28, 2016. Under the decree, the EPA is required to propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D criteria regulations pertaining to oil and natural gas wastes or sign a determination that revision of the regulations is not necessary. 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 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, was 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 June 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, and the rule was stayed nationwide by the U.S. Sixth Circuit Court of Appeals in October 2015, pending resolution of the court challenges. In January 2017, the U.S. Supreme Court accepted review of the rule to determine whether jurisdiction rested with the federal district or appellate courts and, in a decision issued on January 22, 2018, held that legal challenges of the rule must be heard at the district rather than appellate court level. Additionally, following the issuance of a presidential executive order to review the rule, the EPA and Corps proposed a rule in June 2017 to repeal the 2015 rule. The EPA and Corps also announced their intent to issue a new rule defining the Clean Water Act's jurisdiction. On February 6, 2018, the EPA and Corps published a final rule specifying that the contested June 2015 rule would not take effect until February 6, 2020. As a result, future implementation of the June 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 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. When caused by human activity, such events are called induced seismicity. 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 March 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, as has occurred in Oklahoma. More recently, in December 2016, the Oklahoma Corporation Commission's ("OCC") 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 addition, in February 2017, the OCC's Oil and Gas Conservation Division issued an order 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, and imposed further restrictions in the Edmonds area of the state in August 2017. 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. Some 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 October 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. The EPA published a final rule in November 2017 that issued area designations with respect to ground-level ozone for approximately 85% of the U.S. counties as either "attainment/unclassifiable" or "unclassifiable" and is expected to issue attainment or non-attainment designations for the remaining areas of the United States not addressed in the November 2017 final rule in the first half of 2018. 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 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 on an annual basis. In October 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 June 2016 establishing Subpart OOOOa standards for methane emissions. However, in June 2017, the EPA published a proposed rule to stay certain portions of these Subpart OOOOa standards for two years and reconsider the entirety of the 2016 standards but the agency has not yet published a final rule and, as a result, the 2016 standards are currently in effect but future implementation of the 2016 standards is uncertain at this time. Furthermore, in November 2016, the federal Bureau of Land Management ("BLM") published a final rule that established, among other things, requirements to reduce methane emissions arising from venting, flaring and leaks from oil and natural gas production activities on onshore federal and Native American lands. However, in December 2017, the BLM published a final rule to temporarily suspend or delay certain requirements contained in the November 2016 final rule until January 17, 2019, including those requirements relating to the venting, flaring and leakage from oil and natural gas production activities. The suspension of the November 2016 final rule is being challenged in court. Given the long-term trend towards increasing regulation, future federal GHG regulations of the oil and natural gas industry remain a possibility, and should the EPA's June 2016 or the BLM's November 2016 rules remain in effect, or 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 delays or curtailment in such operations, which costs, delays or curtailment could adversely affect our business.

In December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France that prepared an agreement requiring member countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals, every five years beginning in 2020. This "Paris Agreement" was signed by the United States in April 2016 and entered in force in November 2016; however, this agreement does not create any binding obligations for nations to limit their GHG emissions, but rather includes pledges to voluntarily limit or reduce future emissions. 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, which would result in an effective exit date of November 2020. 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.

Finally, it should be noted that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our operations.

Endangered Species. The 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 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 pursuant to the U.S. Safe Drinking Water Act ("SDWA") over certain hydraulic fracturing activities involving the use of diesel fuel and issued permitting guidance that applies to such activities. Additionally, the EPA issued final CAA regulations in 2012 and in June 2016 governing performance standards, including standards for the capture of emissions of methane and volatile organic compounds ("VOCs") released during hydraulic fracturing; published in June 2016 an effluent limit guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants; and published in May 2014 an Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the BLM finalized rules in March 2015 that imposed new or more stringent standards for performing hydraulic fracturing on federal and Native American lands. In June 2016, a Wyoming federal judge struck down this final rule, finding that the BLM lacked authority to promulgate the rule. The BLM appealed the decision to the U.S. Circuit Court of Appeals for the Tenth Circuit in 2016. The appellate court issued a ruling in September 2017 to vacate the Wyoming trial court decision and dismiss the lawsuit challenging the 2015 rule in response to the BLM's issuance of a proposed rulemaking to rescind the 2015 rule and, in December 2017, the BLM published a final rule rescinding the March 2015 rule. In January 2018, litigation challenging the BLM's rescission of the 2015 rule was brought in federal court.

Also, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources "under some circumstances," noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits.

In addition, 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. If new federal, state or local laws or regulations 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, 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 delays 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 delays, any of which developments could have a material adverse effect on our business, financial condition and results of operations.

OSHA Matters

We are also subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes that regulate the protection of the health and safety of workers. Such requirements may include general industry standards, recordkeeping requirements and monitoring of occupational exposure to regulated substances. In addition, the OSHA hazard communication standard requires 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. Historically, our worker health and safety 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.

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 website 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 (the "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 in 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 on Form 10-K.

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. In addition, certain of our customers could become 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; and
- 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 four years, the posted West Texas Intermediate Spot Oil Price (“WTI”) price for oil has ranged from a low of $26.21 per Bbl in February 2016 to a high of $107.26 per Bbl in June 2014. During 2016, WTI prices ranged from $26.21 to $54.06 per Bbl. In June 2017, WTI prices fell below $43.00 per Bbl but had risen to $60.42 per Bbl by the end of 2017. 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 2015 we had a net loss of $59.0 million, in 2016 we had a net loss of $154.7 million and in 2017, we had a net loss of $21.2 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 Credit 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 Credit Facility,” borrowing $13.0 million. The operating and financial restrictions and covenants in our New Credit Facility and any future financing agreements restrict our ability to finance future operations or capital needs or to expand or pursue our business activities. For example, our New Credit 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 Credit 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 Credit 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 Credit Facility could result in an event of default, which may cause indebtedness under our New Credit Facility to become immediately due and payable, and our lenders’ 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 Credit Facility or any new indebtedness could have similar or more restrictive covenants and conditions. For more information about our New Credit Facility, please see “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Our New Credit 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 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 167,000 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.

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 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. When caused by human activity, such events are called induced seismicity. 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 March 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. The Texas Railroad Commission adopted similar rules. More recently, in December 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 addition, in February 2017, the OCC's Oil and Gas Conservation Division issued an order 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 and imposed further reductions in the Edmond area in August 2017. 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.

Currently, hydraulic fracturing is generally exempt from regulation under the SDWA's Underground Injection Control ("UIC") program and is typically regulated by state oil and gas commissions or similar agencies.

However, several federal agencies have asserted regulatory authority over certain 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. In addition, 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 and, in May 2014, published an Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the BLM published a final rule in March 2015 that established new or more stringent standards relating to hydraulic fracturing on federal and Native American lands. However, a Wyoming federal judge struck down this March 2015 final rule in June 2016, finding that the BLM lacked authority to promulgate the rule. The BLM appealed the decision in July 2016 and the appellate court issued a ruling in September 2017 to vacate the Wyoming trial court decision and dismiss the lawsuit challenging the 2015 rule in response to the BLM's issuance of a proposed rule-making to rescind the 2015. On December 29, 2017, the BLM published a final rule rescinding the March 2015 rule. In January 2018, litigation challenging the BLM's rescission of the 2015 rule was brought in federal court. 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 delays or curtailment 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.

In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources "under some circumstances," noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits.

Furthermore, certain interest groups in Colorado opposed to oil and natural gas development generally, and hydraulic fracturing in particular, have from time to time advanced various options for ballot initiatives that, if approved, would allow revisions to the state constitution in a manner that would make such E&P activities in the state more difficult in the future. However, during the November 2016 voting process, voters passed an amendment to the state constitution making it relatively more difficult to place an initiative on the state ballot. As a result, there are more stringent procedures in place for placing an initiative on a state ballot.

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 or regulation could also lead to operational delays 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 the implementation of regulations 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 greenhouse gas 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 delays 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. 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. Changes in existing laws or regulations, or the adoption of new laws or regulations, could delay or curtail 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 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 delays 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 delays, 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. In March 2016, the OSHA amended its legal requirements, publishing a final rule that established a more stringent permissible exposure to respirable crystalline silica and provided other provisions to protect employees. This final rule became effective in June 2016 and will require compliance with the most applicable requirements in June 2018. Several industry groups had filed suit in the federal Court of Appeals for the D.C. Circuit to halt implementation of the rule, but on December 22, 2017, the court dismissed the challenges to the rule. Historically, our environmental employee costs with respect to existing crystalline silica requirements have not had a material adverse effect on our results of operations; however, federal and state regulatory authorities, including OSHA, 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 recent 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 June 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, and the rule was stayed nationwide by the U.S. Sixth Circuit Court of Appeals in October 2015, pending resolution of the court challenges. In January 2017, the U.S. Supreme Court accepted review of the rule to determine whether jurisdiction rested with the federal district or appellate courts and, in a decision issued on January 22, 2018, held that legal challenges of the rule must be heard at the district rather than appellate court level, Additionally, following the issuance of a presidential executive order to review the rule, the EPA and Corps proposed a rule in June 2017 to repeal the 2015 rule. The EPA and Corps also announced their intent to issue a new rule defining the Clean Water Act's jurisdiction. On February 6, 2018, the EPA and Corps published a final rule specifying that the contested June 2015 rule would not take effect until February 6, 2020. As a result, future implementation of the June 2015 rule is uncertain at this time. Also, in June 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 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 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.

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 and Chief Compliance 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. Though our historical turnover rates have been significantly lower than those of our competitors, 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.

New technology may hurt our competitive position.

The oilfield services industry is subject to the introduction of new completion techniques and services using new technologies, some of which may be subject to patent protection. 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 a competitive disadvantage. Further, we may face competitive pressure to implement or acquire certain new technologies at a substantial cost. Some of our competitors 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 products at all, on a timely basis or at an acceptable cost. 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.

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. In addition, 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 June 2016, the EPA published NSPS, known as Subpart OOOOa, that 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 OOOO, by using certain equipment-specific emissions control practices. However, in June 2017, the EPA published a proposed rule to stay certain portions of these Subpart OOOOa standards for two years and reconsider the entirety of the 2016 standards but has not yet published a final rule and, as a result, the 2016 standards are currently in effect but future implementation of the 2016 standards is uncertain at this time. Furthermore, in November 2016, the BLM published a final rule that established, among other things, requirements to reduce methane emissions arising from venting, flaring and leaks from oil and natural gas production activities on onshore federal and Native American lands. However, in December 2017, the BLM published a final rule to temporarily suspend or delay certain requirements contained in the November 2016 final rule until January 17, 2019, including those requirements relating to the venting, flaring and leakage from oil and natural gas production activities. The suspension of the November 2016 final rule is being challenged in court. Additionally, in December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France that prepared an agreement requiring member countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. This "Paris Agreement" was signed by the United States in April 2016 and entered in force in November 2016; however, this agreement does not create any binding obligations for nations to limit their GHG emissions, but rather includes pledges to voluntarily limit or reduce future emissions. 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, which would result in an effective exit date of November 2020. 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 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 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 business 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, cyber-attacks 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 any 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. 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 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 year ended December 31, 2017. For the year ended December 31, 2016 the Company recognized $1.4 million in impairment expenses related to write-downs of assets held for sale.

Risks Related to our Common Stock

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 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.

Furthermore, while we generally must comply with Section 404 of Sarbanes-Oxley for our fiscal year ending December 31, 2018, we are not required to have our independent registered public accounting firm attest to the effectiveness of our internal controls until our first annual report subsequent to our ceasing to be an "emerging growth company" within the meaning of Section 2(a)(19) of the Securities Act. Accordingly, we may not be required to have our independent registered public accounting firm attest to the effectiveness of our internal controls until as late as our annual report for the fiscal year ending December 31, 2023. Once it is required to do so, our independent registered public accounting firm may issue a report that is adverse in the event it is not satisfied with the level at which our controls are documented, designed, operated or reviewed. Compliance with these requirements 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.

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. We are currently evaluating these rules, and we cannot predict or estimate the amount of additional costs we may incur or the timing of such costs.

If we fail to remediate material weaknesses in our internal control over financial reporting, or experience any additional material weaknesses in the future or otherwise fail to develop or maintain an effective system of internal controls in the future, we may not be able to accurately report our financial condition or results of operations which may adversely affect investor confidence in us and, as a result, the value of our common stock.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. As a result of being a public company, we will be required, under Section 404 of Sarbanes-Oxley to furnish a report by management on, among other things, the effectiveness of our internal control over financial reporting beginning with our Annual Report on Form 10-K for the year ending December 31, 2018. This assessment will need to include disclosure of any material weaknesses identified by our management in our internal control over financial reporting. A material weakness is a deficiency or combination of deficiencies in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual and interim financial statements will not be detected or prevented on a timely basis.

We have identified material weaknesses in our internal control over financial reporting and may identify additional material weaknesses in the future or otherwise fail to maintain an effective system of internal controls, which may result in material misstatements of our financial statements or cause us to fail to meet our periodic reporting obligations.

As a public company, we will be required to maintain internal control over financial reporting and to report any material weaknesses in those internal controls, subject to any exemptions that we avail ourselves to under the Jumpstart Our Business Startups Act of 2012 (the “JOBS Act”). For example, we will be required to 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. We are in the process of designing, implementing, and testing internal control over financial reporting required to comply with this obligation. We and our independent registered public accounting firm have identified material weaknesses in internal control over financial reporting as of December 31, 2017. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis. To facilitate the ongoing maintenance and period end closing of the Company books, at certain QES entities, certain individuals are not prevented from both initiating and recording (“creating and posting”) journal entries into the general ledger without proper monitoring or manual approval of the journal entries. Additionally, within two of the QES entities’ accounting systems, members of management have access to and use a ‘super user’ account without monitoring, which grants users significant conflicting capabilities and does not allow for tracking of the user’s activities. Therefore, individuals have the ability to record and/or alter entries within the Company’s general ledger without appropriate review, leading to a reasonable possibility of a material misstatement of the financial statements. Additionally, these material weaknesses could result in misstatements to our financial statements or disclosures that would result in material misstatements to our annual or interim consolidated financial statements that would not be prevented or detected. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our common stock.

We are enhancing our internal controls, processes and related documentation necessary to remediate our material weakness and to perform the evaluation needed to comply with Section 404. We may not be able to complete our remediation, evaluation and testing in a timely fashion. During the evaluation and testing process, if we identify one or more material weaknesses in our internal control over financial reporting, such as the one we identified as described above, we will be unable to conclude that our internal controls are effective. The effectiveness of our controls and procedures may be limited by a variety of factors, including:

- faulty human judgment and simple errors, omissions or mistakes;
- fraudulent action of an individual or collusion of two or more people;
- inappropriate management override of procedures; and
- the possibility that any enhancements to controls and procedures may still not be adequate to assure timely and accurate financial control.

When we cease to be an “emerging growth company” under the federal securities laws, our registered public accounting firm will be required to express an opinion on the effectiveness of our internal controls. If we are unable to confirm that our internal control over financial reporting is effective, or if our registered public accounting firm are unable to express an opinion on the effectiveness of our internal controls, we could lose investor confidence in the accuracy and completeness of our financial reports, which could cause the price of our common stock to decline.

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, 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 76.3% of our voting stock as of March 27, 2018. 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. Due to the Equity Rights Agreement, the Principal Stockholders are also be 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 and its affiliates are not limited in their ability to compete with us, Archer and its affiliates will not be limited in their ability to compete with us in the future, 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.

Although pursuant to the Archer Acquisition, Archer agreed to certain limited noncompetition provisions relating to the businesses we acquired for a period of up to three years (depending on the type of competitive activity), 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, after the expiration of Archer's contractual noncompetition agreements, 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 Quintana or Archer of their ownership interests in us could adversely affect us.

We believe that Quintana's and Archer's ownership interests in us provide them with an economic incentive to assist us to be successful. Upon the expiration of the lock-up restrictions on transfers or sales of our securities signed in connection with our IPO, Quintana and Archer will no longer be subject to any obligation to maintain their ownership interest in us and may elect at any time thereafter to sell all or a substantial portion of or otherwise reduce their ownership interest in us. If Quintana or Archer sells all or a substantial portion of its ownership interest in us, it may have less incentive to assist in our success and its 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 any action by stockholders to be taken only at an annual meeting or special meeting rather than by a written consent of the stockholders, subject to the rights of any series of preferred stock with respect to such rights;
- 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 Credit Facility places certain restrictions on our ability to pay cash dividends. Consequently, your only opportunity to achieve a return on your investment in us will 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.

After the expiration or waiver of the lock-up provision contained in the underwriting agreement entered into in connection with our IPO, 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 33,630,934 shares of our common stock outstanding as of March 27, 2018.

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, the expiration of lock-up agreements 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.

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.

The underwriters of our IPO may release parties to the lock-up agreements entered into in connection with our IPO, which could adversely affect the price of our common stock.

In connection with our IPO, we, all of our directors and executive officers, and certain of our Principal Stockholders entered into lock-up agreements pursuant to which we and they are subject to certain restrictions with respect to the sale or other disposition of our common stock for a period of 180 days following the date of our Registration Statement (as defined below). The underwriters, at any time and without notice, may release all or any portion of the common stock subject to the foregoing lock-up agreements. If shares subject to the lock-up agreements are released, then the common stock, subject to compliance with the Securities Act or exceptions therefrom, will be available for sale into the public markets, which could cause the market price of our common stock to decline and impair our ability to raise capital.

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 that is composed entirely of independent directors 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.

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

Our corporate headquarters 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 (13000 W. HWY 80 E)	Leased	06/30/2022
Midland, TX (3705 S. County Road 1210)	Leased	Month-to-Month
Oklahoma City, OK	Leased	06/30/2026
Willis, TX (11390 FM 830)	Owned	N/A
Willis, TX (12161 FM 830)	Leased	Month-to-Month
Mills, WY	Leased	10/31/2026
Morgantown, WV	Leased	10/31/2019
Denver, CO	Leased	Month-to-Month
Pressure Pumping		
Gillete, WY	Leased	Month-to-Month
Goldsmith, TX	Leased	07/31/2021
Ponca City, OK	Owned	N/A
Union City, OK	Owned	N/A
Cushing, 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 (shared with wireline services)	Leased	03/31/2021
Victoria, TX	Owned	N/A
Longview, TX	Owned	N/A
Arnett, OK	Owned	N/A
Elk City, OK	Leased	04/30/2027
Oklahoma City, OK	Leased	12/12/2026
Kensett, AR	Leased	Month-to-Month
Lore City, OH	Leased	04/14/2020
Wireline		
Guthrie, OK	Owned	N/A
Levelland, TX	Owned	N/A
Odessa, TX (shared with pressure control services)	Leased	03/31/2021
Alice, TX	Leased	12/31/2021
Rosharon, TX	Leased	07/31/2019
Longview, TX	Leased	03/08/2021
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.

PART II

Item 5. Market for Registrant's Common Equity and 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. Prior to that, there was no public market for our common stock. As a result, we have not set forth quarterly information with respect to the high and low prices for our common stock for the two most recent fiscal years. From February 9, 2018, our first day of trading on NYSE, to March 27, 2018, the high and low prices for our common stock were $9.90 and $7.92, respectively.

Holders

As of March 27, 2018, we had approximately 33,630,934 shares of common stock outstanding and 60 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 any 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 Credit Facility places restrictions on our ability to pay cash dividends to holders of our common stock. For more information on our New Credit Facility, please see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Our New Credit Facility."

Securities Authorized for Issuance under Equity Compensation Plans

For disclosures regarding securities authorized for issuance under equity compensation plans, see Part III, Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters" of this report.

Recent Sales of Unregistered Securities

During the year ended December 31, 2017 and prior to our IPO, we issued unregistered securities to certain entities, as described below. These transactions did not involve any underwriters, underwriting discounts or commissions or any public offering, and we believe that these transactions were exempt from the registration requirements pursuant to Section 4(a)(2) of the Securities Act, Regulation D or Regulation S promulgated thereunder or Rule 701 of the Securities Act. The recipients of these securities represented their intention to acquire the securities for investment only and not with a view to or for sale in connection with any distribution thereof, and appropriate legends were affixed to the share certificates and instruments issued in these transactions.

On April 13, 2017, we issued 1,000 shares of common stock to QES Holdco LLC, a Delaware limited liability company created to effect the Reorganization (as defined below) in exchange for $10.00, or $0.01 per share. For additional detail about our Reorganization transactions, please see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Master Reorganization Agreement."

On February 13, 2018, prior to the closing of the IPO and in connection with the Reorganization (as defined below), we issued 23,780,752 shares of common stock on a one-for-one basis to the pre-existing unitholders of QES LP and QES Holdco LLC in exchange for their respective membership interests in each of QES LP and QES Holdco LLC. Following the one-for-one exchange of QES LP units for shares of common stock in the Company, the Company consummated a 31.669363 for 1 reverse stock split of its issued and outstanding common stock.

Use of Proceeds from Registered Securities

On February 13, 2018, we completed our IPO of 9,259,259 shares of common stock at a price to the public of $10.00 per share pursuant to our registration statement on Form S-1 (File 333-219837), as amended and declared effective by the SEC on February 8, 2018 (the "Registration Statement"). On March 9, 2018, the underwriters partially exercised their option to purchase 372,824 additional shares of our common stock at a price to the public of $10.00 per share. Merrill Lynch, Pierce, Fenner & Smith Incorporated and Piper Jaffray & Co. acted as lead book-running managers and representatives of the underwriters in our IPO.

The aggregate gross proceeds of our IPO were $96.3 million, which includes the option exercised by the underwriter. We incurred expenses in connection with our IPO of approximately $2.9 million as of March 27, 2018. After subtracting underwriting discounts and commissions of approximately $5.8 million and the estimated offering expenses, we received net proceeds of approximately $87.6 million from the sale of an aggregate of 9,632,083 shares of common stock. We used these net proceeds, together with $13.0 million of aggregate borrowings under our New Credit Facility, to fully repay the remaining $79.1 million of outstanding indebtedness under our revolving credit facility (the "Revolving Credit Facility"); to fully repay approximately $11.2 million, together with a prepayment fee of 3%, or approximately $1.3 million under our $40.0 million term loan between us, Archer, Robertson QES, Geveran, and Cortland Capital Market Services, LLC as administrative agent (the "Term Loan"); and for general corporate purposes.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

There were no repurchases of equity securities by the Issuer in the year ended December 31, 2017, including no shares withheld upon the vesting of phantom units for the payment of tax obligations.

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Item 6. Selected Financial Data

The Company was incorporated in April 2017 and does not have historical financial operating results. The following table shows summary historical consolidated financial data, for the periods and as of the dates indicated, of QES LP, our accounting predecessor. The summary historical consolidated financial data of our predecessor as of December 31, 2017 and for the years ended December 31, 2017, 2016 and 2015, respectively, were derived from the audited historical consolidated financial statements of our predecessor included elsewhere in this Annual Report. The summary historical consolidated financial data of our predecessor as of and for the year ended December 31, 2014 were derived from the audited historical consolidated financial statements of our predecessor not included in this Annual Report.

The historical results of our predecessor are not necessarily indicative of our future operating results. You should read the following table in conjunction with ''Management's Discussion and Analysis of Financial Condition and Results of Operations'' and the historical consolidated financial statements of our predecessor and accompanying notes included elsewhere in this Annual Report.

	Year Ended December 31,			
	2017	2016	2015	2014
	(in thousands, except unit and per unit data)			
Statement of Operations Data:				
Revenue:				
Directional drilling services	$145,230	$ 75,326	$ 98,129	$212,629
Pressure pumping services	153,118	45,165	85,485	189,663
Pressure control services	89,912	52,388	—	—
Wireline services	49,773	37,549	5,641	—
Total revenue	438,033	210,428	189,255	402,292
Direct operating expenses:				
Directional drilling services	111,978	58,834	75,494	141,974
Pressure pumping services	115,526	50,828	69,175	124,216
Pressure control services	69,483	47,926	—	—
Wireline services	35,708	25,340	8,399	—
Total direct operating expenses	332,695	182,928	153,068	266,190
General and administrative expenses	72,770	73,600	51,798	42,360
Depreciation and amortization	45,687	78,661	39,682	29,548
Fixed asset impairment	—	1,380	—	—
Goodwill impairment	—	15,051	40,250	—
Gain on bargain purchase	—	—	(39,991)	—
Loss (gain) on disposition of assets, net	(2,639)	5,375	302	—
Operating income (loss)	(10,480)	(146,567)	(55,854)	64,194
Interest expense, net	(11,251)	(8,015)	(3,086)	(1,837)
Other income	666	—	—	—
(Loss) income before tax	(21,065)	(154,582)	(58,940)	62,357
Income tax expense	(91)	(167)	(101)	(195)
Net income (loss)	$ (21,156)	$(154,749)	$ (59,041)	$ 62,162
Net loss per common unit:				
Basic	$ (0.05)	$ (0.37)	$ (0.25)	
Diluted	$ (0.05)	$ (0.37)	$ (0.25)	
Weighted average common units outstanding:				
Basic	417,441	417,032	232,318	
Diluted	417,441	417,032	232,318	
Statement of Cash Flows Data:				
Net cash provided by (used in):				
Operating activities	$ (11,540)	$ (42,835)	$ 32,075	$ 68,077
Investing activities	14,510	2,266	(54,438)	$ (46,103)
Financing activities	(6,438)	46,525	15,684	$ (15,756)

	Year Ended December 31,			
	2017	2016	2015	2014
	(in thousands, except unit and per unit data)			
Other Financial Data:				
Segment Adjusted EBITDA:				
Directional drilling services	$ 17,498	$ (76)	$ 2,502	$ 48,644
Pressure pumping services	27,784	(19,372)	(2,497)	44,832
Pressure control services	6,539	(5,804)	—	—
Wireline services	(1,794)	(6,161)	(5,833)	—
Adjusted EBITDA (unaudited)(1)	$ 41,226	$ (36,679)	$ (9,173)	$ 93,742
Purchases of property, plant and equipment	(21,244)	(7,340)	(14,555)	(51,534)
Balance Sheet Data (at end of period):				
Cash and cash equivalents	$ 8,751	$ 12,219	$ 6,263	$ 12,942
Total assets	275,659	273,931	376,337	278,388
Long-term debt, net of discount and deferred financing costs(2)	37,199	116,463	—	59,759
Total liabilities	190,691	167,807	124,426	97,276
Total equity	84,968	106,124	251,911	181,112

(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 a reconciliation of Adjusted EBITDA to net income, the most directly comparable financial measure calculated in accordance with GAAP, please read “Adjusted EBITDA” below.

(2) All of our long-term debt balances as of December 31, 2015, totaling $77.0 million, were classified as current.

Reconciliations to Amounts Reported Under Generally Accepted Accounting Principles

Adjusted EBITDA

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 plus income taxes, net interest expense, depreciation and amortization, impairment charges, net loss on disposition of assets, transaction expenses, rebranding expenses, settlement expenses, severance expenses and equipment standup expense, and less gain on bargain purchase.

We believe Adjusted EBITDA margin 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 and 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 in accordance with 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.

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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 years ended December 31, 2017 and 2016:

	Years Ended December 31,		
	2017	2016	2015(1)
		(in thousands)	
Adjustments to reconcile Adjusted EBITDA to net loss:			
Net loss	$(21,156)	$(154,749)	$(59,041)
Income tax expense	91	167	101
Interest expense, net	11,251	8,015	3,086
Other income	(666)	—	—
Depreciation and amortization expense	45,687	78,661	39,682
Fixed asset impairment	—	1,380	—
Goodwill impairment(2)	—	15,051	40,250
Gain on bargain purchase	—	—	(39,991)
(Gain) Loss on disposition of assets, net	(2,639)	5,375	302
Transaction expense(3)	977	4,358	6,133
Rebranding expense(4)	9	2,237	—
Settlement expense(5)	3,680	1,740	—
Severance expense(6)	243	1,075	305
Equipment and standup expense(7)	3,749	11	—
Adjusted EBITDA	41,226	(36,679)	(9,173)

(1) We closed the acquisition of Cimarron Acid & Frac, LLC ("CAF") in January 2015 (the "CAF Acquisition") and the Archer Acquisition in December 2015. As a result, financial results relating to each acquisition for periods prior to the close of each of the aforementioned acquisitions are not reflected in the full year 2015 results.

(2) For 2015, represents a non-cash impairment charge related to our pressure pumping services segment. For 2016, represents a non-cash impairment charge related to our directional drilling services segment. See Note 3 to the consolidated financial statements included in this Annual Report for additional detail.

(3) For 2016 and 2017, represents professional fees related to investment banking, accounting and legal services associated with entering into the Term Loan that were recorded in general and administrative expenses. For 2015, represents acquisition costs associated with the CAF Acquisition and Archer Acquisition that were recorded in general and administrative expenses.

(4) Relates to expenses incurred in connection with rebranding our business segments in 2016 and 2017. In our actual performance for the year ended December 31, 2017 and the year ended December 31, 2016, $0.01 and $2.2 million was recorded in general and administrative expenses, respectively.

(5) Relates to the non-recurring settlement of lease termination costs in 2016 and 2017 associated with the 2016 market downturn, and sales tax audit accrual and retention payments in 2016 and 2017 associated with the Archer Acquisition. In our actual 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 2016 and 2017 incurred in connection with the integration of the Archer Acquisition as well as a program implemented to reduce head count in connection with the industry downturn. In our actual performance for the year ended December 31, 2017 and the year ended December 31, 2016, $0.2 million and $0.8 million was recorded in direct operating expenses, respectively, and the remainder was recorded in general and administrative expenses. In our actual performance for the year ended December 31, 2015, $0.3 million was recorded in general and administrative expenses and related to the one-time settlement of a non-compete agreement.

(7) Relates to equipment standup costs incurred in connection with the mobilization and redeployment of assets. In our actual performance for the year ended December 31, 2017, approximately $3.6 million was recorded in direct operating expenses and approximately $0.2 million was recorded in general and administration expenses. For the year ended December 31, 2016, approximately $0.01 million was recorded in direct operating expenses.

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 "Selected Financial Data" and 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 business segments: (1) directional drilling services, (2) pressure pumping services, (3) pressure control services and (4) wireline services.

The Company was incorporated on April 13, 2017 and does not have historical financial operating results. 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 explore, produce, and develop oil and gas resources in the United States. Industry conditions are influenced by numerous factors, such as the supply of and demand for oil and gas, domestic and worldwide economic conditions, political instability in oil producing countries and merger and divestiture activity among oil and gas producers. The volatility of the oil and 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 gas operations. As oil and gas prices fluctuate significantly, demand for our services changes correspondingly 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 gas prices increase or decrease.

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 374 rigs on May 27, 2016 to 979 rigs as of March 23, 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. Our revenue has increased each quarter from the quarter ended June 30, 2016 through the quarter ended December 31, 2017. From the second quarter of 2016 through the fourth quarter of 2017, our directional drilling services business segment increased the number of rig days by 166.5%, while day rates have improved from the lows we experienced during the second quarter of 2016. We reactivated our second and third pressure pumping fleets in February and October 2017, respectively, and our frac utilization is approaching full utilization for our active fleets. In addition, in January 2018 we placed initial orders for twelve incremental pumps and ancillary equipment to redeploy our fourth pressure pumping fleet. Utilization of our pressure control and wireline assets has also continued to improve since the second quarter of 2016.

Directional drilling services: Our directional drilling services business 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, underbalanced drilling, measurement-while-drilling ("MWD"), rental tools and pipe inspection services. Our package also offers various technologies, including our positive pulse MWD navigational tool asset fleet, mud motors and ancillary downhole tools, as well as third-party electromagnetic navigational systems. We also provide a suite of integrated and related services, including downhole rental tools and third-party inspection services of drill pipe and downhole 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 business 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 business segment, we have long standing relationships with our customers in this business segment and believe they will continue to utilize our services. As of the quarter ended December 31, 2017, 96% 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, and in some cases, multiple years. With increasing use of pad drilling and reactivation of rigs, through the fourth quarter of 2017 we have increased the number of “follow me rigs” from approximately 30 in the first quarter of 2016 to 55 as of December 31, 2017. We intend to continue to re-deploy additional MWD kits over the course of 2018, as market conditions warrant.

Our directional drilling services business segment accounted for approximately 33.2%, 35.8% and 51.9% of our revenues for the years ended December 31, 2017, 2016 and 2015, respectively.

Pressure pumping services: Our pressure pumping services business 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 hydraulic fracturing, cementing and acidizing services in the Mid-Continent, Rocky Mountain and Permian Basin regions.

Our pressure pumping services are 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 frac 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, mobilization of the equipment to the location and the personnel involved in such services or mobilization. Additional revenue is generated through labor charges and the product sales of consumable supplies that are incidental to the service being performed.

Our pressure pumping services business segment accounted for approximately 35.0%, 21.5% and 45.2% of our revenues for the years ended December 31, 2017, 2016 and 2015, respectively.

Pressure control services: Our pressure control services business segment consists of coiled tubing, rig assisted snubbing, nitrogen, fluid pumping and well control services.

Our coiled tubing units are used in the provision of well-servicing and workover applications, or in support of unconventional completions. 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 consumables (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 consumables.

Our pressure control services business segment services accounted for approximately 20.5% and 24.9% of our revenues for the years ended December 31, 2017 and 2016, respectively. Our pressure control services business segment was a new segment for 2016 and does not have comparative results to 2015.

Wireline services: Our wireline services business segment principally works in connection with hydraulic fracturing services in the form of pump-down services for setting plugs between frac stages, as well as the deployment of perforation equipment in connection with “plug-and-perf” operations. We also offer a full range of other pump-down and cased-hole wireline services, including electro-mechanical pipe-cutting and punching. 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, as well as having exclusive leases to operate Archer’s POINT® proprietary detection system and SPACE® imaging and measurement platform in the U.S. land market.

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 11.4%, 17.8% and 3.0% of our revenues for the years ended December 31, 2017, 2016 and 2015, 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 business segments primarily by asset utilization, revenue, and Adjusted EBITDA.

For our 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. However, given the variance in revenue and profitability from job to job, depending on the type of service to be performed and the equipment, personnel and consumables required for the job, as well as competitive factors and market conditions in the region in which the services are performed, undue reliance should not be placed on utilization as an indicator of our financial or operating performance.

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 GAAP.

We believe Adjusted EBITDA margin 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 and 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 in accordance with 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 read “Selected Financial Data” above.

We measure safety by tracking the total recordable incident rate (“TRIR”) and lost time incident rate (“LTIR”), which are reviewed on a monthly basis. TRIR is a measure of the rate of recordable workplace injuries, defined below, normalized and stated on the basis of 100 workers for an annual period. The factor is derived by multiplying the number of recordable injuries in a calendar year by 200,000 (i.e., the total hours for 100 employees working 2,000 hours per year) and dividing this value by the total hours actually worked in the year. LTIR is a measure of recordable workplace injuries that result in a lost work day beyond the day of incident, normalized and stated on the basis of 100 workers in an annual period. The factor is derived by multiplying the number of lost time injuries in a calendar year by 200,000 (i.e., the total hours for 100 employees working 2,000 hours per year) and dividing this value by the total hours actually worked in the year. For purposes of TRIR and LTIR, a recordable injury includes occupational death, nonfatal occupational illness and other occupational injuries that involve loss of consciousness, restriction of work or motion, transfer to another job, or medical treatment other than first aid. Our TRIR decreased from 1.55 in 2016 to 0.98 in 2017, and our LTIR decreased from 0.34 in 2016 to 0.06 in 2017.

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.

- We completed certain strategic acquisitions and dispositions, including the CAF Acquisition in January 2015 and the Archer Acquisition in December 2015. Over the course of the first quarter of 2017 we sold select wireline and pressure pumping assets for aggregate sale proceeds of $27.6 million. 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.
- Quintana Energy Services Inc. is subject to U.S. federal and state income taxes as a corporation. Our predecessor, QES LP, 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 provision for U.S. federal income taxes or income taxes in any state or locality (other than franchise tax in the State of Texas). Prior to tax reform, we would have been subject to U.S. federal, state and local taxes at a blended statutory rate of 35.8% of pre-tax earnings. Based on the tax reform completed in December 2017, we expect our tax rate to be significantly lower.
- As of December 31, 2017, on a pro forma basis giving effect to (i) the conversion of $33.6 million of outstanding indebtedness under our Term Loan into our common stock, (ii) the closing of the IPO and the use of net proceeds therefrom along with borrowings under our New Credit Facility to fully repay all outstanding borrowings under and terminate our Revolving Credit Facility and our Term Loan and (iii) the entry into our New Credit Facility, we had $13.0 million of total outstanding indebtedness, compared to the actual outstanding indebtedness of $79.1 million as of December 31, 2017.
- Our IPO served as a vesting event under the phantom unit awards granted under our long-term incentive plans. As a result, certain of our 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. Expense associated with these phantom unit awards will be recognized in the first quarter of 2018. See “Executive Compensation—Quintana Energy Services LP Phantom Units” for additional detail on our phantom unit awards and our incentive plans.
- As we further 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 (“SG&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.

Recent Trends and Outlook

Demand for our services is predominately influenced by the level of drilling and completion activity by E&P companies, which is driven largely by the current and anticipated profitability of developing oil and natural gas reserves. Crude oil prices have increased from their lows of $26.21 per barrel (“Bbl”) in early 2016 to $65.88 per Bbl as of March 23, 2018 (based on the West Texas Intermediate Spot Oil Price, or “WTI”), but remain 39% lower than a high of $107.26 per Bbl in June 2014. Natural gas prices have increased from their lows of $1.64 per million British Thermal Units (“MMBtu”) in early 2016 to $2.62 per MMBtu as of March 19, 2018 (based on the Henry Hub spot price), but remain 68% lower than a high of $8.15 per MMBtu in February 2014. Drilling and completion activity in the United States has increased significantly as commodity prices have generally increased, which we believe will correspond with increased demand for our services.

We view the horizontal rig count as a reliable indicator of the overall level of demand for our services. According to Baker Hughes, horizontal rigs accounted for 87% of all total active rigs in the United States as of March 23, 2018, as compared to only 27% a decade earlier. Horizontal drilling allows E&P companies to drill wells with greater exposure to the economic payzone of a targeted formation, thus improving production. The advantages of horizontal drilling have increasingly led to greater demand for high-specification rigs that are more efficient in drilling shale oil and natural gas wells than older drilling rigs. Additionally, high-specification rigs which are capable of pad drilling operations have become more prevalent in North America and enable the operator to drill more wells per rig per year than older rigs. According to Spears & Associates, the average annual number of wells drilled per rig in the United States has risen from 24 in 2012 to 28 in 2017. We believe that the increase in horizontal rigs and increased demand for high-specification rigs will drive demand for our experienced directional drilling personnel and modern equipment.

Completion of horizontal wells has evolved to require increasingly longer laterals and more hydraulic fracturing stages per horizontal well, which increase the exposure of the wellbore to the reservoir and improve production of the well. Hydraulic fracturing operations are conducted via a number of discrete stages along the lateral section of the wellbore. As wellbore lengths have increased, the number of hydraulic fracturing stages has continued to rise. According to Spears & Associates, from 2014 to 2016 the average number of stages per horizontal well increased from 23 stages per well to 34 stages per well, and is expected to further increase to an average of 48 stages per horizontal well in 2018. The market has also trended toward larger scale hydraulic fracturing operations, characterized by more hydraulic horsepower ("HHP") per well. This requires a greater number of hydraulic fracturing units per fleet to execute a completion job. These trends, along with the overall expected recovery of U.S. drilling and completion activity, favor continued growth of the hydraulic fracturing sector. Spears & Associates forecasts that U.S. demand for HHP is expected to increase more than 112% from the fourth quarter of 2016 to the fourth quarter of 2018. As a result, we expect demand for our pressure pumping services to expand, including needs for our hydraulic fracturing and acidizing services.

Demand for our pressure control services is expected to grow along with increases in drilling and completion activity and benefit from the increasing average age of producing oil and natural gas wells. We believe that maintenance of unconventional wells will drive demand for our rig-assisted snubbing, nitrogen and fluid pumping units.

The markets we serve, and the oilfield services market in general, are characterized by fragmentation and consist of a large number of small independent operators serving these markets. We believe our relative scale is a differentiator, as we are a leading independent provider of directional drilling and pressure control services and have significant scale in both our pressure pumping and wireline services.

We are well positioned for the ongoing recovery we are observing in each of our service lines, all of which have already realized pricing improvement from the lows observed in 2016. As market conditions allow, we plan to continue our redeployment of existing assets as activity and pricing levels increase.

While we believe these trends will benefit us, our markets may be adversely affected by industry conditions that are beyond our control. For example, the overall decline in oil prices from their high levels in 2014 to their low levels in 2016 and the uncertainty regarding the sustainability of current oil prices has materially affected and may continue to materially affect the demand for our services and the rates that we are able to charge. Additionally, adverse weather conditions can affect the drilling and completion activities of our customers. During periods of heavy snow, high winds, ice or rain, the logistical capabilities of our suppliers may be delayed or we may be unable to move our equipment between locations, thereby reducing our ability to provide services and generate revenues. For example, freezing weather and high winds in the first quarter of 2018 have affected our available revenue generating hours.

The industry continues to face strain in logistics, vendor service quality and delivery times across various aspects of the third party supply chain, driven by continued growth in demand. We are proactively managing these transitory issues facing the entire industry to limit the impact to our customers and business. In addition, continued tightening of the labor market could result in higher wage rates, as well as increased recruiting, hiring, onboarding and training costs.

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Results of Operations

The following table provides selected operating data for the periods indicated.

	Year Ended December 31, 2017	2016	2015
		(in thousands)	
Statement of Operations Data:			
Revenue	$438,033	$ 210,428	$189,255
Direct operating expenses	332,695	182,928	153,068
General and administrative expenses	72,770	73,600	51,798
Depreciation and amortization	45,687	78,661	39,682
Fixed asset impairment	—	1,380	—
Goodwill impairment	—	15,051	40,250
Gain on bargain purchase	—	—	(39,991)
Loss (gain) on disposition of assets, net	(2,639)	5,375	302
Operating income (loss)	(10,480)	(146,567)	(55,854)
Interest expense, net	(11,251)	(8,015)	(3,086)
Other income	666	—	—
Loss before tax	(21,065)	(154,582)	(58,940)
Income tax (expense) benefit	(91)	(167)	(101)
Net income (loss)	$ (21,156)	$(154,749)	$ (59,041)
Segment Adjusted EBITDA:			
Directional drilling services	$ 17,498	$ (76)	$ 2,502
Pressure pumping services	27,784	(19,372)	(2,497)
Pressure control services	6,539	(5,804)	—
Wireline services	(1,794)	(6,161)	(5,833)
Adjusted EBITDA (unaudited)(1)	$ 41,226	$ (36,679)	$ (9,173)
Other Operational Data:			
Rig days(2)	14,407	7,001	
Average monthly rigs on revenue(3)	58	31	
Total hydraulic fracturing stages	2,993	1,567	
Average revenue per stage	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 "Selected Financial Data — Reconciliations to Amounts Reported Under Generally Accepted Accounting Principles—Adjusted EBITDA" above.

(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 given time period, including days that standby revenues are earned.

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

Revenue. The following table provides our revenues by business segment for the periods indicated:

Revenue

	Year Ended December 31,	
	2017	2016
	(in thousands)	
Revenue:		
Directional drilling services	$145,230	$ 75,326
Pressure pumping services	153,118	45,165
Pressure control services	89,912	52,388
Wireline services	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 business segment was as follows:

Directional drilling services. Directional drilling services business segment 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 to 33.8% for the year ended December 31, 2017. The utilization increase was offset by a (4.0)% decline in dayrate to $9,432 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 business 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 services. Pressure pumping services business segment 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 frac spreads in February 2017 and October 2017, which drove a 91.0% increase in stages to 2,993 for the year ended December 31, 2017. Additionally we experienced a 102.2% increase in average revenue per stage to $47,189 for year ended December 31, 2017, from $23,338 for the year ended December 31, 2016 due to improving market conditions and shift in the job types completed. Approximately 92.2% of our pressure pumping business 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 services. Pressure control services business segment 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 to 29.0% and a 28.0% increase in weighted average pricing to $11,065 for the year ended December 31, 2017. The number of days for which we generated revenue (“revenue days”) for the year ended December 31, 2017 totaled 7,784 compared to 5,825 for the year ended December 31, 2016. The change in utilization and pricing accounted for 56.4% and 43.6% of the pressure control revenue change, respectively.

Wireline services. Wireline services business segment 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% to $9,026. Utilization during the year ended December 31, 2017 was up 31.8% to 30.0% driven by a reduction in equipment fleet, while revenue days increased 3.5% from 5,522 for the year ended December 31, 2016. Approximately 71.4% of our wireline business 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 business segment for the periods indicated:

	Year Ended December 31, 2017	2016
	(in thousands)	
Direct operating expenses:		
Directional drilling services	$ 111,978	$ 58,834
Pressure pumping services	115,526	50,828
Pressure control services	69,483	47,926
Wireline services	35,708	25,340
Total direct operating expenses	332,695	182,928

Direct operating expenses for the year ended December 31, 2017 increased by $149.8 million, or 81.9%, to $332.7 million, from $182.9 million for the year ended December 31, 2016. The increase in direct operating expense was attributable to our business segments as follows:

Directional drilling services. Directional drilling services business segment direct operating expenses increased by $53.2 million, or 90.5%, to $112.0 million for the year ended December 31, 2017, from $58.8 million for the year ended December 31, 2016. This increase was primarily attributable to a 105.8% increase in rig days to 14,407 over the same period, which in turn resulted in higher operating expenses associated with both personnel and equipment.

Pressure pumping services. Pressure pumping services business segment 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 services. Pressure control services business segment 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 costs associated with personnel, equipment and consumables.

Wireline services. Wireline services business segment direct operating expenses increased by $10.4 million, or 41.1%, to $35.7 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 costs associated with personnel, equipment and consumables.

General and administrative expenses. SG&A expenses represent the costs associated with managing and supporting our operations. These expenses decreased by $0.8 million, or 1.1%, to $72.8 million for the year ended December 31, 2017, from $73.6 million for the year ended December 31, 2016. The decrease in general and administrative expenses was primarily driven by reduction in overhead across our business 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 services business segment assets, $0.1 million gain on disposition of pressure control services business segment assets and $0.3 million gain on disposal of wireline services business 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 business segment was as follows:

Directional drilling services. Adjusted EBITDA for our directional drilling services business 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 90.5% due to increased activity levels.

Pressure pumping services. Adjusted EBITDA for our pressure pumping services business 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 frac activity, which was partially offset by a 127.3% increase in direct operating expenses incurred as the business increased utilization and deployed additional frac spreads in February 2017 and October 2017.

Pressure control services. Adjusted EBITDA for our pressure control services business 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 services. Adjusted EBITDA for our wireline services business 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 41.1% increase in direct operating expenses.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

Revenue. The following table provides our revenues by business segment for the periods indicated:

	Year Ended December 31,	
	2016	2015
	(in thousands)	
Revenue:		
Directional drilling services	$ 75,326	$ 98,129
Pressure pumping services	45,165	85,485
Pressure control services	52,388	—
Wireline services	37,549	5,641
Total revenue	210,428	189,255

Revenue

Revenue for the year ended December 31, 2016 increased by $21.2 million, or 11.2%, to $210.4 million from $189.3 million for the year ended December 31, 2015. The increase in revenue by business segment was as follows:

Directional drilling services. Directional drilling services business segment revenue decreased by $22.8 million, or 23.2%, to $75.3 million for the year ended December 31, 2016, from $98.1 million for the year ended December 31, 2015. This decline was primarily attributable to a 53.4% decrease in utilization and a 11.3% decline in day rate as a result of competitive pricing driven by prevailing market conditions. The decline was partially offset by the addition of the Archer directional drilling business in 2016. The change in utilization and pricing accounted for 51.7% and 48.3% of the annual revenue change, respectively.

Pressure pumping services. Pressure pumping services business segment revenue decreased $40.3 million, or 47.2%, to $45.2 million for the year ended December 31, 2016, from $85.5 million for the year ended December 31, 2015. This decline was primarily attributable to competitive market conditions, including a 60.8% decrease in hydraulic fracturing stages completed compared to 2015 and a decrease in revenue per stage of 17.6% year over year. The decline was partially offset by the addition of the Archer pressure pumping services business in 2016. The change in frac stages and pricing accounted for 89.8% and 10.2% of the annual revenue change, respectively.

Pressure control services. Pressure control services business segment revenue was $52.4 million for the year ended December 31, 2016. There are no comparative results for 2015 as this was a new segment for the year ended December 31, 2016.

Wireline services. Wireline services business segment revenue increased by $31.9 million, or 565.6%, to $37.5 million for the year ended December 31, 2016, from $5.6 million for the year ended December 31, 2015. This increase was primarily attributable to a 625% increase in wireline units. The main driver of the increase was the addition of the full year of operations of the legacy Archer wireline business.

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

	Year Ended December 31,	
	2016	2015
	(in thousands)	
Direct operating expenses:		
Directional drilling services	58,834	75,494
Pressure pumping services	50,828	69,175
Pressure control services	47,926	—
Wireline services	25,340	8,399
Total direct operating expenses	182,928	153,068

Direct operating expenses for the year ended December 31, 2016 increased by $29.9 million, or 19.5%, to $182.9 million from $153.1 million for the year ended December 31, 2015. The increase in direct operating expenses by business segment was as follows:

> *Directional drilling services.* Directional drilling services business segment direct operating expenses decreased by $16.7 million, or 22.1%, to $58.8 million from $75.5 million for the year ended December 31, 2015. This decrease was primarily attributable to a 53.4% decline in utilization and a 11.2% decrease in headcount over the same period. The decline was partially offset by the addition of the Archer directional drilling business in 2016.
>
> *Pressure pumping services.* Pressure pumping services business segment direct operating expenses decreased by $18.3 million, or 26.5%, to $50.8 million from $69.2 million for the year ended December 31, 2015. This decrease was primarily attributable to a 44.9% decline in jobs completed and a 37.3% decrease in headcount over the same period, as well as certain settlements of lease termination costs. The decline was partially offset by the addition of the Archer pressure pumping business in 2016.
>
> *Pressure control services.* Pressure control services business segment direct operating expenses was $47.9 million for the year ended December 31, 2016. There were no comparative results for 2015 as this was a new segment for the year ended December 31, 2016.
>
> *Wireline services.* Wireline services business segment direct operating expenses increased by $16.9 million, or 201.7%, to $25.3 million from $8.4 million for the year ended December 31, 2015. This increase was primarily attributable to a 625.0% increase in wireline units and a 285.4% increase in wireline headcount over the same period. The main driver of the increase was the full year operations of the legacy Archer wireline business.

General and administrative expenses. General and administrative expenses represent the costs associated with managing and supporting our operations. These expenses increased by $21.8 million, or 42.1%, to $73.6 million for the year ended December 31, 2016, from $51.8 million for the year ended December 31, 2015. The increase in general and administrative expenses was primarily driven by the growth in the wireline services business segment, which expanded its fleet by 625%, inclusion of the new pressure control services business segment and increased expenses at corporate related to the execution of the Term Loan and the Archer Acquisition, and also includes expenses related to rebranding our business segments and certain one-time severance expenses incurred in connection with the Archer Acquisition and reductions in headcount.

Depreciation and amortization. Depreciation and amortization increased by $39.0 million, or 98.2%, to $78.7 million for 2016 from $39.7 million for 2015. This increase was primarily attributable to additional depreciation and amortization related to the property plant and equipment included in the Archer Acquisition. This increase was partially offset by a decrease in depreciation expense due to asset dispositions, certain assets becoming fully depreciated and reduced capital expenditures in 2016.

Fixed asset impairment. For the year ended December 31, 2016, we recognized fixed asset impairment of $1.4 million due to an impairment on the assets held for sale as of December 31, 2016.

Goodwill impairment. Goodwill impairment in 2016 represented a $15.1 million loss on goodwill that resulted from an impairment of the goodwill of the directional drilling services business segment. Goodwill impairment in 2015 represented a $40.3 million loss on goodwill that resulted from a writedown of goodwill associated with our pressure pumping services business segment.

Loss on disposition of assets, net. Net loss on disposition of assets for the year ended December 31, 2016 was $5.4 million, primarily attributable to $5.8 million loss on disposition of pressure pumping services business segment assets, $0.1 million gain on disposition of pressure control services business segment assets and $0.3 million gain on disposal of wireline services business segment assets, compared to $0.3 million due to the sale of real property from our pressure pumping services business segment for the year ended December 31, 2015.

Gain on bargain purchase. We recognized a gain on bargain purchase of $40.0 million for the year ended December 31, 2015, attributable to the Archer Acquisition. The gain on bargain purchase was attributable $26.2 million in the pressure pumping services business segment, $0.1 million in the directional drilling services business segment and $13.7 million in the pressure control services business segment.

Interest expense. Net interest expense increased $4.9 million, or approximately 159.7%, to $8.0 million in 2016, compared to $3.1 million in 2015. The increase in interest expense was attributable to $35.2 million of increased borrowings over the course of 2016 under our Revolving Credit Facility, which was ultimately reduced by $22.0 million later in the period ended December 31, 2016.

Income taxes. For 2016, we recognized $0.2 million of income tax expense compared to $0.1 million of income tax expense for 2015, an increase of $0.1 million, or 100%. The increase was a result of increased taxable income at certain taxable subsidiaries.

Adjusted EBITDA. Adjusted EBITDA for the year ended December 31, 2016 decreased by $27.5 million, or 300%, to $(36.7) million from $(9.2) million for the year ended December 31, 2015. The decrease in Adjusted EBITDA by business segment was as follows:

Directional drilling services. Adjusted EBITDA for our directional drilling services business segment decreased by $2.6 million, or approximately 103%, to $(0.1) million in 2016, compared to $2.5 million in 2015. The decrease was primarily attributable to a 23.2% reduction in revenue associated with the reduced rig count and drilling capital spending by E&P operators partially offset by direct operating costs decreasing by 22.1%.

Pressure pumping services. Adjusted EBITDA for our pressure pumping services business segment decreased by $16.9 million, or approximately 675.8%, to $(19.4) million in 2016, compared to $(2.5) million in 2015. The decrease was primarily attributable to a 47.2% reduction in revenue driven by reduced completions activity and a 26.5% reduction in direct operating expenses driven by the additional costs assumed via the Archer pressure pumping business.

Pressure control services. Adjusted EBITDA for our pressure control services business segment was $(5.8) million for the year ended December 31, 2016. There were no comparative results for 2015 as this was a new segment for the year ended December 31, 2016.

Wireline services. Adjusted EBITDA for our wireline services business segment decreased by $0.3 million, or approximately 5.6%, to $(6.2) million in 2016, compared to $(5.8) million in 2015. The decrease was attributable to lower utilization and pricing driven by prevailing market conditions and a 201.7% increase in direct operating expenses driven by the additional costs assumed via the Archer wireline business.

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, borrowings under our Revolving Credit Facility and our Term Loan and cash flows from operations. At December 31, 2017, we had $8.8 million of cash and equivalents and $20.0 million available to draw on the Revolving Credit Facility, which resulted in a total liquidity position of $28.8 million. As discussed in Note 8 to our audited consolidated financial statements, as of December 31, 2017 we had $79.1 million of debt outstanding under our Revolving Credit Facility that was scheduled to mature on September 19, 2018, classified as a current liability, and $44.3 million of debt outstanding under our Term Loan.

In connection with the closing of the IPO, we converted $33.6 million of outstanding indebtedness under our Term Loan into shares of common stock of the Company, fully repaid and terminated the Revolving Credit Facility and our Term Loan and entered into our New Credit Facility, which had approximately $13.0 million of outstanding borrowings and $60.8 million of availability for future borrowings as of the closing of our IPO. On a pro forma basis giving effect to these transactions, as of December 31, 2017, we would have had outstanding indebtedness of $13.0 million, $9.6 million of cash on hand and $60.8 million of availability for future borrowings under our New Credit

Facility. For more information on our New Credit Facility, please see “Our New Credit Facility” below. We anticipate that our primary sources of liquidity going forward will be borrowings under our New Credit Facility, cash flows from operations (once positive), and future issuances of debt and equity. As our drilling and completion activity in the United States has increased with the rise in commodity prices since 2016, our cash flow from operations has begun to improve and we expect cash flows to continue to improve if drilling and completion activity continues to increase. However, there is no certainty that cash flows 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, pricing 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 has been for investing in property and equipment used to provide our services. Our primary uses of cash is for replacement 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 expenditures 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) presented below:

	Year Ended December 31,		
	2017	2016	2015
		(in thousands)	
Net cash provided by (used in) operating activities	$(11,540)	$(42,835)	$ 32,075
Net cash provided by (used in) investing activities	$ 14,510	$ 2,266	$(54,438)
Net cash provided by (used in) financing activities	$ (6,438)	$ 46,525	$ 15,684
Net change in cash	$ (3,468)	$ 5,956	$ (6,679)
Cash balance end of period	$ 8,751	$ 12,219	$ 6,263

Net cash provided by (used in) operating activities

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.

Net cash provided by (used in) operating activities was $(42.8) million for the year ended December 31, 2016, compared to $32.1 million for the same period in 2015. The decrease in operating cash flows was primarily attributable to lower utilization and competitive pricing pressure as a result of prevailing market conditions.

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.

Net cash provided by (used in) investing activities

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) investing activities was $2.3 million for the year ended December 31, 2016, compared to $(54.4) million for 2015. We used $7.3 million cash to purchase equipment and we received $9.6 million in exchange for selling assets in 2016 as compared to 2015, when we used $14.6 million cash in investing activities to purchase property and equipment, used $43.6 million for acquisitions, and received $3.7 million for the sale of property and equipment.

Net cash provided by (used in) financing activities

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.

Net cash provided by financing activities was primarily the result of debt borrowings net of repayments that are more fully described under "Revolving Credit Facility" and "Term Loan" below. Net cash provided by financing activities was $46.5 million for the year ended December 31, 2016, compared to $15.7 million for 2015. The financing cash flow was primarily used for borrowings under the Revolving Credit Facility and Term Loan and subsequent repayment of principal on the Revolving Credit Facility.

Our Credit Facilities

Revolving Credit Facility

During 2017, we had a Revolving Credit Facility with an aggregate maximum principal amount of $110.0 million, subject to a borrowing base, and a term of four years that was scheduled to mature on September 19, 2018. Of the outstanding revolving credit advances, $90.0 million were designated Tranche B Advances (as defined in the Revolving Credit Facility) as of December 19, 2016, which Tranche B Advances may not be reborrowed once they have been repaid or prepaid. The Revolving Credit Facility was available to fund working capital and general partnership purposes, including the making of certain permitted restricted payments, subject to the limitations therein, including financial compliance, no default and distributable cash flow. Borrowings under the revolving Credit Facility were secured by substantially all of our assets. In connection with the closing of the IPO, we fully repaid and terminated the Revolving Credit Facility and Term Loan and entered into our New Credit Facility. For more information on our New Credit Facility, please see "Our New Credit Facility" below.

Loans under the Revolving Credit Facility bore interest at a rate that is equal to either a base rate or the London Interbank Offered Rate ("LIBOR"), plus the Applicable Margin (as defined in the Revolving Credit Facility), which was 375 basis points for base rate loans and 475 basis points for LIBOR loans. The base rate was a fluctuating rate of interest per annum equal to the highest of (a) the U.S. prime rate in effect for such day, (b) the sum of the federal funds rate in effect for such day plus 50 basis points per annum and (c) daily one-month LIBOR plus 100 basis points. The unused portion of our Revolving Credit Facility was subject to a commitment fee equal to 50 basis points per annum. Upon any event of default, the interest rate would increase by 2% per annum for the period during which the event of default exists.

The Revolving Credit Facility contained certain customary representations and warranties, affirmative covenants, negative covenants and events of default. The negative covenants included restrictions on our ability to incur additional indebtedness, acquire and sell assets, create liens, make investments and make distributions.

The Revolving Credit Facility required us to maintain a maximum Tranche B Loan to Value Ratio (as defined in the Revolving Credit Facility) of no greater than 70% for each quarter ended after December 19, 2016 and not to permit Liquidity (as defined in the Revolving Credit Facility) to be less than $7.5 million at each calendar month-end. We were in compliance with these debt covenants at December 31, 2017.

If an event of default (as such term was defined in the Revolving Credit Facility) were to occur, the agent would be entitled to take various actions, including the acceleration of amounts due under the Revolving Credit Facility, termination of the commitments under the Revolving Credit Facility and all remedial actions available to a secured creditor. The events of default included customary events for a financing agreement of this type, including, without limitation, payment defaults, material inaccuracies of representations and warranties, defaults in the performance of affirmative or negative covenants (including financial covenants), bankruptcy or related defaults, defaults relating to judgments, breach or nonperformance under a material contract, the occurrence of a change in control and breach, non-performance or early termination of any material contract.

The indebtedness, obligations and liabilities arising under or in connection with the Revolving Credit Facility were unconditionally guaranteed by our subsidiaries.

Term Loan

During 2017, we had a $40 million Term Loan maturing on December 19, 2020. We received $35 million under the Term Loan on December 19, 2016, of which $22 million was used to pay down our Revolving Credit Facility. The remaining $5 million was subsequently funded in January 2017. The Term Loan was secured on a second lien basis and was subordinate to our Revolving Credit Facility. In connection with the closing of the IPO, we converted $33.6 million of outstanding indebtedness under our Term Loan into shares of common stock of the Company, fully repaid and terminated the Revolving Credit Facility and our Term Loan and to entered into our New Credit Facility. For more information on our New Credit Facility, please see "Our New Credit Facility" below.

The outstanding principal amount of the Term Loan, together with the accrued and unpaid interest, would have been required to be repaid on the December 19, 2020 maturity date. We were not required to make principal payments under the Term Loan other than at maturity. The Term Loan was not revolving in nature and principal amounts paid or prepaid could not be re-borrowed. Interest on the unpaid principal was at a rate of 10.0% interest per annum and accrued on a daily basis and was paid in arrears at the end of each fiscal quarter. At the end of each quarter all accrued and unpaid interest was paid in kind by capitalizing and adding to the outstanding principal balance. We did not make any cash interest payments on the Term Loan during 2016 and 2017. As December 31, 2017, $4.3 million was capitalized and added to the outstanding principal balance of the Term Loan.

The Term Loan contained certain customary representations and warranties, affirmative covenants, negative covenants and events of default. The negative covenants included restrictions on our ability to incur additional indebtedness, acquire and sell assets, create liens, make investments and make distributions.

The Term Loan agreement required the maximum Tranche B Loan to Value Ratio (as defined in the Revolving Credit Facility) not to be greater than 77% for each quarter ending after December 19, 2016 and not to permit liquidity to be less than $6.75 million at each calendar month-end. We were in compliance with these debt covenants at December 31, 2017.

If an event of default (as such term is defined in the Term Loan) occurred, the agent would be entitled to take various actions, including the acceleration of amounts due under the Term Loan, termination of the commitments under the Term Loan and all remedial actions available to a secured creditor. The events of default included customary events for a financing agreement of this type, including, without limitation, payment defaults, material inaccuracies of representations and warranties, defaults in the performance of affirmative or negative covenants (including financial covenants), bankruptcy or related defaults, defaults relating to judgments, breach or nonperformance under a material contract, the occurrence of a change in control and breach, non-performance or early termination of any material contract.

Our New Credit Facility

Concurrently with the closing of our IPO, we entered into a new senior secured asset-based revolving credit facility consisting of a maximum $100 million of revolving credit commitments, with both a swing line with a sublimit of $10 million and letter of credit subfacility with a sublimit of $20 million. As of the closing of our IPO, we had approximately $13.0 million of outstanding borrowings and $60.8 million of availability under our New Credit Facility, which may be utilized for working capital and other general corporate purposes. Borrowings under our new credit facility may vary significantly from time to time depending on our cash needs at any given time.

Our new credit facility was entered into by the Company and certain other domestic subsidiaries of the Company (collectively, the "Borrowers") and evidenced by a credit agreement dated as of February 13, 2018, with Bank of America, N.A., as administrative agent, and certain other financial institutions party thereto (the "New Credit Facility"). Pursuant to the New Credit Facility, the Borrowers are entitled to borrow (and/or request letters of credit be issued) up to the amount of the borrowing base then in effect. The borrowing is determined by the sum of a percentage of value of the Borrowers' billed accounts receivable, unbilled accounts receivable and inventory, subject to customary reserves and eligibility criteria. At no time will the maximum principal amount of revolving credit loans, together with the face amount of letters of credit, under the New Credit Facility be permitted to exceed the lesser of the then effective borrowing base (less any applicable reserves) or $100 million, absent the Borrowers obtaining additional commitments from existing or new lenders. As of the effective date of the New Credit Facility, the initial borrowing base was approximately $77.6 million.

All of the obligations under the New Credit Facility are guaranteed by each of the Borrowers (as to the obligations of each of the other Borrowers) and by certain of the Borrowers’ domestic restricted subsidiaries and secured by a first priority perfected security interest (subject to permitted liens) in substantially all of the personal property of the Borrowers and such subsidiary guarantors, excluding certain assets.

Loans to the Borrowers under the New Credit Facility are base rate loans or LIBOR loans. The applicable margin for base rate loans vary from 1.50% to 2.00% per annum, and the applicable margin for LIBOR loans will vary from 2.50% to 3.00% per annum, in each case depending on the Borrowers’ average daily usage of the New Credit Facility during the preceding fiscal quarter. The Borrowers are permitted to repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs.

In addition, a fee of either 0.50% or 0.625% (depending upon usage of the New Credit Facility) per annum will be charged on the average daily unused portion of the revolving commitments. Such fee is payable quarterly in arrears.

The New Credit 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 Credit Facility at or above specified thresholds or by the existence of an event of default under the New Credit Facility. Certain baskets and carve-outs from the negative covenants, including as to permit certain restricted payments and investments, are subject to maintaining availability under the New Credit Facility at or above a specified threshold and the absence of a default under the New Credit Facility.

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

The New Credit 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 Credit Facility, the lenders will be able to declare any outstanding principal balance of our New Credit 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 Credit Facility.

Capital Requirements and Sources of Liquidity

During 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 services business segment, pressure pumping services business segment, pressure control services business segment and wireline services business segment, respectively, for aggregate net capital expenditures of approximately $21.2 million primarily for the activation of our third and fourth frac spreads and standard maintenance.

For the year ended December 31, 2016, our capital expenditures, excluding acquisitions, were approximately $6.5 million, $0.1 million, $0.7 million and $0.0 million in our directional drilling services business segment, pressure pumping services business segment, pressure control services business segment and wireline services business 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.

For the year ended December 31, 2015, our aggregate capital expenditures were approximately $14.6 million. This amount includes approximately $4.4 million, $4.0 million and $6.2 million, respectively, allocated to our directional drilling, pressure pumping services and wireline services business segments, including the purchase of new drilling motors and wireline units.

We currently estimate that our capital expenditures for our existing fleets and approved capacity additions during 2018 will range from $75.0 million to $85.0 million, including approximately $20.0 million to $22.0 million for the remaining cost to purchase equipment for our fourth pressure pumping fleet, approximately $14.0 million to $17.0 million to invest in large diameter coiled tubing units, and the remainder for maintenance and other capital expenditures. We expect to fund these expenditures through a combination of cash on hand, cash generated by our operations and borrowings under our New Credit Facility.

We believe that the proceeds from the IPO, our operating cash flow and available borrowings under our New Credit Facility will be sufficient to fund our operations for at least the next 12 months. As drilling and completion activity in the United States has increased with the rise in commodity prices since 2016, our cash flow from operations has begun to improve and we expect cash flows to continue to improve if drilling and completion activity continues to increase. However, 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. 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 2018 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 Credit 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.

Contractual and Commercial Obligations

The following table summarizes our contractual obligations and commercial commitments as of December 31, 2017 (in thousands):

	Total	Less Than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Contractual obligations:					
Long-term debt, including current portion(1)	$123,399	$ 79,071	$44,328	$ —	$ —
Operating lease obligations(2)	34,667	12,204	14,820	6,096	1,547
Capital lease obligations(3)	5,900	702	1,371	1,260	2,567
Purchase commitments to sand suppliers(4)	12,868	5,989	6,879	—	—
	$176,834	$ 97,966	$67,398	$ 7,356	$ 4,114

(1) The long-term debt excludes interest payments on each obligation. The table above does not reflect our use of a portion of the net proceeds from the IPO, along with borrowings under our New Credit Facility, to fully repay all outstanding borrowings under and terminate our Revolving Credit Facility and Term Loan.

(2) Operating lease obligations relate to equipment, tools, office facilities and other property.

(3) Capital lease obligations relate to long-term facilities leases.

(4) The purchase commitments to sand suppliers represent our monthly obligation to purchase a minimum amount of sand from each of two sand suppliers. If the minimum purchase requirement is not met, the shortfall is settled at the end of the year in cash. Pricing in both contracts is based on an index tied to the WTI spot price and based on whether delivery is taken at the location of the applicable plant. Disclosure in this table provides the Company's purchase obligations based on minimum liquidated damages and assumes that the WTI spot price is below $70.00/Bbl and $62.50/Bbl for each of the two contracts.

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, 2017.

Critical Accounting Policies

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 LP'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 four 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, 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 the allowance. At December 31, 2015, allowance for bad debts totaled $1 million, or 2.1% of accounts receivable before the allowance. See Note 2 to the consolidated financial statements for further information.

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, 2017, 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.

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 stock or common units on the grant date of our equity based compensation, our management utilizes three valuation methodologies: (i) discounted cash flow ("DCF") analysis, (ii) public peer trading analysis and (iii) asset value analysis. We have consistently used DCF analysis and public peer trading analysis in our equity valuations over time, and starting mid-2016, incorporated an asset value analysis as well given the deterioration of our cash flow (our operating cash flows trended negative in 2016) and liquidity during that period, leading to the conclusion that incorporating an asset value analysis was appropriate as well.

- 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 asset value analysis is a more conservative valuation approach based on the intrinsic liquidation value of our property, plant and equipment and working capital rather than the our cash flow potential. We from time to time obtain asset appraisals completed by an independent third party and will take the most recent appraisal into account in connection with this liquidation analysis. For example, we obtained a third-party appraisal in October 2016 for our Revolving Credit Facility lenders that we considered in connection with performing the asset value analysis in February 2017. There is subjectivity in determining the liquidation values of our assets as there are limited comparable transactions and auctions to clearly point to a market value.

The equity values derived by these three methodologies 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.

Upon the closing of the IPO, we recognized approximately $10.0 million of equity based compensation expense.

Recent Accounting Pronouncements

See Note 1 to our audited consolidated financial statements for a discussion of recently issued accounting pronouncements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The demand, pricing and terms for oil and gas services provided by us are largely dependent upon the level of activity for the U.S. oil and natural gas industry. Industry conditions are influenced by numerous factors over which we have no control, including, but not limited to: the supply of and demand for oil and natural gas; the 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 expected rates of declining current production; the discovery rates of new oil and natural gas reserves; available pipeline and other transportation capacity; weather conditions; domestic and worldwide economic conditions; political instability in oil-producing countries; environmental regulations; technical advances affecting energy consumption; the price and availability of alternative fuels; the ability of oil and natural gas producers to raise equity capital and debt financing; and merger and divestiture activity among oil and natural gas producers.

The level of activity in the U.S. oil and natural gas E&P industry is volatile. Expected trends in oil and natural gas production activities may not continue and demand for our services may not reflect the level of activity in the industry. Any prolonged substantial reduction in oil and natural gas prices would likely affect oil and natural gas production levels and therefore affect demand for our services. A material decline in oil and natural gas prices or U.S. activity levels could have a material adverse effect on our business, financial condition, results of operations and cash flows. Demand for our services has continued to improve since May 2016 after our industry experienced a significant downturn beginning in late 2014. Our improving outlook in both activity levels and margin performance are based on our relative scale and strong positioning in each of our four business segments. Should oil and gas prices again decline, the demand for the services we offer could be negatively impacted.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2017, 2016 and 2015. Although the impact of inflation has been insignificant in recent years, it is still a factor in the U.S. economy and we tend to experience inflationary pressure on the cost of oilfield services and equipment as increasing oil and gas prices increase drilling activity in our areas of operations and the rest of equipment, materials and supplies required for our services increase.

Interest Rate Risk

We had a cash and cash equivalents balance of $8.8 million at December 31, 2017. We do not enter into investments for trading or speculative purposes. We do not believe that we have any material exposure to changes in the fair value of these investments as a result of changes in interest rates. Declines in interest rates, however, will reduce future income from cash equivalent investments.

We had $79.1 million outstanding under the Revolving Credit Facility at December 31, 2017, which had a weighted average interest rate on amounts borrowed under the Revolving Credit Facility of approximately 6.1%. Based on the Company's debt structure as of December 31, 2017, a 1.0% increase or decrease in the interest rates would increase or decrease interest expense by approximately $1.2 million per year. In connection with the closing of the IPO, we converted $33.6 million of outstanding indebtedness under our Term Loan into shares of common stock of the Company, fully repaid and terminated the Revolving Credit Facility and the remaining borrowings under our Term Loan and to enter into our New Credit Facility. For more information on our New Credit Facility, please see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Our New Credit Facility" above. Our New Credit Facility also has a variable interest rate. Our Term Loan had a fixed paid-in-kind interest rate of 10.0% per annum. We do not currently hedge our interest rate exposure.

Item 8. Financial Statements and Supplementary Data

Index to Consolidated Financial Statements

QUINTANA ENERGY SERVICES LP (PREDECESSOR)

Report of Independent Registered Public Accounting Firm

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

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Quintana Energy Services LP and its subsidiaries as of December 31, 2017 and 2016, and the related consolidated statements of operations, of partners' equity and of cash flows for each of the three years in the period ended December 31, 2017, 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, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 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.

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 29, 2018

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

QUINTANA ENERGY SERVICES LP
(PREDECESSOR)

CONSOLIDATED BALANCE SHEETS

	December 31, 2017	December 31, 2016
	(in thousands of dollars and units, except unit data)	
Assets		
Current assets		
Cash and cash equivalents	$ 8,751	$ 12,219
Accounts receivable, net of allowance of $776 and $880, respectively	83,325	36,745
Unbilled receivables	9,645	7,692
Assets held for sale	—	27,278
Inventories	22,693	19,549
Prepaid expenses and other current assets	9,520	5,547
Total current assets	133,934	109,030
Property, plant and equipment, net	128,518	150,706
Intangibles assets, net	10,832	13,228
Other assets	2,375	967
Total assets	$ 275,659	$ 273,931
Liabilities and Partners' Equity		
Current liabilities		
Current portion of debt and capital lease obligations	$ 79,443	$ 291
Accounts payable	36,027	28,124
Accrued liabilities	33,825	18,511
Total current liabilities	149,295	46,926
Deferred tax liability	185	135
Long-term debt, net of deferred financing costs of $1,709 and $2,284, respectively	37,199	116,463
Long-term capital lease obligations	3,829	4,044
Other long-term liabilities	183	239
Total liabilities	190,691	167,807
Commitments and contingencies (Note 13)		
Partners' equity		
Common units, 417,441 issued and outstanding	212,630	212,630
Retained deficit	(127,662)	(106,506)
Total partners' equity	84,968	106,124
Total liabilities and partners' equity	$ 275,659	$ 273,931

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

QUINTANA ENERGY SERVICES LP
(PREDECESSOR)

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended		
	December 31, 2017	December 31, 2016	December 31, 2015
	(in thousands of dollars and units, except per unit data)		
Revenues:	$ 438,033	$ 210,428	$ 189,255
Costs and Expenses:			
Direct operating expenses	332,695	182,928	153,068
General and administrative expenses	72,770	73,600	51,798
Depreciation and amortization	45,687	78,661	39,682
Fixed asset impairment	—	1,380	—
Goodwill impairment	—	15,051	40,250
Gain on bargain purchase	—	—	(39,991)
(Gain) Loss on disposition of assets	(2,639)	5,375	302
Operating loss	(10,480)	(146,567)	(55,854)
Interest expense	(11,251)	(8,015)	(3,086)
Other income	666	—	—
Loss before tax	(21,065)	(154,582)	(58,940)
Income tax expense	(91)	(167)	(101)
Net loss	$ (21,156)	$ (154,749)	$ (59,041)
Net loss per common unit:			
Basic	$ (0.05)	$ (0.37)	$ (0.25)
Diluted	$ (0.05)	$ (0.37)	$ (0.25)
Weighted average common units outstanding:			
Basic	417,441	417,032	232,318
Diluted	417,441	417,032	232,318

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

QUINTANA ENERGY SERVICES LP
(PREDECESSOR)

CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY

	Common Unitholders				
	Number of Units	Paid-in Capital	General Partner	Retained Earnings/ (Deficit)	Total Partners' Equity
	(in thousands of dollars)				
Balance at December 31, 2015	409,951	203,669	—	48,243	251,912
Issuance of units through private placement	7,490	3,000	—	—	3,000
Issuance of warrants	—	5,961	—	—	5,961
Net loss	—	—	—	(154,749)	(154,749)
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

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

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QUINTANA ENERGY SERVICES LP
(PREDECESSOR)

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended		
	December 31, 2017	December 31, 2016	December 31, 2015
	(in thousands of dollars)		
Cash flows from operating activities			
Net loss	$ (21,156)	$ (154,749)	$ (59,041)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities			
Depreciation and amortization	45,687	78,661	39,682
(Gain) Loss on disposition of assets	(10,500)	1,268	(1,367)
Non cash interest expense	5,960	845	622
Fixed asset impairment	—	1,380	—
Goodwill impairment	—	15,051	40,250
Gain on bargain purchase	—	—	(39,991)
Provision for doubtful accounts	289	142	294
Deferred income tax expense (benefit)	50	(42)	(128)
Changes in operating assets and liabilities:			
Accounts receivable	(46,869)	9,688	69,068
Unbilled receivables	(1,953)	(4,213)	5,447
Inventories	(3,144)	1,559	229
Prepaid expenses and other current assets	1,812	3,894	1,337
Other noncurrent assets	(1,439)	632	273
Accounts payable	6,969	8,842	(13,517)
Accrued liabilities	12,810	(5,778)	(11,083)
Other long-term liabilities	(56)	(15)	—
Net cash provided by (used in) operating activities	(11,540)	(42,835)	32,075
Cash flows from investing activities			
Purchases of property, plant and equipment	(21,244)	(7,340)	(14,555)
Acquisition of property, plant, equipment and related intangibles	—	—	(43,583)
Proceeds from sale of property, plant and equipment	35,754	9,606	3,700
Net cash provided by (used in) investing activities	14,510	2,266	(54,438)
Cash flows from financing activities			
Proceeds from revolving debt	11,035	35,159	53,700
Payments on revolving debt	(21,964)	(22,000)	(37,977)
Proceeds from term loans	5,000	28,600	—
Proceeds from warrants, net of issuance costs	—	5,961	—
Payments on capital lease obligations	(315)	(317)	—
Issuance of units	—	1,000	—
Payment of deferred financing costs	(194)	(1,878)	(39)
Net cash provided by (used in) financing activities	(6,438)	46,525	15,684
Net increase (decrease) in cash and cash equivalents	(3,468)	5,956	(6,679)
Cash and cash equivalents			
Beginning of period	12,219	6,263	12,942
End of period	$ 8,751	$ 12,219	$ 6,263
Supplemental cash flow information			
Cash paid for interest	5,755	5,935	2,065
Income taxes paid	77	198	618
Supplemental noncash investing and financing activities			
Prepaid insurance financed through note payable	1,666	950	888
Fixed asset purchase in accounts payable and accrued liabilities	934	93	10

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

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(PREDECESSOR)

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended		
	December 31, 2017	December 31, 2016	December 31, 2015
	(in thousands of dollars)		
Conversion of accrued interest to debt	4,202	126	—
Non cash payment for property, plant and equipment	711	—	—
Non cash proceeds from sale of assets held for sale	3,990	—	—
Assets acquired in a business combination	—	—	162,766
Liabilities assumed in a business combination	—	—	30,057
Equity issued for a business combination	—	—	129,841
Equity issued as payment in kind for professional services	—	2,000	—

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Nature of Operations

Quintana Energy Services LP ("the Company", "QES", "we", or "our") is a privately owned oilfield services company that is majority owned by Quintana Energy Partners, L.P., an affiliate of Quintana Capital Group, L.P. ("Quintana") and Archer Limited ("Archer"). The Company provides a wide range of completion, production, directional drilling services, pressure pumping, and other complimentary oilfield services to land-based exploration and production customers operating in unconventional resource plays and conventional basins throughout the United States.

The Company operates through four reporting segments, which include Pressure Pumping, Directional Drilling, Wireline, and Pressure Control.

NOTE 2—BASIS OF PRESENTATION AND PRINCIPLES OF CONSOLIDATION

The accompanying 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 the accounts of QES and all our subsidiaries, which are 100% owned. All significant inter-company transactions and account balances have been eliminated upon consolidation.

Certain prior year amounts have been reclassified to conform to current year presentation. These reclassifications had no impact on the Company's results of operations, financial position or changes in partner's equity.

Segment Reporting

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

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 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 14 - 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.

QUINTANA ENERGY SERVICES LP
(PREDECESSOR)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Revenue Recognition

QES generates revenue from multiple sources within its four operating segments. In all cases, revenue is recognized when services are performed, the collection of the receivables is probable, persuasive evidence of an arrangement exists, and the price is fixed or determinable. Services are sold without warranty. The specific revenue sources are outlined as follows:

Pressure pumping services revenue. Through its pressure pumping services business 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 frac 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 services revenue. Through its directional drilling services business 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 services revenue. Through its pressure control services business 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 services revenue. Through its wireline services business 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.

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.

QUINTANA ENERGY SERVICES LP
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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

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, 2017 and 2016, the allowance for doubtful accounts was approximately $0.8 million and $0.9 million, respectively. Bad debt expense of $0.3 million was included in selling, general and administration expenses on the consolidated statement of operations for the years ended December 31, 2017, 2016 and 2015.

Unbilled Receivables

Unbilled receivables are the amounts of recoverable revenue that have not been 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 our directional drilling services segment. All other segments are determined using the first-in, first-out method (“FIFO”).

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 year ended December 31, 2017. For the year ended December 31, 2016, an impairment of $1.4 million was recognized on assets that were held for sale, sold shortly after the year ended before the report was issued.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 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 of each year, 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 used the income and market approaches to estimate the fair value of its reporting units. The income approach was based on a discounted cash flow model, which utilizes present values of estimated cash flows to estimate fair value. The future cash flows were 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 rig count, and negative cash flows, was taken into consideration. The future cash flows are discounted using a market-participant risk-adjusted weighted average cost of capital. These assumptions were 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 were derived and applied to the estimated earnings of the reporting unit to determine an estimated fair value. Earnings estimates were 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 and were $1.0 million, $0.8 million, and $0.6 million for the years ended December 31, 2017, 2016, and 2015, respectively. Included within the $0.8 million expensed in 2016, is $0.3 million relating to debt modification as a result of the credit amendment. Unamortized deferred financing costs were $2.2 million and $3.0 million at December 31, 2017 and 2016, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Income Taxes

Except for two immaterial subsidiaries that are c-corporations subject to U.S Federal tax and taxable in certain states, the Company and its subsidiaries are treated as partnerships or disregarded entities for U.S. federal income tax purposes. Accordingly, taxable income and losses, with the exceptions noted above, are reported on the income tax returns of the members of the Company. Partners are taxed individually on their share of the Company's earnings.

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, 2017, since we are a pass-through entity, management considers that the abovementioned Act will have an immaterial impact. However, going forward, the Company will analyze the impact based on revised circumstances.

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.

Unit-based compensation

The Company records compensation relating to unit-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, based on the calculated fair value of the award. See "Note 15—Unit-Based Compensation" for additional information related to unit-based compensation.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Recent Accounting Pronouncements

Standard adopted

In July 2015, the Financial Accounting Standards Board ("FASB") issued accounting standards update ("ASU") No. 2015-11, *Inventory – Simplifying the Measurement of Inventory*, which applies to inventory measured using first-in, first-out or average cost. The guidance in this update states that inventory within its scope shall be measured at the lower of cost or net realizable value, and when the net realizable value of inventory is lower than its cost, the difference shall be recognized as a loss in earnings. The Company adopted the accounting guidance as of January 1, 2017. The adoption of this ASU did not have a material impact on the Company's consolidated financial statements.

In April 2015, the FASB issued ASU 2015-03, *Simplifying the Presentation of Debt Issuance Costs*, which requires debt issuance costs to be presented in the balance sheet as a direct deduction from the carrying value of the associated debt liability, consistent with the presentation of a debt discount. The Company adopted this new accounting standard, and as a result, debt issuance costs related to the term loan in 2016 (see "Note 8 – Long-Term Debt and Capital Lease Obligations") is presented in the balance sheet as a direct deduction from the carrying amount of the debt liability. The unamortized debt issuance related to the revolving credit facility continues to be presented as an asset.

Standards not yet adopted

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers*, a comprehensive new revenue recognition standard that will supersede the existing revenue recognition guidance. The new accounting guidance creates a framework by which an entity will allocate the transaction price to separate performance obligations and recognize revenue when each performance obligation is satisfied. Under the new standard, entities will be 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 as of 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 as of the current period. In July and December 2016, the FASB issued various additional authoritative guidance for the new revenue recognition standard. The accounting standard will be effective for reporting periods beginning after December 15, 2017 and is not expected to have a material impact on the Company's consolidated financial position, results of operations and cash flows. The Company has elected the modified retrospective method of adoption.

In February 2016, the FASB issued ASU No. 2016-02, *Leases*. The new standard requires lessees to recognize a right of use asset and a lease liability for virtually all leases. The guidance is effective for the Company for the fiscal year beginning January 1, 2019. While the exact impact of this standard is not known, the guidance is expected to have a material impact on the Company's consolidated financial statements, due to the leased assets and corresponding lease liability that will be recognized, as the Company has operating and real property lease arrangements for which it is the lessee.

In January, 2017, the FASB issued ASU 2017-01, *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, which can be early adopted, is effective for the Company beginning on January 1, 2018. The Company will assess the impact in the event the Company has a business combination.

In May 2017, the FASB issued ASU 2017-09, *Compensation* (Topic 718): scope of Modification Accounting, which clarifies what constitutes a modification of a share-based payment award. This update is effective for fiscal years and interim periods within fiscal years beginning after December 16, 2017, with early adoption permitted. There have been no modification of our unit-based payment awards so the standard is not expected to impact the Company.

QUINTANA ENERGY SERVICES LP
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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 3—Goodwill and Intangible assets

During 2016, we recognized an impairment of goodwill totaling $15.1 million, all of which related to our directional drilling services business segment. The Company chose to bypass the qualitative step and move forward to step one of the quantitative steps. The results of step one impairment testing for the directional drilling services business segment during our annual impairment assessment indicated its estimated fair value was less than its carrying value and step two testing determined there was no value remaining to be allocated to the goodwill associated with the directional drilling services business segment. The impairment of goodwill was due to the continual decline in commodity pricing and historical low rig activity in 2015, which continued in 2016. After the impairment of the goodwill that related to our directional drilling services business segment in 2016, the Company had no further goodwill.

Definite-Lived Intangible Assets

There were no triggering events during 2017 and in 2016. The changes in the carrying amounts of other intangible assets for the year ended December 31, 2017 and December 31, 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, 2015	$ 1,750	$ 11,710	$ 4,560	$18,020
Accumulated Amortization	(583)	(901)	(912)	(2,396)
Net Balance as of December 31, 2015	1,167	10,809	3,648	15,624
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

Amortization expense for the years ended December 31, 2017, 2016 and 2015 was approximately $2.4 million for each year.

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

Years Ending December 31,	
2018	$ 1,813
2019	1,813
2020	901
2021	902
Thereafter	5,403
	$10,832

NOTE 4—Assets Held for Sale

There were no assets held for sale as of December 31, 2017. The Company's assets held for sale as of December 31, 2016 were $27.3 million and were all sold during the year ended December 31, 2017. The Company received $27.6 million in sale proceeds of which $4.0 million was a credit for prepaid services and the remainder was cash. These assets consisted of primarily machinery and equipment, and included some vehicles and unused land and buildings in the pressure pumping services business segment.

QUINTANA ENERGY SERVICES LP
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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 5—Inventories

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

	As of December 31,	
	2017	2016
Consumables	$ 7,085	$ 6,056
Spare parts	15,608	13,493
Inventories	$22,693	$19,549

NOTE 6—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 for the years ended December 31, 2017, 2016 and 2015 was $43.3 million, $76.3 million, and $39.7 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, 2017, 2016, and 2015 were $7.9 million, $4.1 million, and $1.7 million respectively. Gain/(loss) related to the sale of PP&E, including assets held for sale, for the years ended December 31, 2017, 2016, and 2015 were $2.6 million, ($5.4) million, and ($0.3) 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,	
		2017	2016
Land	Indefinite	$ 3,999	$ 4,050
Service equipment	1 ½ - 10 years	262,795	250,435
Machinery and equipment	7-15 years	51,333	55,897
Buildings and leasehold improvements	5-39 years	27,061	27,290
Software	3-5 years	2,012	1,123
Office furniture and equipment	3-10 years	2,376	3,098
		349,576	341,893
Less: Accumulated depreciation		(224,764)	(193,985)
		124,812	147,908
Construction in progress		3,706	2,798
Property, plant and equipment, net		$ 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,	
		2017	2016
Machinery and equipment	3 Years	181	—
Buildings and leasehold improvements	20 Years	2,252	2,252
		2,433	2,252
Less: Accumulated depreciation		(415)	(193)
		$2,018	$2,059

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 7—Accrued Liabilities

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

	As of December 31, 2017	2016
Current accrued liabilities		
Accrued payables	$11,905	$ 5,312
Payroll and payroll taxes	6,089	2,322
Bonus	6,019	1,003
Workers compensation insurance premiums	1,760	1,965
Sales tax	2,923	959
Ad valorem tax	728	823
Health insurance claims	913	2,365
Other accrued liabilities	3,488	3,762
Total accrued liabilities	$33,825	$18,511

NOTE 8—Long-Term Debt and Capital Lease Obligations

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

	As of December 31, 2017	2016
Revolving credit facility maturing September 19, 2018	$ 79,071	$ 90,000
10% term loan due December 2020	44,328	35,100
Less: deferred financing costs	(1,709)	(2,284)
Less: discount on term loan	(5,419)	(6,353)
Total debt and capital lease obligations	116,270	116,463
Capital leases	4,200	4,335
Less: current portion of debt and capital lease obligation	(79,443)	(291)
Long-term debt and capital lease obligations	$ 41,028	$120,507

Long-Term Debt

The Company had a revolving credit facility ("the revolving credit facility"), which had a maximum borrowing facility of $110.0 million. All obligations under the credit agreement for the 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. As discussed in detail under "Note 18 – Subsequent Events," subsequent to the year ended December 31, 2017 all obligations under the revolving credit facility were settled in full and the credit agreement was terminated.

The Company also had a four-year $40.0 million term loan agreement with a lending group, which included Archer and an affiliate of Quintana that was scheduled to mature in December 2020. In December 2016, the Company received $35.0 million, of which $22.0 million was used to pay down the facility, and the remaining $5.0 million was received in January 2017. The 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 $6.75 million. The Company was in compliance with debt covenants at December 31, 2017. As discussed in detail under "Note 18–Subsequent Events," subsequent to the year ended December 31, 2017, all obligations under the term loan agreement were settled in full and the agreement was terminated.

Subsequent to the year ended December 31, 2017 the Company entered into a new senior asset-based revolving credit facility consisting of a maximum $100.0 million of revolving credit commitment. See "Note 18 – Subsequent Events" for further details.

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Revolving Credit Facility

As of December 31, 2017, there was $5.4 million of outstanding letters of credit, and $20.0 million available to draw on the revolving credit facility.

The revolving credit facility did not require any principal payments and was scheduled to mature on September 19, 2018. Amounts outstanding under the revolving credit facility bore interest based either on: (i) the adjusted base rate plus an applicable margin of 3.75%, or (ii) the Eurodollar rate plus the applicable margin of 4.75%. The revolving credit facility also required the Company to pay a commitment fee equal to 0.5% of unused commitments. The revolving credit facility was permitted to be prepaid from time to time without premium or penalty.

The weighted average interest on the borrowings outstanding at December 31, 2017, 2016 and 2015 were 6.1%, 5.52%, and 2.74%, respectively.

Term Loan

As of December 31, 2017 and December 31, 2016, $44.3 million and $35.1 million was outstanding under the term loan agreement, respectively. From the original $40.0 million principal, $5.0 million was funded in January 2017.

The outstanding principal amount of the loan, together with the accrued and unpaid interest was required to be repaid on or prior to the December 19, 2020 maturity date. The Company was not required to make principal payments. The loan was not revolving in nature and principal amounts paid or prepaid was not permitted to be re-borrowed. Interest on the unpaid principal was at a rate of 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. The Company did not make any cash interest payments during the year ended December 31, 2017 on the term loan. As of December 31, 2017 and 2016, $4.3 million and $0.1 million was capitalized and included in the outstanding principal balance, respectively.

Capital Lease Obligations

The Company has long-term lease agreements for a manufacturing and office facility for the operations of its pressure control services business segment in Oklahoma City and Elk City, Oklahoma. Each lease is accounted for as a capital lease.

The lease for the facility in Oklahoma City 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 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 interest rates that range from between 5.2% and 16%. These assets created a capital lease obligation of $180,000.

As of December 31, 2017, the future minimum lease payments acquired under the Company’s capital leases are as follows (in thousands of dollars):

Years Ending December 31,	
2018	$ 702
2019	702
2020	669
2021	630
2022	630
Thereafter	2,567
	$5,900

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

NOTE 9—Partners' Equity

The Company's authorized members' capital consisted of 651,101,652 units. On December 19, 2016, in connection with the four-year $40.0 million term loan agreement, the Company issued unrestricted penny warrants to purchase 227,886,000 common units with the debt. The exercise of the penny warrants was at the discretion of the debt holder and were exercisable until December 19, 2026. Subsequent to the year ended December 31, 2017, and in connection with the IPO (as defined below) the warrant holders exercised their warrants for units in the Company and subsequently exchanged such units for common shares of Quintana Energy Services Inc. Following the one-for-one exchange of common units of the Company for shares of common stock in Quintana Energy Services Inc., Quintana Energy Services Inc. consummated a 31.669363 for 1 reverse stock split of its issued and outstanding common stock.

NOTE 10—Income Taxes

A discussion of non-taxable nature of the Company and its subsidiaries and the applicable taxes are detailed in "Note 2 – Basis of Presentation and Principles of Consolidation under Income Taxes."

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

	Years December 31,		
	2017	2016	2015
Current income tax (expense) benefit			
Federal	$(40)	$(244)	$(179)
State	(1)	35	(50)
	(41)	(209)	(229)
Deferred income tax (expense) benefit			
Federal	(45)	37	128
State	(5)	5	—
	(50)	42	128
Total income tax expense	$(91)	$(167)	$(101)

Net deferred tax assets and liabilities were classified in the consolidated balance sheets as follows (in thousands of dollars):

	As of December 31,	
	2017	2016
Deferred tax liabilities		
Property, plant and equipment	$ 185	$ 135

Income tax rates applied to the net income of the taxable entities differs from the statutory tax rates due to various permanent differences in book net income on a U.S. GAAP basis and taxable net income used in the calculation of income taxes. The primary differences between the book net income and taxable net income are due to the benefit of nontaxable flow-through entities, Oklahoma state income taxes, and Texas state franchise taxes.

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The federal tax expense relates to one of the Company's entities whose legal status is a c-corporation. The state tax relates to the Texas margin tax, which is based on Texas sourced taxable margin as discussed in the summary of significant accounting policies.

NOTE 11—Related Party Transactions

The Company utilizes a Quintana affiliate to pay and process the payroll of some of its corporate employees. Such amounts are reimbursed by the Company on a monthly basis.

On December 19, 2016 the Company entered into a new four-year $40.0 million term loan agreement with a lending group, which includes related parties of the Company, including Archer, Quintana, and affiliates of the two related parties (See "Note 8 – Long-Term Debt and Capital Lease Obligations"). The term loan was attached with penny warrants (See "Note 9 – Partners' Equity").

During 2016, the Company had in place a support services agreement with Archer Well Company Inc. on a transitional basis, for the processing of payroll, benefits and certain administrative services during the integration of the entities acquired from Archer Limited in 2015.

At December 31, 2017, 2016, and 2015, QES had the following transactions with related parties (in thousands of dollars):

	As of December 31,	
	2017	2016
Accounts receivable from other affiliates	$ —	$ 22
Accounts payable to affiliates of Quintana	81	780
Accounts payable to affiliates of Archer Well, Inc	9	1,370

	Year Ended December 31,		
	2017	2016	2015
Operating expenses from affiliates of Quintana	$529	$1,628	$1,538
Operating expenses from affiliates of Archer Well, Inc	10	2,095	—

NOTE 12—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, 2017, one customer revenue represented 10.3% 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, 2017 and 2016, one customer had a balance due that represented 18.3% and 11.2% respectively, of the Company's consolidated accounts receivable.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 13—Commitments and Contingencies

Operating Leases

The Company has entered into various non-cancelable operating leases for equipment, tools, office facilities and other property. As of December 31, 2017, the future minimum lease payments under non-cancelable operating leases were as follows (in thousands of dollars):

Year Ending December 31,	
2018	$12,204
2019	9,548
2020	5,272
2021	4,011
2022	2,085
Thereafter	1,547
	$34,667

Rent expense totaled approximately $22.1 million, $11.6 million, $7.6 million for the years ended December 31, 2017, 2016 and 2015, respectively, mostly consisting of tool rental expense.

Purchase Commitments

Pressure Pumping is party to a sand handling services and storage contract originally dated in January 2012 and amended in October 2014. The contract is a three-year agreement requiring the Company to make a monthly payment of approximately $0.1 million for a guaranteed yearly handling rate of 100,000 tons of frac sand. Any excess over the 100,000 tons during a contract year will be charged at a rate of $7.50 per ton. The agreement was effective January 1, 2015.

Pressure Pumping is currently party to product purchase agreements that call for the purchase of 210,000 tons of sand in 2018. The product purchase agreements provide for certain penalties in the event of a shortfall in purchase volumes.

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 its pending litigation and claims is assessed and estimates are 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 the Fair Labor Standards Act ("FLSA") relating to non-payment of overtime pay. 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 14—Segment Information

QES currently has four reportable business segments: directional drilling services, pressure pumping services, pressure control services, and wireline services. These business segments have been selected based on the Company's CODM's assessment of resource allocation and performance. The CODM evaluates the performance of our business segments based on revenue and income measures, which include non-GAAP measures.

The Company views Adjusted EBITDA as an important indicator of segment performance. The Company defines Segment Adjusted EBITDA as net income, plus taxes, interest expense, depreciation and amortization, impairment charges, gain and (loss) on disposition of assets and less gain on bargain purchase. The CODM uses Segment Adjusted EBITDA as the primary measure of segment operating performance.

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

	Year Ended December 31, 2017	2016	2015
Directional drilling services	$ 17,498	(76)	$ 2,502
Pressure pumping services	27,784	(19,372)	(2,497)
Pressure control services	6,539	(5,804)	—
Wireline services	(1,794)	(6,161)	(5,833)
Corporate and Other Non-Recurring Expenses	(16,793)	(14,687)	(9,783)
Income tax expense	(91)	(167)	(101)
Interest expense	(11,251)	(8,015)	(3,086)
Depreciation and amortization	(45,687)	(78,661)	(39,682)
Fixed asset impairment	—	(1,380)	—
Goodwill impairment	—	(15,051)	(40,250)
Gain on bargain purchase	—	—	39,991
Gain (Loss) on disposition of assets, net	2,639	(5,375)	(302)
Net loss	**(21,156)**	**(154,749)**	**(59,041)**

Financial information related to the Company's financial position as of December 31, 2017, 2016, and 2015, by segment, is as follow (in thousands of dollars):

	Total assets As of December 31, 2017	2016
Directional drilling services	$ 82,789	$ 72,589
Pressure pumping services	111,322	126,066
Pressure control services	52,884	42,813
Wireline services	28,988	27,391
Total	275,983	268,859
Corporate & Other	7,695	11,127
Eliminations	(8,019)	(6,055)
Total assets	$275,659	$273,931

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

	Directional Drilling Services	Pressure Pumping Services	Pressure Control Services	Wireline Services	Total
Year Ended December 31, 2017					
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

	Directional Drilling Services	Pressure Pumping Services	Pressure Control Services	Wireline Services	Total
Year Ended December 31, 2016					
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

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	Directional Drilling Services	Pressure Pumping Services	Pressure Control Services	Wireline Services	Total
Year Ended December 31, 2015					
Revenues	$ 98,129	$ 85,485	$ —	$ 5,641	$189,255
Depreciation and amortization	14,684	23,350	—	1,648	39,682
Capital expenditures	4,354	4,040	—	6,161	14,555

NOTE 15 – Unit-Based Compensation

Our officers, directors and key employees may be granted units awards in the form of phantom units, which is an award of common units with no exercise price, where each unit represents the right to receive, at the end of a stipulated period, one unrestricted membership unit with no exercise price, subject to the terms of the phantom unit agreement. Full vesting of the units is based on dual vesting components. The first is the time vesting component and the second is a performance-based vesting component which are met by the consummation of a specified transaction, which includes a change in control, a partnership public offering, or a reverse merger. As of December 31, 2017, total unamortized compensation costs related to unvested stock awards was $28.9 million.

2015 Grant

During 2015, 5.8 million phantom units were awarded to executive officers, none of which had fully vested as of December 31, 2017. The time vesting component was met as of December 31, 2015. A specified transaction being consummated is not within the control of the Company, was not consummated as of December 31, 2017 and accordingly, was not considered probable. As a result, no expense has been recognized relating to this grant.

2017 Grant

During the year ended December 31 2017, 46.3 million phantom units were awarded to executive officers and key management, none of which had fully vested as of December 31, 2017. The time vesting component vests equally over four years. A specified transaction being consummated is not within the control of the Company was not consummated as of December 31, 2017, and accordingly, was not considered probable. As a result, no expense has been recognized relating to this grant.

The phantom unit agreements call for each phantom unit to be settled for one unit unless the board of directors of the Company, in its discretion, elects to pay an amount of cash equal to the fair market value of a unit on the full vesting date. As of December 31, 2017, there were approximately 52 million phantom units granted, none of which had fully vested, due to the transaction consummated vesting provision noted above. There were no expenses relating to the phantom units recorded during the years ended December 31, 2017, 2016, and 2015, respectively.

Roll forward of phantom units as of December 31, 2017 is as follows:

	Number of Units (in thousands)	Grant Date Fair Value per Unit	Weighted Average Remaining Life (in years)
Outstanding at December 31, 2015	5,775	$ 0.66	—
Granted	—	—	—
Forfeited	—	—	—
Expired	—	—	—
Outstanding at December 31, 2016	5,775	$ 0.66	—
Granted	46,300	0.55	3.46
Forfeited	(543)	0.55	—
Expired	—	—	—
Outstanding at December 31, 2017	51,532	$ 0.56	3.46

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NOTE 16 – Loss Per Unit

Basic loss per units ("EPS") is based on the weighted average number of common units outstanding during the period. Diluted EPS includes additional common units that would have been outstanding if potential common units with dilutive effect had been issued. A reconciliation of the number of units used for the basic and diluted EPS computations is as follows:

	Years Ended December 31,		
	2017	2016	2015
	(In thousands, except per unit amounts)		
Numerator:			
Net loss attributed to common unit holders	$ (21,156)	$(154,749)	$ (59,041)
Denominator:			
Weighted average common units outstanding – basic	417,441	417,032	232,318
Weighted average common units outstanding – diluted	417,441	417,032	232,318
Net loss per common unit:			
Basic	$ (0.05)	$ (0.37)	$ (0.25)
Diluted	$ (0.05)	$ (0.37)	$ (0.25)

The Company has issued potentially dilutive instruments such as warrants and phantom units. However, the Company did not include these instruments in its calculation of diluted loss per unit for the periods presented, because to include them would be anti-dilutive. The following shows potentially dilutive instruments:

	Years Ended December 31,		
	2017	2016	2015
	(In thousands)		
Warrants	227,886	227,886	—
Phantom Units	51,532	5,775	5,775
	279,418	233,661	5,775

NOTE 17 – Selected Quarterly Selected Data (Unaudited)

The following tables sets forth certain unaudited financial and operating information for each quarter in the years ended December 31, 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 2017			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenue	$ 85,439	$108,457	$113,274	$130,863
Cost and Expenses:				
Direct operating Expenses	66,836	80,935	89,082	95,842
General and administrative expenses	17,743	16,757	19,441	18,829
Depreciation and amortization	11,594	11,432	11,238	11,423
Loss (gain) on disposition of assets, net	(1,657)	(332)	(310)	(340)
Operating income (loss)	(9,077)	(335)	(6,177)	5,109
Interest, expense, net	(2,601)	(2,788)	(2,901)	(2,961)
Other income (expense), net	—	—	724	(58)
Income (loss) before income taxes	(11,678)	(3,123)	(8,354)	2,090
Income tax (expense) benefit – Federal	6	9	(84)	(22)
Net income (loss)	$(11,672)	$ (3,114)	$ (8,438)	$ 2,068

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	Year Ended December 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 income (loss)	(38,848)	(30,878)	(43,599)	(33,242)
Interest, expense, net	(1,460)	(1,674)	(2,405)	(2,476)
Income (loss) before income taxes	(40,308)	(32,552)	(46,004)	(35,718)
Income tax (expense) benefit – Federal	34	(81)	20	(140)
Net income (loss)	$(40,274)	$(32,633)	$(45,984)	$(35,858)

NOTE 18- Subsequent Events

Subsequent to the year ended December 31, 2017, on February 9, 2018, in connection with the filing of the registration statement on Form S-1 under the Securities Act of 1933 for the initial public offering (the “IPO”) of shares of common stock of the Quintana Energy Services Inc. (“QES Inc.”), QES Inc. was formed as a Delaware corporation to become a holding corporation for the Company and its subsidiaries. Immediately prior to the completion of the IPO (as discussed above), QES Holdco LLC and Archer Holdco LLC, who owned the general partner interest in Quintana Energy Services LP, contributed all their interest in Quintana Energy Services GP LLC to QES Inc. The existing investors of the Company contributed all of their direct and indirect equity interests to QES Inc. in exchange for shares of common stock in QES Inc. These transactions are referred to collectively as the “Organizational Transactions.” As a result, all membership interests in the Company were exchanged for an aggregate of 23,780,752 shares of common stock in QES Inc. The Organizational Transactions represented a transaction between entities under common control and will be accounted for similar to pooling of interest, whereby QES Inc. became the successor and the Company the predecessor for the purposes of financial reporting.

On February 13, 2018, QES Inc. completed its IPO of 9,259,259 shares of its common stock. The gross proceeds of the IPO to the Company, at the public offering price of $10.00 per share, was $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 $4.2 million in offering expenses payable by us with respect to the shares sold by QES Inc. 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% term loan due 2020, as described in “Note 8-Long-Term Debt and Capital Lease Obligations.” The remaining proceeds will be used for general corporate purposes. In connection with the consummation of the IPO, on March 9, 2018, the underwriters exerised their over allotment option to purchase an additional 372,824 shares of common stock of QES Inc., which resulted in additional net proceeds of approximately $3.5 million (the “Option Exercise”). Upon the completion of the Option Exercise, QES Inc. had 33,630,934 shares of common stock outstanding.

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On February 13, 2018, QES Inc., and the guarantors party thereto entered into an 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 revolving credit facility, which was scheduled to mature on September 19, 2018, as described in “Note 8-Long-Term Debt and Capital Lease Obligations,” which agreement was terminated in connection 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 the borrowing capacity was $77.6 million. Upon closing of the New ABL Facility, $13.0 million was immediately drawn. No early termination fees were incurred by the Company in connection with the termination of the revolving credit facility.

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. The Company's disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by the Company in reports that it files under the Exchange Act is accumulated and communicated to its management, including its principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. As required by Rule 13a-15(b) under the Exchange Act, the Company's management, with the participation of its principal executive officer and principal financial officer, have evaluated the effectiveness of the Company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2017. Based upon that evaluation, the Company's principal executive officer and principal financial officer concluded that its disclosure controls and procedures were effective at a reasonable assurance level as of December 31, 2017.

Management's Report Regarding Internal Control; Attestation report of the registered public accounting firm. This Annual Report does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of the Company's registered public accounting firm due to a transition period established by rules of the SEC for newly public companies. A report of management's assessment regarding internal control over financial reporting will be required to be included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2018, and the attestation report of the Company's registered public accounting firm will not be required so long as the Company is an emerging growth company.

Changes in Internal Control over Financial Reporting. We and our independent registered public accounting firm identified material weaknesses in our internal control over financial reporting as of December 31, 2017 and 2016. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis. To facilitate the ongoing maintenance and period end closing of the Company books, at certain QES entities, certain individuals are not prevented from both initiating and recording ("creating and posting") journal entries into the general ledger without proper monitoring or manual approval of the journal entries. Additionally, within certain QES entities' accounting systems, members of management have access to and use a 'super user' account without monitoring, which grants users significant conflicting capabilities and does not allow for tracking of the user's activities. Therefore, individuals have the ability to record and/or alter entries within the Company's general ledger without appropriate review, leading to a reasonable possibility of a material misstatement of the financial statements.

We are in the process of implementing measures designed to improve our internal control over financial reporting and remediate the control deficiencies that led to the material weaknesses, including actively seeking to recruit additional finance and accounting personnel, are evaluating and formalizing the roles and responsibilities of our finance and accounting personnel across our business units. We can give no assurance that these actions will remediate this deficiency in internal control or that additional material weaknesses or significant deficiencies in our internal control over financial reporting will not be identified in the future. Additionally, the material weaknesses could result in misstatements to our financial statements or disclosures that would result in material misstatements to our annual or interim consolidated financial statements that would not be prevented or detected. Except as described herein, there has been no change in our internal control over financial reporting during the quarter ended December 31, 2017 that has materially affected, or is 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

Information About Our Directors and Executive Officers

Set forth below are the name, age, position and description of the business experience of each of our executive officers and directors as of March 27, 2018. The address of each director and executive officer is: 1415 Louisiana Street, Suite 2900, Houston, TX 77002. There are no family relationships among any of our directors or executive officers.

Name	Age	Position
D. Rogers Herndon	49	Chief Executive Officer, President and Director
Christopher J. Baker	45	Executive Vice President and Chief Operating Officer
Keefer M. Lehner	32	Executive Vice President and Chief Financial Officer
Max L. Bouthillette	49	Executive Vice President, General Counsel, Chief Compliance Officer and Corporate Secretary
Corbin J. Robertson, Jr.	70	Director and Chairman of the Board of Directors
Dalton Boutté, Jr.	63	Director
Rocky L. Duckworth	67	Director
Gunnar Eliassen	32	Director
Dag Skindlo	49	Director

D. Rogers Herndon. Mr. Herndon has served as Chief Executive Officer and President and member of the board of directors of the Company since its formation, and has served as Chief Executive Officer and President of QES LP since November 2014. Mr. Herndon joined Quintana Capital Group, L.P. (with its affiliated funds, “Quintana”), one of our Principal Stockholders, in 2011 as a Principal of the Quintana private equity funds and has served in the roles of President, Chief Operating Officer and Chief Investment Officer. Directly prior to joining Quintana, Mr. Herndon served as Executive Vice President and as a member of the Office of the CEO for Reliant/RRI Energy, Inc., responsible for corporate strategy, business development and mergers and acquisitions activities. Mr. Herndon joined Reliant Energy in 2006 as Sr. Vice President of Commercial Operations. Mr. Herndon’s prior experience includes roles as Managing Director, Global Commodities with Bank of America and senior commercial leadership positions with PSEG Energy Resource and Trade and Enron Corp. Mr. Herndon was a co-founder of Phillips Royalty Partners, LP. Mr. Herndon attended Washington and Lee University where he earned a B.A. in Economics and the Wharton School of Business where he received an M.B.A. in Finance. Our board of directors believes Mr. Herndon is qualified to serve on our board due to his extensive background in the energy sector with over 25 years of operating and investing experience.

Christopher J. Baker. Mr. Baker has served as Executive Vice President and Chief Operating Officer of the Company since its formation, and has served in the same role at QES LP since November 2014. Mr. Baker previously served as Managing Director—Oilfield Services of the Quintana private equity funds, where he was responsible for sourcing, evaluating and executing oilfield service investments, as well as overseeing the growth of and managing and monitoring the activities of Quintana’s oilfield service portfolio companies since 2008. Prior to joining Quintana, Mr. Baker served as an Associate with Citigroup Global Markets Inc.’s (“Citi”) Corporate and Investment Bank where he conducted corporate finance and valuation activities focused on structuring non-investment grade debt transactions in the energy sector. Prior to his time at Citi, Mr. Baker was Vice President of Operations for Theta II Enterprises, Inc. where he focused on project management of complex subsea and inland marine pipeline construction projects. Mr. Baker attended Louisiana State University, where he earned a B.S. in Mechanical Engineering, and Rice University, where he earned an M.B.A.

Keefer M. Lehner. Mr. Lehner has served as Executive Vice President and Chief Financial Officer of the Company since its formation. Mr. Lehner has served in that same role at QES LP since January 2017 and previously served as QES LP’s Vice President, Corporate Development of QES LP’s general partner since November 2014. Mr. Lehner previously served in various positions at the Quintana private equity funds, including Vice President, from 2010 to 2014, where he was responsible for sourcing, evaluating and executing investments, as well as managing and monitoring the activities of Quintana’s portfolio companies. During his tenure at Quintana, Mr. Lehner monitored and advised the growth of Q Consolidated Oil Well Services, LLC (“COWS”) and Q Directional Drilling, LLC (“DDC”). Prior to joining Quintana in 2010, Mr. Lehner worked in the investment banking division of Simmons & Company International, where he focused on mergers, acquisitions and capital raises for public and private clients engaged in all facets of the energy industry. Mr. Lehner attended Villanova University, where he earned a B.S.B.A. in Finance.

Max L. Bouthillette. Mr. Bouthillette has served as Executive Vice President, General Counsel, Chief Compliance Officer and Corporate Secretary of the Company since its formation. Mr. Bouthillette has served on QES LP's board of directors since April 2016. Prior to joining the Company, Mr. Bouthillette was with Archer Limited, one of our Principal Stockholders, where he served as Executive Vice President and General Counsel from 2010 to 2017 and additionally as President of Archer's operations in South and North America since 2016. In May of 2017, Archer Limited voluntarily filed a petition under Chapter 15 of the United States Bankruptcy Code to obtain recognition of a legal proceeding in Bermuda and enforcement in the United States of an amendment to its revolving credit facility. The recognition by the United States Bankruptcy Court concluded a successful financial restructuring for Archer Limited, including a substantial capital raise and amendment to existing loan facilities. Mr. Bouthillette has more than 23 years of legal experience for oilfield services companies, and previously served as Chief Compliance Officer and Deputy General Counsel for BJ Services from 2006 to 2010, as a partner with Baker Hostetler LLP from 2004 to 2006 and with Schlumberger in North America (Litigation Counsel), Asia (OFS Counsel) and Europe (General Counsel Products) from 1998 to 2003. Mr. Bouthillette holds a B.B.A in Accounting from Texas A&M University and a Juris Doctorate from the University of Houston Law Center.

Corbin J. Robertson, Jr. Mr. Robertson has served as Chairman of the Company's board of directors since our formation and has served as Chairman of the board of directors of the general partner of QES LP since the board was established. Mr. Robertson has also served as Chief Executive Officer and Chairman of the board of directors of GP Natural Resource Partners LLC since 2002. He has served as the Chief Executive Officer and Chairman of the board of directors of the general partners of Western Pocahontas Properties Limited Partnership since 1986, Great Northern Properties Limited Partnership since 1992, Quintana Minerals Corporation since 1978 and as Chairman of the board of directors of New Gauley Coal Corporation since 1986. He also serves as a Principal with Quintana Capital Group, Chairman of the Board of the Cullen Trust for Higher Education and on the boards of the American Petroleum Institute, the National Petroleum Council, the Baylor College of Medicine and the World Health and Golf Association. In 2006, Mr. Robertson was inducted into the Texas Business Hall of Fame. Mr. Robertson attended the University of Texas at Austin where he earned a B.B.A. from the Business Honors Program. Our board of directors believes Mr. Robertson is qualified to serve on our board of directors due to his extensive industry experience, his extensive experience with oil and gas investments and his board service for several companies in the oil and gas industry.

Dalton Boutté, Jr. Mr. Boutté has served on our board of directors since February 8, 2018. Mr. Boutté worked for Schlumberger from 1980 until his retirement in 2010. In his last ten years with Schlumberger, Mr. Boutté held various senior level positions, including President for Europe/Africa/CSI (2001-2001), Vice President of Worldwide Oilfield Services (2001-2003) and President of WesternGeco (2003-2009) and also served as Executive Vice President of Schlumberger Limited (2004-2010). Mr. Boutté also currently serves as an independent director of Seitel Inc. Mr. Boutté has a Bachelor of Science in Civil Engineering from University of New Orleans and was a Visiting Fellow at Massachusetts Institute of Technology. We believe that Mr. Boutté's extensive oilfield services background and his experience as an independent director of companies in the oil and natural gas industry qualify him for service on our board of directors and our audit committee.

Rocky L. Duckworth. Mr. Duckworth has served on our board of directors since February 8, 2018. From 1987 to 2000, Mr. Duckworth served as the partner-in-charge for the Oklahoma City office at KPMG LLP ("KPMG"), and from 2000 until his retirement in 2010, he served as the energy industry leader of KPMG's audit practice and as a lead partner for global energy clients. Until his retirement, Mr. Duckworth had been with KPMG or its predecessor firm since 1972. Since his retirement, Mr. Duckworth has been a private investor. Additionally, Mr. Duckworth served a six year term on the Texas State Board of Public Accountancy. Mr. Duckworth has served on the board of directors of three public companies; Glori Energy, Inc., Northern Tier Energy GP LLC and Magnum Hunter Resources Corp. Mr. Duckworth has a Bachelor of Science in Accounting from Oklahoma State University and he holds a Certified Public Accountant license in Texas and Oklahoma. We believe that Mr. Duckworth's extensive accounting background and his experience as a director of public companies qualify him for service on our board of directors and our audit committee.

Gunnar Eliassen. Mr. Eliassen has served on the Company's board of directors since our formation, and has served on the board of directors of the general partner of QES LP since January 2017. Mr. Eliassen has been employed by Seatankers Consultancy Services (UK), an affiliated company of Geveran since 2016, where he is responsible for overseeing and managing various public and private investments. Mr. Eliassen's past experience includes Partner at

Pareto Securities (New York), where he worked from 2011 to 2015 and was responsible for execution of public and private capital markets transactions with emphasis on the energy sector. Mr. Eliassen received a Master in Finance from the Norwegian School of Economics. Our board of directors believes Mr. Eliassen is qualified to serve on our board due to his extensive experience with public and private investments, including investments in the oil and gas industry.

Dag Skindlo. Mr. Skindlo has served on the Company's board of directors since our formation, and has served on the board of directors of the general partner of QES LP since April 2016. Mr. Skindlo has served as member of the board of directors and as the Chief Financial Officer for Archer Limited, one of our Principal Stockholders, since April 2016. In May of 2017, Archer Limited voluntarily filed a petition under Chapter 15 of the United States Bankruptcy Code to obtain recognition of a legal proceeding in Bermuda and enforcement in the United States of an amendment to its revolving credit facility. The recognition by the United States Bankruptcy Court concluded a successful financial restructuring for Archer Limited, including a substantial capital raise and amendment to existing loan facilities. Mr. Skindlo is a business-oriented executive with 24 years of oil and gas industry experience. Mr. Skindlo joined Schlumberger in 1992 where he held various financial and operational positions. Mr. Skindlo then joined the Aker Group of companies in 2005 where his experience from Aker Kvaerner, Aker Solutions and Kvaerner includes both global CFO roles and Managing Director roles for several large industrial business divisions. Prior to joining Archer in 2016, Mr. Skindlo was with private equity group HitecVision where he served as CEO for Aquamarine Subsea. Mr. Skindlo earned a Master of Science in Economics and Business Administration from the Norwegian School of Economics and Business Administration (NHH). Our board of directors believes Mr. Skindlo is qualified to serve on our board due to his vast business experience, having founded and served as a director and as an officer of multiple companies, both private and public and service on the boards of numerous non-profit organizations.

Corporate Governance

Status as a Controlled Company

Upon the completion of the IPO, our Principal Stockholders owned, on a combined basis, 25,654,384 shares of common stock, representing, on a combined basis, approximately 76.3% of the voting power of our company as of March 27, 2018. The Principal Stockholders are deemed a group pursuant to the Equity Rights Agreement. As a result, we are considered a controlled company under Sarbanes-Oxley and the rules of the NYSE. A controlled company does not need its board of directors to have a majority of independent directors or to form an independent compensation or nominating and corporate governance committee. As a controlled company, we will remain subject to rules of Sarbanes-Oxley and the NYSE that require us to have an audit committee composed entirely of independent directors. Under these rules, we must have at least one independent director on our audit committee by the date our common stock is listed on the NYSE, at least two independent directors on our audit committee within 90 days of the listing date and at least three independent directors on our audit committee within one year of the listing date.

If at any time we cease to be a controlled company, we will take all action necessary to comply with Sarbanes-Oxley and the NYSE corporate governance standards, including by appointing a majority of independent directors to our board of directors and ensuring we have a compensation committee and a nominating and corporate governance committee, each composed entirely of independent directors, subject to a permitted "phase-in" period. While not currently mandatory given our controlled company status, we have voluntarily established a compensation committee that is composed of both independent and non-independent directors. Our board of directors currently consists of a single class of directors each serving one-year terms. After we cease to be a controlled company, our board of directors will be divided into three classes of directors, with each class as equal in number as possible, serving staggered three-year terms, and such directors will be removable only for "cause."

Composition of Our Board of Directors

Our board of directors currently consists of six members. Pursuant to the Equity Rights Agreement, Quintana has the right to appoint two directors to our board of directors, Archer has the right to appoint two directors to our board of directors and Geveran has the right to appoint one director to our board of directors. The current board representative appointed by Quintana is Corbin J. Robertson, Jr. The current board representatives appointed by Archer are Dag Skindlo and Gunnar Eliassen.

In accordance with our amended and restated certificate of incorporation, after we cease to be a controlled company, our board of directors will be divided into three classes with staggered three-year terms. At each annual general meeting of stockholders, the successors to directors whose terms then expire will be elected to serve from the time of election and qualification until the third annual meeting following election. Our amended and restated certificate of incorporation provides that the number of directors may be set and changed only by resolution of the board of directors. Any additional directorships resulting from an increase in the number of directors will be distributed among the three classes so that, as nearly as possible, each class will consist of one-third of the directors. The division of our board of directors into three classes with staggered three-year terms may delay or prevent a change of our management or a change in control.

In evaluating director candidates, we will assess whether a candidate possesses the integrity, judgment, knowledge, experience, skills and expertise that are likely to enhance the board's ability to manage and direct our affairs and business, including, when applicable, to enhance the ability of the committees of the board to fulfill their duties of increasing the length of time necessary to change the composition of a majority of the board of directors.

Director Independence

Our board has determined that each of Messrs. Boutté and Duckworth is independent under the NYSE listing standards.

Committees of the Board of Directors

Audit Committee

We are required to have an audit committee of at least three members, and all its members are required to meet the independence and experience standards established by the NYSE and Rule 10A-3 promulgated under the Exchange Act, subject to certain transitional relief during the one-year period following the closing of the IPO as described above. Messrs. Boutté and Duckworth serve as the current members of the audit committee. Mr. Duckworth serves as the chairman of the audit committee. Our board of directors has determined that each member of the audit committee is "independent" as defined by the NYSE listing standards and Rule 10A-3 of the Exchange Act. In making this determination, our board of directors considered the current and prior relationships that each director has with our company and all other facts and circumstances our board of directors deemed relevant in determining their independence, including the transactions involving Mr. Boutté described in "Certain Relationships and Related Transactions, and Director Independence." In addition, each member of our audit committee has the ability to read and understand fundamental financial statements, and Mr. Duckworth meets the requirements of an "audit committee financial expert" as defined by the rules of the SEC.

The audit committee assists the board of directors in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and corporate policies and controls. The audit committee has the sole authority to retain and terminate our independent registered public accounting firm, approve all auditing services and related fees and the terms thereof performed by our independent registered public accounting firm and pre-approve any non-audit services and tax services to be rendered by our independent registered public accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm is given unrestricted access to the audit committee and our management, as necessary. Our audit committee charter defines the committee's primary duties in a manner substantially consistent with the rules of the SEC and NYSE corporate governance standards. Our audit committee charter is available on our website at www.quintanaenergyservices.com.

Compensation Committee

Messrs. Boutté, Duckworth, Robertson and Skindlo serve as the members of our compensation committee. Mr. Boutté serves as chairman of the compensation committee. Our board of directors has determined that each of Messrs. Boutté and Duckworth is "independent" as defined by the NYSE listing standards. In making this determination, our board of directors considered the current and prior relationships that each such director has with our Company and all other facts and circumstances our board of directors deemed relevant in determining their independence, including the transactions involving Mr. Boutté described in "Certain Relationships and Related Transactions, and Director Independence." For each independent member of the compensation committee, our board of directors considered all factors specifically relevant to determining whether a director has a relationship to the Company that is material to that director's ability to be independent from management in connection with the duties of a compensation committee member, including the sources of such director's compensation, such as any consulting, advisory or other compensatory fees paid by the Company, and whether the director has an affiliate relationship with the Company, a subsidiary of the Company or an affiliate of a subsidiary of the Company.

The compensation committee has the ability to establish salaries, incentives and other forms of compensation for officers and other employees. The compensation committee also administers our incentive compensation and benefit plans. Our compensation committee charter defines the committee's primary duties in a manner substantially consistent with the rules of the SEC and NYSE corporate governance standards. Our compensation committee charter is available on our website at www.quintanaenergyservices.com.

The compensation committee also has the authority to retain, compensate, direct, oversee and terminate outside counsel, compensation consultants and other advisors hired to assist the compensation committee. The compensation committee intends to retain Frederic W. Cook & Co., Inc. ("FW Cook") as its independent compensation consultant for matters related to executive and director compensation. In selecting FW Cook as its independent compensation consultant, the compensation committee will assess the independence of FW Cook pursuant to SEC rules and request an independence letter from FW Cook, as well as other documentation addressing the firm's independence. FW Cook will report exclusively to the compensation committee and does not provide any additional services to the Company. The compensation committee will discuss these considerations and will conclude whether FW Cook is independent and whether we have any conflicts of interest with FW Cook.

Compensation Committee Interlocks and Insider Participation

None of our executive officers serve on the board of directors or compensation committee of a company that has an executive officer that serves on our board or compensation committee. No member of our board is an executive officer of a company in which one of our executive officers serves as a member of the board of directors or compensation committee of that company.

Executive Sessions of our Board of Directors

The non-management directors will have regularly scheduled meetings in executive session, to be held as determined necessary and appropriate by the Chairman of the Board or any director, and which are held at a minimum following each regularly scheduled quarterly board meeting. In the event that the non-management directors include directors who are not independent under the listing requirements of the NYSE, then at least once a year, there is an executive session including only independent directors. Mr. Duckworth serves at the presiding director at executive sessions of our board of directors.

Risk Oversight

The board is actively involved in oversight of risks that could affect us. This oversight function is conducted primarily through committees of our board, but the full board retains responsibility for general oversight of risks. The audit committee is charged with oversight of our system of internal controls and risks relating to financial reporting, legal, regulatory and accounting compliance. Our board will continue to satisfy its oversight responsibility through full reports from the audit committee chair regarding the committee's considerations and actions, as well as through regular reports directly from officers responsible for oversight of particular risks within our Company.

Code of Business Conduct and Ethics

Our board of directors adopted a code of business conduct and ethics applicable to our employees, directors and officers, in accordance with applicable U.S. federal securities laws and the corporate governance rules of the NYSE. The code of business conduct and ethics can be found on our website located at www.quintanaenergyservices.com. Any stockholder may request a printed copy of the code of business conduct and ethics by submitting a written request to our Secretary. Any amendment to, or waiver from, the code of business conduct and ethics may be made only by our board of directors, and any amendment or waiver that apply to our principal executive officer, principal financial officer, principal accounting officer or controller and are required to be disclosed will be promptly disclosed on our website as required by applicable U.S. federal securities laws and the corporate governance rules of the NYSE.

Corporate Governance Guidelines

Our board of directors adopted corporate governance guidelines in accordance with the corporate governance rules of the NYSE. Our corporate governance guidelines are available on our website located at www.quintanaenergyservices.com.

Indemnification Agreements

We entered into indemnification agreements with each of the directors and executive officers effective upon the closing of our IPO. These agreements require us to indemnify these individuals to the fullest extent permitted by law against expenses incurred as a result of any proceeding in which they are involved by reason of their service to us and, if requested, to advance expenses incurred as a result of any such proceeding.

Stockholder Communications

Stockholders and any other interested parties may send communications to the board, any committee of the board, the Chairman of the Board, or any other director in particular to: Quintana Energy Services Inc., 1415 Louisiana, Suite 2900, Houston, Texas 77002, Attention: General Counsel & Corporate Secretary, or via email at legal@qesinc.com. Shareholders and any other interested parties should mark the envelope containing each communication as "Shareholder Communication with Directors" and clearly identify the intended recipient(s) of the communication.

The Company's General Counsel will review each communication received from shareholders and other interested parties and will forward the communication, as expeditiously as reasonably practicable, to the addressees if: (1) the communication complies with the requirements of any applicable policy adopted by the board relating to the subject matter of the communication; and (2) the communication falls within the scope of matters generally considered by the board. To the extent the subject matter of a communication relates to matters that have been delegated by the board to a committee or to an executive officer of the Company, then the Company's General Counsel may forward the communication to the executive officer or chairman of the committee to which the matter has been delegated.

Item 11. Executive Compensation

Quintana Energy Services Inc., was incorporated on April 13, 2017 and did not accrue, pay or otherwise incur any liability with respect to compensation for any employees prior to such incorporation. Accordingly, the determination of who qualifies as a named executive officer for fiscal year 2017 is based, in part, on the compensation earned by or paid to employees for services provided to QES LP, our accounting predecessor, and its general partner.

The tables and narrative disclosure below provide compensation disclosure that satisfies the requirements applicable to emerging growth companies, as defined in the JOBS Act.

In accordance with the foregoing, our named executive officers are:

Name	Principal Position
D. Rogers Herndon	Chief Executive Officer, President and Director
Christopher J. Baker	Executive Vice President and Chief Operating Officer
Keefer M. Lehner	Executive Vice President and Chief Financial Officer

In addition, until January 2017, our named executive officers also provided services to Quintana Minerals Corporation and certain of its affiliates. Accordingly, amounts set forth in the Summary Compensation Table below for 2016 only reflect compensation paid to or earned by our named executive officers during fiscal year 2016 for services provided to QES LP and its general partner.

Summary Compensation Table

The following table summarizes, with respect to our named executive officers, information relating to compensation earned for services rendered in all capacities during the fiscal years ended December 31, 2017 and December 31, 2016.

Name and Principal Position	Year	Salary ($)	Bonus($)(1)(2)	Stock Awards($)(3)	Non-Equity Incentive Plan Compensation ($)(4)	All Other Compensation ($)(5)	Total ($)
D. Rogers Herndon	2017	$403,077	$ 175,000	$4,777,494	$ 630,000	—	$5,985,571
Chief Executive Officer, President and Director	2016	$400,205	$ 31,250	—	—	$ 22,755	$ 454,210
Christopher J. Baker	2017	$355,000	$ 125,000	$3,782,183	$ 555,000	$ 5,550	$4,822,733
Executive Vice President Chief Operating Officer	2016	$350,180	$ 10,000	—	$ 20,000	$ 26,916	$ 397,096
Keefer M. Lehner	2017	$268,462	$ 100,000	$2,587,809	$ 420,000	$ 4,200	$3,380,471
Executive Vice President and Chief Financial Officer	2016	$259,956	$ 7,500	—	$ 15,000	$ 27,961	$ 302,917

(1) For fiscal year 2017, the amounts in this column reflect retention bonuses earned by our named executive officers during fiscal year 2017 in the following amounts: (a) Mr. Herndon, $175,000, (b) Mr. Baker, $125,000 and (c) Mr. Lehner, $100,000.

(2) For fiscal year 2016, the amounts in this column reflect discretionary bonuses earned by our named executive officers during fiscal year 2016.

(3) The amounts in this column reflect the aggregate grant date fair value of phantom units in QES LP granted during fiscal year 2017, determined in accordance with FASB ASC Topic 718, Compensation—Stock Compensation, excluding the effect of estimated forfeitures. Each phantom unit generally represents a right to receive one common unit of QES LP (or, if elected by the board of directors of the general partner of QES LP, an amount in cash equal to the fair market value thereof) upon (a) the satisfaction of the applicable time-based vesting schedule and (b) the consummation of a "specified transaction." However, in connection with our IPO, the phantom units were equitably adjusted and converted into the right to receive shares of our common stock (or, if elected by our board of directors, cash equal to the fair market value thereof). For information on the terms and conditions of the phantom units, including vesting conditions, please see "Additional Narrative Disclosures—Quintana Energy Services LP Phantom Units" below.

(4) The amounts in this column for 2017 reflect bonuses earned by our named executive officers pursuant to the 2017 Incentive Compensation Program while the amounts in this column for 2016 reflect bonuses earned by Messrs. Baker and Lehner pursuant to the 2016 Incentive Compensation Program. For more information on the 2017 and 2016 Incentive Compensation Programs, see "—Additional Narrative Disclosures—Incentive Compensation Program" below.

(5) The amounts in this column for 2017 reflect employer matching contributions to the named executive officers’ retirement accounts under the Quintana Energy Services 401(k) Plan during fiscal year 2017. The amounts in this column for 2016 reflect employer matching contributions to the named executive officers’ retirement accounts under the Quintana Minerals Corporation Tax Advantaged Thrift Plan and the Quintana Minerals Corporation Retirement Plan during fiscal year 2016. For more information, see “—Additional Narrative Disclosures—Other Benefits” below.

Additional Narrative Disclosures

Base Salary

Each named executive officer’s base salary is a fixed component of compensation that does not vary depending on the level of performance achieved. Base salaries are determined for each named executive officer based on his position and responsibility. Our board of directors (and, historically, the board of directors of the general partner of QES LP) reviews the base salaries for each named executive officer annually as well as at the time of any promotion or significant change in job responsibilities and, in connection with each review, such board of directors has considered individual and company performance over the course of the applicable year. Pursuant to the employment agreements between us and each named executive officer, a named executive officer’s base salary may be increased but not decreased without the named executive officer’s written consent.

Cash Bonuses

Our named executive officers have historically been eligible to receive discretionary annual cash incentive bonuses, based on individual performance, company performance and pre-established performance criteria, to recognize their significant contributions and aid in our retention efforts. Our board of directors (and, historically, the board of directors of the general partner of QES LP) determines whether each named executive officer is eligible to receive a cash bonus for a given year and sets the amount of such cash bonus.

For fiscal year 2016, the board of directors of the general partner of QES LP determined that (i) Mr. Herndon earned a cash bonus in an amount equal to $31,250, (ii) Mr. Baker earned a cash bonus in an amount equal to $10,000 and (iii) Mr. Lehner earned a cash bonus in an amount equal to $7,500.

Incentive Compensation Programs

2016 Incentive Compensation Program

In May 2016, the board of directors of the general partner of QES LP established the 2016 Incentive Compensation Program for certain key personnel, including Messrs. Baker and Lehner, in order to recognize the contribution of such individuals to our business. Under the 2016 Incentive Compensation Program, we provided Messrs. Baker and Lehner with the opportunity to earn a cash incentive bonus for each month from May 2016 through December 2016 based on the financial performance of QES LP as measured by earnings before interest, taxes, depreciation and amortization (“EBITDA”). Mr. Baker was eligible to receive a monthly cash incentive bonus of $20,000 and Mr. Lehner was eligible to receive a monthly cash incentive bonus of $15,000, in each case, subject to satisfaction of the applicable EBITDA target and each named executive officer’s continuous employment by us through the applicable payment date. Depending on which EBITDA target was satisfied for a given month, Messrs. Baker and Lehner were eligible to earn 0%, 25%, 50% or 100% of the monthly cash incentive bonus. For fiscal year 2016, the board of directors of the general partner of QES LP determined that Mr. Baker earned an aggregate of $20,000 and Mr. Lehner earned an aggregate of $15,000 under the 2016 Incentive Compensation Program.

2017 Incentive Compensation Program

In February 2017, the board of directors of the general partner of QES LP established the 2017 Incentive Compensation Program for certain key personnel, including our named executive officers, in order to recognize their contribution to our business. Under the 2017 Incentive Compensation Program, we provided our named executive officers with the opportunity to earn a cash incentive bonus for fiscal year 2017 based on the financial performance of QES LP as measured by EBITDA less their capital expenditures. Our named executive officers were eligible to earn a target incentive bonus in the following amounts: (i) Mr. Herndon, $315,000, (ii) Mr. Baker, $277,500 and (iii) Mr. Lehner, $210,000. Subject to the satisfaction of the applicable performance goal and each named executive officer’s continuous employment by us through the applicable payment date, our named executive officers were eligible to earn between 0% and 200% of the target incentive bonus. For fiscal year 2017, the board of directors of the general partner of QES LP determined that Mr. Herndon earned $630,000, Mr. Baker earned $555,000 and Mr. Lehner earned $420,000 under the 2017 Incentive Compensation Program.

Executive Retention Program

On October 25, 2016, we provided each named executive officer with the opportunity to earn a one-time cash retention bonus under our Executive Retention Program in the following amounts: (i) Mr. Herndon, $175,000, (ii) Mr. Baker, $125,000 and (iii) Mr. Lehner, $100,000. Each retention bonus required that the named executive officer remain continuously employed by us through the payment date (which was March 31, 2017), provided that the named executive officer would still have been entitled to receive the retention bonus on the actual payment date if he (a) was terminated by us without cause or (b) resigned from his employment for good reason, in each case, prior to such payment date.

Quintana Energy Services LP Phantom Units

Pursuant to the Quintana Energy Services LP Long-Term Incentive Plan (the “Prior Plan”), our named executive officers were previously granted awards of phantom units in QES LP.

Each phantom unit represented the right to receive one common unit of QES LP (or, if elected by the board of directors of the general partner of QES LP, an amount in cash equal to fair market value of one common unit of QES LP) upon full vesting of such phantom unit. In addition, upon full vesting of a named executive officer’s phantom units, the named executive officer would have been entitled to receive the accrued value of any distributions that would have been paid had the named executive officer been a holder of the number of common units subject to the award from the date of grant. In connection with our IPO, all outstanding phantom units were equitably adjusted and converted into rights to receive shares of our common stock (or, if elected by our board of directors, cash equal to the fair market value thereof).

Original Phantom Units

On April 9, 2015, 1,750,000 phantom units were granted to Mr. Baker and 1,125,000 phantom units were granted to Mr. Lehner and on June 1, 2015, 2,500,000 phantom units were granted to Mr. Herndon (such phantom units, the “Original Phantom Units”). After accounting for the 31.669363 for 1 reverse stock split that occurred in connection with our IPO, Mr. Baker held 55,258 Original Phantom Units, Mr. Lehner held 35,522 Original Phantom Units and Mr. Herndon held 78,940 Original Phantom Units immediately following the equitable adjustment and conversion of the Original Phantom Units into rights to receive shares of our common stock (or, if elected by our board of directors, cash equal to the fair market value thereof).

The Original Phantom Units held by our named executive officers were subject to (i) time vesting in accordance with a vesting schedule set forth in each named executive officer’s Original Phantom Unit agreement and (ii) event vesting, which required the consummation of a “Specified Transaction” (as defined in the applicable Original Phantom Unit agreements). Pursuant to an action taken by the board of directors of the general partner of QES LP in December 2015, all outstanding Original Phantom Units held by our named executive officers became time vested but would not become fully vested until such Original Phantom Units become event vested upon the consummation of a Specified Transaction. Our IPO constituted a Specified Transaction under the Original Phantom Unit agreements and, as a result, Original Phantom Units held by our named executive officers became fully vested upon the consummation of our IPO. Such Original Phantom Units were settled shortly following the IPO and our named executive officers received shares of our common stock upon settlement. Following such settlement, no Original Phantom Units remain outstanding.

New Phantom Units

In February 2017, our named executive officers were granted additional phantom units (the “New Phantom Units”) in the following amounts: Mr. Herndon, 8,681,355 phantom units, (ii) Mr. Baker, 6,872,740 phantom units and (iii) Mr. Lehner, 4,702,401 phantom units. After accounting for the 31.669363 for 1 reverse stock split that occurred in connection with our IPO, Mr. Herndon held 274,125 New Phantom Units, Mr. Baker held 217,015 New Phantom Units and Mr. Lehner held 149,484 New Phantom Units immediately following the equitable adjustment and conversion of the New Phantom Units into rights to receive shares of our common stock (or, if elected by our board of directors, cash equal to the fair market value thereof).

In order to become fully vested, the New Phantom Units held by our named executive officers are subject to (i) time vesting in four equal installments on the first four anniversaries of the applicable date of grant as set forth in each named executive officer's New Phantom Unit agreement (or, if earlier, become 100% time vested upon the consummation of a "Change in Control" (as defined in the applicable New Phantom Unit agreements)) and (ii) event vesting, which requires the consummation of a Change in Control or a "Specified Transaction" (as defined in the applicable New Phantom Unit agreements). On the seventh anniversary of the grant date of an award of New Phantom Units, any New Phantom Units that have not fully vested will be automatically terminated and forfeited. The New Phantom Unit agreements also include certain restrictive covenants, including provisions that generally prohibit our named executive officers from soliciting customers, officers or employees of us or our affiliates during the term of each named executive officer's employment with us and for a period of one year following the termination of such employment.

Our IPO constituted a Specified Transaction under the New Phantom Unit agreements and, as a result, New Phantom Units held by our named executive officers became event vested upon the consummation of our IPO. However, in order to become fully vested, the New Phantom Units must also become time vested. In February 2018, one-fourth of the New Phantom Units held by our named executive officers became time vested and, hence, fully vested. Such New Phantom Units were settled in March 2018 and our named executive officers received shares of our common stock upon settlement.

Other Benefits

We offer participation in broad-based retirement, health and welfare plans to all of our employees. We maintain a plan intended to provide benefits under section 401(k) of the Internal Revenue Code of 1986, as amended (the "401(k) Plan"), where employees are allowed to contribute portions of their base compensation into a retirement account in order to encourage all employees, including any participating named executive officers, to save for the future. Prior to, and during part of, fiscal year 2017, we did not provide matching contributions to participants in the 401(k) Plan due to market conditions. However, in June 2017, we reinstated, and continue to provide, matching contributions in an amount equal to 50% of the first 6% of an employee's eligible compensation that is contributed to the 401(k) Plan.

Prior to 2017, our named executive officers also participated in two defined contribution plans maintained by Quintana Minerals Corporation, specifically (i) the Quintana Minerals Corporation Tax Advantaged Thrift Plan, a 401(k) plan, which provides for an employer matching contribution on 100% of the first 4.5% of each employee's eligible compensation and (ii) the Quintana Minerals Corporation Retirement Plan, a money purchase plan, which provides for a fixed employer contribution of 8 ⅓% of each employee's eligible compensation.

Employment Agreements

On July 1, 2017, we entered into employment agreements with our named executive officers that superseded and replaced the prior employment agreements that were in effect with our named executive officers. The employment agreements became effective on July 1, 2017 (the "Employment Agreements"). Each Employment Agreement generally provides for a three year term, which commenced on July 1, 2017, with automatic renewals for successive one-year periods thereafter. Each Employment Agreement generally outlines the named executive officer's duties and positions and provides for (i) an annualized base salary, (ii) a discretionary annual cash incentive bonus with a target amount equal to 75% of the named executive officer's base salary and (iii) eligibility to participate in any equity compensation arrangements or plans offered by us to senior executives.

Each Employment Agreement provides for the following benefits upon a termination of a named executive officer's employment by us without "Cause," resignation by a named executive officer for "Good Reason" or due to "Disability" (each quoted term as defined in the applicable Employment Agreement): (i) a lump sum payment equal to (A) for Mr. Herndon, two times Mr. Herndon's base salary or (B) for Messrs. Baker and Lehner, one and one-half times the named executive officer's base salary, (ii) an amount equal to (A) for Mr. Herndon, two times Mr. Herndon's target bonus for the year in which the termination occurs or (B) for Messrs. Baker and Lehner, one and one-half times the named executive officer's target bonus for the year in which the termination occurs, in each case, payable in four equal installments with the first installment paid on the Company's first regular pay date on or after the 60th day following such termination and the remaining three installments paid in each of the three calendar quarters immediately following the quarter in which the termination occurs and (iii) for a period of 18 months following such termination, reimbursement of premiums paid by the executive pursuant to the Consolidated Omnibus Budget Reconciliation Act of 1985 and/or sections 601 through 608 of the Employee Retirement Security Act of 1974 to continue coverage in our health, dental and vision insurance plans in which the executive and/or his dependents participated immediately prior to the termination (the "COBRA Premium"), provided that such reimbursement does not subject us or our affiliates to sanctions imposed pursuant to Section 2716 of the Public Health Service Act and related regulations and guidance (collectively, the "PHSA"). If a named executive officer's employment is terminated due to death, the named executive officer's estate will be entitled to receive (i) a pro-rata share of the named executive officer's target bonus for the fiscal year in which the termination occurs and (ii) continued payments of the named executive officer's base salary for a period of 12 months.

Under each Employment Agreement, if a named executive officer's employment is terminated for Good Reason or without Cause within 12 months of a "Change in Control" (as defined in the applicable Employment Agreement), then the named executive officer will be entitled to receive: (i) a lump sum payment equal to two times the named executive officer's base salary, (ii) an amount equal to the named executive officer's target bonus for two years, payable in four equal installments with the first installment on the Company's first regular pay date on or after the 60th day following such termination and the remaining three installments paid in each of the three calendar quarters immediately following the quarter in which the termination occurs and (iii) for a period of 18 months following such termination, reimbursement of the COBRA Premium, provided that such reimbursement does not subject us or our affiliates to sanctions imposed pursuant to Section 2716 of the PHSA.

If a named executive officer is terminated for any reason other than those described above, no further compensation or benefits will be provided pursuant to the Employment Agreements. The Employment Agreements also contain certain restrictive covenants, including provisions that generally prohibit a named executive officer from competing with the Company and its affiliates or soliciting clients, executives, officers, directors or other employees of the Company and its affiliates. These restrictions generally apply during the term of the named executive officer's employment and for a period of one year following the termination of such employment.

The Employment Agreements do not provide a tax gross-up provision for federal excise taxes that may be imposed under Section 4999 of the Code. Instead, each Employment Agreement includes a modified cutback provision, which states that, if amounts payable to a named executive officer under the Employment Agreement (together with any other amounts that are payable by us as a result of a change in control (the "Payments") exceed the amount allowed under Section 280G of the Code for such named executive officer, thereby subjecting the named executive officer to an excise tax under Section 4999 of the Code, then the Payments will either be: (i) reduced to the level at which no excise tax applies, such that the full amount of the Payments would be equal to $1 less than three times the named executive officer's "base amount," which is generally the average W-2 earnings for the five calendar years immediately preceding the date of termination, or (ii) paid in full, which would subject the named executive officer to the excise tax. We will determine, in good faith, which alternative produces the best net after tax position for a named executive officer.

The foregoing descriptions of the Employment Agreements are qualified in their entirety by reference to the respective Employment Agreement for each named executive officer. A copy of each Employment Agreement have been filed as exhibits to this Annual Report.

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Outstanding Equity Awards at 2017 Fiscal Year-End

The following table reflects information regarding outstanding equity-based awards held by our Named Executive Officers as of December 31, 2017.

	Stock Awards		
Name	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)(1)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(2)	
D. Rogers Herndon	11,181,355	$	5,462,424
Christopher J. Baker	8,622,740	$	4,212,464
Keefer M. Lehner	5,827,401	$	2,846,858

(1) Represents phantom units granted to our named executive officers that were outstanding as of December 31, 2017 (without giving effect to the reverse stock split that occurred in connection with our IPO). For information on the terms and conditions of the phantom units, including vesting conditions and the number of phantom units held by our named executive officers after giving effect to the reverse stock split that occurred in connection with our IPO, please see "—Additional Narrative Disclosures—Quintana Energy Services LP Phantom Units" below.

(2) This column reflects the aggregate market value of all outstanding unvested phantom units held by each named executive officer on December 31, 2017 and is calculated by multiplying the number of phantom units outstanding on December 31, 2017 by the value of a common unit of QES LP on such date, which was approximately $0.49. Upon the consummation of our IPO, all Original Phantom Units held by our named executive officers, specifically (i) 2,500,000 phantom units held by Mr. Herndon, (ii) 1,750,000 phantom units held by Mr. Baker and (iii) 1,125,000 phantom units held by Mr. Lehner, which amounts do not reflect to the reverse stock split that occurred in connection with our IPO, became fully vested and were settled shortly following our IPO in the form of shares of our common stock. Shortly following our IPO, one-fourth of the New Phantom Units held by our named executive officers, specifically (i) 2,170,339 phantom units held by Mr. Herndon, (ii) 1,718,185 phantom units held by Mr. Baker and (iii) 1,175,600 phantom units held by Mr. Lehner, which amounts do not reflect to the reverse stock split that occurred in connection with our IPO, became fully vested and were settled in March 2018 in the form of shares of our common stock.

Director Compensation

Our board of directors was established in April 2017. We believe that attracting and retaining qualified non-employee directors is critical to the future value of our growth and governance. Accordingly, in connection with our IPO, we implemented a comprehensive director compensation policy for our nonemployee directors, which consists of:

- an annual cash retainer of $60,000, payable in quarterly installments;
- an annual fee of $15,000 to the chair of the audit committee and an annual fee of $10,000 to the chair of the compensation committee;
- an annual fee of $10,000 to each member of the audit committee (other than the chair) and an annual fee of $5,000 to each member of the compensation committee (other than the chair); and
- an annual equity-based award granted under the 2018 Plan with an aggregate fair market value of at least $100,000 on the date of grant.

All members of our board of directors are also reimbursed for certain reasonable expenses incurred in connection with their services to us.

Beginning in July 2017, directors who are employed by Quintana, Archer or Geveran (i.e., Messrs. Robertson, Skindlo and Eliassen, respectively) became entitled to receive the annual cash retainer of $60,000, payable in quarterly installments, described above for service on our board of directors.

Name	Fees earned or paid in cash ($)		Total ($)
Corbin J. Robertson, Jr.(1)	$	40,000	$40,000
Dag Skindlo	$	40,000	$40,000
Gunnar Eliassen	$	40,000	$40,000
Rocky L. Duckworth		—	—
Dalton Boutté, Jr		—	—

(1) The fees earned by Mr. Robertson for service on our board of directors during fiscal year 2017 were paid directly to QEP Management Co., LP, a Quintana affiliate.

Compensation Committee Report

As an emerging growth company, the Company is not required to include a Compensation Discussion and Analysis section in this Annual Report.

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

Beneficial Ownership Information

The following table sets forth information with respect to the beneficial ownership of our common stock as of March 27, 2018 by:

- each person known to us to beneficially own more than 5% of any class of our outstanding voting securities;
- each member of our board of directors;
- each of our named executive officers; and
- all of our directors and executive officers as a group.

All information with respect to beneficial ownership has been furnished by the respective 5% or more stockholders, directors or executive officers, as the case may be. Unless otherwise noted, the mailing address of each listed beneficial owner is 1415 Louisiana Street, Suite 2900, Houston, Texas 77002.

	Shares Beneficially Owned	
	Number	%(1)
5% or Greater Stockholders		
Quintana Capital Group, L.P. and its affiliates(2)(3)	6,559,524	19.5%
Archer Holdco LLC and its affiliates(2)(4)	9,494,306	28.2%
Geveran Investments Limited and its affiliates(2)(5)	6,602,688	19.6%
Robertson QES Investment LLC(2)(6)	2,886,041	8.6%
Directors and Executive Officers		
D. Rogers Herndon(6)	126,770	*
Christopher J. Baker	86,429	*
Keefer M. Lehner	56,887	*
Corbin J. Robertson, Jr.(2)(3)(6)	9,557,390	28.4%
Dalton Boutté	0	*
Rocky L. Duckworth	0	*
Gunnar Eliassen	5,205	*
Dag Skindlo	10,410	*
All Directors and Executive Officers as a Group (9 persons)	9,860,373	29.3%

* Less than 1%

(1) Based on 33,630,934 shares of common stock outstanding as of March 27, 2018.

(2) Information is based on a Schedule 13D jointly filed with the SEC on February 26, 2018 (the "Control Group 13D") by Quintana Capital Group, L.P., Quintana Capital Group GP Ltd., Quintana Energy Partners, L.P., Quintana Energy Partners—QES Holdings, L.L.C., Quintana Energy Fund—FI, LP, Quintana Energy Fund—TE, LP, QEP Management Co., L.P., QEP Management Co. GP, LLC, Archer Limited, Archer Assets UK Limited, Archer Well Company Inc., Archer Holdco LLC, Robertson QES Investment LLC, Corbin J. Robertson, Jr., John Fredriksen, C.K. Limited, Greenwich Holdings Limited, Famatown Finance Limited and Geveran Investments Limited (together, the "Control Group"). As of March 27, 2018, the Control Group held 25,654,384 shares of our common stock, representing 76.3% of the Company's outstanding common stock. Each member of the Control Group may be deemed to have shared voting power and beneficial ownership over these shares by virtue of the Equity Rights Agreement discussed above.

(3) Pursuant to the Control Group 13D, includes 5,345,505 shares of common stock for which Quintana Energy Partners—QES Holdings, L.L.C. is the record owner, 795,018 shares of common stock for which Quintana Energy Fund—FI, LP is the record owner, and 319,001 shares of common stock for which Quintana Energy Fund—TE, LP is the record owner. Quintana Energy Partners, L.P. controls Quintana Energy Partners—QES Holdings L.L.C. The general partner of each of Quintana Energy Partners, L.P., Quintana Energy Fund—FI, LP and Quintana Energy Fund—TE, LP is Quintana Capital Group, L.P. Quintana Capital Group GP Ltd. is the general partner of Quintana Capital Group, L.P. and may be deemed to have beneficial ownership of the shares directly held by Quintana Energy Partners—QES Holdings, L.L.C., Quintana Energy Fund—TE, LP and Quintana Energy Fund—FI, LP. The board of directors of Quintana Capital Group GP Ltd. consists of Paul Cornell, Donald

L. Evans, Warren S. Hawkins, Corbin J. Robertson, Jr., Corbin J. Robertson III and William K. Robertson, none of whom individually have voting and dispositive power over these shares. Each of Corbin J. Robertson III and William K. Robertson are the children of Corbin J. Robertson. Each such person expressly disclaims beneficial ownership over these shares, except to the extent of any pecuniary interest therein. Corbin J. Robertson, Jr., as a member of the board of directors of Quintana Capital Group GP Ltd., may be deemed to beneficially own these shares due to his additional rights regarding the management of Quintana Capital Group GP Ltd. QEP Management Co., LP is the record owner of 100,000 of these shares. QEP Management Co. GP, LLC, the general partner of QEP Management Co., LP, may also be deemed to be the beneficial owner of these shares. The board of managers of QEP Management Co. GP LLC consists of Donald L. Evans, Warren S. Hawkins, Corbin J. Robertson, Jr., Corbin J. Robertson III and William K. Robertson, none of whom individually have voting and dispositive power over these shares. Each of Corbin J. Robertson III and William K. Robertson are the children of Corbin J. Robertson, Jr. Each such person expressly disclaims beneficial ownership over these shares, except to the extent of any pecuniary interest therein. Corbin J. Robertson, Jr., as a member of the board of managers of QEP Management Co. GP, LLC, may be deemed to beneficially own these shares due to his additional rights regarding the management of QEP Management Co. GP, LLC. The mailing address of Quintana Capital Group, L.P. and its affiliates is 1415 Louisiana Street, Suite 2400, Houston Texas 77002.

(4) Pursuant to the Control Group 13D, Archer Holdco LLC is the record owner of these shares. Archer Holdco LLC is wholly-owned by Archer Well Company Inc., which is wholly-owned by Archer Assets UK Limited, which is wholly-owned by Archer Limited. The board of directors of Archer Limited has voting and dispositive power over these shares and therefore may also be deemed to be the beneficial owner of these shares. The board of directors of Archer Limited consists of Alf Ragnar Lovdal, John Reynolds, Kate Blankenship, Giovanni Dell'Orto and Dag Skindlo, none of whom individually have voting and dispositive power over these shares. Each such person expressly disclaims beneficial ownership over these shares, except to the extent of any pecuniary interest therein. The mailing address for Archer Holdco LLC is 5510 Clara Rd., Houston, Texas 77041.

(5) Pursuant to the Control Group 13D, Geveran Investments Limited is the record holder of 4,602,688 of these shares and its affiliate, Famatown Finance Limited, is the record holder of 2,000,000 of these shares. Geveran Investments Limited and Famatown Finance Limited are wholly-owned subsidiaries of Greenwich Holdings Limited. C.K. Limited is the trustee of various trusts established by John Fredriksen for the benefit of his immediate family, which trusts are the sole shareholders of Greenwich Holdings Limited and the indirect owners of Geveran Investments Limited and Famatown Finance Limited. Mr. Fredriksen may be deemed to beneficially own these 6,602,688 shares through his indirect influence over Geveran Investments Limited, Famatown Finance Limited, and Greenwich Holdings Limited. Mr. Fredriksen disclaims beneficial ownership of these 6,602,688 shares except to the extent of his voting and dispositive interests in such shares. Mr. Fredriksen has no pecuniary interest in these 6,602,688 shares. The mailing address for Geveran Investments Limited is Deana Beach Apartments Block 1, 4th Floor, Promachou Eleftherias Street Ayos Athanasios, Limassol 4103, Cyprus.

(6) Pursuant to the Control Group 13D, Robertson QES Investment LLC is the record owner of such shares. The sole manager of Robertson QES Investment LLC has voting and dispositive power over these shares. Corbin J. Robertson, Jr. serves as the sole manager of Robertson QES Investment LLC and expressly disclaims ownership over these shares, except to the extent of any pecuniary interest therein. Mr. Herndon, and certain children of Mr. Robertson or entities they control, including Corbin J. Robertson III, Christine Morenz, and William K. Robertson, are members of Robertson QES Investment LLC and expressly disclaim ownership over these shares, except to the extent of any pecuniary interest therein. The mailing address for Robertson QES Investment LLC is 1415 Louisiana Street, Suite 2400, Houston, Texas 77002.

Securities Authorized for Issuance under Equity Compensation Plans

The following table summarizes information about our equity compensation plans as of December 31, 2017:

	(a)	(b)	(c)
	Number of securities to be issued upon exercise of outstanding options, warrants and rights (2)	**Weighted-average exercise price of outstanding options, warrants and rights**	**Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (3)**
Equity compensation plans approved by security holders (1)	—	—	—
Equity compensation plans not approved by security holders	1,627,215	$ —	3,300,000
Total	1,627,215		3,300,000

(1) The Quintana Energy Services Inc. Amended and Restated Long-Term Incentive Plan and the Quintana Energy Services Inc. 2018 Long Term Incentive Plan were assumed and adopted, respectively, in connection with our IPO.
(2) Consists of shares of our common stock that may be issued upon settlement of phantom unit awards granted under the Quintana Energy Services Inc. Amended and Restated Long-Term Incentive Plan.
(3) Consists of shares of our common stock that remain available for future issuance under the Quintana Energy Services Inc. 2018 Long Term Incentive Plan. Following the adoption of the Quintana Energy Services Inc. 2018 Long Term Incentive Plan, no further awards will be granted under the Quintana Energy Services Inc. Amended and Restated Long-Term Incentive Plan.

Section 16(a) Beneficial Ownership Reporting Compliance

Under Section 16(a) of the Exchange Act and SEC rules, beginning on February 8, 2018, our directors, executive officers and beneficial owners of more than 10% of any class of equity security are required to file periodic reports of their ownership, and changes in that ownership, with the SEC. During 2017, no periodic reports were required to be filed by our executive officers, directors and beneficial owners of more than 10% of our common stock.

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

Historical Transactions with Affiliates

The Term Loan and Warrants

On December 19, 2016, we entered into the Term Loan, by and among QES LP, certain of its subsidiaries and the lenders party thereto. Under the terms of the Term Loan, as of December 31, 2017, we had received an aggregate of $40.0 million from Archer Holdco, Robertson QES and Geveran (together, the “Term Loan Lenders”), collectively in exchange for warrants exercisable for an aggregate amount of 227,885,578 common units of QES LP.

Also pursuant to the Term Loan, we entered into that certain Warrant Agreement, dated December 19, 2016, by and among QES LP, Archer Holdco, Robertson QES and Geveran, pursuant to which the Term Loan Lenders are given the right to exercise their respective amount of warrants until December 19, 2026 and, upon any corporate conversion of the Company, convert such warrants into common stock of the Company. The warrant holders net exercised the outstanding warrants in connection with our Reorganization (as defined below) completed in connection with our IPO.

In connection with the Term Loan, we also executed that certain Pledge Agreement, dated December 19, 2016, by and among QES LP, certain of its subsidiaries and Cortland Capital Market Services, LLC (“Cortland”), as administrative agent, pursuant to which we and our subsidiaries pledged and granted to Cortland a continuing lien on and security interest in certain collateral to secure all of our obligations under the Term Loan. The remaining balance under the Term Loan was repaid with the net proceeds from the IPO and the Term Loan and the related Pledge Agreement and Warrant Agreement were subsequently terminated.

For additional detail on the Term Loan, please see “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Term Loan.” For additional detail on the ownership of Robertson QES, please see Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters” above.

The Archer Acquisition

On December 31, 2015, through the Archer Acquisition we acquired from Archer all of the outstanding shares of Archer Pressure Pumping LLC, Archer Directional Drilling Services LLC, Archer Wireline LLC, Archer Leasing and Procurement LLC and Great White Pressure Control LLC (collectively, the “Archer Well Services Entities”) in exchange for a 42.0% equity interest in QES LP. The purchase price, which consisted solely of common units of QES LP, had a fair value of $92.6 million. No debt was assumed in the transaction.

Post-closing of the Archer Acquisition, we reimbursed Archer approximately $0.5 million for services related to insurance and approximately $0.9 million for certain medical benefits.

In connection with the Archer Acquisition, we obtained support services from Archer on a transitional basis for the processing of payroll, benefits and certain administration services during the integration of the Archer Well Services Entities. We paid Archer $0.7 million under this transition services agreement in the year ended December 31, 2016.

Other Related Party Transactions

In the CAF Acquisition on January 9, 2015, through a series of transactions also involving QES Holdco LLC, we acquired CAF for a total purchase price of approximately $80.5 million, including assumed debt of $52.7 million. The purchase price consisted of (i) payment of approximately $43.3 million in cash (including $38.7 million of cash paid to extinguish certain of CAF's third-party debt obligations), (ii) an approximate 4.0% membership interest in QES Holdco LLC (which includes the conversion of a $14.0 million seller note of CAF into certain membership interests in QES Holdco LLC) and (iii) an approximate 3.4% limited partnership interest in QES LP. The entire cash portion of the CAF Acquisition was funded with borrowings under the Revolving Credit Facility. In connection with the CAF Acquisition, QES Holdco LLC contributed all of its equity interests in COWS, DDC and the contemporaneously acquired interests in CAF to us in exchange for an approximate 96.6% limited partnership interest in QES LP and its assumption of the Revolving Credit Facility. For a description of our Revolving Credit Facility see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Revolving Credit Facility."

From March 2013 through June 2015, Mr. Boutté, one of our directors, served as an advisor to Quintana Energy Partners, L.P., and received, in exchange for his consulting services, a total of $140,000 from Quintana Energy Partners, L.P. Additionally, from July 2015 through March 2016, Mr. Boutté served as an advisor to QES LP, and received, in exchange for his consulting services, a total of $45,000 from QES LP. Our board has determined that Mr. Boutté's former advisory roles do not affect his independence under either the NYSE rules and regulations or for purposes of serving on our audit or compensation committees.

At the closing of the IPO, (i) Mr. Robertson, our chairman of the board of directors, purchased an aggregate of 100,000 shares of common stock at the initial public offering price of $10.00 per share, (ii) an affiliate of Quintana, QEP Management Co., LP purchased an aggregate of 100,000 shares of common stock at the initial public offering price of $10.00 per share, (iii) a trust of which Mr. Robertson is a beneficiary purchased an aggregate of 100,000 shares of common stock at the initial public offering price of $10.00 per share, (iv) two children of Mr. Robertson, William K. Robertson and Christine Morenz, or entities affiliated with them, purchased an aggregate of 200,000 shares of common stock at the initial public offering price of $10.00 per share, (v) an affiliate of Geveran purchased an aggregate of 2,000,000 shares of common stock at the initial public offering price of $10.00 per share and (vi) Archer purchased an aggregate of 1,000,000 shares of common stock at the initial public offering price of $10.00 per share (the purchases in clauses (i)-(vi) above, collectively, the "IPO Purchases"). For additional detail regarding the ownership of QEP Management Co., LP, please see "Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters" above.

Payments to Quintana

We utilize vendors that have relationships with a Quintana affiliate. The Quintana affiliate pays those vendors on behalf of us and we reimburse the Quintana affiliate. In addition, we utilize a Quintana affiliate to pay and process the payroll of our corporate employees, for which we reimburse the Quintana affiliate on a monthly basis. The Company reimbursed Quintana, including Quintana Minerals Corporation, in the aggregate amounts of $1.5 million, $1.6 million and $0.5 million for each of the fiscal years ended 2015, 2016 and 2017, respectively.

These amounts included amounts related to our executive officers, who were employed by Quintana Minerals Corporation until January 2017. The Company reimbursed Quintana Minerals Corporation for our executive officers' salaries in the aggregate amounts of $0.6 million, $1.0 million and $0.0 million for each of the fiscal years ended 2015, 2016 and 2017, respectively.

Master Reorganization Agreement

In connection with our IPO, we entered into a master reorganization agreement (the "Master Reorganization Agreement") with, among others, QES LP and QES Holdco LLC.

Subject to the terms and conditions set forth in the Master Reorganization Agreement, the parties thereto agreed to effect a series of restructuring transactions (the "Reorganization") in connection with the IPO, consisting of (i) the net exercise of all outstanding warrants held by Archer, Robertson QES and affiliates of Geveran for common units of QES LP; (ii) the Company's acquisition of all of the outstanding equity of QES Holdco LLC and QES LP, establishing the Company as the holding company for QES Holdco LLC, QES LP and the subsidiaries of QES LP; (iii) the Company's issuance of shares of Common Stock to the existing investors of QES LP in exchange for their respective direct or indirect common units in QES LP, including shares issued pursuant to the net exercise of their warrants (as described below), and their direct or indirect membership interests in QES Holdco LLC; (iv) the consummation of a 31.669363 for 1 reverse stock split of our issued and outstanding common stock effective immediately prior to the consummation of the IPO and the conversion of approximately $33.6 million of outstanding indebtedness under our Term Loan into shares of our common stock at the initial public offering price (the "Term Loan Conversion"); and (v) the Term Loan Conversion. The foregoing transactions were undertaken in reliance on an exemption from the registration requirements of the Securities Act, pursuant to Section 4(a)(2) thereof. For additional detail on the ownership of Robertson QES, please see Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters" above.

Registration Rights Agreement

In connection with our IPO, we entered into a registration rights agreement (the "Registration Rights Agreement") with certain of the Principal Stockholders, pursuant to which we have agreed to register the sales of shares of our common stock held by such stockholders under certain circumstances.

Demand Rights. Subject to the limitations set forth below, each of the Principal Stockholders has the right to request the registration under the Securities Act of all or any portion of their common stock.

Piggyback Rights. Subject to certain exceptions, if at any time we propose to register an offering of common stock or conduct an underwritten offering, whether or not for our own account, then we must notify in writing the Principal Stockholders (or their permitted transferees) of such proposal no later than ten days prior to the initiation of such anticipated filings or commencement of the underwritten offering, as applicable, to allow them to include a specified number of their shares in that registration statement or underwritten offering, as applicable.

Conditions and Limitations; Expenses. These registration rights are subject to certain conditions and limitations, including the right of the underwriters to limit the number of shares to be included in a registration and our right to delay or withdraw a registration statement under certain circumstances. We will generally pay all registration expenses in connection with our obligations under the Registration Rights Agreement, regardless of whether a registration statement is filed or becomes effective.

Equity Rights Agreement

In connection with our IPO, we entered into the Equity Rights Agreement with certain of the Principal Stockholders. 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. The number of directors to be appointed by each of Quintana, Archer and Geveran will be redetermined immediately upon any disposition of the outstanding shares of our common stock held by Quintana, Archer, Robertson QES or Geveran. The current board representative appointed by Quintana is Corbin J. Robertson, Jr. The current board representatives appointed by Archer are Dag Skindlo and Gunnar Eliassen.

Procedures for Review, Approval and Ratification of Transactions with Related Persons

A "Related Party Transaction" is a transaction, arrangement or relationship in which we or any of our subsidiaries was, is or will be a participant, the amount of which involved exceeds $120,000, and in which any related person had, has or will have a direct or indirect material interest. A "Related Person" means:

- any person who is, or at any time during the applicable period was, one of our executive officers or one of our directors;

- any person who is known by us to be the beneficial owner of more than 5.0% of our common stock;
- any immediate family member of any of the foregoing persons, which means any child, stepchild, parent, stepparent, spouse, sibling, mother-in-law, father-in-law, son-in-law, daughter-in-law, brother-in-law or sister-in-law of a director, executive officer or a beneficial owner of more than 5.0% of our common stock, and any person (other than a tenant or employee) sharing the household of such director, executive officer or beneficial owner of more than 5.0% of our common stock; and
- any firm, corporation or other entity in which any of the foregoing persons is a partner or principal or in a similar position or in which such person has a 10.0% or greater beneficial ownership interest.

In connection with the IPO, our board of directors adopted a written related party transactions policy. Pursuant to this policy, our audit committee will review all material facts of all Related Party Transactions and either approve or disapprove entry into the Related Party Transaction, subject to certain limited exceptions. In determining whether to approve or disapprove entry into a Related Party Transaction, our audit committee shall take into account, among other factors, the following: (i) whether the Related Party Transaction is on terms no less favorable than terms generally available to an unaffiliated third-party under the same or similar circumstances and (ii) the extent of the Related Person's interest in the transaction. Furthermore, the policy requires that all Related Party Transactions required to be disclosed in our filings with the SEC be so disclosed in accordance with applicable laws, rules and regulations.

All of the transactions described above, except for participation in our IPO, were entered into prior to the adoption of the related party transaction policy, but all were approved by our board of directors considering similar factors to those described above. The audit committee ratified the IPO Purchases.

Item 14. Principal Accounting Fees and Services

Audit and Other Fee Information

Set forth below is a summary of certain fees paid to our principal accountant for services related to the fiscal years ended December 31, 2017 and December 31, 2016.

	2017	2016
	(in thousands)	
Audit fees	$2,379.3	1,041.0
Tax fees	587.7	552.7
Total	$2,967.0	1,593.7

Audit Fees

Audit fees consisted of fees for professional services rendered for the audits of our consolidated financial statements for fiscal year 2017 and 2016 included in our Registration Statement on Form S-1 and Annual Report on Form 10-K.

Tax Fees

Tax fees consisted of fees for professional services rendered by our principal accountant for tax compliance, tax advice, and tax planning.

There were no audit-related fees or other fees paid to our principal accountant in the fiscal years ended December 31, 2017 or 2016.

The audit committee of our board of directors operates under a written audit committee charter adopted by the board. A copy of the charter is available on our website www.quintanaenergyservices.com. The charter requires the audit committee to approve in advance all audit and non-audit services to be provided by our independent registered public accounting firm. For the years ended December 31, 2017 and 2016, we did not have an audit committee or pre-approval policy.

PART IV

Item 15. Exhibits, Financial Statement Schedules

Exhibit number	Description
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).
3.1	Amended and Restated Certificate of Incorporation of Quintana Energy Services Inc. (Incorporated by reference to Exhibit 3.2 of Quintana Energy Services Inc.'s Current Report on Form 8-K filed on February 14, 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).

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Exhibit number	Description
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).
10.12+	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).
10.13+	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).
10.14+	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).
10.15+	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).
10.16+	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).
10.17+	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).
10.18+	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).
10.19+	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).
10.20+	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).

Exhibit number	Description
10.21+	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).
10.22+	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).
10.23+	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).
21.1*	List of Subsidiaries of Quintana Energy Services Inc.
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 Financial 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. 10-K Summary.

Not applicable.

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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
Chief Executive Officer, President and Director

Date: March 29, 2018

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 29, 2018.

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/ Gbolade Odeneye Gbolade Odeneye	Vice President and Corporate Controller (*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.	Member of the Board of Directors
/s/ Rocky L. Duckworth Rocky L. Duckworth	Member of the Board of Directors
/s/ Gunnar Eliassen Gunnar Eliassen	Member of the Board of Directors
/s/ Dag Skindlo Dag Skindlo	Member of the Board of Directors

Exhibit 21.1

Subsidiaries of Quintana Energy Services Inc.

Entity	**State of Formation**
Quintana Energy Services LLC	Delaware
QES Directional Drilling, LLC	Delaware
Q Consolidated Well Services, LLC	Delaware
QES Pressure Control LLC	Oklahoma
QES Wireline LLC	Texas
QES Intermediate LLC	Delaware
QES Management LLC	Delaware
CIS-Oklahoma, LLC	Delaware
QES Pressure Pumping LLC	Delaware
Oklahoma Oilwell Cementing Company	Oklahoma
Consolidated OWS Management, Inc.	Delaware
Centerline Trucking, LLC	Delaware
Twister Drilling Tools, LLC	Delaware
Q Directional MGMT, Inc.	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (No. 333-223021) of Quintana Energy Services Inc. of our report dated March 29, 2018 relating to the financial statements of Quintana Energy Services LP, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
March 29, 2018

Exhibit 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED,
AS ADOPTED PURSUANT TO SECTION 302 OF
THE SARBANES-OXLEY ACT OF 2002

I, D. Rogers Herndon, certify that:

1. I have reviewed this Annual Report on Form 10-K of Quintana Energy Services Inc. (the “registrant”);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   c. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: March 29, 2018

/s/ D. Rogers Herndon
D. Rogers Herndon
Chief Executive Officer, President and Director

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED,
AS ADOPTED PURSUANT TO SECTION 302 OF
THE SARBANES-OXLEY ACT OF 2002

I, Keefer M. Lehner, certify that:

6. I have reviewed this Annual Report on Form 10-K of Quintana Energy Services Inc. (the "registrant");

7. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

8. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

9. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   c. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

10. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 29, 2018

/s/ Keefer M. Lehner
Keefer M. Lehner
Executive Vice President and Chief Financial Officer

Exhibit 32.1

**CERTIFICATION OF
CHIEF EXECUTIVE OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES OXLEY ACT OF 2002**

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, in connection with the Annual Report of Quintana Energy Services Inc. (the “Company”) on Form 10-K for the period ended December 31, 2017, as filed with the Securities and Exchange Commission on the date hereof (the “Periodic Report”), I, D. Rogers Herndon, Chief Executive Officer, President and Director of the Company, hereby certify that, to my knowledge:

(1) the Periodic Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Periodic Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 29, 2018

/s/ D. Rogers Herndon
D. Rogers Herndon
Chief Executive Officer, President and Director

Exhibit 32.2

**CERTIFICATION OF
CHIEF FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES OXLEY ACT OF 2002**

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, in connection with the Annual Report of Quintana Energy Services Inc. (the "Company") on Form 10-K for the period ended December 31, 2017, as filed with the Securities and Exchange Commission on the date hereof (the "Periodic Report"), I, Keefer M. Lehner, Executive Vice President and Chief Financial Officer, hereby certify that, to my knowledge:

(1) the Periodic Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Periodic Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 29, 2018

/s/ Keefer M. Lehner
Keefer M. Lehner
Executive Vice President and Chief Financial Officer