Independence Contract Drilling, Inc.
Form 10-K
February 26, 2018

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-K
þ 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 001-36590
INDEPENDENCE CONTRACT DRILLING, INC.
(Exact name of registrant as specified in its charter)

Delaware	37-1653648
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
11601 North Galayda Street	
Houston, Texas	77086
(Address of principal executive offices)	(Zip code)

(281) 598-1230
(Registrant's telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

Title of Class	Name of each exchange on which registered
Common Stock, $0.01 par value 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 þ
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 þ
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 þ No
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ
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. (Check one):

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

Emerging growth company þ

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. Yes þ No

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes No þ

The aggregate market value of the registrant's common stock held by non-affiliates of the registrant was approximately $113,958,200 as of June 30, 2017, the last business day of the registrant's most recently completed second fiscal quarter (based on a closing price of $3.89 per share as reported on the New York Stock Exchange and 29,295,167 shares held by non-affiliates).

There were 38,098,248 shares of the registrant's common stock outstanding as of February 20, 2018.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the registrant's 2018 Annual Meeting of Stockholders (to be filed within 120 days of the close of the registrant's fiscal year) are incorporated by reference into Part III of this Annual Report on Form 10-K.

INDEPENDENCE CONTRACT DRILLING, INC.
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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in this Annual Report on Form 10-K, including those that express a belief, expectation or intention, as well as those that are not statements of historical fact, may constitute “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. These forward-looking statements may include projections and estimates concerning the timing and success of specific projects and our future revenues, income and capital spending. Our forward-looking statements are generally accompanied by words such as “estimate,” “project,” “predict,” “believe,” “expect,” “anticipate,” “potential,” “plan,” “goal,” “will” or other words that convey the uncerta future events or outcomes. We have based these forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. These and other important factors may cause our actual results, performance or achievements to differ materially from any future results, performance or achievements expressed or implied by these forward-looking statements. These risks, contingencies and uncertainties include, but are not limited to, the following:

- a decline in or substantial volatility of crude oil and natural gas commodity prices;
- a sustained decrease in domestic spending by the oil and natural gas exploration and production industry;
- our inability to implement our business and growth strategy;
- fluctuation of our operating results and volatility of our industry;
- inability to maintain or increase pricing of our contract drilling services, or early termination of any term contract for which early termination compensation is not paid;
- our backlog of term contracts declining rapidly;
- the loss of any of our customers, financial distress or management changes of potential customers or failure to obtain contract renewals and additional customer contracts for our drilling services;
- overcapacity and competition in our industry;
- an increase in interest rates and deterioration in the credit markets;
- our inability to comply with the financial and other covenants in debt agreements that we may enter into as a result of reduced revenues and financial performance;
- a substantial reduction in borrowing base under our credit facility as a result of a decline in the appraised value of our drilling rigs or reduction in the number of rigs operating;
- unanticipated costs, delays and other difficulties in executing our long-term growth strategy;
- the loss of key management personnel;
- new technology that may cause our drilling methods or equipment to become less competitive;
- labor costs or shortages of skilled workers;
- the loss of or interruption in operations of one or more key vendors;
- the effect of operating hazards and severe weather on our rigs, facilities, business, operations and financial results, and limitations on our insurance coverage;
- increased regulation of drilling in unconventional formations;
- the incurrence of significant costs and liabilities in the future resulting from our failure to comply with new or existing environmental regulations or an accidental release of hazardous substances into the environment; and
- the potential failure by us to establish and maintain effective internal control over financial reporting.

All forward-looking statements are necessarily only estimates of future results, and there can be no assurance that actual results will not differ materially from expectations, and, therefore, you are cautioned not to place undue reliance on such statements. Any forward-looking statements are qualified in their entirety by reference to the factors discussed throughout this Annual Report on Form 10-K, including those described in (1) Part I, “Item 1A. Risk Factors” and (2) Part II, “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.” Further, any forward-looking statement speaks only as of the date on which it is made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which the statement is made or to reflect the occurrence of unanticipated events.

PART I

ITEM 1. BUSINESS

Overview

Except as expressly stated or the context otherwise requires, the terms "we," "us," "our," the "Company" and "ICD" refer to Independence Contract Drilling, Inc.

We provide land-based contract drilling services for oil and natural gas producers targeting unconventional resource plays in the United States. We construct, own and operate a premium land rig fleet comprised entirely of technologically advanced, custom designed ShaleDriller® rigs that are specifically engineered and designed to optimize the development of our customers' most technically demanding oil and natural gas properties. We are focused on creating stockholder and customer value through our commitment to operational excellence and our focus on safety.

Our standardized fleet consists of 14 premium 200 Series ShaleDriller rigs, all of which are equipped with our integrated omni-directional walking system that is specifically designed to optimize pad drilling for our customers. Every rig in our fleet is a 1500-hp, AC programmable rig ("AC rig") designed to be fast-moving between drilling sites and is equipped with 7500 psi mud systems, top drives, automated tubular handling systems and blowout preventer ("BOP") handling systems. All of our rigs are equipped with bi-fuel capabilities that enable the rig to operate on either diesel or a natural gas-diesel blend.

Our first rig commenced drilling in May 2012. We currently focus our operations on unconventional resource plays located in geographic regions that we can efficiently support from our Houston, Texas facilities in order to maximize economies of scale. Currently, our rigs are operating in the Permian Basin, Eagle Ford Shale and the Haynesville Shale. Our rigs have previously operated in the Mid-Continent and Eaglebine regions.

Our business depends on the level of exploration and production activity by oil and natural gas companies operating in the United States, and in particular, the regions where we actively market our contract drilling services. The oil and natural gas exploration and production industry is a historically cyclical industry characterized by significant changes in the levels of exploration and development activities. Oil and natural gas prices and market expectations of potential changes in those prices significantly affect the levels of those activities. Worldwide political, regulatory, economic, and military events, as well as natural disasters have contributed to oil and natural gas price volatility historically, and are likely to continue to do so in the future. Any prolonged reduction in the overall level of exploration and development activities in the United States and the regions where we market our contract drilling services, whether resulting from changes in oil and natural gas prices or otherwise, could materially and adversely affect our business.

Industry Trends

Land Rig Replacement Cycle

The increase in horizontal drilling in the United States over the past ten years has resulted in an ongoing land-rig replacement cycle in which the contract drilling industry is systematically upgrading its legacy fleets of electrical silicon-controlled rectifier ("SCR") rigs and mechanical rigs with modern AC rigs that are specifically designed to optimize this type of drilling activity. Additionally, a growing focus on horizontal drilling of longer-reach lateral wells from multi-well pads is driving a further delineation in the United States land rig fleet between pad-optimal rigs specifically designed and engineered for such applications and AC and legacy rigs not specifically engineered for such applications.

The following describes the three different types of rig drives:

Mechanical Rigs. Mechanical rigs were not designed and are not well suited for the demanding requirements of drilling horizontal wells. A mechanical rig powers its systems through a combination of belts, chains and transmissions. This arrangement requires the rig to be rigged up with precise alignment of the belts and chains, which requires substantial time during a rig move. In addition, mechanical power loading of key rig systems, including drawworks, pumps and rotating equipment results in very imprecise control of system parameters, causing lower drill bit life, lower rate of penetration and difficulty maintaining wellbore trajectory.

SCR Rigs. In contrast to mechanical rigs, SCR rigs rely on direct current, or DC, to power the key rig systems. Load is changed by adjusting the amperage supplied to electric motors powering key rig systems. While a substantial improvement over mechanical belts and chains, SCR control is imprecise, and DC power levels normally drift resulting in fluctuations in pump speed and pressure, bit rotation speed, and weight on bit. These fluctuations can cause wellbore deviation, shorter bit life and less optimal rates of penetration. In addition, SCR equipment is heavy and energy inefficient.

AC Rigs. Compared to SCR and mechanical rigs, AC rigs are ideally suited for drilling horizontal wells. The first AC rigs were introduced into the United States land market in the early 2000s, and since that time their use has grown significantly as the use of horizontal drilling has increased. AC rigs use a computer-controlled variable frequency drive ("VFD") to precisely adjust key rig operating parameters and systems allowing for optimization of the rate of penetration, extended bit life and improved control of wellbore trajectory. These factors reduce the amount of time a wellbore is “open hole,” or uncased. Shorter open hole times dramatically reduce adjacent formation damage that can be caused by shale hydration or drilling fluid invasion and enhance the operator’s ability to optimally run and cement casing to complete the drilled well. In addition, when compared to SCR and mechanical rigs, AC rigs are electrically more efficient, produce more torque, utilize regenerative braking, and have digital controls. AC motors are also smaller, lighter and require less maintenance than DC motors.

Shift to Manufacturing Wellbore Model

Following their significant investments made in unconventional resource plays, many exploration and production ("E&P") companies are now focused on developing these investments in a systematic manner. Efficient development of these resource plays involves drilling programs that drill large numbers of wells in succession, as opposed to a single or a few wells designed to delineate a field or hold a lease. We view this as analogous to a manufacturing process that requires an engineered program and is focused on economies of scale to reduce overall field development costs. Cost effective development drilling requires more complex well designs, shorter cycle times, and the use of innovative technology in order to reduce an E&P company’s overall field development costs.

One method in which an E&P operator may reduce overall field development costs is through the use of a multi-well pad development program. Pad drilling involves the drilling of multiple wells from a single location, which provides benefits to the E&P company in the form of per well cost savings and accelerated cash flows as compared to non-pad developments. These cost savings result from reduced time required to move the rig between wells, centralized hydraulic fracturing operations and the efficient installation of central production facilities and pipelines. In addition, by performing drilling operations on one well with simultaneous completion operations on a second well, operators do not have to wait until the entire pad is complete to begin earning a return on their investment. Pad drilling promotes “manufacturing” efficiencies by enabling “batch” drilling, whereby an operator drills all of the wells’ surface holes as the first batch, then drills all of the intermediate sections as the second batch, and concludes with the drilling all of the laterals as the final batch. Efficiencies are created because hole sizes change less frequently, and operators use the same mud system and tools repeatedly. We believe as operators have shifted over time to horizontal drilling, they have implemented pad drilling in order to maximize economics and optimize development plans. In order to maximize the efficiencies gained from pad drilling, a rig must be capable of moving quickly from one well to another and able to address the complexities associated with the growing number of wells per pad. In addition to quickly moving from well to well, omni-directional walking systems are ideally suited for pad drilling because they are capable of efficiently addressing situations on a pad in which wellbores are not precisely aligned or when level variations exist on the pad, which becomes increasingly likely as pads become larger and more complex.

Another method utilized by operators to increase efficiencies and maximize well economics is the drilling of longer lateral horizontal wells. Operators in our target areas have continued to increase the lateral length of their horizontal wells. Longer laterals provide greater production zones as the portion of the wellbore that passes through the target formation increases, optimizing the impact of hydraulic fracturing and stimulation. The drilling of longer laterals necessitates the use of increased horsepower drawworks and top drive systems, which provide maximum torque and rotational control and allows the operator to maintain the integrity of its drilling plan throughout the wellbore. Additionally, higher pressure mud pumps are required to pump fluids through significantly longer wellbores. The competitive advantage of higher pressure mud pumps grows as the lateral length increases, as only high pressure pumps can effectively address the severe pressure drop, while providing the required hydraulic horsepower at the bit face and sufficient flow to remove drill cuttings and keep the hole clean.

Pad Optimal Equipment

Cost effective development drilling in a manufacturing wellbore model requires more complex well designs, shorter cycle times, and the use of innovative technology in order to reduce an E&P company’s overall field development costs. Drilling rigs that are designed to maximize drilling efficiency, reduce cycle times, maximize energy efficiency, increase penetration rates while drilling, and drill longer-reach horizontal wells will reduce an E&P company's overall field development costs and provide them with greater optionality when designing their field development program. As a result, we believe that E&P companies drilling horizontal wells are going to increasingly demand not only AC rigs that are optimal for horizontal drilling, but premium AC rigs such as our ShaleDriller rig that are "pad optimal" and include the following equipment and design features:

- AC Programmable. AC rigs use a variable frequency drive that allows precise computer control of motor speed during operations. This greater control of motor speed provides more precise drilling of the wellbore. Among other attributes,

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when compared to electrical SCR rigs and mechanical rigs, AC rigs are electrically more efficient, produce consistent torque, utilize regenerative braking, and have digital controls and AC motors that require less maintenance. AC rigs allow our customers to drill faster, which, in general, eliminates reservoir permeability damage, and to drill wellbores that more precisely track planned trajectories without doglegs. This, in turn, minimizes open hole time and enables our customers to more effectively and efficiently run casing, cement and successfully complete their wells.

- Pad Optimized, Omni-Directional Walking System. Our omni-directional walking system is engineered and designed as an integrated part of our ShaleDriller rig's substructure to optimize pad drilling economics for our customers. Pad drilling involves the drilling of multiple wells from a single location, which provides benefits to the E&P company in the form of cost savings and accelerated cash flows. Our walking system allows our rigs to move in any direction quickly between wellheads, rapidly and efficiently adjust to misaligned wellbores, walk over raised wellheads, and increase operational safety due to fewer required rig up and rig down movements.

- Bi-Fuel Capable. All of our ShaleDriller rigs are bi-fuel capable. Bi-fuel operations offer a reduction in carbon emissions and provide significant fuel cost savings for our customers.

- Efficient Mobilization Between Drilling Sites. A rig that can rapidly move between drilling sites has become increasingly desired by, and impactful to, E&P companies because it reduces cycle times allowing them to drill more wells in the same period of time. In addition to being specifically designed for moving between wells on a pad, our ShaleDriller rig is designed to move rapidly on conventional rig moves between drilling sites. Our custom designed substructure moves in a single semi-trailer load and allows for automated and rapid rig up and rig down without the use of cranes. This significantly reduces overall move time compared to a traditional substructure design, provides cost savings to our customers, and enables a safer rig up and rig down process.

- 1500-hp Drawworks. All of our rigs are powered with 1500-hp drawworks and are well suited for the development of the vast majority of our customers' unconventional resource assets. Compared to a 1000-hp or smaller rig, a 1500-hp rig has superior capability to handle extended drill string lengths required to drill long horizontal wells, which are becoming more common in the markets we serve.

- 7500psi Mud Systems. The drilling of longer laterals necessitates the use of higher pressure mud pumps to pump fluids through significantly longer wellbores. The competitive advantage of higher pressure mud pumps grows as the lateral length gets longer, as only high pressure pumps can effectively address the severe pressure drop while providing the required hydraulic horsepower at the bit face and sufficient flow to remove drill cuttings and keep the hole clean.

Oil and Natural Gas Prices and Drilling Activity

Both oil and natural gas prices began to decline in the second half of 2014, declined further during 2015 and remained low in 2016. The closing price of oil was as high as $106.06 per barrel during the third quarter of 2014, was $37.13 per barrel on December 31, 2015 and reached a low of $26.19 on February 11, 2016 (West Texas Intermediate - Cushing, Oklahoma ("WTI") spot price as reported by the United States Energy Information Administration (the "EIA")). Similarly, natural gas prices (as measured at Henry Hub) declined from an average of $4.37 per MMBtu in 2014, to $2.62 per MMBtu in 2015, $2.52 per MMBtu in 2016. As a result, our industry experienced an exceptional downturn and market conditions have only begun to stabilize and slowly recover.

In November 2016, Organization of Petroleum Exporting Countries ("OPEC") members formally agreed to reduce their production quotas, starting January 1, 2017. These production cuts significantly reduced the overhang of global oil supplies. OPEC members met in December 2017 and agreed to extend the freeze into 2018, and are expected to meet again in June 2018 to review market conditions and the impact of their freeze on global supplies. In addition to OPEC members, certain non-OPEC producers such as Russia have agreed to production cuts, which has also supported crude oil and related energy commodity prices.

As a result of these supply cuts and positive demand trends, crude oil prices recovered to the $45 to $55 per barrel range, with WTI oil prices reaching a three-year high of $66.27 on January 26, 2018. Similarly, natural gas prices at Henry Hub averaged $2.99 per MMBtu in 2017, and have averaged $3.41 per MMBtu in 2018, as of February 20, 2018. While this continued recovery in pricing is promising, there are no indications at this time that oil and natural gas prices and rig counts will recover to their previous highs experienced in 2014.

Due to this deterioration and stabilization of commodity prices well below previous highs, our customers are principally focused on their most economic wells, and driving cost and production efficiencies that deliver the most economic wells with the lowest capital costs. As a result of this drive towards production and cost efficiencies, operators are focusing more of their capital spending on horizontal drilling programs compared to vertical drilling, and are more focused on utilizing drilling equipment and techniques that optimize costs and efficiency. Thus, we believe the rapid market deterioration and stabilization of oil prices well below historical highs has significantly accelerated the pace of the ongoing land rig replacement cycle and continued shift to horizontal drilling from multi-well pads utilizing “pad optimal” rig technology.

As market conditions have improved from trough levels in 2016 and begun to stabilize higher, demand for our ShaleDriller rigs has improved. At December 31, 2017, all of our rigs were under contract and operating. In addition to improving utilization, contract tenors improved with customers signing term contracts of six to twelve months or longer, and at higher dayrates compared to trough levels, with the potential to move higher if market conditions continue to improve. However, if oil prices were to fall below $45 per barrel for any sustained period of time, market conditions and demand for our products and services could deteriorate.

Customer Contracts and Backlog

Drilling contracts are obtained through competitive bidding or as a result of negotiations with customers, and may cover multi-well and multi-year projects. Each of our rigs operates under a separate drilling contract or drilling order subject to a master drilling contract. We perform drilling services on a “daywork” contract basis, under which we charge a specified rate per day. The dayrate under each of our contracts is a negotiated price determined by the location, depth and complexity of the wells to be drilled, operating conditions, the duration of the contract, and market conditions. We have not accepted any, and do not anticipate entering into, any “turn-key” (fixed sum to deliver a hole to a stated depth) or “footage” (fixed rate per foot of hole drilled) contracts. The duration of land drilling contracts can vary from “well-to-well” or to a fixed term ranging from a few months to several years. The revenue generated by a rig in a given year is the product of the dayrate fee and the number of days the rig is earning this fee based on activity and the terms of the contract, referred to as utilization. “Well-to-well” contracts are typically cancelable at the option of either party upon the completion of drilling at a particular site. Fixed-term contracts customarily provide for termination at the election of the customer, with an “early termination payment” to be paid to the drilling contractor if a contract is terminated prior to the expiration of the fixed term. However, under certain limited circumstances, such as destruction of a drilling rig, the drilling contractor’s bankruptcy, sustained unacceptable performance by the drilling contractor or delivery of a rig beyond certain grace and/or liquidated damage periods, no early termination payment would be paid to the drilling contractor. Drilling contracts also contain provisions regarding indemnification against certain types of claims involving injury to persons, property and for acts of pollution, which are subject to negotiation on a contract-by-contract basis.

Under a typical daywork contract, we earn a dayrate fee while the rig is operating, and we earn a moving rate fee while the rig is moving between wells or drilling locations under the contract. If the rig is on standby or is not drilling due to a force majeure event unrelated to damage to the rig, contracts typically provide that we earn a rate during this period of time, which rate may be equal to or less than the operating rate.

Mobilization rates are determined by market conditions and are generally reimbursed by the customer. In most instances, contracts typically provide for additional payments associated with this initial mobilization of a drilling rig and that we receive a demobilization fee at the end of the contract term in certain circumstances equal to the estimated cost to transport the rig from the final drilling location and to compensate us for the estimated demobilization time.

Drilling contracts typically provide that the contractor continues to earn the operating dayrate while a rig is not operating but under repair or maintenance, so long as the non-operating time due to repair and maintenance does not exceed a specified number of hours in a given day or calendar month.

Prior to the significant decline in market conditions that began in late 2014, we were able to regularly obtain long-term contracts with terms between one and three years. Throughout 2015 and 2016, the vast majority of new rig contracts were short-term well-to-well contracts or contracts with terms less than six months. As a result, our contract drilling backlog, or the expected future revenue from executed contracts with original terms of six months or greater, declined significantly from $152.8 million as of December 31, 2014, to $74.4 million as of December 31, 2015 and to $42.5 million as of December 31, 2016. During 2017, as a result of the current stabilization in the market, the majority of our contracts were from six to twelve months. As of December 31, 2017, our backlog was $51.5 million, prior to four contract extensions signed in the first quarter of 2018. Approximately $47.6 million of our backlog at December 31, 2017 is expected to be realized during 2018. Our backlog does not include potential reductions in rates for unscheduled standby during periods in which the rig is moving, on standby or incurring maintenance and repair time in excess of contractually allowed downtime. In addition, rigs under term contracts may realize revenue on a standby-without-crew basis, which allows us to preserve our expected cash margins from the contract but reduces our overall top line revenue. To the extent that we have rigs under term contracts operating on a standby or standby-without-crew basis, our top line revenues will be less than our reported backlog from term contracts.

The following chart summarizes the weighted average number of rigs as of December 31, 2017 that we have operating under term contracts through 2018 and 2019.

	Quarter Ending March 31, 2018	Quarter Ending June 30, 2018	Quarter Ending September 30, 2018	Quarter Ending December 31, 2018	Year Ending 2019
Weighted Average Number of Rigs (1)	13.5	8.2	3.4	2.2	0.6

(1) Weighted average number of rigs calculated based upon the aggregate number of expected revenue days to be realized during the period from term contracts divided by the number of days in the applicable period. Term contracts include all contracts with original terms of 6 months or greater, and exclude well-to-well or short-term contracts.

Since the end of 2017, we have successfully signed new extensions on four contracts. As a result, our backlog as of December 31, 2017, adjusted to include these new extensions signed through February 15, 2018, is $74.5 million, of which $65.4 million is expected to be realized during 2018.

The following chart summarizes the weighted average number of rigs as of February 15, 2018 that we have operating under term contracts through 2018 and 2019.

	Quarter Ending March 31, 2018	Quarter Ending June 30, 2018	Quarter Ending September 30, 2018	Quarter Ending December 31, 2018	Year Ending 2019
Weighted Average Number of Rigs (1)	14.0	11.1	7.2	4.8	1.3

(1) Weighted average number of rigs calculated based upon the aggregate number of expected revenue days to be realized during the period from term contracts divided by the number of days in the applicable period. Term contracts include all contracts with original terms of 6 months or greater, and exclude well-to-well or short-term contracts.

Our Customers

Customers for contract drilling services in the United States include major oil and natural gas companies, independent oil and natural gas companies, as well as numerous small to mid-sized publicly-traded and privately held oil and natural gas companies. We market our contract drilling services to all such customers. During 2017, our customers representing more than 10% of our revenues were GeoSouthern Energy Corporation, Devon Energy, RSP Permian, LLC, and Pioneer Natural Resources USA, Inc. While we would attempt to remarket our rigs if we lost any material customer, given current market conditions, the terms of such new contract, if any were found, may be less favorable than the terms of our current contracts. Therefore, the loss of any material customer could have an adverse effect on our business.

Industry/Competition

To a large degree, our business depends on the level of capital spending by oil and natural gas companies for exploration, development and production activities. A sustained increase or decrease in the price of oil and natural gas could have a material impact on the exploration, development and production activities of our customers and could materially affect our financial position, results of operations and cash flows.

The contract drilling industry is highly competitive and has become even more so under current market conditions. The price for contract drilling services is a key competitive factor in the United States land contract drilling markets, in part because equipment used in our businesses can be moved from one area to another in response to market conditions. In addition to price, we believe the principal competitive factors in our markets are availability and condition of equipment, efficiency of equipment, quality of personnel, service quality, experience and safety record. Many of our competitors are larger, publicly-held corporations with significantly greater resources and longer operating histories than us. Our largest competitors for high-end AC land drilling contract services are Helmerich & Payne, Inc., Precision Drilling Corporation, Nabors Industries, Ltd. and Patterson-UTI Energy, Inc.

Many of our larger competitors are able to offer ancillary products and services with their contract drilling services, and recently, some of our larger competitors have begun integrating and offering contract drilling services in connection with directional drilling and other services that we do not offer.

Government and Environmental Regulation

All of our operations and facilities are subject to numerous federal, state and local laws, rules and regulations related to various aspects of our business, including:

- drilling of oil and natural gas wells;
- the relationships with our employees;
- containment and disposal of hazardous materials, oilfield waste, other waste materials and acids; and
- use of underground storage tanks.

To date, we do not believe applicable environmental laws and regulations in the United States have required the expenditure by the contract drilling industry of significant resources outside the ordinary course of business. However, compliance costs under existing laws or under any new requirements could become material, and we could incur liability in any instance of noncompliance.

Our business is generally affected by political developments and by federal, state and local laws and regulations that relate to the oil and natural gas industry. The adoption of laws and regulations affecting the oil and natural gas industry for economic, environmental and other policy reasons could increase costs relating to drilling and production, and otherwise have an adverse effect on our operations. Federal, state and local environmental laws and regulations currently apply to our operations and may become more stringent in the future. Any suspension or moratorium of the services we provide, whether or not short-term in nature, by a federal, state or local governmental authority, could have a material adverse effect on our business, financial condition and results of operation.

In the United States, the federal Comprehensive Environmental Response Compensation and Liability Act of 1980, as amended ("CERCLA"), and comparable state statutes impose liability, without regard to fault or legality of conduct, on classes of persons considered to be responsible for the release of a "hazardous substance" into the environment. These persons include:

- current and past owners and operators of the site where the release occurred, and
- persons who disposed of or arranged for the disposal of "hazardous substances" released at the site.

Under CERCLA, such persons may be subject to join and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. 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.

The federal Resource Conservation and Recovery Act ("RCRA"), as amended, and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Although CERCLA currently excludes petroleum from the definition of "hazardous substances," and RCRA excludes certain classes of exploration and production wastes from regulation as hazardous waste under Subtitle C of RCRA, such exemptions by Congress under both CERCLA and RCRA may be deleted, limited, or modified in the future. If such changes are made to CERCLA and/or RCRA, we could be required to remove and remediate previously disposed of materials (including materials disposed of or released by prior owners or operators) from properties (including ground water contaminated with hydrocarbons) and to perform removal or remedial actions to prevent future contamination.

The federal Water Pollution Control Act, as amended, also known as the Clean Water Act, and the Oil Pollution Act of 1990, as amended (the "Oil Pollution Act"), and analogous state laws and their respective implementing regulations govern:

- the prevention of discharges of pollutants, including oil and produced water spills, into waters of the United States; and
- liability for drainage into waters of the United States.

The Oil Pollution Act imposes strict liability for a comprehensive and expansive list of damages from an oil spill into waters from facilities. Liability may be imposed for oil removal costs and a variety of public and private damages. Administrative, civil or criminal penalties may also be imposed for violation of federal safety, construction and operating regulations, and for failure to report a spill or to cooperate fully in a clean-up.

The Oil Pollution Act also expands the authority and capability of the federal government to direct and manage oil spill clean-up and operations, and requires operators to prepare oil spill response plans in cases where it can reasonably be expected that substantial harm will be done to the environment by discharges on or into navigable waters. Failure to comply with ongoing requirements or inadequate cooperation during a spill event may subject a responsible party, such as us, to administrative, civil or criminal actions. Although the liability for owners and operators is the same under the federal Water Pollution Act, the damages recoverable under the Oil Pollution Act are potentially much greater and can include natural resource damages.

Our contract drilling services will be marketed in oil and natural gas producing regions that utilize hydraulic fracturing services to enhance the production of oil and natural gas from formations with low permeability, such as shales. Due to concerns raised relating to potential impacts of hydraulic fracturing on groundwater quality and the increased occurrence of seismic activity, legislative and regulatory efforts at the federal level and in some states have been initiated to render permitting and compliance requirements more stringent for hydraulic fracturing or prohibit the activity altogether. Such efforts could have an adverse effect on oil and natural gas production activities, which in turn could have an adverse effect on the contract drilling services that we render for our exploration and production customers.

Our operations are also subject to federal, state and local laws, rules and regulations for the control of air emissions, including the federal Clean Air Act. The federal Clean Air Act, and comparable state laws, regulates emissions of various air pollutants through, for example, air emissions permitting programs. In addition, the Environmental Protection Agency (the "EPA") has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources including pursuing the energy extraction sector under a National Enforcement Initiative. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. Finally, more stringent federal, state and local regulations, such as the EPA rules issued in April 2012, which add new requirements for the oil and natural gas sector under the New Source Review Program and the National Emission Standards for Hazardous Air Pollutants program, could result in increased costs and the need for operational changes. Any direct and indirect costs of meeting these requirements may adversely affect our business, results of operations and financial condition.

On December 7, 2009, the EPA announced its findings that emissions of GHG present an “endangerment to human health and the environment.” The EPA based this finding on a conclusion that greenhouse gases are contributing to the warming of the Earth’s atmosphere and other climate changes. The EPA began to adopt regulations that would require a reduction in emissions of greenhouse gases from certain stationary sources and has required monitoring and reporting for other stationary sources. Mandatory reporting requirements for additional regional, federal or state requirements have been imposed and additional requirements may be imposed in the future. New legislation or regulatory programs that restrict emissions of greenhouse gases in areas in which we conduct business could have an adverse effect on our operations and demand for our services. For example, during 2012, the EPA published rules that include standards to reduce methane emissions associated with oil and natural gas production. In May 2016, the EPA finalized regulations that set methane emission standards for new and modified oil and natural gas facilities, including production facilities. In July 2017, the EPA proposed a two-year stay of certain requirements of this rule pending reconsideration of the rule. Currently, our operations are not adversely impacted by existing state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business. Finally, it should be noted that some scientists have concluded 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 exploration and production operations.

We are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in compliance with these applicable requirements and with other OSHA and comparable requirements.

Additionally, environmental laws such as the federal Endangered Species Act ("ESA") and the Migratory Bird Treaty Act, may impact exploration, development and production activities on public or private lands. The ESA provides broad protection for species of fish, wildlife and plants that are listed as threatened or endangered in the United States, and prohibits taking of endangered species. Federal agencies are required to ensure that any action authorized, funded or carried out by them is not likely to jeopardize the continued existence of listed species or modify their critical habitat. While some of our customers' properties may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. However, the designation of previously unidentified endangered or threatened species or the designation of previously unprotected areas as a critical habitat could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Risks and Insurance

Our operations are subject to the many hazards inherent in the drilling business, including:

- accidents at the work location;
- blow-outs;
- cratering;
- fires; and
- explosions.

These and other hazards could cause:

- personal injury or death;
- suspension of drilling operations; or
- damage or destruction of our equipment and that of others;
- damage to producing formations and surrounding areas; and
- environmental damage.

Damage to the environment, including property contamination in the form of soil or ground water contamination, could also result from our operations, including through:

- oil or produced water spillage;
- natural gas leaks; and
- fires.

We maintain insurance coverage of types and amounts that we believe to be customary in the industry, but we may not be fully insured against all risks, either because insurance is not available or because of the high premium costs. Such risks include personal injury, well disasters, extensive fire damage, damage to the environment, and other hazards. The insurance coverage that we maintain includes insurance for fire, windstorm and other risks of physical loss to our rigs and other assets, employer's liability, automobile liability, commercial general liability insurance and workers compensation insurance. We cannot assure, however, that any insurance obtained by us will be adequate to cover any losses or liabilities, or that this insurance will continue to be available or available on terms that are acceptable to us. While we carry insurance to cover physical damage to, or loss of, our drilling rigs and other assets, such insurance does not cover the full replacement cost of the rigs or other assets, and we do not carry insurance against loss of earnings resulting from such damage. Liabilities for which we are not insured, or which exceed the policy limits of our applicable insurance, could have a material adverse effect on our financial condition and results of operations. Further, we may experience difficulties in collecting from insurers, or such insurers may deny all or a portion of our claims for insurance coverage.

In addition to insurance coverage, we also attempt to obtain indemnification from our customers for certain risks. These indemnities typically require our customers to hold us harmless in the event of loss of production or reservoir damage. There is no assurance that we will obtain such contractual indemnity, and if obtained, whether such indemnity will be enforceable, whether the customer will be able to satisfy such indemnity or whether such indemnity will be supported by adequate insurance maintained by the customer.

If a significant accident or other event occurs and is not fully covered by insurance or is not an enforceable or recoverable indemnity from a third party, it could have a material adverse effect on our business, financial condition, cash flows and results of operations. See “Risk Factors - Our operations involve operating hazards, which if not insured or indemnified against, could adversely affect our results of operations and financial condition.”

Employees

As of December 31, 2017, we had approximately 390 employees, none of whom were contract employees or were represented by a union. The number of our employees fluctuates depending on our construction and drilling activities.

Seasonality

Seasonality has not significantly affected our overall operations. However, our drilling operations can be affected by severe winter storms or other weather related events. Additionally, toward the end of some years, we experience slower contracting activity as customers' capital expenditure budgets are depleted.

Drilling Equipment, Suppliers and Subcontractors

We use many suppliers of drilling equipment and services. Although this drilling equipment and services have historically been available, there is no assurance that such drilling equipment and services will continue to be available on favorable terms or at all. We also utilize numerous manufacturers and independent subcontractors from various trades to supply key components to the rigs that we construct for our use. These key components include masts and substructures, top drives, high pressure mud pumps, pressure control equipment, engines, and VFD control systems. We believe that we have alternative sources for each of these components.

Website Access to Our Periodic SEC Reports

Our internet address is http://www.icdrilling.com. We file and furnish Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q and Current Reports on Form 8-K, and amendments to these reports, with the Securities and Exchange Commission (the "SEC"), which are available free of charge through our website as soon as reasonably practicable after such reports are filed with or furnished to the SEC. Materials we file with the SEC may be read and copied at the SEC's Public Reference Room at 100 F Street, NE, Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC also maintains an internet website at http://www.sec.gov that contains reports, proxy and information statements, and other information regarding our company that we file and furnish electronically with the SEC.

We may from time to time provide important disclosures to investors by posting them in the investor relations section of our website, as allowed by SEC rules. Information on our website is not incorporated by reference into this Annual report on Form 10-K and you should not consider information on our website as part of this Annual Report on Form 10-K.

ITEM 1A. RISK FACTORS

We face many challenges and risks in the industry in which we operate. You should carefully consider each of the following risk factors and all of the other information set forth in this Annual Report on Form 10-K, including our financial statements and related notes, and the documents and other information incorporated by reference herein, before investing in our shares. The risks and uncertainties described are not the only ones we face. Additional risk factors not presently known to us or which we currently consider immaterial may also adversely affect us. If any of these risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, the trading price of our shares could decline and you could lose all or part of your investment.

Risks Related to Our Business

Significant declines in oil and natural gas prices could continue and adversely affect demand for contract drilling services, which could have a material adverse effect on our results of operations and financial condition.

Oil prices began to decline in the second half of 2014 and declined further during 2015 and 2016. The closing price of oil was as high as $106.06 per barrel during the third quarter of 2014, was $37.13 per barrel on December 31, 2015 and reached a low of $26.19 on February 11, 2016 (WTI spot price as reported by the EIA). Similarly, natural gas prices (as measured at Henry Hub) declined from an average of $4.37 per MMBtu in 2014, to $2.62 per MMBtu in 2015, $2.52 per MMBtu in 2016. As a result, our industry experienced an exceptional downturn and market conditions have only begun to stabilize and slowly recover.

Although crude oil prices recovered to the $45 to $55 per barrel range, and natural gas prices at Henry Hub averaged $2.99 per MMBtu in 2017, there are no indications at this time that oil and natural gas prices and rig counts will recover to their previous highs experienced in 2014. We believe the current stabilization in market conditions is predicated on oil prices remaining in the $45 to $55 per barrel or higher range, and if oil prices were to fall below these levels for any sustainable period, demand and pricing for our contract drilling services could decline and have a material adverse affect on our operations and financial condition.

In addition, we currently finance our capital expenditures and operations pursuant to a committed $85.0 million revolving line of credit. A significant portion of our borrowing base is tied to the appraised value of our drilling rigs, which value may decline if market conditions deteriorate further. A significant decline in our borrowing base could have a material adverse effect on our financial condition. Our amended and restated credit agreement (the "Credit Facility) also contains certain restrictive covenants, including a leverage and fixed charge ratio covenant based upon the cash flows of the company, and a minimum utilization covenant. Thus, a significant reduction in our cash flows as a result of the decline in demand for our products and services, or significant decline in our operating rig count due to an inability to recontract rigs could reduce or limit the level of funds we are able to borrow under our existing Credit Facility or cause us to violate one or more of our restrictive covenants, which could have a material adverse effect on our financial condition.

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

As a provider of land-based contract drilling services, our business depends on the level of exploration and production activity by oil and natural gas companies operating in the United States, and in particular, the regions where we actively market our contract drilling services. The oil and natural gas exploration and production industry is a historically cyclical industry characterized by significant changes in the levels of exploration and development activities. Oil and natural gas prices and market expectations of potential changes in those prices significantly affect the levels of those activities. Worldwide political, regulatory, economic, and military events as well as natural disasters have contributed to oil and natural gas price volatility and are likely to continue to do so in the future. Any prolonged reduction in the overall level of exploration and development activities in the United States and the regions where we market our contract drilling services, whether resulting from changes in oil and natural gas prices or otherwise, could materially and adversely affect us in many ways by negatively impacting:

- our revenues, cash flows and profitability;
- our ability to recontract drilling rigs upon expiration of existing contracts;

- our ability to recontract drilling rigs at profitable dayrates;
- our ability to invest in capital expenditures necessary to maintain our drilling fleet and respond to customer requirements;
- the fair market value of our drilling rig fleet and other assets;

- our ability to obtain additional debt and equity capital required to implement our rig construction and growth strategy, and the cost of that capital; and
- our ability to retain skilled rig personnel whom we need to implement our growth strategy.

Depending on the market prices of oil and natural gas, oil and natural gas exploration and production companies may cancel or curtail their drilling programs and may lower production spending on existing wells, thereby reducing demand for our services. Many factors beyond our control affect oil and natural gas prices, including, but not limited to:

- the cost of exploring for, producing and delivering oil and natural gas;
- the discovery and development rate of new oil and natural gas reserves, especially shale and other unconventional natural gas resources for which we market our rigs;
- the rate of decline of existing and new oil and natural gas reserves;
- available pipeline and other oil and natural gas transportation capacity;
- the levels of oil and natural gas storage;
- the ability of oil and natural gas exploration and production companies to raise capital;
- economic conditions in the United States and elsewhere;
- actions by the Organization of Petroleum Exporting Countries;
- political instability in the Middle East and other major oil and natural gas producing regions;
- governmental regulations, sanctions and trade restrictions, both domestic and foreign;
- domestic and foreign tax policy;
- weather conditions in the United States;
- the pace adopted by foreign governments for the exploration, development and production of their national reserves;
- the price of foreign imports of oil and natural gas;
- the strength or weakness of the United States dollar;
- the overall supply and demand for oil and natural gas; and
- the development of alternate energy sources and the long-term effects of worldwide energy conservation measures.

As discussed above, oil and natural gas prices have been volatile historically and, we believe, will continue to be so in the future. We also believe the current stabilization in market conditions for our services is predicated on oil prices remaining in the $45 to $55 per barrel or higher range, and if oil prices were to fall below these levels for any sustainable period, demand and pricing for our contract drilling services could decline and have a material adverse affect on our operations and financial condition.

Oil and natural gas prices, and market expectations of potential changes in these prices, significantly impact the level of worldwide drilling and production services activities. Reduced demand for oil and natural gas generally results in lower prices for these commodities and may impact the economics of planned drilling projects and ongoing production projects, resulting in the curtailment, reduction, delay or postponement of such projects for an indeterminate period of time. When drilling and production activity and spending decline, both dayrates and utilization have also historically declined. Further declines in oil and natural gas prices and the general economy, could materially and adversely affect our business, results of operations, financial condition and growth strategy.

In addition, if oil and natural gas prices decline, companies that planned to finance exploration, development or production projects through the capital markets may be forced to curtail, reduce, postpone or delay drilling activities even further, and also may experience an inability to pay suppliers. Adverse conditions in the global economic environment could also impact our vendors' and suppliers' ability to meet obligations to provide materials and services in general. If any of the foregoing were to occur, or if current depressed market conditions continue for a prolonged period of time, it could have a material adverse effect on our business and financial results and our ability to timely and successfully implement our growth strategy.

Any loss of large customers could have a material adverse effect on our financial condition and results of operations.

Our customer base consists of E&P companies that drill oil and natural gas wells in the United States in the regions where we market our rigs. As of December 31, 2017, we have rigs operating or earning revenues from six different customers, including one customer who has contracted five of our rigs, and two customers that have contracted three of our rigs. It is likely that we will continue to derive a significant portion of our revenue from a relatively small number of customers in the future. Daywork contracts in the contract drilling industry typically do not obligate those customers to order additional services from the drilling contractor beyond those for which they have currently contracted. If a customer decided not to continue to use our services or to terminate an existing contract, or if there is a change of management or ownership of a customer or a material adverse change in the financial condition of one of our customers, it could have a material adverse effect on our revenues, cash flows, and financial condition.

If our customers delay paying or fail to pay a significant amount of our outstanding receivables, it could have a material adverse effect on our business, financial condition, cash flows and results of operations.
In most cases, we bill our customers for our services in arrears and are, therefore, subject to our customers delaying or failing to pay our invoices. In weak economic environments, we may experience increased delays and failures due to, among other reasons, a reduction in our customers' cash flow from operations and their access to the credit markets. If our customers delay paying or fail to pay us a significant amount of our outstanding receivables, it could have a material adverse effect on our liquidity, results of operations, and financial condition.
We currently have eleven rigs operating under contracts with terms expiring during 2018. If we are unable to continue to operate rigs in the spot-market or renew our expiring contracts or continue their operation in the spot-market, it could have a material adverse effect on our results of operations and financial condition.
Upon expiration of a drilling contract, our customers have no obligation to extend the contract term or recontract the drilling rig, and may elect to release the rig. In the event a customer elects to terminate a drilling contract prior to the expiration of its drilling term, all of our current drilling contracts provide that our customers pay an early termination payment. We cannot assure that any replacement contract can be obtained for any of our rigs operating in the spot-market or with terms expiring, and if obtained, that it would be on terms as favorable as those of our existing drilling contracts or at profitable levels. The failure to renew or timely replace one or more of our expiring contracts could have a material adverse effect on our results of operations and financial condition.
Our operations involve operating hazards, which if not insured or indemnified against, could adversely affect our results of operations and financial condition.
Our operations are subject to the many hazards inherent in the drilling and well services industries, including the risks of:

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

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

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

Although, we seek to protect ourselves from some but not all operating hazards through insurance coverage, some risks are either not insurable or insurance is available only at rates that we consider uneconomical. Depending on competitive conditions and other factors, we attempt to obtain contractual protection against uninsured operating risks from our customers. However, customers who provide contractual indemnification protection may not in all cases maintain adequate insurance or otherwise have the financial resources necessary to support their indemnification obligations. Our insurance or indemnification arrangements may not adequately protect us against liability or loss from all the hazards of our operations. We do not carry loss of business insurance for a rig being out of service.
We maintain insurance against some, but not all, of the potential risks affecting our operations and only in coverage amounts and deductible levels that we believe to be economical. Our insurance coverage includes deductibles which must be met prior to recovery. Additionally, our insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect us against liability from all potential consequences and damages. The occurrence of a significant event that we have not fully insured or indemnified against or the failure of a customer to meet its indemnification obligations to us could materially and adversely affect our results of operations and

financial condition. Furthermore, we may be unable to maintain adequate insurance in the future at rates we consider reasonable. Incurring a liability for which we are not fully insured or indemnified could have a material adverse effect on our financial condition and results of operations.

We operate in a highly competitive industry in which price competition could reduce our profitability.
We encounter substantial competition from other drilling contractors. The competition in the markets in which we operate has intensified as recent mergers among E&P companies have reduced the number of available customers and the downturn in oil prices has decreased demand for drilling rigs and resulted in downward pricing pressure on operating drilling rigs.
Contract drilling companies compete primarily on a regional basis, and the intensity of competition may vary significantly from region to region at any particular time. Most drilling services contracts are awarded on the basis of competitive bids, which also results in price competition.
In addition to pricing, we believe the principal competitive factors in our markets are availability and condition of equipment, quality of personnel, efficiency of equipment, service quality, experience and safety record. The success of our business depends on our ability to offer safe and highly efficient operations, the quality and efficiency of our rigs and the skills and experience of our rig crews.
As a result of competition, we may lose market share or be unable to maintain or increase prices for our present services or to acquire additional business opportunities, which could have a material adverse effect on our business, results of operations and financial condition. In addition, the failure to maintain an adequate safety record could harm our ability to secure new drilling contracts. As a relatively new contract driller with limited operating history, there can be no assurance that we will be able to maintain the reputation for safety and quality required to successfully compete against our competition.
We face competition from many competitors with greater resources and greater ability to rapidly respond to changing customer requirements and market conditions.
We compete with large national and multi-national companies that have longer operating histories, greater financial, technical and other resources and greater name recognition than we do. Many of our larger competitors are able to offer ancillary products and services with their contract drilling services, and recently, some of our larger competitors have begun integrating and offering contract drilling services in connection with directional drilling and other services that we do not offer. In this regard, large diversified oilfield service companies have begun to market bundled services, including contract drilling services, in the United States. If any of these combined offerings gain acceptance within the United States market, it could place us at a competitive disadvantage that has an adverse impact on our future results of operations and profitability.
Furthermore, some of our competitors' greater capabilities in these areas may enable them to better withstand industry downturns, compete more effectively on the basis of price and technology, retain skilled rig personnel, and build new rigs or acquire and refurbish existing rigs so as to be able to place rigs into service more quickly than us in periods of high drilling demand.
In addition, we compete with several smaller companies capable of competing effectively on a regional or local basis. Smaller competitors may be able to respond more quickly to new or emerging technologies and services and changes in customer requirements.
Finally, some E&P companies perform horizontal and directional drilling on their wells using their own equipment and personnel. Any increase in the development and utilization of in-house drilling capabilities by our customers could decrease the demand for our services and have a material adverse impact on our business.
New technology may cause our drilling methods or equipment to become less competitive.
The drilling industry is subject to the introduction of new drilling and completion methods and equipment using new technologies, some of which may be subject to patent protection. Changes in technology or improvements in competitors' equipment could make our equipment less competitive or require significant capital investments to build and maintain a competitive advantage. Further, we may face competitive pressure to design, implement or acquire certain new technologies at a substantial cost. Some of our competitors have greater financial, technical and personnel resources that may allow them to implement new technologies before we can. If we are unable to implement new and emerging technologies on a timely basis or at an acceptable cost, it may have a material adverse effect on our business, results of operations, financial condition and growth strategy.

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

Hydraulic fracturing is a commonly used process that involves injection of water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore. The adoption of any federal, state or local laws or the implementation of regulations or ordinances restricting or increasing the costs of hydraulic fracturing could potentially increase our costs of operations and cause a decrease in drilling activity levels in the Permian Basin and other unconventional resource plays and an associated decrease in demand for our rigs and service, any or all of which could adversely affect our financial position, results of operations and cash flows.

The federal Energy Policy Act of 2005 amended the Underground Injection Control provisions of the federal Safe Drinking Water Act (“SDWA”) to exclude certain hydraulic fracturing practices from the definition of “underground injection.” The EPA has asserted regulatory authority over certain hydraulic fracturing activities involving diesel fuel and published guidance relating to such practices in February 2014. From time to time, Congress has considered bills to repeal the exemption for hydraulic fracturing from the SDWA, which would have the effect of allowing the EPA to promulgate new regulations and permitting requirements for hydraulic fracturing, potentially including chemical disclosure requirements. At the state level, several states in which we operate have adopted regulations requiring the disclosure of certain information regarding hydraulic fracturing fluids.

Scrutiny of hydraulic fracturing activities continues in other ways. A number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA conducted a study of the potential impacts of hydraulic fracturing on drinking water and issued a final report in December 2016. This study and other studies that may be undertaken by the EPA or other federal agencies could spur initiatives to further regulate hydraulic fracturing under the SDWA or other statutory and/or regulatory mechanisms. Additionally, in June 2016, the EPA published a rule establishing pretreatment standards which prohibit the disposal of unconventional oil and natural gas wastewater at publicly owned treatment works.

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

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and natural gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale plays, incurred by our customers or could make it more difficult to perform hydraulic fracturing in the unconventional resource plays where we focus our operations.

We depend on the services of key executives, the loss of whom could materially harm our business.

Our senior executives are important to our success because they are instrumental in setting our strategic direction, operating our business and technology, identifying, recruiting and training key personnel, and identifying customers and expansion opportunities. We also depend on the relationships that our senior management has with many of our customers. Losing the services of any of these individuals could adversely affect our business until a suitable replacement could be found. We do not maintain key man life insurance on any of our senior executives. As a result, we are not insured against any losses resulting from the death of our key employees.

Rig upgrade, refurbishment and new rig construction projects, as well as the reactivation of rigs that have been idle for six months or longer, are subject to risks which could cause delays or cost overruns and adversely affect our cash flows, results of operations, and financial position.

New drilling rigs or rigs being upgraded, converted or re-activated following a period of stack may experience start-up complications and may encounter other operational problems that could result in significant delays, uncompensated downtime, reduced dayrates or the cancellation, termination or non-renewal of drilling contracts. Rig construction and upgrade projects are subject to risks of delay or significant cost overruns inherent in any large construction project from numerous factors, including the following:

- shortages of equipment, materials or skilled labor;
- unscheduled delays in the delivery of ordered materials and equipment or shipyard construction;

- failure of equipment to meet quality and/or performance standards;
- financial or operating difficulties of equipment vendors;
- unanticipated actual or purported change orders;
- inability by us or our customer to obtain required permits or approvals, or to meet applicable regulatory standards in our areas of operations;
- unanticipated cost increases between order and delivery;
- adverse weather conditions and other events of force majeure;
- design or engineering changes; and
- work stoppages and other labor disputes.

The occurrence of any of these events could have a material adverse effect on our cash flows, results of operations and financial position.

As we construct additional rigs in the future, we may experience difficulty integrating those rigs into our operations. Additionally, we may incur leverage and add additional financial risk to our business. To the extent we incur additional leverage in our business, it may adversely affect our results of operations, financial position and growth strategy.

The process of constructing rigs may involve unforeseen difficulties and may require a disproportionate amount of management's attention and other resources. We may not be able to successfully manage and integrate new rigs into our existing operations or successfully market our rigs and build market share attributable to drilling rigs that we construct. To the extent we experience some or all of these difficulties, our results of operations, financial condition and growth strategy could be adversely affected.

Expanding our fleet may cause us to incur additional financial leverage, increasing our financial risk and debt service requirements, which could adversely affect our business, results of operations, financial condition and growth strategy.

Our current estimated backlog of contract drilling revenue may not ultimately be realized.

As of December 31, 2017, our estimated contract drilling backlog for future revenues under term contracts, which we define as contracts with a fixed term of six months or more, was approximately $51.5 million. Our backlog does not include potential reductions in rates for unscheduled standby during periods in which the rig is moving, on standby or incurring maintenance and repair time in excess of contractually allowed downtime. To the extent that we have rigs under term contracts operating on a standby or standby-without-crew basis, our top line revenues will be less than our reported backlog from term contracts.

Fixed-term drilling contracts customarily provide for termination at the election of the customer, with an "early termination payment" to us if a contract is terminated prior to the expiration of the fixed term. Additionally, in certain circumstances, for example, destruction of a drilling rig that is not replaced within a specified period of time, our bankruptcy, or a breach of our contract obligations, the customer may not be obligated to make an early termination payment to us. Additionally, during depressed market conditions, such as those we are currently experiencing, or otherwise, customers may be unable to satisfy their contractual obligations or may seek to terminate, renegotiate or fail to honor their contractual obligations. In addition, we may not be able to perform under these contracts due to events beyond our control, and our customers may seek to cancel or negotiate our contracts for various reasons, including those described above. As a result, we may be unable to realize all of our current contract drilling backlog. In addition, the renegotiation or termination of fixed-term contracts without the receipt of early termination payments could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Our operating and maintenance costs with respect to our rigs include fixed costs that will not decline in proportion to decreases in dayrates.

We do not expect our operating and maintenance costs with respect to our rigs to necessarily fluctuate in proportion to changes in operating revenue. Operating revenue may fluctuate as a function of changes in dayrate, but costs for operating a rig and property taxes are generally fixed or only semi-variable regardless of the dayrate being earned. During times of reduced activity, reductions in costs may not be immediate as portions of the crew may be required to prepare our rigs for stacking, after which time the crew members are assigned to active rigs or dismissed. Moreover, when our rigs are mobilized from one geographic location to another, the labor and other operating and maintenance costs can vary significantly. In general, labor costs increase due to higher salary levels, inflation, and increases in workers' compensation insurance. Equipment maintenance expenses fluctuate depending upon the type of activity the unit is performing and the age and condition of the equipment. Contract preparation expenses vary based on the scope and length of contract preparation required and the duration of the firm contractual period over which such expenditures are amortized.

We participate in a capital intensive business. We may not be able to finance future growth of our operations.

The contract drilling industry is capital intensive. Our cash flow from operations and the continued availability of credit are subject to a number of variables, including general economic conditions, conditions in the oil and natural gas market, and more specifically, our rig utilization rates, operating margins and ability to control costs and obtain contracts in a competitive industry. Our cash flow from operations and present borrowing capacity may not be sufficient to fund our anticipated capital expenditures and working capital requirements. We may from time to time seek additional financing, either in the form of bank borrowings, sales of debt or equity securities or otherwise. To the extent our capital resources and cash flow from operations are at any time insufficient to fund our activities or repay our indebtedness as it becomes due, we will need to raise additional funds through public or private financing or additional borrowings. We may not be able to obtain any such capital resources in the amount or at the time when needed. Based upon the significant downturn in market conditions, any new sources of debt capital would require substantially higher interest requirements, and any new sources of equity capital could be substantially dilutive to existing shareholders. Any limitations on our access to capital or increase in the cost of that capital could significantly impair our growth strategy. Our ability to maintain our targeted credit profile could affect our cost of capital as well as our ability to execute our growth strategy. In addition, a variety of factors beyond our control could impact the availability or cost of capital, including domestic or international economic conditions, increases in key benchmark interest rates and/or credit spreads, the adoption of new or amended banking or capital market laws or regulations, the re-pricing of market risks and volatility in capital and financial markets. If we are at any time not able to obtain the necessary capital resources, our financial condition and results of operations could be materially adversely affected.

We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under applicable debt instruments, which may not be successful.

Our ability to make scheduled payments on or to refinance indebtedness under our Credit Facility depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the interest or principal, when due, on our indebtedness. If our cash flows and capital resources are insufficient to fund 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. Our ability to restructure or refinance indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict business operations. The terms of existing or future debt instruments may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet debt service and other obligations. Our Credit Facility currently restricts our ability to dispose of assets and our use of the proceeds from such disposition subject to certain defined exceptions. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet scheduled debt service obligations.

Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.

Our Credit Facility contains a number of significant covenants, including restrictive covenants that may limit our ability to, among other things:

- incur or guarantee additional indebtedness;
- make loans to others;
- make investments;
- merge or consolidate with another entity;
- transfer, lease or dispose of all or substantially all of our assets;

- make certain payments;
- create or incur liens;
- purchase, hold or acquire capital stock or certain other types of securities;
- pay cash dividends;
- enter into certain transactions with affiliates; and
- engage in certain other transactions without the prior consent of the lenders.

A breach of any covenant in our Credit Facility would result in a default. A resulting event of default, if not waived, could result in acceleration of the payment of the indebtedness outstanding under, and a termination of, our Credit Facility and in a default with respect to, and an acceleration of, the indebtedness outstanding under any other debt agreements. The accelerated indebtedness would become immediately due and payable. If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance such indebtedness. Even if new financing were available at that time, it may not be on terms that are acceptable to us.

A failure of any of our lenders to honor commitments or advance funds under our Credit Facility would have a material adverse effect on our ability to fund our operations and business strategy.

Our Credit Facility limits the amounts we can borrow up to a borrowing base amount, although capped based on lender commitments, which is calculated monthly and is based upon the appraised value of our eligible drilling fleet and a percentage of our eligible accounts receivable. If a rig becomes idle for longer than 90 consecutive days, it is removed from our borrowing base until it is recontracted. The borrowing base under our Credit Facility was $106.7 million as calculated as of December 31, 2017, with lender commitments of $85.0 million.

In the future, we may not be able to access adequate funding under our Credit Facility as a result of a decrease in borrowing base based upon the outcome of a subsequent borrowing base redetermination or an unwillingness or inability on the part of lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover the defaulting lender’s portion. As a result, we may be unable to implement our respective drilling and development plan, make acquisitions or otherwise carry out business plans, which would have a material adverse effect on our financial condition and results of operations.

We may be adversely impacted by work stoppages or other labor matters.

We depend on skilled employees to build and operate our rigs, and any prolonged labor disruption involving our employees could have a material adverse impact on our results of operations and financial condition by disrupting our ability to perform drilling-related services for our customers. Moreover, unionization efforts have been made from time to time within our industry, with varying degrees of success. Any such unionization could increase our costs or limit our flexibility.

Failure to hire and retain skilled personnel could adversely affect our business.

The delivery of our services and products and construction of our rigs requires personnel with specialized skills and experience who can perform physically demanding work. As a result of the volatility of the contract drilling industry and the demanding nature of the work, workers may choose to pursue employment in fields that offer a more desirable work environment at wage rates that are competitive, which occurred during the dramatic industry downturn that began in 2014 and lasted throughout 2016. Between December 31, 2016 and December 31, 2017, the United States land rig count, as reported by Baker Hughes, rose by 271 rigs, with a disproportionate amount of this increase occurring in the Company’s target markets of Texas and its contiguous states. This increase in activity has increased competition for, and decreased the availability of, experienced rig crews. This increased competition could result in an increase to our operating costs if we are forced to raise wages to compete for experienced rig crew talent, and could results in increased training and new hire related costs if we are required to train and assimilate lesser experienced crew personnel into our organization.

Potential inability or lack of desire by workers to commute to our facilities and job sites and competition for workers from competitors or other industries are factors that could affect our ability to attract and retain workers. A significant increase in the wages paid by competing employers could result in a reduction of our skilled labor force, increases in the wage rates that we must pay, or both. If either or both of these events were to occur, our capacity and profitability could be diminished and our growth potential could be impaired.

Our ability to be productive and profitable will depend upon our ability to employ and retain skilled personnel and we cannot assure that at times of high demand we will be able to retain, recruit and train an adequate number of skilled workers. In addition, our ability to expand our operations will depend in part on our ability to increase the size of our skilled labor force. Our inability to attract and retain skilled workers in sufficient numbers to satisfy our existing service contracts and enter into new contracts could materially adversely affect our business, financial condition, results of operations and growth strategy.

We depend on a limited number of vendors, some of which are thinly capitalized and the loss of any of which could disrupt our operations.

Our contract drilling operations and our ability to construct new drilling rigs in a timely manner depend on the availability of various rig equipment, including VFD drives and drillers cabins, top drives, mud pumps, engines and drill pipe, as well as replacement parts, related rig equipment and fuel. Some of these have been in short supply from time to time. In addition, key rig components critical to the construction of our rigs are either purchased from or fabricated by a single or limited number of vendors, including vendors that may compete against us from time to time. For many of these products and services, there are only a limited number of vendors and suppliers available to us.

We do not currently have any long-term supply contracts with any of our suppliers or subcontractors and may be at a competitive disadvantage compared to our larger competitors when purchasing from these suppliers and subcontractors. Shortages could occur in these essential components due to an interruption of supply or increased demands in the industry. If we are unable to procure certain of such rig components or services from our subcontractors we would be required to reduce or delay our rig construction and other operations, which could have a material adverse effect on our business, results of operations, financial condition and growth strategy.

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

Increased or decreased demand among drilling contractors for consumable supplies, including fuel, and ancillary rig equipment, such as pumps, valves, drillpipe and engines, may lead to delays in obtaining these materials and our inability to operate our rigs in an efficient manner. Most of our contracts provide that our customers purchase the fuel that run our drilling rigs and thus bear the financial impact of increased fuel prices. However, prolonged shortages in the availability of fuel to run our drilling rigs resulting from action of the elements, terrorism or other force majeure events could result in the suspension of our contracts and have a material adverse effect on our financial condition and results of operations. We have periodically experienced increased lead times in purchasing ancillary equipment for our drilling rigs. To the extent there are significant delays in being able to purchase important components for our rigs, certain of our rigs may not be available for operation or may not be able to operate as efficiently as expected, which could adversely affect our results of operations and financial condition.

Reduced demand can drive suppliers from the market. With reduced suppliers, consumables for our operations may not be readily available. Additionally, suppliers may experience shortfalls in obtaining their materials and/or labor. Suppliers who have been regular providers to us may experience shortfalls that may lead to delays as we secure other sources.

Legal proceedings could have a negative impact on our business.

The nature of our business makes us susceptible to legal proceedings and governmental investigations from time to time. Lawsuits or claims against us could have a material adverse effect on our business, financial condition and results of operations. Any litigation or claims, even if fully indemnified or insured, could negatively affect our reputation among our customers and the public, and make it more difficult for us to compete effectively or obtain adequate insurance in the future.

Regulatory compliance costs and restrictions, as well as any delays in obtaining permits by our customers for their operations, could impair our business.

The operations of our customers are subject to or impacted by a wide array of regulations in the jurisdictions in which they operate. As a result of changes in regulations and laws relating to the oil and natural gas industry, including land drilling, our customers' operations could be disrupted or curtailed by governmental authorities. In most states, our customers are required to obtain permits from one or more governmental agencies in order to perform drilling and completion activities. Such permits are typically required by state agencies, but can also be required by federal and local governmental agencies. The requirements for such permits vary depending on the location where such drilling and completion 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 which may be imposed in connection with the granting of the permit. Additionally, the high cost of compliance with applicable regulations may cause customers to discontinue or limit their operations or defer planned drilling, and may discourage companies from continuing development activities. As a result, demand for our services could be substantially affected by regulations adversely impacting the oil and natural gas industry.

We are subject to environmental, health and safety laws and regulations that may expose us to significant liabilities for penalties, damages or costs of remediation or compliance.

Our operations are subject to federal, regional, state and local laws and regulations relating to protection of natural resources and the environment, 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, including the acquisition of permits to conduct regulated activities, the incurrence of capital expenditures to mitigate or prevent releases of materials from our facilities, the imposition of substantial liabilities for pollution resulting from our operations and the application of specific health and safety criteria addressing worker protection. Failure to comply with these laws and regulations could result in investigations, restrictions or orders suspending well operations, the assessment of administrative, civil and criminal penalties, the revocation of permits and the issuance of corrective action orders, any of which could have a material adverse effect on our business, results of operations and financial condition.

There is inherent risk of environmental costs and liabilities in our business as a result of our handling of petroleum hydrocarbons and oilfield and industrial wastes, air emissions and wastewater discharges related to our operations, and historical industry operations and waste disposal practices. Some environmental laws and regulations may impose strict, joint and several liability, which means that in some situations, we could be exposed to liability as a result of our conduct that was without fault or lawful at the time it occurred or as a result of the conduct of, or conditions caused by, prior operators or other third parties. Clean-up 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 financial condition and results of operations.

Laws protecting the environment generally have become more stringent over time and are expected to continue to do so, which could lead to material increases in costs for future environmental compliance and remediation. The modification or interpretation of existing laws or regulations, or the adoption of new laws or regulations, could curtail exploratory or developmental drilling for oil and natural gas, could limit well servicing opportunities or impose unforeseen liabilities. We may not be able to recover some or any of our costs of compliance with these laws and regulations from insurance.

Potential listing of species as “endangered” under the federal ESA could result in increased costs and new operating restrictions or delays on our oil and natural gas exploration and production customers, which could adversely reduce the amount of contract drilling services that we provide to such customers.

The federal ESA and analogous state laws regulate a variety of activities, including oil and natural gas development, which could have an adverse effect on species listed as threatened or endangered under the ESA or their habitats. The designation of previously unidentified endangered or threatened species or the designation of previously unprotected areas as a critical habitat could cause oil could cause oil and natural gas exploration and production operators to incur additional costs or become subject to operating delays, restrictions or bans in affected areas, which impacts could adversely reduce the amount of drilling activities in affected areas, including support services that we provide to such operators under our contract drilling services segment. Numerous species have been listed or proposed for protected status in areas in which we provide or could in the future provide field services. For instance, the sage grouse, the lesser prairie-chicken and certain wildflower species, among others, are species that have been or are being considered for protected status under the ESA and whose range can coincide with our oil and natural gas production activities. The presence of protected species in areas where operators for whom we provide contract drilling services conduct exploration and production operations could impair such operators’ ability to timely complete well drilling and development and, consequently, adversely affect the amount of contract drilling or other field services that we provided to such operators, which reduction of services could have a significant adverse effect on our results of operations and financial position.

Climate change legislation or regulations restricting or regulating emissions of greenhouse gases could result in increased operating costs and reduced demand for our field services.

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases from industrial and energy sources contribute to increases of carbon dioxide levels in the Earth’s atmosphere and oceans and contribute to global warming and other environmental effects, the EPA has adopted various regulations under the federal Clean Air Act addressing emissions of greenhouse gases that may affect the oil and natural gas industry. During 2012, the EPA published rules that include standards to reduce methane emissions associated with oil and natural gas production. In May 2016, the EPA finalized regulations that set methane emission standards for new and modified oil and natural gas facilities, including production facilities. In July 2017, the EPA proposed a two-year stay of certain requirements of this rule pending reconsideration of the rule. In addition, the United States has been involved in international negotiations regarding greenhouse gas reductions under the United Nations Framework Convention on Climate Change and was among the 195 nations that signed an international accord in December 2015 with the objective of limiting greenhouse gas emission. The Paris Agreement entered into force in November 2016; however, the United States announced its intention to withdraw from the Paris Agreement on June 1, 2017. The United States’ status and continued participation in these and other initiatives or regulatory changes could result in increased costs of development and production and could have adverse effects on our operations. Additionally, certain U.S. states and regional coalitions of states have adopted measures regulating or limiting greenhouse gases from certain sources or have adopted policies seeking to reduce overall emissions of greenhouse gases. The adoption and implementation of any international treaty or of any federal or state legislation or regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to comply with such requirements and possibly require the reduction or limitation of emissions of greenhouse gases associated with our operations and other sources within the industrial or energy sectors. Such legislation or regulations could adversely affect demand for the production of oil and natural gas and thus reduce demand for the services we provide to oil and natural gas producers as well as increase our operating costs by requiring additional costs to operate and maintain equipment and facilities, install emissions controls, acquire allowances or pay taxes and fees relating to emissions, which could adversely affect our results of operations and financial condition. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases may produce changes in climate or weather, such as increased frequency and severity of storms, floods and other climatic events, which if any such effects were to occur, could have adverse physical effects on our operations, physical assets and field services to exploration and production operators.

The effects of severe weather could adversely affect our operations.

Changes in climate due to global warming trends could adversely affect our operations by limiting, or increasing the costs associated with, equipment or product supplies. In addition, coastal flooding and adverse weather conditions such as increased frequency and/or severity of hurricanes could impair our ability to operate in affected regions of the country. Oil and natural gas operations of our customers located in Louisiana and parts of Texas may be adversely affected by hurricanes and tropical storms, resulting in reduced demand for our services. Repercussions of severe weather conditions may include: curtailment of services; weather-related damage to facilities and equipment; suspension of operations; inability to deliver equipment, personnel and products to job sites in accordance with contract schedules; and loss of productivity. These constraints could delay our operations and materially increase our operating and capital costs. Unusually warm winters also adversely affect the demand for our services by decreasing the demand for natural gas.

Our business is subject to cybersecurity risks and threats.

Threats to information technology systems associated with cybersecurity risks and cyber incidents or attacks continue to grow. It is possible that our business, financial and other systems could be compromised, which might not be noticed for some period of time. Risks associated with these threats include, among other things, loss of intellectual property, disruption of our and customers’ business operations and safety procedures, loss or damage to our worksite data delivery systems, and increased costs to prevent, respond to or mitigate cybersecurity events.

Any future implementation of price controls on oil and natural gas would affect our operations.

Certain groups have asserted efforts to have the United States Congress impose some form of price controls on either oil, natural gas, or both. There is no way at this time to know what results these efforts may have. However, any future limits on the price of oil or natural gas could have a material adverse effect on our business, financial condition and results of operations.

Improvements in or new discoveries of alternative energy technologies could have a material adverse effect on our financial condition and results of operations.

Since our business depends on the level of activity in the oil and natural gas industry, any improvement in or new discoveries of alternative energy technologies that increase the use of alternative forms of energy and reduce the demand for oil and natural gas could have a material adverse effect on our business, financial condition and results of operations.

Risks Related to Our Liquidity

The borrowing base under our Credit Facility may decline during 2018.

At December 31, 2017, the borrowing base under our Credit Facility was $106.7 million, and we had $36.5 million of availability remaining of our $85.0 million commitment on that date. The borrowing base under the facility is calculated based upon the sum of (1) 85% of our eligible accounts receivable and (2) an advance percentage multiplied by the appraised forced liquidation value of our eligible drilling rigs. In most circumstances, all of accounts receivable are considered eligible unless they are more than 90 days past due.

With respect to the portion of the borrowing base tied to the appraised forced liquidation value of our eligible rigs, a rig is generally included in the borrowing base unless it has ceased earning revenue under a contract for 90 consecutive days or greater, and it will continue to be excluded until such time as a new drilling contract for the rig is executed.

At December 31, 2017, the advance percentage utilized to calculate the borrowing base was 73.75%. Under the terms of the Credit Facility, this advance rate will decline 1.25% each quarter beginning January 1, 2018 through June 2019. Thereafter, through the maturity date, the advance rate remains at 65.0%.

The lenders have the right to reappraise our drilling fleet throughout the year, and there cannot be any assurance that future appraisals will not adversely affect the appraised values of our rigs due to the aging of our rigs or if market conditions decline.

At December 31, 2017, we had 14 rigs that were eligible to be included in the equipment portion of the borrowing base.

If at any time our borrowing base falls below our outstanding balance under our Credit Facility, and we were not able to promptly repay such deficiency, we would be required to repay to the banks any deficiency amount. In such event, if our available cash balances were not sufficient to repay such amounts, we would be required to obtain other debt or equity financing necessary to cure such deficiency, and there can be no assurance that such additional financing sources would be available to us, or available on terms acceptable to us. Any inability to timely cure any deficiency between our borrowing base and Credit Facility balance may have a material adverse effect on our liquidity and financial condition.

Our ability to comply with the leverage covenant and fixed charge coverage ratio covenant contained in our Credit Facility is based upon our future cash flows and debt levels.

Our Credit Facility requires us to maintain a leverage ratio of net debt to adjusted earnings before interest, taxes, depreciation and amortization ("EBITDA"), not to exceed the following in the respective time periods: 1Q'18 and 2Q'18: 4.0x; 3Q'18 and 4Q'18: 3.75x; 1Q'19 and 2Q'19: 3.5x; 3Q'19: 3.25x; and thereafter 3.0x. Adjusted EBITDA is calculated as net income plus interest, taxes, depreciation and amortization, non-cash stock based compensation, and certain other gains, losses, and expenses (including up to $2.0 million of Galayda yard costs previously capitalized when construction activities were continuous). As of December 31, 2017, the leverage ratio covenant was not to exceed 4.0x.

The Credit Facility also requires us to maintain a fixed charge coverage ratio ("FCCR") of not less than 1.1 to 1.0. The FCCR is equal to adjusted EBITDA less capital expenditures divided by cash interest expense plus scheduled principal payments, cash dividends and capital lease obligations plus cash taxes paid. The following capital expenditures are excluded from the calculation of FCCR: (1) capital expenditures incurred before November 1, 2015 and (2) capital expenditures financed through capital sources other than the Credit Facility on or after July 1, 2017.

Our compliance with each of these covenants depends significantly upon our level of cash flows in 2018 and beyond, which are based upon factors such as spot dayrates and rig utilization that are difficult to predict based upon the downturn in market conditions our industry has experienced. In particular, our ability to comply with our leverage and FCCR covenant in 2018 and beyond is predicated upon market conditions not deteriorating. If we are not able to comply with the covenants contained in our Credit Facility, we would be required to seek a waiver or amendment to the facility, or seek alternative financing sources, and there can be no assurance that we would be able to obtain such waivers, amendments or alternative financing sources. Any failure to comply with the financial covenants contained in our Credit Facility, or to cure any such non-compliance may have a material adverse effect on our liquidity and financial condition.

Our ability to complete our two partially completed new build rigs is dependent upon our ability to maintain adequate liquidity and availability under our Credit Facility.

A key component of our growth strategy is completing two new build 200 Series rigs for which we already have made substantial investments. Our ability to complete these projects will be dependent upon adequate availability under our Credit Facility, and more importantly, on our ability to comply with the covenants, including financial covenants, under our Credit Facility after taking into account the increased debt levels we would incur associated with completing these projects. Therefore, there is no assurance that we can complete all of these capital projects and fully execute our near-term growth strategy.

Our Credit Facility contains a subjective acceleration clause, and a springing lock-box arrangement that is triggered when availability under our Credit Facility falls below $10 million. Under applicable accounting rules, outstanding balances under our Credit Facility will be reclassified from long-term to current if this triggering event occurs.

The Credit Facility matures on November 5, 2020. The Credit Facility provides for a springing lock-box arrangement that is only triggered upon the occurrence of an event of default under the Credit Facility or if availability under the Credit Facility falls below the greater of (A) $10.0 million and (B) the lesser of 10% of the borrowing base or 10% of the total commitments under the facility. The Credit Facility provides that an event of default may occur if a material adverse change to us occurs, which is considered a subjective acceleration clause under applicable accounting rules. Under ASC 470-10-45, because of the existence of this clause, borrowings under the Credit Facility will be required to be classified as current in the event the springing lock-box event occurs, regardless of the actual maturity of the borrowings. We had $48.5 million in outstanding borrowings under the Credit Facility at December 31, 2017. Remaining availability of our $85.0 million commitment under the Credit Facility was $36.5 million at December 31, 2017, and we are currently in compliance with all covenants under the Credit Facility. The lenders have the right to reappraise our drilling fleet in the future as well, and there cannot be any assurance that future appraisals will not adversely affect the appraised values of our rigs due to the aging of our rigs or if market conditions decline.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for capital expenditures and place us at a competitive disadvantage. For example, total long-term debt at December 31, 2017 included $48.5 million of floating-rate debt attributed to borrowings at an average interest rate of 6.04%, and the impact on annual cash flow of a 10% change in the floating-rate (approximately 0.60%) would be approximately $0.3 million annually based on the floating-rate debt and other obligations outstanding at December 31, 2017; however, there are no assurances that possible rate changes would be limited to such amounts. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our desired growth and operating results.

Risks Related to our Common Stock

Our stock price is subject to volatility.

The market price of common stock of companies engaged in the oil and natural gas service industry, including our common stock price, has been highly volatile. Stock price volatility could adversely affect our business operations by, among other things, impeding our ability to attract and retain qualified personnel and to obtain additional financing. In addition to the other risk factors discussed in this section, the price and volume volatility of our common stock may be affected by:

- operating results that vary from the expectations of securities analysts and investors;
- factors influencing the levels of global oil and natural gas exploration and exploitation activities, such as a downturn in oil prices;
- the operating and securities price performance of companies that investors or analysts consider comparable to us;
- announcements of strategic developments, acquisitions and other material events by us or our competitors; and
- changes in global financial markets and global economies and general market conditions, such as interest rates, commodity and equity prices and the value of financial assets.

To the extent that the price of our common stock remains at lower levels or it declines further, our ability to raise funds through the issuance of equity or otherwise use our common stock as consideration will be reduced. In addition, increases in our leverage may make it more difficult for us to access additional capital. These factors may limit our ability to implement our operating and growth plans.

Because we have no plans to pay any dividends for the foreseeable future, investors must look solely to stock appreciation for a return on their investment in us.

We have not paid cash dividends on our common stock since our incorporation and our Credit Facility prohibits us from paying cash dividends on our common stock. We do not anticipate paying any cash dividends in the foreseeable future. We currently intend to retain any future earnings to support our operations and growth. Any payment of cash dividends in the future will be dependent on the amount of funds legally available, our financial condition, capital requirements, ability to pay such dividends under our then existing Credit Facility and other factors that our board of directors may deem relevant. Accordingly, investors must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize any future gains on their investment.

Provisions in our organizational documents and under Delaware law could delay or prevent a change in control of our company at a premium that a stockholder may consider favorable, which could adversely affect the price of our common stock.

The existence of some provisions in our organizational documents and under Delaware law could delay or prevent a change in control of our company that a stockholder may consider favorable, which could adversely affect the price of our common stock. The provisions in our amended and restated certificate of incorporation and amended and restated bylaws that could delay or prevent an unsolicited change in control of our company include:

- provisions regulating the ability of our stockholders to nominate candidates for election as directors or to bring matters for action at annual meetings of our stockholders;
- limitations on the ability of our stockholders to call a special meeting and act by written consent; and

- the authorization given to our board of directors to issue and set the terms of preferred stock.

Future offerings of debt securities, which would rank senior to our common stock in the event of our liquidation, and future offerings of equity securities, which would dilute our existing stockholders or rank senior to our common stock, may adversely affect the market value of our common stock.

We intend to evaluate and may attempt to increase our capital resources by offering debt or equity securities, including commercial paper, medium-term notes, senior or subordinated notes, convertible notes and classes of preferred stock. In the event of our liquidation, holders of our debt securities and preferred stock and lenders with respect to other borrowings will receive a distribution of our available assets prior to the holders of our common stock. Additional equity offerings may dilute the holdings of our existing stockholders or reduce the market value of our common stock, or both. Our preferred stock, if issued, could have a preference on liquidating distributions or a preference on dividend payments that would limit amounts available for distribution to holders of our common stock. Because our decision to issue securities in any future offering will depend on market conditions and other factors beyond our control, we cannot predict or estimate the amount, timing or nature of our future offerings. Thus, holders of our common stock bear the risk of our future offerings reducing the market value of our common stock and diluting their shareholdings in us.

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.

In April 2012, President Obama signed into law the Jumpstart Our Business Startups Act of 2012 (the "JOBS Act"). We are classified as an emerging growth company (an "EGC") under the JOBS Act. For as long as we are an EGC, 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 the Sarbanes-Oxley Act of 2002; (ii) comply with any new requirements adopted by the Public Company Accounting Oversight Board (the "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 disclosure regarding executive compensation required of larger public companies; or (iv) hold nonbinding advisory votes on executive compensation. We will remain an EGC 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 million in market value of our common stock held by non-affiliates, or issue more than $1.0 billion of non-convertible debt over a three-year period.

To the extent that we rely on any of the exemptions available to EGCs, we will provide 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.

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 us 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 preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

We own an approximate 14.4 acre corporate headquarters and rig assembly yard complex located at 11601 North Galayda Street, Houston, Texas 77086. The complex includes approximately 18,000 square feet of office space and 76,000 square feet of warehouse space. During 2017, our management committed to a plan to sell this property in order to relocate to office space and a yard facility more suitable to our needs. As of December 31, 2017, the property is available for sale. We also lease an additional approximate 0.2 acres of land for equipment and supply storage. Additionally, we lease office space in northwest Houston as a temporary location for our corporate operations after our corporate headquarter offices suffered water related damage from the heavy rainfall that occurred during Hurricane Harvey in August 2017.

We believe that all of our existing properties are suitable for their intended uses and are sufficient to support our operations. We do not believe that any single property is material to our operations and, if necessary, we could obtain a replacement facility. We continuously evaluate the needs of our business, and we will purchase or lease additional properties or reduce our properties, as our business requires.

ITEM 3. LEGAL PROCEEDINGS

We are the subject of certain legal proceedings and claims arising in the ordinary course of business from time to time. Management cannot predict the ultimate outcome of such legal proceedings and claims. While the legal proceedings and claims may be asserted for amounts that may be material should an unfavorable outcome be the result, management does not currently expect that the resolution of these matters will have a material adverse effect on our financial position or results of operations. In addition, management monitors our legal proceedings and claims on a quarterly basis and establishes and adjusts any reserves as appropriate to reflect our assessment of the then-current status of such matters.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Information for Common Stock

Our common stock is traded on the New York Stock Exchange under the symbol "ICD". The table below presents the high and low daily closing sales prices of the common stock, as reported by the New York Stock Exchange, for the periods indicated:

	High	Low
2017:		
First Quarter	$7.14	$4.70
Second Quarter	$5.81	$3.30
Third Quarter	$4.22	$3.03
Fourth Quarter	$4.06	$2.80
2016:		
First Quarter	$5.40	$3.44
Second Quarter	$5.88	$3.76
Third Quarter	$5.63	$4.68
Fourth Quarter	$6.97	$3.93

Holders of Record

As of February 20, 2018, we had 38,098,248 shares of common stock outstanding held by approximately 20 holders of record. This number includes registered stockholders and does not include stockholders who hold their shares institutionally.

Dividend Policy

We have not declared or paid any cash dividends on our common stock, our Credit Facility prohibits us from paying cash dividends on our common stock, and we do not currently anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain all future earnings to fund the development and growth of our business. Any future determination relating to our dividend policy will be at the discretion of our board of directors and will depend on funds legally available, our results of operations, financial condition, capital requirements, the ability to pay cash dividends under our then existing Credit Facility and other factors deemed relevant by our board.

Stock Performance Graph

The following stock performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended (the "Securities Act"), or the Securities Exchange Act of 1934, as amended (the "Exchange Act"), except to the extent that we specifically incorporate such information by reference into such a filing. The graph and information is included for historical comparative purposes only and should not be considered indicative of future stock performance.

The following graph compares our cumulative total stockholder return during the period from our initial public offering (IPO) on August 7, 2014 to December 31, 2017 with total stockholder return during the same period for the Standard & Poors 500 Index and an index of peer companies. The graph assumes that (i) $100 was invested in our common stock on August 8, 2014 at our IPO price of $11.00 per share, (ii) $100 was invested in each index on August 8, 2014 at the closing price on such date, and (iii) all dividends, if any, were reinvested.

	8/8/2014	9/30/2014	12/31/2014	6/30/2015	12/31/2015	6/30/2016	12/31/2016	6/30/2017	12/31/2017
Independence Contract Drilling, Inc.	$ 100.00	$ 106.24	$ 47.20	$ 80.20	$ 45.66	$ 49.10	$ 60.58	$ 35.17	$ 35.99
S&P 500 Index	$ 100.00	$ 102.42	$ 107.47	$ 108.77	$ 108.91	$ 113.01	$ 121.81	$ 133.12	$ 148.22
Peer Index	$ 100.00	$ 92.85	$ 56.16	$ 60.68	$ 43.34	$ 56.95	$ 70.06	$ 49.54	$ 55.87

The index of peer companies consists of: Helmerich & Payne, Inc., Nabors Industries, Ltd., Patterson-UTI Energy, Inc., Pioneer Energy Services Corp., Precision Drilling Corporation, Trinidad Drilling Ltd., Superior Energy Services, Inc. and RPC, Inc.

Recent Sales of Unregistered Securities; Use of Proceeds from Registered Securities

None.

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Issuer Purchases of Equity Securities

During the fourth quarter of 2017, we withheld shares of our common stock to satisfy minimum tax withholding obligations in connection with the vesting of certain stock awards. These shares are deemed to be "issuer purchases" of shares that are required to be disclosed pursuant to this Item but were not purchased as part of a publicly announced program to repurchase common shares. The following table provides information relating to our repurchase of shares of common stock during the three months ended December 31, 2017 (dollars in thousands, except average price paid per share):

	Issuer Purchases of Equity Securities			
Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Approximate Dollar Value of Shares That May Yet be Purchased Under the Program (1)
October 1 — October 31	—	$ —	—	$ —
November 1 — November 30	—	$ —	—	$ —
December 1 — December 31	3,515	$ 3.44	—	$ —

(1) We do not have a current share repurchase program authorized by the board of directors.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth our selected historical financial data. Our selected historical financial data as of and for the periods presented below were derived from our audited financial statements.

Our historical results are not necessarily indicative of our future operating results. The share information gives effect to a 1.57-for-1 stock split in the form of a stock dividend on July 24, 2014. The selected historical financial data presented below is qualified in its entirety by reference to, and should be read in conjunction with, "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the financial statements and related Notes included in "Item 8. Financial Statements and Supplementary Data."

	Year Ended				
(In thousands, except per share data)	December 31, 2017	December 31, 2016	December 31, 2015	December 31, 2014	December 31, 2013
Statement of operations data[1]:					
Revenues	$90,007	$70,062	$88,418	$70,347	$42,786
Operating costs	67,733	43,277	52,087	42,654	28,401
Selling, general and administrative[2]	13,213	16,144	14,483	12,222	8,911
Depreciation and amortization	25,844	23,808	21,151	16,181	10,186
Goodwill impairment and other charges[3]	—	—	—	30,627	—
Asset impairments, net of insurance recoveries[4]	2,568	3,822	2,708	1,711	—
Loss (gain) on disposition of assets, net	1,677	1,942	2,940	19	(55)
Total cost and expenses	111,035	88,993	93,369	103,414	47,443
Operating loss	(21,028)	(18,931)	(4,951)	(33,067)	(4,657)
Interest expense	(2,983)	(3,045)	(3,254)	(1,648)	(257)
Gain on warrant derivative[5]	—	—	—	3,189	1,035
Loss before income taxes	(24,011)	(21,976)	(8,205)	(31,526)	(3,879)
Income tax expense (benefit)	287	202	(325)	(3,358)	(1,882)
Net loss	$(24,298)	$(22,178)	$(7,880)	$(28,168)	$(1,997)
Weighted-average number of shares outstanding (basic and diluted)	37,762	33,118	23,904	17,078	12,179
Net loss per share (basic and diluted)	$(0.64)	$(0.67)	$(0.33)	$(1.65)	$(0.16)
Cash flow data:					
Net cash provided by operating activities	$4,933	$16,973	$27,379	$3,809	$5,997
Net cash used in investing activities	(30,094)	(20,058)	(72,219)	(112,686)	(59,273)
Net cash provided by financing activities	20,623	4,812	39,427	116,904	18,599
Balance sheet data:					
Total assets	$304,645	$302,107	$314,789	$289,547	$184,968
Long-term debt	49,278	26,078	62,708	—	19,780
Total liabilities	69,163	44,855	82,052	52,811	40,096
Total stockholders’ equity	235,482	257,252	232,737	236,736	144,872

(1) There are no other components of comprehensive income or loss.

(2) For the year ended December 31, 2016, includes a one-time retirement payment of $1.5 million.

(3) Represents the impairment of goodwill totaling $11.0 million and accelerated amortization of our rig manufacturing intellectual property totaling $19.6 million.

(4) For the year ended December 31, 2017, primarily represents asset impairment expense associated with the impairment of certain held for sale assets and the impairment of our corporate headquarters as a result of water damage attributable to Hurricane Harvey that affected the Houston area in late August of 2017. For the year ended December 31, 2016, represents asset impairment expense associated with the impairment of certain assets designated as held for sale. For the year ended December 31, 2015, represents asset impairment expense associated with the impairment of various rig components of our last remaining non-walking rig and asset impairment expense associated with damage to a driller's cabin, offset by final insurance recoveries. For the year ended December 31, 2014, represents asset impairment expense associated with damage sustained to the mast and other operating equipment on one of our non-walking rigs, net of insurance claim recoveries. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations."

(5) Represents a non-cash gain associated with the decrease in the estimated fair value of a warrant to purchase 2.2 million shares issued to Global Energy Services, Inc. in the acquisition transaction that was completed in March 2012. The warrant expired unexercised on March 2, 2015.

ITEM 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

You should read the following discussion and analysis of our financial condition and results of operations together with "Item 6. Selected Financial Data" and the financial statements and related notes that are included in "Item 8. Financial Statements and Supplementary Data." This discussion contains forward-looking statements based upon current expectations that involve risks and uncertainties. Our actual results may differ materially from those anticipated in these forward-looking statements as a result of various factors, including without limitation those described in Cautionary Statement Regarding Forward-Looking Statements and “Item 1A. Risk Factors” or in other parts of this Annual Report on Form 10-K.

Management Overview

We were incorporated in Delaware on November 4, 2011. We provide land-based contract drilling services for oil and natural gas producers targeting unconventional resource plays in the United States. We construct, own and operate a premium land rig fleet comprised entirely of technologically advanced, custom designed ShaleDriller rigs that are specifically engineered and designed to optimize the development of our customers’ most technically demanding oil and natural gas properties. Our first rig began drilling in May 2012.

Our standardized fleet consists of 14 premium 200 Series ShaleDriller rigs, all of which are equipped with our integrated omni-directional walking system that is specifically designed to optimize pad drilling for our customers. Every rig in our fleet is a 1500-hp, AC programmable rig (“AC rig”) designed to be fast-moving between drilling sites and is equipped with 7500 psi mud systems, top drives, automated tubular handling systems and blowout preventer (“BOP”) handling systems. All of our rigs are equipped with bi-fuel capabilities that enable the rig to operate on either diesel or a natural gas-diesel blend.

Our business depends on the level of exploration and production activity by oil and natural gas companies operating in the United States, and in particular, the regions where we actively market our contract drilling services. The oil and natural gas exploration and production industry is a historically cyclical industry characterized by significant changes in the levels of exploration and development activities. Oil and natural gas prices and market expectations of potential changes in those prices significantly affect the levels of those activities. Worldwide political, regulatory, economic, and military events, as well as natural disasters have contributed to oil and natural gas price volatility historically, and are likely to continue to do so in the future. Any prolonged reduction in the overall level of exploration and development activities in the United States and the regions where we market our contract drilling services, whether resulting from changes in oil and natural gas prices or otherwise, could materially and adversely affect our business.

Both oil and natural gas prices began to decline in the second half of 2014, declined further during 2015 and remained low in 2016. The closing price of oil was as high as $106.06 per barrel during the third quarter of 2014, was $37.13 per barrel on December 31, 2015 and reached a low of $26.19 on February 11, 2016 (West Texas Intermediate - Cushing, Oklahoma (“WTI”) spot price as reported by the United States Energy Information Administration (the “EIA”)). Similarly, natural gas prices (as measured at Henry Hub) declined from an average of $4.37 per MMBtu in 2014, to $2.62 per MMBtu in 2015, $2.52 per MMBtu in 2016. As a result, our industry experienced an exceptional downturn and market conditions have only begun to stabilize and slowly recover.

In November 2016, Organization of Petroleum Exporting Countries (“OPEC”) members formally agreed to reduce their production quotas, starting January 1, 2017. These production cuts significantly reduced the overhang of global oil supplies. OPEC members met in December 2017 and agreed to extend the freeze into 2018, and are expected to meet again in June 2018 to review market conditions and the impact of their freeze on global supplies. In addition to OPEC members, certain non-OPEC producers such as Russia have agreed to production cuts, which has also supported crude oil and related energy commodity prices.

As a result of these supply cuts and positive demand trends, crude oil prices recovered to the $45 to $55 per barrel range, with WTI oil prices reaching a three-year high of $66.27 on January 26, 2018. Similarly, natural gas prices at Henry Hub averaged $2.99 per MMBtu in 2017, and have averaged $3.41 per MMBtu in 2018, as of February 20, 2018. While this continued recovery in pricing is promising, there are no indications at this time that oil and natural gas prices and rig counts will recover to their previous highs experienced in 2014.

Due to this deterioration and stabilization of commodity prices well below previous highs, our customers are principally focused on their most economic wells, and driving cost and production efficiencies that deliver the most economic wells with the lowest capital costs. As a result of this drive towards production and cost efficiencies, operators are focusing more of their capital spending on horizontal drilling programs compared to vertical drilling, and are more focused on utilizing drilling equipment and techniques that optimize costs and efficiency. Thus, we believe the rapid market deterioration and stabilization of oil prices well below historical highs has significantly accelerated the pace of the ongoing land rig replacement cycle and continued shift to horizontal drilling from multi-well pads utilizing “pad optimal” rig technology. As market conditions have improved from trough levels in 2016 and begun to stabilize higher, demand for our ShaleDriller rigs has improved. At December 31, 2017, all 14 of our rigs were under contract. In addition to improving utilization, contract tenors are improving with customers willing to sign term contracts of six to twelve months or longer, and at higher dayrates compared to trough levels, with the potential to move higher if market conditions continue to improve. However, the pace and duration of the current recovery is unknown, and if oil prices were to fall below $45 per barrel for any sustained period of time, market conditions and demand for our products and services could deteriorate.

Emerging Growth Company

We are an emerging growth company ("EGC") as defined under the Jumpstart Our Business Startups Act of 2012, commonly referred to as the “JOBS Act”. We will remain an EGC for up to five years from the date of the completion of our initial public offering (the “IPO”) on August 13, 2014, or until the earlier of (1) the last day of the fiscal year in which our total annual gross revenues exceed $1.07 billion, (2) the date that we become a “large accelerated filer” as defined in Rule 12b-2 under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), which would occur if the market value of our common equity that is held by non-affiliates is $700 million or more as of the last business day of our most recently completed second fiscal quarter or (3) the date on which we have issued more than $1 billion in non-convertible debt during the preceding three-year period.

As an EGC, we may take advantage of certain exemptions from various reporting requirements that are applicable to other public companies that are not EGCs including, but not limited to:

- not being required to comply with the auditor attestation requirements related to our internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act;
- reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements; and
- exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and shareholder approval of any golden parachute payments not previously approved.

In addition, Section 107 of the JOBS Act provides that an EGC can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act of 1933, as amended, for complying with new or revised accounting standards. Under this provision, an EGC can delay the adoption of certain accounting standards until those standards would otherwise apply to private companies. We have not elected to avail ourselves of the extended transition period available to EGCs, therefore, we will be subject to new or revised accounting standards at the same time as other public companies that are not EGCs.

Significant Developments

Assets Held for Sale

During the fourth quarter of 2016, we began a review of our rig fleet and other capital equipment with a focus on opportunities to standardize certain rig components across our fleet. The standardization of this equipment creates operating efficiencies in maintaining this equipment, as well as efficiencies when crews transfer between rigs. As a result of our review, we identified several non-standard items which, while fully functional, were less than optimal from an operations perspective. We recorded an asset impairment charge of $3.8 million in the fourth quarter of 2016, to write down these assets to fair value less estimated cost to sell. Such assets were classified as held for sale on our December 31, 2016 balance sheet. In the second quarter of 2017, we sold $1.6 million of these assets and recognized a loss on the sale of assets of $0.8 million. In the fourth quarter of 2017, we impaired the entire carrying value, or $1.0 million, related to certain of the assets held for sale, for which management currently believes there is substantial doubt that the third party manufacturer will service and warranty the equipment. As of December 31, 2017, the carrying value of drilling equipment in assets held for sale is $1.2 million.

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During the second quarter of 2017, our management committed to a plan to sell our corporate headquarters and rig assembly yard complex located at 11601 North Galayda Street, Houston, Texas, in order to relocate to office space and a yard facility more suitable to our needs. As a result, we reclassified an aggregate $4.0 million of land, buildings and equipment from property, plant and equipment to assets held for sale on our balance sheet after recognizing a $0.5 million asset impairment charge representing the difference between the carrying value and the estimated fair value, less the estimated costs to sell the related property. In the third quarter of 2017, we recorded an additional asset impairment on the property, reducing assets held for sale, of $0.6 million, as a result of water related damage from the heavy rainfall that occurred during Hurricane Harvey in August 2017. As of December 31, 2017, the carrying value of the Galayda property in assets held for sale is $3.4 million.

Amendment of Credit Facility

In July 2017, we amended our existing amended and restated credit agreement ("the Credit Facility"). The Credit Facility amendment maintained the aggregate commitments under the facility at $85.0 million and extended the maturity date by two years to November 5, 2020. In addition, the amendment provided for an additional uncommitted $65.0 million accordion feature that allows for future increases in facility commitments.

Interest under the Credit Facility remains unchanged. The amendment contained various changes to the financial and other covenants to accommodate the extension in term, including changes to the leverage ratio covenant, fixed charge coverage ratio covenant and rig utilization ratio covenant.

Retirement and Resignation of President and Chief Operating Officer

In June 2016, our President and Chief Operating Officer announced his retirement as an officer and director of ICD effective June 30, 2016. In connection with his retirement, we entered into a Retirement Agreement on June 9, 2016 (the “Retirement Agreement”), setting out certain terms and conditions governing the executive’s retirement. Under the terms of the Retirement Agreement, we agreed to make certain retirement benefits available to the executive, including a cash retirement payment of approximately $1.5 million which was paid in one lump sum on January 3, 2017 and accelerated vesting of certain outstanding equity awards. The retirement payment was recorded as accrued salaries in our balance sheet and as selling, general and administrative expense in our statements of operations as of and for the year ended December 31, 2016.

Public Offering of Common Stock

On April 26, 2016, we completed an underwritten public offering of 13,225,000 shares of common stock at a price to the public of $3.50 per share. We received net proceeds of approximately $42.9 million, after deducting underwriting discounts and commissions and offering expenses.

We used the net proceeds from this offering to repay a portion of the outstanding borrowings under our Credit Facility and for general corporate purposes.

Disposal of Drilling Equipment due to Rig Conversion and Impairment of our last Remaining Non-Walking Rig

During 2017 and 2016, we recorded an additional $0.8 million and $1.8 million, respectively, loss on disposal associated with the upgrade of the mud systems on our rigs to high pressure status.

During 2015, we began to convert one of our non-walking rigs to pad optimal status, equipped with our 200 Series substructure, omni-directional walking system and 7500psi mud system. As part of this rig conversion, key components of the prior rig were decommissioned and were replaced, including the rig's substructure and mud system components which were no longer compatible with the converted rig. As a result, we recorded a preliminary estimate of the loss on disposal totaling $2.5 million.

During 2015, we recorded an impairment charge of $3.6 million relating to the substructure, mast and various other rig components of our last remaining non-walking rig due to its limited marketability in its current configuration given market conditions.

Our Revenues

We earn contract drilling revenues pursuant to drilling contracts entered into with our customers. We perform drilling services on a “daywork” basis, under which we charge a specified rate per day, or “dayrate.” The dayrate associated with each of our contracts is a negotiated price determined by the capabilities of the rig, location, depth and complexity of the wells to be drilled, operating conditions, duration of the contract and market conditions. The term of land drilling contracts may be for a defined number of wells or for a fixed time period. We generally receive lump-sum payments for the mobilization of rigs and other drilling equipment at the commencement of a new drilling contract. Revenue and costs associated with the initial mobilization are deferred and recognized ratably over the term of the related drilling contract once the rig spuds. Costs incurred to relocate rigs and other equipment to an area in which a contract has not been secured are expensed as incurred. If a contract is terminated prior to the specified contract term, early termination payments received from the customer are only recognized as revenues when all contractual obligations, such as mitigation requirements, are satisfied. While under contract, our rigs generally earn a reduced rate while the rig is moving between wells or drilling locations, or on standby waiting for the customer. Reimbursements for the purchase of supplies, equipment, trucking and other services that are provided at the request of our customers are recorded as revenue when incurred. The related costs are recorded as operating expenses when incurred. Revenue is presented net of any sales tax charged to the customer that we are required to remit to local or state governmental taxing authorities.

Our Operating Costs

Our operating costs include all expenses associated with operating and maintaining our drilling rigs. Operating costs include all “rig level” expenses such as labor and related payroll costs, repair and maintenance expenses, supplies, workers' compensation and other insurance, ad valorem taxes and equipment rental costs. Also included in our operating costs are certain costs that are not incurred at the “rig level.” These costs include expenses directly associated with our operations management team as well as our safety and maintenance personnel who are not directly assigned to our rigs but are responsible for the oversight and support of our operations and safety and maintenance programs across our fleet.

Our operating costs also include costs and expenses associated with construction activities at our Galayda yard location to the extent that construction activities cease or are not continuous. As a result of the significant downturn in industry conditions, we substantially reduced our rig construction activities during the fourth quarter of 2015 and into 2016. As a result, we began expensing a portion of our Galayda yard construction costs during the fourth quarter of 2015 and expect to continue expensing such costs until we resume continuous rig construction activities.

During 2017 and 2016, our operating costs also included approximately $1.1 million and $3.5 million, respectively, of costs associated with the reactivation of idle and standby rigs. These costs include costs associated with recommissioning the rig, the hiring and training of new crews and the purchase of supplies and other consumables required for the operation of the rigs.

How We Evaluate our Operations

We regularly use a number of financial and operational measures to analyze and evaluate the performance of our business and compensate our employees, including the following:

- Safety Performance. Maintaining a strong safety record is a critical component of our business strategy. We believe we are one of the few land drillers that utilizes a safety management system that complies with the Bureau of Safety and Environmental Enforcement’s SEMS II workplace safety rules. We measure safety by tracking the total recordable incident rate for our operations. In addition, we closely monitor and measure compliance with our safety policies and procedures, including “near miss” reports and job safety analysis compliance.
- Utilization. Rig utilization measures the total amount of time that our rigs are earning revenue under a contract during a particular period. We measure utilization by dividing the total number of Operating Days for a rig by the total number of days the rig is available for operation in the applicable calendar period. A rig is available for operation commencing on the earlier of the date it spuds its initial well following construction or when it has been completed and is actively marketed. “Operating Days” represent the total number of days a rig is earning revenue under a contract, beginning when the rig spuds its initial well under the contract and ending with the completion of the rig’s demobilization.
- Revenue Per Day. Revenue per day measures the amount of revenue that an operating rig earns on a daily basis during a particular period. We calculate revenue per day by dividing total contract drilling revenue earned during the applicable period by the number of Operating Days in the period. Revenues attributable to costs reimbursed by customers are excluded from this measure.
- Operating Cost Per Day. Operating cost per day measures the operating costs incurred on a daily basis during a particular period. We calculate operating cost per day by dividing total operating costs during the applicable period by the number of Operating Days in the period. Operating costs attributable to costs reimbursed by customers are excluded from this measure.

- Operating Efficiency and Uptime. Maintaining our rigs' operational efficiency is a critical component of our business strategy. We measure our operating efficiency by tracking each drilling rig's unscheduled downtime on a daily, monthly, quarterly and annual basis.

Results of Operations

The following summarizes our financial and operating data for the years ended December 31, 2017, 2016 and 2015:

(In thousands, except per share data)	Year Ended December 31, 2017	December 31, 2016	December 31, 2015
Revenues	$90,007	$ 70,062	$ 88,418
Costs and expenses			
Operating costs	67,733	43,277	52,087
Selling, general and administrative	13,213	16,144	14,483
Depreciation and amortization	25,844	23,808	21,151
Asset impairments, net of insurance recoveries	2,568	3,822	2,708
Loss on disposition of assets, net	1,677	1,942	2,940
Total cost and expenses	111,035	88,993	93,369
Operating loss	(21,028)	(18,931)	(4,951)
Interest expense	(2,983)	(3,045)	(3,254)
Loss before income taxes	(24,011)	(21,976)	(8,205)
Income tax expense (benefit)	287	202	(325)
Net loss	$(24,298)	$ (22,178)	$ (7,880)
Other financial and operating data			
Number of completed rigs (end of year)	14	14	14
Rig operating days [(1)]	4,707	3,385	3,732
Average number of operating rigs [(2)]	12.90	9.25	10.22
Rig utilization [(3)]	96.0 %	73.6 %	85.0 %
Average revenue per operating day [(4)]	$18,137	$ 19,661	$ 22,921
Average cost per operating day [(5)]	$12,899	$ 10,274	$ 12,857
Average rig margin per operating day	$5,238	$ 9,387	$ 10,064
Oil price per Bbl [(6)] (end of year)	$60.46	$ 53.75	$ 37.13
Natural gas price per Mcf [(7)] (end of year)	$3.69	$ 3.71	$ 2.28

(1) Rig operating days represent the number of days our rigs are earning revenue under a contract during the period, including days that standby revenues are earned. During the twelve months ended December 31, 2017, 2016 and 2015 there were 77.9, 882.1 and 471.3 operating days in which the Company earned revenue on a standby basis, respectively, including 69.0, 839.0 and 125.5 standby-without-crew days, respectively.

(2) Average number of operating rigs is calculated by dividing the total number of rig operating days in the period by the total number of calendar days in the period.

(3) Rig utilization is calculated as rig operating days divided by the total number of days our drilling rigs are available during the applicable period.

(4) Average revenue per operating day represents total contract drilling revenues earned during the period divided by rig operating days in the period. Excluded in calculating average revenue per operating day are revenues associated with the reimbursement of out-of-pocket costs paid by customers of $4.6 million, $3.5 million and $2.9 million during the years ended December 31, 2017, 2016 and 2015, respectively. Included in calculating average revenue per operating day for the year ended December 31, 2016 were $1.8 million of early termination revenues associated with a contract termination at the end of the first quarter of 2016.

(5) Average cost per operating day represents total operating costs incurred during the period divided by rig operating days in the period. The following costs are excluded in calculating average cost per operating day: (i) out-of-pocket costs reimbursed by customers of $4.6 million, $3.5 million and $2.9 million during the years ended December 31, 2017, 2016 and 2015, respectively, (ii) new crew training costs of $0.1 million, $0.5 million and $0.8 million during the years ended December 31, 2017, 2016 and 2015, respectively, (iii) construction overhead costs expensed due to reduced rig construction activity of $1.1 million, $1.5 million and $0.5 million during the years ended December 31, 2017, 2016 and 2015, respectively, (iv) rig reactivation costs associated with the redeployment of previously stacked rigs, excluding new crew training costs (included in (ii) above), of $1.0 million and $3.0 million during the years ended December 31, 2017 and 2016, respectively, and (v) out-of-pocket expenses of $0.1 million, net of insurance recoveries, incurred as a result of damage to one of our rig's mast during the first quarter of 2017.

(6) WTI spot price as reported by the United States Energy Information Administration.

(7) Henry Hub spot price as reported by the United States Energy Information Administration.

Comparison of the years ended December 31, 2017 and 2016

Revenues

Revenues for the year ended December 31, 2017 were $90.0 million, representing a 28.5% increase over revenues for the year ended December 31, 2016 of $70.1 million. This increase was primarily related to an increase in the average number of operating rigs between periods, offset by lower average revenue per operating day. The average number of rigs operating increased to 12.9 during 2017, compared to 9.25 during 2016 and revenue per operating day decreased to $18,137 during 2017 compared to revenue per operating day of $19,661 during 2016. This decrease in average revenue per day resulted primarily from lower average day rates as compared to the prior year and a higher early termination rate on a rig in 2016.

Operating Costs

Operating costs for the year ended December 31, 2017 were $67.7 million, representing a 56.5% increase over operating costs for the year ended December 31, 2016 of $43.3 million. This increase was related to an increase in the average number of operating rigs between periods and a decrease in the number of rigs operating on a standby-without-crew basis, which incur minimal operating costs. There were 69 standby-without-crew days in 2017, compared to 839 standby-without-crew days in 2016. On a cost per operating day basis, our cost per day increased to $12,899 during 2017, compared to cost per day of $10,274 during 2016. This increase was primarily due to the decrease in the number of rigs operating on a standby-without-crew basis as compared to the prior year. Additionally, during 2017 and 2016, our operating costs also included approximately $1.1 million and $3.5 million, respectively, of costs associated with the reactivation of idle and standby rigs. These costs include costs associated with recommissioning the rig, the hiring and training of new crews and the purchase of supplies and other consumables required for the operation of the rigs.

Selling, General and Administrative Expenses

Selling, general and administrative expenses for the year ended December 31, 2017 were $13.2 million, representing a 18.2% decrease over selling, general and administrative expenses for the year ended December 31, 2016 of $16.1 million. This decrease primarily relates to the recognition of $1.5 million of retirement expense in 2016, as well as higher incentive compensation expense in 2016, offset by higher training expenses in the current year.

Depreciation and Amortization

Depreciation and amortization for the year ended December 31, 2017 was $25.8 million, representing a 8.6% increase compared to $23.8 million for the year ended December 31, 2016. This increase was directly related to the introduction of new drilling rigs constructed or upgraded by us in 2016 and 2017. We begin depreciating our rigs on a straight-line basis when they commence drilling operations.

Asset Impairments, net of Insurance Recoveries

During the second quarter of 2017, our management committed to a plan to sell our corporate headquarters and rig assembly yard complex located at 11601 North Galayda Street, Houston, Texas, in order to relocate to office space and a yard facility more suitable to our needs. As a result, we reclassified an aggregate $4.0 million of land, buildings and equipment from property, plant and equipment to assets held for sale on our balance sheet after recognizing a $0.5 million asset impairment charge representing the difference between the carrying value and the estimated fair value, less the estimated costs to sell the related property. In the third quarter of 2017, we recorded an additional asset impairment on the property, reducing assets held for sale, of $0.6 million, as a result of water related damage from the heavy rainfall that occurred during Hurricane Harvey in August 2017.

During the fourth quarter of 2017, we impaired the entire carrying value, or $1.0 million, related to certain of the assets held for sale, for which management currently believes there is substantial doubt that the third party manufacturer will service and warranty the equipment. Additionally, in 2017, we recorded $0.5 million of impairment expense on certain other damaged drilling equipment.

During the fourth quarter of 2016, we began a review of our rig fleet and other capital equipment with a focus on opportunities to standardize certain rig components across our fleet. The standardization of this equipment creates operating efficiencies in maintaining this equipment, as well as efficiencies when crews transfer between rigs. As a result of our review, we identified several non-standard items which, while fully functional, were less than optimal from an operations perspective. We recorded an asset impairment charge of $3.8 million in the fourth quarter of 2016, to write down these assets to fair value less estimated cost to sell. Such assets were classified as held for sale on our December 31, 2016 balance sheet.

Loss on Disposition of Assets

A loss on the disposition of assets totaling $1.7 million was recorded for the twelve months ended December 31, 2017 compared to a loss on the disposition of assets totaling $1.9 million in the prior year comparable period.

During 2017, we upgraded mud pumps on three rigs and as a result disposed of certain related equipment for a loss of $0.8 million. We also sold certain held for sale assets for a loss of $0.8 million. Additionally, there was a net loss of $0.1 million related to the sale or disposition of miscellaneous drilling equipment.

During 2016, we upgraded mud pumps on five rigs and as a result disposed of certain related equipment for $1.8 million. Additionally, there was a net loss of $0.1 million related to the sale or disposition of miscellaneous drilling equipment.

Interest Expense

Interest expense was $3.0 million for the years ended December 31, 2017 and 2016. Credit Facility debt balances were higher in 2017, incurring higher interest expense compared to 2016, as our Credit Facility debt balance was paid down with the proceeds from the secondary offering completed in April 2016. This was offset by higher interest expense in 2016 associated with the write off of unamortized deferred financing costs as a result of the reduction in the aggregate commitments of our Credit Facility amended in April 2016 of $0.5 million.

Income Tax Expense

The income tax expense recorded for the year ended December 31, 2017 amounted to $0.3 million compared to income tax expense of $0.2 million for the year ended December 31, 2016. During 2015, we changed our method of calculating our allowable deduction for the Texas margin tax. As a result, we filed an amended tax return in Texas for 2013 to claim a $0.1 million refund. This refund was received in 2016. The effective tax rate was 1.2% for the year ended 2017 compared to 0.9% for the year ended 2016. Taxes in the current year relate to state taxes. Taxes in the prior year relate to Texas margin tax.

Comparison of the years ended December 31, 2016 and 2015

Revenues

Revenues for the year ended December 31, 2016 were $70.1 million, representing a 20.8% decrease over revenues for the year ended December 31, 2015 of $88.4 million. This decrease was primarily related to a reduction in the average number of operating rigs between periods and lower average revenue per operating day. The average number of rigs operating declined to 9.25 during 2016, compared to 10.22 during 2015 and revenue per operating day decreased to $19,661 during 2016 compared to revenue per operating day of $22,921 during 2015. This decrease in average revenue per day resulted primarily from lower average day rates as compared to 2015 and an increase in rigs earning revenue on a standby-without-crew basis.

Operating Costs

Operating costs for the year ended December 31, 2016 were $43.3 million, representing a 16.9% decrease over operating costs for the year ended December 31, 2015 of $52.1 million. This decrease was related to a reduction in the average number of operating rigs and an increase in the number of rigs operating on a standby-without-crew basis during 2016 as they incurred minimal operating costs, partially offset by rig reactivation and crew staging costs of approximately $3.5 million related to seven rigs that were reactivated during 2016. On a cost per operating day basis, our cost per day decreased to $10,274 during 2016, compared to cost per day of $12,857 during 2015. This decrease was primarily due to an increase in the number of rigs earning revenue on a standby-without-crew basis during 2016.

Selling, General and Administrative Expenses

Selling, general and administrative expenses for the year ended December 31, 2016 were $16.1 million, representing a 11.5% increase over selling, general and administrative expenses for the year ended December 31, 2015 of $14.5 million. This increase primarily relates to the recognition of $1.5 million of expense associated with the retirement of one of our executive officers in June 2016, and increased incentive compensation expense, offset by lower professional fees and other expenses as compared to the prior year.

Depreciation and Amortization

Depreciation and amortization for the year ended December 31, 2016 was $23.8 million, representing a 12.6% increase compared to $21.2 million for the year ended December 31, 2015. This increase was directly related to the introduction of new drilling rigs constructed or upgraded by us in 2015 and 2016. We begin depreciating our rigs on a straight-line basis when they commence drilling operations.

Asset Impairments, net of Insurance Recoveries

During the fourth quarter of 2016, we began a review of our rig fleet and other capital equipment with a focus on opportunities to standardize certain rig components across our fleet. The standardization of this equipment will create operating efficiencies in maintaining this equipment, as well as efficiencies when crews transfer between rigs. As a result of this review, we identified several non-standard items which, while fully functional, are less than optimal from an operations perspective. We recorded a non-cash charge of $3.8 million in the fourth quarter of 2016, to write down these assets to estimated fair value less cost to sell. Such assets were classified as held-for-sale on our December 31, 2016 balance sheet.

In 2015 we recorded an impairment charge of $3.6 million relating to the substructure, mast and various other rig components of our last remaining non-walking rig due to its limited marketability in its current configuration given market conditions. Additionally, we recorded a net impairment of $0.4 million associated with damage to a driller's cabin as well as the impairment of various other drilling equipment during the twelve months ended December 31, 2015.

Loss on Disposition of Assets

A loss on the disposition of assets totaling $1.9 million was recorded for the twelve months ended December 31, 2016 compared to a loss on the disposition of assets totaling $2.9 million in the prior year comparable period.

During 2016, we upgraded mud pumps on five rigs and as a result disposed of certain related equipment for $1.8 million. Additionally, there was a net loss of $0.1 million related to the sale or disposition of miscellaneous drilling equipment.

During 2015, we began to convert one of our non-walking rigs to pad optimal status, equipped with our 200 series substructure, multi-directional walking system and 7500psi mud system. As part of this rig conversion, key components of the prior rig were decommissioned and replaced, including the rig's substructure and mud system components. As a result, we recorded a preliminary estimate of the loss on disposal of assets totaling $2.5 million related to the disposal of drilling equipment which was no longer compatible with the converted rig. Additionally in 2015, there was a loss of $0.4 million related to the sale or disposition of miscellaneous drilling equipment.

Interest Expense

Interest expense for the year ended December 31, 2016 was $3.0 million, as compared to $3.3 million for the year ended December 31, 2015 primarily as a result of the paydown of debt of our Credit Facility with the proceeds from the secondary offering completed in April 2016. Additionally, as a result of the reductions in the aggregate commitments of our Credit Facility amended in April 2016 and October 2015, we wrote off $0.5 million and $0.4 million, respectively of unamortized deferred financing costs associated with the original and amended Credit Facility recorded prior to the April 2016 and October 2015 amendments.

Income Tax Expense (Benefit)

The income tax expense recorded for the year ended December 31, 2016 amounted to $0.2 million compared to an income tax benefit of $0.3 million for the year ended December 31, 2015. During 2015, we changed our method of calculating our allowable deduction for the Texas margin tax. As a result, we filed an amended tax return in Texas for 2013 to claim a $0.1 million refund. This refund was received in 2016. The effective tax rate was 0.9% for the year ended 2016 compared to 4.0% for the year ended 2015. All taxes in both 2016 and 2015 relate to Texas margin tax.

Liquidity and Capital Resources

Our liquidity as of December 31, 2017 included approximately $36.5 million of our $85.0 million commitment availability under our Credit Facility and $2.5 million of cash. The aggregate commitments under our Credit Facility are currently $85.0 million, and the borrowing base under our Credit Facility at December 31, 2017, was $106.7 million. Our principal use of capital has been the construction of land drilling rigs and associated equipment, working capital and inventories to support our drilling operations. Our first drilling rig was completed and began operating in May 2012. As of December 31, 2017, we had 14 200 Series rigs. Our primary sources of capital to date have been funds received from our initial private placement, our IPO, our April 2016 public offering of common stock, and cash flows from operations and our Credit Facility.

Public Offering of Common Stock

On April 26, 2016, we completed an underwritten public offering of 13,225,000 shares of common stock at a price to the public of $3.50 per share. We received net proceeds of approximately $42.9 million, after deducting underwriting discounts and commissions and offering expenses.

We used the net proceeds from this offering to repay a portion of the outstanding borrowings under our Credit Facility and for general corporate purposes.

Cash Flows

	Year Ended December 31,		
(in thousands)	2017	2016	2015
Net cash provided by operating activities	$4,933	$16,973	$27,379
Net cash used in investing activities	(30,094)	(20,058)	(72,219)
Net cash provided by financing activities	20,623	4,812	39,427
Net (decrease) increase in cash and cash equivalents	$(4,538)	$1,727	$(5,413)

Net Cash Provided By Operating Activities

Cash provided by operating activities was $4.9 million for the twelve months ended December 31, 2017 compared to $17.0 million during the same period in 2016. Factors affecting changes in operating cash flows are similar to those that impact net earnings, with the exception of non-cash items such as depreciation and amortization, impairments, gains or losses on disposals of assets, stock-based compensation, deferred taxes and amortization of deferred financing costs. Additionally, changes in working capital items such as accounts receivable, inventory, prepaid expense, accounts payable and accrued liabilities can significantly affect operating cash flows. Cash flows from operating activities during 2017 were lower as a result of an increase in net loss of $2.1 million, adjusted for non-cash items, of $34.4 million compared to $35.0 million in 2016. This was offset by working capital changes that decreased cash flows from operating activities in 2017 by $5.1 million compared to working capital changes that increased cash flows from operating activities $4.2 million in 2016.

Cash provided by operating activities was $17.0 million for the twelve months ended December 31, 2016 compared to $27.4 million during the same period in 2015. Factors affecting changes in operating cash flows are similar to those that impact net earnings, with the exception of non-cash items such as depreciation and amortization, impairments, gains or losses on disposals of assets, stock-based compensation, deferred taxes and amortization of deferred financing costs. Additionally, changes in working capital items such as accounts receivable, inventory, prepaid expense, accounts payable and accrued liabilities can significantly affect operating cash flows. Cash flows from operating activities during 2016 were lower as a result of an increase in net loss of $14.3 million, adjusted for non-cash items, of $35.0 million compared to $31.7 million in 2015. This was offset by working capital changes that increased cash flows from operating activities in 2016 by $4.2 million compared to $3.6 million in 2015.

Net Cash Used In Investing Activities

Cash used in investing activities was $30.1 million for the twelve months ended December 31, 2017 compared to $20.1 million during the same period in 2016. This increase was attributable to higher maintenance capital expenditures as a result of the increase in operating rigs versus standby-without-crew. Our primary activities in 2017 related to rig upgrades and maintenance capital expenditures. During 2017, cash payments of $31.3 million for capital expenditures were offset by proceeds from the sale of property, plant and equipment of $1.3 million. Cash payments during 2017 included approximately $6.2 million associated with equipment purchased in 2016. During the 2016 period, cash payments of $21.1 million for capital expenditures were offset by the receipt of insurance proceeds of $0.2 million and proceeds from the sale of property, plant and equipment of $0.9 million.

Cash used in investing activities was $20.1 million for the twelve months ended December 31, 2016 compared to $72.2 million during the same period in 2015. This decrease was attributable to lower capital expenditures as a result of less favorable market conditions. Our primary activities in 2016 related to rig upgrades, purchases of long lead time items for future new build rigs and maintenance capital expenditures. During 2016, cash payments of $21.1 million for capital expenditures were offset by insurance proceeds of $0.2 million and proceeds from the sale of property, plant and equipment of $0.9 million. Cash payments during 2016 included approximately $4.5 million associated with equipment purchased in 2015. During the 2015 period, cash payments of $75.5 million for capital expenditures were offset by the receipt of insurance proceeds of $2.9 million and proceeds from the sale of property, plant and equipment of $0.4 million.

Net Cash Provided by Financing Activities

Cash provided by financing activities was $20.6 million for the twelve months ended December 31, 2017 compared to $4.8 million during the same period in 2016. During 2017, we made borrowings under our Credit Facility of $44.5 million, offset by repayments under our Credit Facility of $21.7 million, restricted stock units withheld for taxes paid of $0.9 million, financing costs paid associated with the amendment to the Credit Facility of $0.5 million, the purchase of $0.2 million of treasury stock and payments for capital lease obligations of $0.6 million.

Cash provided by financing activities was $4.8 million for the twelve months ended December 31, 2016 compared to $39.4 million during the same period in 2015. During 2016, we received proceeds of $42.9 million from a public offering and made borrowings under our Credit Facility of $49.0 million, offset by repayments under our Credit Facility of $86.0 million, financing costs paid associated with the amendment to the Credit Facility of $0.2 million and the purchase of $0.4 million of treasury stock and payments for capital lease obligations of $0.5 million.

Future Liquidity Requirements

Our liquidity as of December 31, 2017 included approximately $36.5 million of availability of our $85.0 million commitment under our Credit Facility and $2.5 million of cash. The aggregate commitments under our Credit Facility are currently $85.0 million, and the borrowing base under our Credit Facility at December 31, 2017 was $106.7 million.

We expect our future capital and liquidity needs to be related to funding capital expenditures for our next new build rig, capital spare inventory, operating expenses, maintenance capital expenditures, working capital and general corporate purposes. We believe that our cash and cash equivalents, cash flows from operating activities and borrowings under our Credit Facility will adequately finance all of our purchase commitments, capital expenditures and other cash requirements over the next twelve months.

You should read "Item 1A Risk Factors" in particular, "Risks Related to Our Liquidity", for additional information regarding risks surrounding our operations and financial liquidity.

Long-term Debt

In November 2014, we entered into an amended and restated credit agreement with a syndicate of financial institutions led by CIT Finance, LLC, that provided for a committed $155.0 million Credit Facility and an additional uncommitted $25.0 million accordion feature that allowed for future increases in the facility. In 2015, we amended the Credit Facility to provide for a springing lock-box arrangement and, in light of market conditions and our reduced capital plans, reduce aggregate commitments to $125.0 million and modify certain maintenance covenants. In 2016, we amended the Credit Facility to reduce aggregate commitments to $85.0 million and further modify certain maintenance covenants. In connection with this amendment, we expensed certain previously deferred debt issuance costs totaling $0.5 million reflecting the reduction in borrowing capacity. In 2017, we amended the Credit Facility to extend the maturity date by two years to November 5, 2020 and provide for an additional uncommitted $65.0 million accordion feature that allowed for future increases in facility commitments. Interest under the Credit Facility remained unchanged. The amendment contained various changes to the financial and other covenants to accommodate the extension in term, including changes to the leverage ratio covenant, fixed charge coverage ratio covenant and rig utilization ratio covenant.

The obligations under the Credit Facility are secured by all of our assets and are unconditionally guaranteed by all of our current and future direct and indirect subsidiaries.

Borrowings under the Credit Facility are subject to a borrowing base formula that allows for borrowings of up to 85% of eligible trade accounts receivable not more than 90 days outstanding, plus up to a certain percentage, the "advance rate", of the appraised forced liquidation value of our eligible, completed and owned drilling rigs. As of December 31, 2017, the advance rate was 73.75%. The advance rate declines 1.25% each quarter beginning January 1, 2018 through June 2019. Thereafter, through the maturity date, the advance rate remains at 65.0%. Rigs that remain idle for 90 consecutive days or longer are removed from the borrowing base until they are contracted. In addition, rigs are appraised two times a year and are subject to upward or downward revisions as a result of market conditions as well as the age of the rig.

At our election, interest under the Credit Facility is determined by reference at our option to either (i) the London Interbank Offered Rate (“LIBOR”), plus 4.5% or (ii) a “base rate” equal to the higher of the prime rate published by JP Morgan Chase Bank or three-month LIBOR plus 1%, plus in each case, 3.5%, the federal funds effective rate plus 0.05%. We also pay, on a quarterly basis, a commitment fee of 0.50% per annum on the unused portion of the Credit Facility commitment. As of December 31, 2017, the weighted average interest rate on our borrowings was 6.04%.

The amended Credit Facility contains various financial covenants including a leverage covenant, springing fixed charge coverage ratio and rig utilization ratio. Additionally, there are restrictive covenants that limit our ability to, among other things: incur or guarantee additional indebtedness or issue disqualified capital stock; transfer or sell assets; pay dividends or distributions; redeem subordinated indebtedness; make certain types of investments or make other restricted payments; create or incur liens; consummate a merger; consolidation or sale of all or substantially all assets; and engage in business other than a business that is the same or similar to the current business and reasonably related businesses. The Credit Facility does, however, permit us to incur up to $20.0 million of additional indebtedness for the purchase of additional rigs or rig equipment. As of December 31, 2017, we are in compliance with these covenants.

Under the Credit Agreement, as amended, for purposes of calculating EBITDA, non-cash stock-based compensation is added back to EBITDA as well as up to $2.0 million per year of previously capitalized construction costs that was incurred in 2017.

The Credit Facility provides that an event of default may occur if a material adverse change to ICD occurs, which is considered a subjective acceleration clause under applicable accounting rules. In accordance with ASC 470-10-45, because of the existence of this clause, borrowings under the Credit Facility will be required to be classified as current in the event the springing lock-box event occurs, regardless of the actual maturity of the borrowings. The Fourth Amendment reduced the requirement for a mandatory lock-box trigger from $15.0 million of availability under the Credit Facility to $10.0 million of availability under the Credit Facility.

We had $48.5 million in outstanding borrowings under the Credit Facility at December 31, 2017. Remaining availability of our $85.0 million commitment under the Credit Facility was $36.5 million at December 31, 2017.

Additionally, included in our long-term debt are capital leases. During the first quarter of 2016, our vehicle lease agreements were amended, which resulted in a change in the classification of certain leases from operating leases to capital leases. On the amendment date we recorded $0.8 million in capital lease obligations, representing the lesser of fair market value or the present value of future minimum lease payments on the conversion date. These leases generally have initial terms of 36 months and are paid monthly.

Contractual Obligations

As of December 31, 2017, we had contractual obligations as described below. Our obligations include non-cancelable capital leases, as well as "off balance sheet arrangements" whereby the liabilities associated with non-cancelable operating leases and unconditional purchase obligations are not fully reflected in our balance sheets.

(in thousands)	2018	2019	2020	Thereafter	Total
Credit Facility	$—	$—	$48,541	$ —	$48,541
Interest on long-term debt	3,242	3,241	2,829	—	9,312
Capital and operating leases	759	627	306	—	1,692
Purchase obligations	3,683	—	—	—	3,683
Total contractual obligations	$7,684	$3,868	$51,676	$ —	$63,228

Our long-term debt as of December 31, 2017 consisted of amounts due under our Credit Facility. Interest on long-term debt is related to our estimated future contractual interest obligations on long-term indebtedness outstanding as of December 31, 2017 under our Credit Facility. We use our incremental borrowing rate at the inception of each capital lease to calculate the interest on the capital leases. Our capital leases relate to certain vehicles and our operating leases relate primarily to real estate and certain vehicles.

Our purchase obligations relate primarily to outstanding purchase orders for rig equipment or components ordered but not received. We have made progress payments on these orders of approximately $0.8 million that could be forfeited if we were to cancel these orders.

Critical Accounting Policies and Accounting Estimates

The financial statements are impacted by the accounting policies and estimates and assumptions used by management during their preparation. These estimates and assumptions are evaluated on an on-going basis. Estimates are based on historical experience and on various other assumptions that we believe to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities if not readily available from other sources. Actual results may differ from these estimates under different assumptions or conditions. The following is a discussion of the critical accounting policies and estimates used in our financial statements. Other significant accounting policies are summarized in Note 2 to the financial statements included in "Item 8. Financial Statements and Supplementary Data."

Revenue and Cost Recognition

Our revenues are principally derived from contract drilling services. We record contract drilling revenue for daywork contracts daily as work progresses, assuming collectability is reasonably assured. Daywork drilling contracts provide that revenue is earned daily based on a specified rate per day over the term of the contract which can be for a specific period of time or a specified number of wells. We generally receive lump-sum payments for the mobilization of rigs and other drilling equipment at the commencement of a new drilling contract. Revenue and costs associated with the mobilization are deferred and recognized ratably over the term of the related drilling contract once the rig spuds. Costs incurred to relocate rigs and other equipment to an area in which a contract has not been secured are expensed as incurred. If a contract is terminated prior to the specified contract term, early termination payments received from the customer are only recognized as revenues when all contractual obligations, such as mitigation requirements, are satisfied. Reimbursements for the purchase of supplies, equipment, trucking and other services that are provided at the request of our customers are recorded as revenue when incurred. The related costs are recorded as operating expenses when incurred. Revenue is presented net of any sales tax charged to the customer that we are required to remit to local or state governmental taxing authorities.

Property, Plant and Equipment

Property, plant and equipment, including renewals and betterments, are stated at cost less accumulated depreciation. All property, plant and equipment are depreciated using the straight-line method based on the estimated useful lives of the assets. The cost of maintenance and repairs are expensed as incurred. Major overhauls and upgrades are capitalized and depreciated over their remaining useful life.

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Depreciation of property, plant and equipment is recorded based on the estimated useful lives of the assets as follows:

	Estimated Useful Life
Buildings	20 - 39 years
Drilling rigs and related equipment	3 - 20 years
Machinery, equipment and other	3 - 7 years
Vehicles	2 - 5 years
Software	2 - 7 years

We review our assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. The recoverability of assets that are held and used is measured by comparison of the estimated future undiscounted cash flows associated with the asset to the carrying amount of the asset. If the carrying value of such assets is less than the estimated undiscounted cash flow, an impairment charge is recorded in the amount by which the carrying amount of the assets exceeds their estimated fair value. As of December 31, 2017, we determined that there were no conditions that existed that would suggest rig carrying values may not be recoverable.

During the second quarter of 2017, our management committed to a plan to sell our corporate headquarters and rig assembly yard complex located at 11601 North Galayda Street, Houston, Texas, in order to relocate to office space and a yard facility more suitable to our needs. As a result, we reclassified an aggregate $4.0 million of land, buildings and equipment from property, plant and equipment to assets held for sale on our balance sheet after recognizing a $0.5 million asset impairment charge representing the difference between the carrying value and the estimated fair value, less the estimated costs to sell the related property. In the third quarter of 2017, we recorded an additional asset impairment on the property, reducing assets held for sale, of $0.6 million, as a result of water related damage from the heavy rainfall that occurred during Hurricane Harvey in August 2017.

In 2016, we began a review of our rig fleet and other capital equipment with a focus on opportunities to standardize certain rig components across our fleet. The standardization of this equipment creates operating efficiencies in maintaining this equipment, as well as efficiencies when crews transfer between rigs. As a result of our review, we identified several non-standard items which, while fully functional, were less than optimal from an operations perspective. We recorded a non-cash asset impairment charge of $3.8 million in the fourth quarter of 2016, to write down these assets to fair value less estimated cost to sell. Such assets were classified as held for sale on our December 31, 2016 balance sheet. In the second quarter of 2017, we sold $1.6 million of these assets and recognized a loss on the sale of assets of $0.8 million. In the fourth quarter of 2017, we impaired the entire carrying value, or $1.0 million, related to certain of the assets held for sale, for which management currently believes there is substantial doubt that the third party manufacturer will service and warranty the equipment.

In 2015, due to depressed industry conditions, we carried out an impairment evaluation for each of our drilling rigs. Based on the evaluation, during the fourth quarter of 2015, we recorded an impairment of $3.6 million related to the substructure, mast and various other rig components of our last remaining non-walking rig due to its limited marketability in its current configuration given market conditions. Additionally, we also recorded an impairment, net of insurance recoveries, of $0.4 million associated with the damage to the driller's cabin and the impairment of various other drilling equipment during the year ended December 31, 2015.

Capitalized Interest

We capitalize interest costs related to rig construction projects. Interest costs are capitalized during the construction period based on the weighted average interest rate of the related debt. Capitalized interest for the years ended December 31, 2017, 2016 and 2015 amounted to $0.1 million, $0.1 million and $0.9 million, respectively.

Income Taxes

We use the asset and liability method of accounting for income taxes. Under this method, we record deferred income taxes based upon differences between the financial reporting basis and tax basis of assets and liabilities, and use enacted tax rates and laws that we expect will be in effect when we realize those assets or settle those liabilities. We review deferred tax assets for a valuation allowance based upon management’s estimates of whether it is more likely than not that a portion of the deferred tax asset will be fully realized in a future period.

We recognize the financial statement benefit of a tax position only after determining that the relevant taxing authority would more-likely-than-not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority.

Our policy is to include interest and penalties related to the unrecognized tax benefits within the income tax expense (benefit) line item in our statement of operations.

New tax legislation, commonly referred to as the Tax Cuts and Jobs Act, was enacted on December 22, 2017. ASC 740, Accounting for Income Taxes, requires companies to recognize the effect of tax law changes in the period of enactment even though the effective date for most provisions is for tax years beginning after December 31, 2017. Since our federal deferred tax asset was fully offset by a valuation allowance the overall net adjustment to our tax provision in the three months ended December 31, 2017 due to the reduction in the U.S. corporate income tax rate to 21% did not materially affect our financial statements. Significant provisions that are not yet effective but may impact income taxes in future years include: the repeal of the corporate Alternative Minimum Tax, the limitation on the current deductibility of net interest expense in excess of 30% of adjusted taxable income for levered balance sheets, a limitation on utilization of net operating losses generated after tax year 2017 to 80% of taxable income, the unlimited carryforward of net operating losses generated after tax year 2017, temporary 100% expensing of certain business assets, additional limitations on certain general and administrative expenses, and changes in determining the excessive compensation limitation. Currently, we do not anticipate paying cash federal income taxes in the near term due to any of the legislative changes, primarily due to the availability of our net operating loss carryforwards. Future interpretations relating to the recently enacted U.S. federal income tax legislation which vary from our current interpretation and possible changes to state tax laws in response to the recently enacted federal legislation may have a significant effect on this projection.

Stock-Based Compensation

We record compensation expense over the applicable requisite service period for all stock-based compensation based on the grant date fair value of the award. The expense is included in selling, general and administrative expense in our statement of operations or capitalized in connection with rig construction activity.

Other Matters

Off-Balance Sheet Arrangements

We are party to certain arrangements defined as “off-balance sheet arrangements” that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors. These arrangements relate to non-cancelable operating leases and unconditional purchase obligations not fully reflected on our balance sheets. See Note 11 in Part II “Item 8. Financial Statements and Supplementary Data” for additional information.

Emerging Growth Company

We have not elected to avail ourselves of the extended transition period available to emerging growth companies ("EGCs") as provided in Section 7(a)(2)(B) of the Securities Act of 1933, as amended, for complying with new or revised accounting standards, therefore, we will be subject to new or revised accounting standards at the same time as other public companies that are not EGCs.

Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board (the "FASB") issued Accounting Standards Update (“ASU”) No. 2014-09, Revenue from Contracts with Customers, followed by the issuance of certain additional related accounting standards updates (collectively codified in "ASC 606"), to provide guidance on the recognition of revenue from customers. Under ASC 606, an entity will recognize revenue, when it transfers promised goods or services to customers in an amount that reflects what it expects in exchange for the goods or services. ASC 606 also requires more detailed disclosures to enable users of the financial statements to understand the nature, amount, timing and uncertainty, if any, of revenue and cash flows arising from contracts with customers. We have substantially completed our evaluation of the impact ASC 606 will have on our financial statements. ASC 606 will not have a material impact on the timing of our revenue recognition, however, certain revenues and costs historically presented on a gross basis in our financial statements may be presented on a net basis. We adopted ASC 606 on January 1, 2018, utilizing the modified retrospective approach, which requires us to apply the new revenue standard to (i) all new revenue contracts entered into after January 1, 2018 and (ii) all existing revenue contracts as of January 1, 2018 through a cumulative effect adjustment to equity. In accordance with this approach, our revenues for periods prior to January 1, 2018 will not be adjusted. Given that ASC 606 will not impact the timing of our revenue recognition, no cumulative effect adjustment was required as of January 1, 2018. As mentioned above, certain of our reimbursable revenues may be presented on a net basis beginning as of January 1, 2018, depending on whether we are deemed to be the principal or the agent in the arrangement, which we will evaluate on a case by case basis. Our reimbursable revenues have historically been less than 3% of our total revenues.

In February 2016, the FASB issued ASU No. 2016-02, Leases, to establish the principles that lessees and lessors shall apply to report useful information to users of financial statements about the amount, timing, and uncertainty of cash flows arising from a lease. Under the new guidance, lessees will be required to recognize (with the exception of short-term leases) at the commencement date, a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and a right-of-use asset, which is an asset that represents the lessee’s right to use, or control the use of, a specified asset for the lease term. This guidance is effective for public companies for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early application is permitted for all public business entities. We are currently evaluating the impact this guidance will have on our financial statements and have engaged a third party consultant to assist us on this evaluation process.

In June 2016, the FASB issued ASU No. 2016-13, Financial Instruments - Credit Losses: Measurement of Credit Losses on Financial Instruments, as additional guidance on the measurement of credit losses on financial instruments. The new guidance requires the measurement of all expected credit losses for financial assets held at the reporting date based on historical experience, current conditions and reasonable supportable forecasts. In addition, the guidance amends the accounting for credit losses on available-for-sale debt securities and purchased financial assets with credit deterioration. The new guidance is effective for SEC filers for interim and annual periods beginning after December 15, 2019, with early adoption permitted for interim and annual periods beginning after December 15, 2018. We are in the initial stages of evaluating the impact this guidance will have on our accounts receivable.

In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows, to address diversity in how certain cash receipts and cash payments are presented and classified in the statement of cash flows. The update addresses the following eight specific cash flow issues: Debt prepayment or debt extinguishment costs; settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies (COLIs) (including bank-owned life insurance policies (BOLIs)); distributions received from equity method investees; beneficial interests in securitization transactions; and separately identifiable cash flows and application of the predominance principle. The amendments are effective for public business entities for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. Early adoption is permitted, including adoption in an interim period. We expect the implementation of this standard to change the classification of the described transactions within our statement of cash flows.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to a variety of market risks including risks related to potential adverse changes in interest rates and commodity prices. We actively monitor exposure to market risk and continue to develop and utilize appropriate risk management techniques. We do not use derivative financial instruments for trading or to speculate on changes in commodity prices.

Interest Rate Risk

Total long-term debt at December 31, 2017 included $48.5 million of floating-rate debt attributed to borrowings at an average interest rate of 6.04%. As a result, our annual interest cost in 2018 will fluctuate based on short-term interest rates. The impact on annual cash flow of a 10% change in the floating-rate (approximately 0.60%) would be approximately $0.3 million annually based on the floating-rate debt and other obligations outstanding at December 31, 2017; however, there are no assurances that possible rate changes would be limited to such amounts.

Commodity Price Risk

The demand for contract drilling services is a result of E&P companies spending money to explore and develop drilling prospects in search of oil and natural gas. This customer spending is driven by their cash flow and financial strength, which is affected by trends in crude oil and natural gas commodity prices. Crude oil prices are determined by a number of factors including supply and demand, worldwide economic conditions and geopolitical factors. Crude oil and natural gas prices have historically been volatile and very difficult to predict. This volatility can lead many E&P companies to base their capital spending on much more conservative estimates of commodity prices. As a result, demand for contract drilling services is not always purely a function of the movement of current commodity prices.

Following the November 2016 decision by OPEC to reduce production quotas, oil prices recovered to the $45 to $55 per barrel range. More recently, oil prices began to recover further, reaching a three year high of $66.27 on January 26, 2018. While this continued recovery in pricing is promising, there are no indications at this time that oil and natural gas prices and rig counts will recover to their previous highs experienced in 2014.

Due to this deterioration and stabilization of commodity prices well below previous highs, our customers are principally focused on their most economic wells, and driving cost and production efficiencies that deliver the most economic wells with the lowest capital costs. As a result of this drive towards production and cost efficiencies, operators are focusing more of their capital spending on horizontal drilling programs compared to vertical drilling, and are more focused on utilizing drilling equipment and techniques that optimize costs and efficiency. Thus, we believe the rapid market deterioration and stabilization of oil prices well below historical highs has significantly accelerated the pace of the ongoing land rig replacement cycle and continued shift to horizontal drilling from multi-well pads utilizing “pad optimal” rig technology.

As market conditions have improved from trough levels in 2016 and begun to stabilize higher, demand for our ShaleDriller rigs has improved. At December 31, 2017, all of our rigs were under contract. In addition to improving utilization, contract tenors are improving with customers being willing to sign term contracts of six to twelve months or longer, and at higher dayrates compared to trough levels. However, the pace and duration of the current recovery is unknown, and if commodity prices were to fall below $45 for any sustained period of time, market conditions and demand for our products and services could deteriorate.

Credit and Capital Market Risk

Our customers may finance their drilling activities through cash flow from operations, the incurrence of debt or the issuance of equity. Any deterioration in the credit and capital markets, as currently being experienced, can make it difficult for our customers to obtain funding for their capital needs. A reduction of cash flow resulting from declines in commodity prices, or a reduction of available financing may result in a reduction in customer spending and the demand for our drilling services. This reduction in spending could have a material adverse effect on our business, financial condition and results of operations.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Independence Contract Drilling, Inc.
Houston, Texas

Opinion on the Financial Statements

We have audited the accompanying balance sheets of Independence Contract Drilling, Inc. (the “Company”) as of December 31, 2017 and 2016, the related statements of operations, stockholders’ equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes and financial statement schedule listed in the accompanying index (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2017 and 2016, and the results of its operations and its 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 financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s 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 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 financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ BDO USA, LLP
We have served as the Company's auditor since 2015.
Houston, Texas
February 26, 2018

Independence Contract Drilling, Inc.
Balance Sheets
(In thousands, except par value and share amounts)

	December 31, 2017	December 31, 2016
Assets		
Cash and cash equivalents	$ 2,533	$ 7,071
Accounts receivable, net	18,056	11,468
Inventories	2,710	2,336
Assets held for sale	4,637	3,915
Prepaid expenses and other current assets	2,957	3,102
Total current assets	30,893	27,892
Property, plant and equipment, net	272,388	273,188
Other long-term assets, net	1,364	1,027
Total assets	$ 304,645	$ 302,107
Liabilities and Stockholders' Equity		
Liabilities		
Current portion of long-term debt	$ 533	$ 441
Accounts payable	11,627	10,031
Accrued liabilities	6,969	7,821
Total current liabilities	19,129	18,293
Long-term debt	49,278	26,078
Deferred income taxes, net	683	396
Other long-term liabilities	73	88
Total liabilities	69,163	44,855
Commitments and contingencies (Note 11)		
Stockholders' equity		
Common stock, $0.01 par value, 100,000,000 shares authorized; 38,246,919 and 37,831,723 shares issued, respectively; and 37,985,225 and 37,617,920 shares outstanding, respectively	380	376
Additional paid-in capital	326,616	323,918
Accumulated deficit	(89,645)	(65,347)
Treasury stock, at cost, 261,694 and 213,803 shares, respectively	(1,869)	(1,695)
Total stockholders' equity	235,482	257,252
Total liabilities and stockholders' equity	$ 304,645	$ 302,107

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

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Independence Contract Drilling, Inc.
Statements of Operations
(In thousands, except per share amounts)

	Year Ended December 31,		
	2017	2016	2015
Revenues	$90,007	$70,062	$88,418
Costs and expenses			
Operating costs	67,733	43,277	52,087
Selling, general and administrative	13,213	16,144	14,483
Depreciation and amortization	25,844	23,808	21,151
Asset impairments, net of insurance recoveries	2,568	3,822	2,708
Loss on disposition of assets, net	1,677	1,942	2,940
Total cost and expenses	111,035	88,993	93,369
Operating loss	(21,028)	(18,931)	(4,951)
Interest expense	(2,983)	(3,045)	(3,254)
Loss before income taxes	(24,011)	(21,976)	(8,205)
Income tax expense (benefit)	287	202	(325)
Net loss	$(24,298)	$(22,178)	$(7,880)
Loss per share:			
Basic and diluted	$(0.64)	$(0.67)	$(0.33)
Weighted average number of common shares outstanding:			
Basic and diluted	37,762	33,118	23,904

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

Independence Contract Drilling, Inc.
Statements of Changes in Stockholders' Equity
(In thousands, except share amounts)

	Common Stock		Additional Paid-in Capital	Accumulated Deficit	Treasury Stock	Total Stockholders' Equity
	Shares	Amount				
Balances at December 31, 2014	24,455,709	$ 245	$ 272,751	$ (35,289)	$ (971)	$ 236,736
Restricted stock forfeited	(14,419)	—	—	—	—	—
Restricted stock units vested	13,636	—	—	—	—	—
Purchase of treasury stock	(51,267)	(1)	1	—	(315)	(315)
Stock-based compensation	—	—	4,196	—	—	4,196
Net loss	—	—	—	(7,880)	—	(7,880)
Balances at December 31, 2015	24,403,659	$ 244	$ 276,948	$ (43,169)	$ (1,286)	$ 232,737
Restricted stock forfeited	(8,182)	—	—	—	—	—
Restricted stock units vested	74,968	—	—	—	—	—
Purchase of treasury stock	(77,525)	—	—	—	(409)	(409)
Public offering, net of offering costs	13,225,000	132	42,788	—	—	42,920
Stock-based compensation	—	—	4,182	—	—	4,182
Net loss	—	—	—	(22,178)	—	(22,178)
Balances at December 31, 2016	37,617,920	$ 376	$ 323,918	$ (65,347)	$ (1,695)	$ 257,252
Restricted stock forfeited	(3,195)	—	—	—	—	—
RSUs vested, net of shares withheld for taxes	418,391	4	(867)	—	—	(863)
Purchase of treasury stock	(47,891)	—	—	—	(174)	(174)
Stock-based compensation	—	—	3,565	—	—	3,565
Net loss	—	—	—	(24,298)	—	(24,298)
Balances at December 31, 2017	37,985,225	$ 380	$ 326,616	$ (89,645)	$ (1,869)	$ 235,482

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

Independence Contract Drilling, Inc.
Statements of Cash Flows
(In thousands)

	Year Ended December 31,		
	2017	2016	2015
Cash flows from operating activities			
Net loss	$(24,298)	$(22,178)	$(7,880)
Adjustments to reconcile net loss to net cash provided by operating activities			
Depreciation and amortization	25,844	23,808	21,151
Asset impairments, net of insurance recoveries	2,568	3,822	2,708
Stock-based compensation	3,565	4,249	3,542
Stock-based compensation - executive retirement	—	(67)	—
Loss on disposition of assets, net	1,677	1,942	2,940
Deferred income taxes	287	203	193
Amortization of deferred financing costs	434	532	629
Write-off of deferred financing costs	—	504	394
Bad debt expense	—	—	132
Changes in operating assets and liabilities			
Accounts receivable	(6,588)	6,772	755
Inventories	(301)	55	(263)
Prepaid expenses and other assets	133	212	(853)
Accounts payable and accrued liabilities	1,612	(2,881)	4,339
Income taxes payable	—	—	(408)
Net cash provided by operating activities	4,933	16,973	27,379
Cash flows from investing activities			
Purchases of property, plant and equipment	(31,347)	(21,106)	(75,532)
Proceeds from insurance claims	—	188	2,899
Proceeds from the sale of assets	1,253	860	414
Net cash used in investing activities	(30,094)	(20,058)	(72,219)
Cash flows from financing activities			
Borrowings under Credit Facility	44,451	49,048	140,610
Repayments under Credit Facility	(21,662)	(86,004)	(100,421)
Public offering proceeds, net of offering costs	—	42,920	—
Purchase of treasury stock	(174)	(409)	(315)
RSUs withheld for taxes	(863)	—	—
Financing costs paid	(530)	(217)	(447)
Payments of capital lease obligations	(599)	(526)	—
Net cash provided by financing activities	20,623	4,812	39,427
Net (decrease) increase in cash and cash equivalents	(4,538)	1,727	(5,413)
Cash and cash equivalents			
Beginning of year	7,071	5,344	10,757
End of year	$2,533	$7,071	$5,344

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

Independence Contract Drilling, Inc.
Notes to Financial Statements

1. Nature of Operations and Recent Developments

Except as expressly stated or the context otherwise requires, the terms "we," "us," "our," "ICD," and the "Company" refer to Independence Contract Drilling, Inc.

We provide land-based contract drilling services for oil and natural gas producers targeting unconventional resource plays in the United States. We construct, own and operate a fleet comprised entirely of custom designed ShaleDriller rigs.

Our standardized fleet currently consists of 14 premium 200 Series ShaleDriller rigs, all of which are equipped with our integrated omni-directional walking system that is specifically designed to optimize pad drilling for our customers. Every rig in our fleet is a 1500-hp, AC programmable rig (“AC rig”) designed to be fast-moving between drilling sites and is equipped with 7500 psi mud systems, top drives, automated tubular handling systems and blowout preventer (“BOP”) handling systems. All of our rigs are equipped with bi-fuel capabilities that enable the rig to operate on either diesel or a natural gas-diesel blend.

Our first rig began drilling in May 2012. We currently focus our operations on unconventional resource plays located in geographic regions that we can efficiently support from our Houston, Texas facilities in order to maximize economies of scale. Currently, our rigs are operating in the Permian Basin, Eagle Ford Shale and the Haynesville Shale. Our rigs have previously operated in the Mid-Continent and Eaglebine regions.

Our business depends on the level of exploration and production activity by oil and natural gas companies operating in the United States, and in particular, the regions where we actively market our contract drilling services. The oil and natural gas exploration and production industry is a historically cyclical industry characterized by significant changes in the levels of exploration and development activities. Oil and natural gas prices and market expectations of potential changes in those prices significantly affect the levels of those activities. Worldwide political, regulatory, economic, and military events, as well as natural disasters have contributed to oil and natural gas price volatility historically, and are likely to continue to do so in the future. Any prolonged reduction in the overall level of exploration and development activities in the United States and the regions where we market our contract drilling services, whether resulting from changes in oil and natural gas prices or otherwise, could materially and adversely affect our business.

Oil and Natural Gas Prices and Drilling Activity

Both oil and natural gas prices began to decline in the second half of 2014, declined further during 2015 and remained low in 2016. The closing price of oil was as high as $106.06 per barrel during the third quarter of 2014, was $37.13 per barrel on December 31, 2015 and reached a low of $26.19 on February 11, 2016 (West Texas Intermediate - Cushing, Oklahoma (“WTI”) spot price as reported by the United States Energy Information Administration (the “EIA”)). Similarly, natural gas prices (as measured at Henry Hub) declined from an average of $4.37 per MMBtu in 2014, to $2.62 per MMBtu in 2015, and to $2.52 per MMBtu in 2016. As a result, our industry experienced an exceptional downturn and market conditions have only begun to stabilize and slowly recover.

In November 2016, Organization of Petroleum Exporting Countries (“OPEC”) members formally agreed to reduce their production quotas, starting January 1, 2017. These production cuts significantly reduced the overhang of global oil supplies. OPEC members met in December 2017 and agreed to extend the freeze into 2018, and are expected to meet again in June 2018 to review market conditions and the impact of their freeze on global supplies. In addition to OPEC members, certain non-OPEC producers such as Russia have agreed to production cuts, which has also supported crude oil and related energy commodity prices.

As a result of these supply cuts and positive demand trends, crude oil prices recovered to the $45 to $55 per barrel range, with WTI oil prices reaching a three-year high of $66.27 on January 26, 2018. Similarly, natural gas prices at Henry Hub averaged $2.99 per MMBtu in 2017, and have averaged $3.41 per MMBtu in 2018, as of February 20, 2018. While this continued recovery in pricing is promising, there are no indications at this time that oil and natural gas prices and rig counts will recover to their previous highs experienced in 2014.

As market conditions have improved from trough levels in 2016 and begun to stabilize higher, demand for our ShaleDriller rigs has improved. At December 31, 2017, all of our rigs were under contract. In addition to improving utilization, contract tenors are improving with customers willing to sign term contracts of six to twelve months or longer, and at higher dayrates compared to trough levels. However, the pace and duration of the current recovery is unknown, and if oil prices were to fall below $45 per barrel for any sustained period of time, market conditions and demand for our products and services could deteriorate.

Assets Held for Sale

During the fourth quarter of 2016, we began a review of our rig fleet and other capital equipment with a focus on opportunities to standardize certain rig components across our fleet. The standardization of this equipment creates operating efficiencies in maintaining this equipment, as well as efficiencies when crews transfer between rigs. As a result of our review, we identified several non-standard items which, while fully functional, were less than optimal from an operations perspective. We recorded a non-cash asset impairment charge of $3.8 million in the fourth quarter of 2016, to write down these assets to estimated fair value less estimated cost to sell. Such assets were classified as held for sale on our December 31, 2016 balance sheet. In the second quarter of 2017, we sold $1.6 million of these assets and recognized a loss on the sale of assets of $0.8 million. In the fourth quarter of 2017, we impaired the entire carrying value, or $1.0 million, related to certain of the assets held for sale, for which management currently believes there is substantial doubt that the third party manufacturer will service and warranty the equipment. As of December 31, 2017, the carrying value of drilling equipment in assets held for sale is $1.2 million.

During the second quarter of 2017, our management committed to a plan to sell our corporate headquarters and rig assembly yard complex located at 11601 North Galayda Street, Houston, Texas, in order to relocate to office space and a yard facility more suitable to our needs. As a result, we reclassified an aggregate $4.0 million of land, buildings and equipment from property, plant and equipment to assets held for sale on our balance sheet after recognizing a $0.5 million asset impairment charge representing the difference between the carrying value and the estimated fair value, less the estimated costs to sell the related property. In the third quarter of 2017, we recorded an additional asset impairment on the property, reducing assets held for sale, of $0.6 million, as a result of water related damage from the heavy rainfall that occurred during Hurricane Harvey in August 2017. As of December 31, 2017, the carrying value of the Galayda property in assets held for sale is $3.4 million.

Amendment of Credit Facility

In July 2017, we amended our existing amended and restated credit agreement ("the Credit Facility"). The Credit Facility amendment maintained the aggregate commitments under the facility at $85.0 million and extended the maturity date by two years to November 5, 2020. In addition, the amendment provided for an additional uncommitted $65.0 million accordion feature that allows for future increases in facility commitments.

Interest under the Credit Facility remains unchanged. The amendment contained various changes to the financial and other covenants to accommodate the extension in term, including changes to the leverage ratio covenant, fixed charge coverage ratio covenant and rig utilization ratio covenant.

2. Summary of Significant Accounting Policies

Basis of Presentation

These audited financial statements include all the accounts of ICD, and have been prepared in accordance with accounting principles generally accepted in the United States of America (“GAAP”). As we had no items of other comprehensive income in any period presented, no other comprehensive income is presented.

Cash and Cash Equivalents

We consider short-term, highly liquid investments that have an original maturity of three months or less to be cash equivalents.

Accounts Receivable

Accounts receivable is comprised primarily of amounts due from our customers for contract drilling services. Accounts receivable are reduced to reflect estimated realizable values by an allowance for doubtful accounts based on historical collection experience and specific review of current individual accounts. Receivables are written off when they are deemed to be uncollectible. The allowance for doubtful accounts totaled $8 thousand as of December 31, 2017 and 2016.

Inventories

Inventory is stated at lower of cost or market and consists primarily of supplies held for use in our drilling operations. Cost is determined on an average cost basis.

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Property, Plant and Equipment, net

Property, plant and equipment, including renewals and betterments, are stated at cost less accumulated depreciation. All property, plant and equipment are depreciated using the straight-line method based on the estimated useful lives of the assets. The cost of maintenance and repairs are expensed as incurred. Major overhauls and upgrades are capitalized and depreciated over their remaining useful life.

Depreciation of property, plant and equipment is recorded based on the estimated useful lives of the assets as follows:

	Estimated Useful Life
Buildings	20 - 39 years
Drilling rigs and related equipment	3 - 20 years
Machinery, equipment and other	3 - 7 years
Vehicles	2 - 5 years
Software	2 - 7 years

We own substantially all of our rig assembly yard and corporate offices located in Houston, Texas. We lease a number of vehicles and land for equipment and inventory storage. Leases are evaluated at inception or at any subsequent material modification to determine if the lease should be classified as a capital or operating lease.

We review our assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. The recoverability of assets that are held and used is measured by comparison of the estimated future undiscounted cash flows associated with the asset to the carrying amount of the asset. If the carrying value of such assets is less than the estimated undiscounted cash flow, an impairment charge is recorded in the amount by which the carrying amount of the assets exceeds their estimated fair value.

Construction in progress represents the costs incurred for drilling rigs that remain under construction at the end of the period. This includes third party costs relating to the purchase of rig components as well as labor, material and other identifiable direct and indirect costs associated with the construction of the rig.

Capitalized Interest

We capitalize interest costs related to rig construction projects. Interest costs are capitalized during the construction period based on the weighted average interest rate of the related debt. Capitalized interest amounted to $0.1 million, $0.1 million and $0.9 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Financial Instruments and Fair value

Fair value is a market-based measurement that should be determined based on assumptions that market participants would use in pricing an asset or liability. As a basis for considering such assumptions, there exists a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value as follows:

Level 1	Unadjusted quoted market prices for identical assets or liabilities in an active market;
Level 2	Quoted market prices for identical assets or liabilities in an active market that have been adjusted for items such as effects of restrictions for transferability and those that are not quoted but are observable through corroboration with observable market data, including quoted market prices for similar assets; and
Level 3	Unobservable inputs for the asset or liability only used when there is little, if any, market activity for the asset or liability at the measurement date

This hierarchy requires us to use observable market data, when available, and to minimize the use of unobservable inputs when determining fair value.

The carrying value of certain of our assets and liabilities, consisting primarily of cash and cash equivalents, accounts receivable and accounts payable, approximates their fair value due to the short-term nature of such instruments.

The fair value of our long-term debt is determined by Level 3 measurements based on quoted market prices and terms for similar instruments, where available, and on the amount of future cash flows associated with the debt, discounted using our current borrowing rate for comparable debt instruments (the Income Method). Based on our evaluation of the risk free rate, the market yield and credit spreads on comparable company publicly traded debt issues, we used an annualized discount rate,

including a credit valuation allowance, of 5.6%. The fair value of our lease obligations is determined using Level 3 measurements using our current incremental borrowing rate. The estimated fair value of our long-term debt totaled $50.6 million and $26.6 million as of December 31, 2017 and 2016, respectively, compared to a carrying amount of $49.3 million and $26.1 million as of December 31, 2017 and 2016, respectively. The fair value of our assets held for sale is determined using Level 3 measurements.

Fair value measurements are applied with respect to our non-financial assets and liabilities measured on a nonrecurring basis, which would consist of measurements primarily of long-lived assets. There were no transfers between levels of the hierarchy for the years ended December 31, 2017 and 2016.

Revenue and Cost Recognition

Our revenues are principally derived from contract drilling services. We record contract drilling revenue for daywork contracts daily as work progresses, assuming collectability is reasonably assured. Daywork drilling contracts provide that revenue is earned daily based on specified rates per day for various activities over the term of the contract, which can be for a specific period of time or a specified number of wells. We generally receive lump-sum payments for the mobilization of rigs and other drilling equipment at the commencement of a new drilling contract. Revenue and costs associated with the initial mobilization are deferred and recognized ratably over the term of the related drilling contract once the rig spuds. Costs incurred to relocate rigs and other equipment to an area in which a contract has not been secured are expensed as incurred. If a contract is terminated prior to the specified contract term, early termination payments received from the customer are only recognized as revenues when all contractual obligations, such as mitigation requirements, are satisfied. Reimbursements for the purchase of supplies, equipment, trucking and other services that are provided at the request of our customers are recorded as revenue when incurred. The related costs are recorded as operating expenses when incurred. Revenue is presented net of any sales tax charged to the customer that we are required to remit to local or state governmental taxing authorities.

Stock-Based Compensation

We record compensation expense over the applicable requisite service period for all stock-based compensation based on the grant date fair value of the award. The expense is included in selling, general and administrative expense in our statements of operations or capitalized in connection with rig construction activity.

Income Taxes

We use the asset and liability method of accounting for income taxes. Under this method, we record deferred income taxes based upon differences between the financial reporting basis and tax basis of assets and liabilities, and use enacted tax rates and laws that we expect will be in effect when we realize those assets or settle those liabilities. We review deferred tax assets for a valuation allowance based upon management’s estimates of whether it is more likely than not that a portion of the deferred tax asset will be fully realized in a future period.

We recognize the financial statement benefit of a tax position only after determining that the relevant taxing authority would more-likely-than-not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority.

Our policy is to include interest and penalties related to the unrecognized tax benefits within the income tax expense (benefit) line item in our statements of operations.

New tax legislation, commonly referred to as the Tax Cuts and Jobs Act, was enacted on December 22, 2017. ASC 740, Accounting for Income Taxes, requires companies to recognize the effect of tax law changes in the period of enactment even though the effective date for most provisions is for tax years beginning after December 31, 2017. Since our federal deferred tax asset was fully offset by a valuation allowance, the overall net adjustment to our tax provision in the three months ended December 31, 2017 due to the reduction in the U.S. corporate income tax rate to 21% did not materially affect our financial statements. Significant provisions that are not yet effective but may impact income taxes in future years include: the repeal of the corporate Alternative Minimum Tax, the limitation on the current deductibility of net interest expense in excess of 30% of adjusted taxable income for levered balance sheets, a limitation on utilization of net operating losses generated after tax year 2017 to 80% of taxable income, the unlimited carryforward of net operating losses generated after tax year 2017, temporary 100% expensing of certain business assets, additional limitations on certain general and administrative expenses, and changes in determining the excessive compensation limitation. Currently, we do not anticipate paying cash federal income taxes in the near term due to any of the legislative changes, primarily due to the availability of our net operating loss carryforwards. Future interpretations relating to the recently enacted U.S. federal income tax legislation which vary from our current interpretation and possible changes to state tax laws in response to the recently enacted federal legislation may have a significant effect on this projection.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make certain estimates and assumptions. These estimates and assumptions affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the balance sheet date, and the reported amounts of revenues and expenses recognized during the reporting period. Actual results could differ from these estimates. Significant estimates made by management include depreciation of property, plant and equipment, impairment of property, plant and equipment, and the collectibility of accounts receivable.

Other Matters

We have not elected to avail ourselves of the extended transition period available to emerging growth companies ("EGCs") as provided in Section 7(a)(2)(B) of the Securities Act of 1933, as amended, for complying with new or revised accounting standards, therefore, we will be subject to new or revised accounting standards at the same time as other public companies that are not EGCs.

Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board (the "FASB") issued Accounting Standards Update (“ASU”) No. 2014-09, Revenue from Contracts with Customers, followed by the issuance of certain additional related accounting standards updates (collectively codified in "ASC 606"), to provide guidance on the recognition of revenue from customers. Under ASC 606, an entity will recognize revenue, when it transfers promised goods or services to customers in an amount that reflects what it expects in exchange for the goods or services. ASC 606 also requires more detailed disclosures to enable users of the financial statements to understand the nature, amount, timing and uncertainty, if any, of revenue and cash flows arising from contracts with customers. We have substantially completed our evaluation of the impact ASC 606 will have on our financial statements. ASC 606 will not have a material impact on the timing of our revenue recognition, however, certain revenues and costs historically presented on a gross basis in our financial statements may be presented on a net basis. We adopted ASC 606 on January 1, 2018, utilizing the modified retrospective approach, which requires us to apply the new revenue standard to (i) all new revenue contracts entered into after January 1, 2018 and (ii) all existing revenue contracts as of January 1, 2018 through a cumulative effect adjustment to equity. In accordance with this approach, our revenues for periods prior to January 1, 2018 will not be adjusted. Given that ASC 606 will not impact the timing of our revenue recognition, no cumulative effect adjustment was required as of January 1, 2018. As mentioned above, certain of our reimbursable revenues may be presented on a net basis beginning as of January 1, 2018, depending on whether we are deemed to be the principal or the agent in the arrangement, which we will evaluate on a case by case basis. Our reimbursable revenues have historically been less than 3% of our total revenues.

In February 2016, the FASB issued ASU No. 2016-02, Leases, to establish the principles that lessees and lessors shall apply to report useful information to users of financial statements about the amount, timing, and uncertainty of cash flows arising from a lease. Under the new guidance, lessees will be required to recognize (with the exception of short-term leases) at the commencement date, a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and a right-of-use asset, which is an asset that represents the lessee’s right to use, or control the use of, a specified asset for the lease term. This guidance is effective for public companies for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early application is permitted for all public business entities. We are currently evaluating the impact this guidance will have on our financial statements and have engaged a third party consultant to assist us on this evaluation process.

In June 2016, the FASB issued ASU No. 2016-13, Financial Instruments - Credit Losses: Measurement of Credit Losses on Financial Instruments, as additional guidance on the measurement of credit losses on financial instruments. The new guidance requires the measurement of all expected credit losses for financial assets held at the reporting date based on historical experience, current conditions and reasonable supportable forecasts. In addition, the guidance amends the accounting for credit losses on available-for-sale debt securities and purchased financial assets with credit deterioration. The new guidance is effective for SEC filers for interim and annual periods beginning after December 15, 2019, with early adoption permitted for interim and annual periods beginning after December 15, 2018. We are in the initial stages of evaluating the impact this guidance will have on our accounts receivable.

In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows, to address diversity in how certain cash receipts and cash payments are presented and classified in the statement of cash flows. The update addresses the following eight specific cash flow issues: Debt prepayment or debt extinguishment costs; settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies (COLIs) (including bank-owned life insurance policies (BOLIs)); distributions received from equity method investees; beneficial interests in securitization transactions; and separately identifiable cash flows and application of the predominance principle. The amendments are effective for public business entities for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. Early adoption is permitted, including adoption in an interim period. We expect the implementation of this standard to change the classification of the described transactions within our statement of cash flows.

3. Inventories

Inventories consisted of the following:

	December 31,	
(in thousands)	2017	2016
Rig components and supplies	$2,710	$2,336

We determined that no reserve for obsolescence was needed at December 31, 2017 or 2016. No inventory obsolescence expense was recognized during the years ended December 31, 2017, 2016 and 2015.

4. Property, Plant and Equipment

Major classes of property, plant, and equipment, which include capital lease assets, consisted of the following (in millions):

	December 31,	
(in thousands)	2017	2016
Land	$—	$1,344
Buildings	—	4,206
Drilling rigs and related equipment	332,338	294,002
Machinery, equipment and other	1,246	1,571
Capital leases	1,786	1,129
Vehicles	555	405
Software	818	806
Construction in progress	20,706	31,974
Total	$357,449	$335,437
Less: Accumulated depreciation	(85,061)	(62,249)
Total Property, plant and equipment, net	$272,388	$273,188

Repairs and maintenance expense included in operating costs in our statements of operations totaled $14.3 million, $7.7 million and $10.5 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Depreciation expense was $25.8 million, $23.8 million and $21.2 million for the years ended December 31, 2017, 2016 and 2015, respectively.

As of December 31, 2017, property, plant and equipment in our balance sheets included $1.3 million of vehicles under capital lease, which is net of $0.5 million of accumulated amortization. As of December 31, 2016, property, plant and equipment in our balance sheets included $0.8 million of vehicles under capital lease, net of $0.3 million of accumulated amortization.

During 2017, our management committed to a plan to sell our corporate headquarters and rig assembly yard complex in order to relocate to office space and a yard facility more suitable to our needs. As a result, we reclassified an aggregate $4.0 million of land, buildings and equipment from property, plant and equipment to assets held for sale on our balance sheet, after recognizing a $0.5 million asset impairment charge representing the difference between the carrying value and the fair value, less the costs to sell the related property. In the third quarter of 2017, we recorded an additional asset impairment on the property, reducing assets held for sale, of $0.6 million, as a result of water related damage from the heavy rainfall that occurred during Hurricane Harvey in August 2017.

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During 2017 and 2016, we recorded an additional $0.8 million and $1.8 million, respectively, loss on disposal associated with the upgrade of the mud systems on our rigs to high pressure status.

During 2015, we began to convert one of our non-walking rigs to pad optimal status, equipped with our 200 Series substructure, omni-directional walking system and 7500psi mud system. As part of this rig conversion, key components of the prior rig were decommissioned and replaced, including the rig's substructure and various mud system components which were no longer compatible with the converted rig. As a result, we recorded a preliminary estimate of the related disposal loss totaling $2.5 million.

During 2015, we recorded an impairment charge of $3.6 million relating to the substructure, mast and various other rig components of our last remaining non-walking rig due to its limited marketability in its current configuration given market conditions.

5. Supplemental Balance Sheet and Cash Flow Information

Accrued liabilities consisted of the following:

	December 31,	
(in thousands)	2017	2016
Accrued salaries and other compensation [1]	$2,646	$3,784
Insurance	507	787
Deferred revenues	762	1,139
Property, sales and other tax	2,693	1,943
Other	361	168
	$6,969	$7,821

(1) In June 2016, our President and Chief Operating Officer announced his retirement as an officer and director of ICD effective June 30, 2016. In connection with his retirement, we entered into a Retirement Agreement on June 9, 2016 (the “Retirement Agreement”), setting out certain terms and conditions governing the executive’s retirement. Under the terms of the Retirement Agreement, we agreed to make certain retirement benefits available to the executive, including a cash retirement payment of approximately $1.5 million which was paid in one lump sum on January 3, 2017 and accelerated vesting of certain outstanding equity awards. The retirement payment was recorded as accrued salaries in our balance sheet and as selling, general and administrative expense in our statements of operations as of and for the year ended December 31, 2016.

Supplemental cash flow information:

	Year Ended December 31,		
(in thousands)	2017	2016	2015
Supplemental disclosure of cash flow information			
Cash paid during the year for interest	$2,680	$2,198	$3,173
Cash (received) paid during the year for taxes	—	(133)	22
Supplemental disclosure of non-cash investing and financing activities			
Stock-based compensation capitalized as property, plant and equipment	—	—	654
Change in property, plant and equipment purchases in accounts payable	(882)	1,670	(14,750)
Additions to property, plant & equipment through capital leases	1,102	1,293	—

6. Long-term Debt

Our Long-term Debt consisted of the following:

	December 31,	
(in thousands)	2017	2016
Credit Facility due November 5, 2020	$48,541	$25,752
Capital lease obligations	1,270	767
	49,811	26,519
Less: current portion	(533)	(441)
Long-term debt	$49,278	$26,078

Credit Facility

In November 2014, we entered into our Credit Facility with a syndicate of financial institutions led by CIT Finance, LLC, that provided for a committed $155.0 million Credit Facility and an additional uncommitted $25.0 million accordion feature that allowed for future increases in the facility. In 2015, we amended the Credit Facility to provide for a springing lock-box arrangement and, in light of market conditions and our reduced capital plans, reduce aggregate commitments to $125.0 million and modify certain maintenance covenants. In 2016, we amended the Credit Facility to reduce aggregate commitments to $85.0 million and further modify certain maintenance covenants. In connection with this amendment, we expensed certain previously deferred debt issuance costs totaling $0.5 million reflecting the reduction in borrowing capacity. In 2017, we amended the Credit Facility to extend the maturity date by two years to November 5, 2020 and provide for an additional uncommitted $65.0 million accordion feature that allows for future increases in facility commitments.

Interest under the Credit Facility remains unchanged. The amendment contained various changes to the financial and other covenants to accommodate the extension in term, including changes to the leverage ratio covenant, fixed charge coverage ratio covenant and rig utilization ratio covenant.

The obligations under the Credit Facility are secured by all of our assets and are unconditionally guaranteed by all of our current and future direct and indirect subsidiaries.

Borrowings under the Credit Facility are subject to a borrowing base formula that allows for borrowings of up to 85% of eligible trade accounts receivable not more than 90 days outstanding, plus up to a certain percentage, the "advance rate", of the appraised forced liquidation value of our eligible, completed and owned drilling rigs. As of December 31, 2017, the advance rate was 73.75%. The advance rate declines 1.25% each quarter beginning January 1, 2018 through June 2019. Thereafter, through the maturity date, the advance rate remains at 65.0%. Rigs that remain idle for 90 consecutive days or longer are removed from the borrowing base until they are contracted. In addition, rigs are appraised two times a year and are subject to upward or downward revisions as a result of market conditions as well as the age of the rig.

At our election, interest under the Credit Facility is determined by reference at our option to either (i) the London Interbank Offered Rate (“LIBOR”), plus 4.5% or (ii) a “base rate” equal to the higher of the prime rate published by JP Morgan Chase Bank or three-month LIBOR plus 1%, plus in each case, 3.5%, the federal funds effective rate plus 0.05%. We also pay, on a quarterly basis, a commitment fee of 0.50% per annum on the unused portion of the Credit Facility commitment. As of December 31, 2017, the weighted average interest rate on our borrowings was 6.04%.
The amended Credit Facility contains various financial covenants including a leverage covenant, springing fixed charge coverage ratio and rig utilization ratio. Additionally, there are restrictive covenants that limit our ability to, among other things: incur or guarantee additional indebtedness or issue disqualified capital stock; transfer or sell assets; pay dividends or distributions; redeem subordinated indebtedness; make certain types of investments or make other restricted payments; create or incur liens; consummate a merger; consolidation or sale of all or substantially all assets; and engage in business other than a business that is the same or similar to the current business and reasonably

related businesses. The Credit Facility does, however, permit us to incur up to $20.0 million of additional indebtedness for the purchase of additional rigs or rig equipment. As of December 31, 2017, we are in compliance with these covenants.

Under the Credit Agreement, as amended, for purposes of calculating EBITDA, non-cash stock-based compensation is added back to EBITDA, as well as up to $2.0 million per year of previously capitalized construction costs that was incurred in 2017.

The Credit Facility provides that an event of default may occur if a material adverse change to ICD occurs, which is considered a subjective acceleration clause under applicable accounting rules. In accordance with ASC 470-10-45, because of the existence of this clause, borrowings under the Credit Facility will be required to be classified as current in the event the springing lock-box event occurs, regardless of the actual maturity of the borrowings. The Fourth Amendment reduced the requirement for a mandatory lock-box trigger from $15.0 million of availability under the Credit Facility to $10.0 million of availability under the Credit Facility.

We had $48.5 million in outstanding borrowings under the Credit Facility at December 31, 2017. Remaining availability of our $85.0 million commitment under the Credit Facility was $36.5 million at December 31, 2017.

Capital Lease Obligations

During the first quarter of 2016, our vehicle lease agreements were amended, which resulted in a change in the classification of certain leases from operating leases to capital leases. On the amendment date we recorded $0.8 million in capital lease obligations, representing the lesser of fair market value or the present value of future minimum lease payments on the conversion date. These leases generally have initial terms of 36 months and are paid monthly.

7. Income Taxes

The components of the income tax benefit are as follows:

	Year Ended December 31,		
(in thousands)	2017	2016	2015
Current:			
Federal	$—	$—	$—
State	—	(1)	(518)
	$—	$(1)	$(518)
Deferred:			
Federal	$—	$—	$—
State	287	203	193
	$287	$203	$193
Income tax expense (benefit)	$287	$202	$(325)

The following is a reconciliation of the income tax benefit that was recorded compared to taxes provided at the United States statutory rate:

	Year Ended December 31,		
(in thousands)	2017	2016	2015
Income tax benefit at the statutory federal rate (35%)	$(8,404)	$(7,691)	$(2,871)
Effect of federal rate change to ending deferred tax assets and liabilities	7,994	—	—
Nondeductible expenses	34	23	148
Valuation allowance	(1,377)	7,063	2,261
State taxes, net of federal benefit	9	204	(211)
Stock-based compensation and other	2,031	603	348
Income tax expense (benefit)	$287	$202	$(325)
Effective tax rate	1.2 %	0.9 %	4.0 %

Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of our deferred tax assets and liabilities are as follows:

	December 31,	
(in thousands)	2017	2016
Deferred income tax assets		
Bad debts	$2	$3
Stock-based compensation	1,344	3,050
Accrued liabilities and other	29	49
Deferred revenue	180	413
Net operating losses	29,274	31,130
Total net deferred tax assets	$30,829	$34,645
Deferred income tax liabilities		
Prepaids	$(210)	$(378)
Property, plant and equipment	(18,906)	(20,890)
Total net deferred tax liabilities	$(19,116)	$(21,268)
Valuation allowance	$(12,396)	$(13,773)
Net deferred tax liability	$(683)	$(396)

As of December 31, 2017, the Company had a total of $131.5 million of net operating loss carryforwards, which begin to expire in 2031.

On December 22, 2017, the United States enacted tax reform legislation commonly known as the Tax Cuts and Jobs Act (the “Act”), resulting in significant modifications to existing law. The Company has completed the accounting for the effects of the Act during 2017. Our financial statements for the year ended December 31, 2017, reflect the effects of the Act which includes a reduction in the corporate tax rate from 35% to 21%. Accordingly, our deferred tax assets and liabilities were revalued at the newly enacted rates expected to be effective in 2018 and forward. Since our federal deferred tax asset was fully offset by a valuation allowance, the overall net adjustment to our tax provision in the three months ended December 31, 2017 due to the reduction in the U.S. corporate income tax rate to 21% did not materially affect our financial statements.

Section 382 of the Internal Revenue Code (“Section 382”) imposes limitations on a corporation’s ability to utilize its NOLs if it experiences an ownership change. In general terms, an ownership change may result from transactions increasing the ownership percentage of certain shareholders in the stock of the corporation by more than 50 percentage points over a three year period. In the event of an ownership change, utilization of the NOLs would be subject to an annual limitation under Section 382. The Company believes it incurred an ownership change in April 2016. The Company is subject to an annual limitation on the usage of its NOL, however, the Company also believes that the entire NOL that existed in April 2016 will be fully available to the Company over the life of the NOL carryforward period. Management will continue to monitor the potential impact of Section 382 with respect to its NOL carryforward.

Accounting for uncertainty in income taxes prescribes a recognition threshold and measurement methodology for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. As of December 31, 2017, we had no unrecognized tax benefits. We file income tax returns in the United States and in various state jurisdictions. With few exceptions, we are subject to United States federal, state and local income tax examinations by tax authorities for tax periods 2012 and forward. Our federal and state tax returns for 2012 and subsequent years remain subject to examination by tax authorities. Although we cannot predict the outcome of future tax examinations, we do not anticipate that the ultimate resolution of these examinations will have a material impact on our financial position, results of operations, or cash flows.

In assessing the realizability of the deferred tax assets, we consider whether it is more likely than not that some or all of the deferred tax assets will not be realized. The ultimate realization of the deferred tax assets is dependent upon the generation of future income in periods in which the deferred tax assets can be utilized. In all years presented, we determined that the deferred tax assets did not meet the more likely than not threshold of being utilized and thus recorded a valuation allowance. All of our deferred tax liability as of December 31, 2017 relates to state taxes.

Estimated interest and penalties related to potential underpayment on any unrecognized tax benefits are classified as a component of tax expense in the statement of operations. We have not recorded any interest or penalties associated with unrecognized tax benefits.

8. Stock-Based Compensation

In March 2012, we adopted the 2012 Omnibus Long-Term Incentive Plan (the “2012 Plan”) providing for common stock-based awards to employees and to non-employee directors. The 2012 plan was subsequently amended in August 2014 and June 2016. The 2012 Plan, as amended, permits the granting of various types of awards, including stock options, restricted stock and restricted stock unit awards, and up to 4,754,000 shares were authorized for issuance. Restricted stock and restricted stock units may be granted for no consideration other than prior and future services. The purchase price per share for stock options may not be less than the market price of the underlying stock on the date of grant. Stock options expire ten years after the grant date. We have the right to satisfy option exercises from treasury shares and from authorized but unissued shares. As of December 31, 2017, approximately 1,740,917 shares were available for future awards.

In the first quarter of 2017, we adopted ASU 2016-09, Compensation - Stock Compensation: Improvements to Employee Share-Based Payment Accounting. The FASB issued this accounting standard in an effort to simplify the accounting for employee share-based payments and improve the usefulness of the information provided to users of financial statements. Our policy is to account for forfeitures of share-based compensation awards as they occur.

A summary of compensation cost recognized for stock-based payment arrangements is as follows:

	Year Ended December 31,		
(in thousands)	2017	2016	2015
Compensation cost recognized:			
Stock options	$—	$81	$430
Restricted stock and restricted stock units	3,565	4,101	3,766
Total stock-based compensation	$3,565	$4,182	$4,196

There was no stock-based compensation capitalized in connection with rig construction activity during the years ended December 31, 2017 and 2016, and approximately $0.7 million in stock-based compensation was capitalized in connection with rig construction activity during the year ended December 31, 2015.

Stock Options

Certain options were granted on March 2, 2012 and began vesting on their date of grant, with 25% of such options vesting on the grant date, and 25% of such options vesting on each anniversary thereafter until fully vested on March 2, 2015. A subsequent grant of 15,700 options was made in August 2012, one third of which vest on each anniversary of the grant date over three years. In December 2012, we granted an additional 229,613 stock options that vest over five years in three equal tranches commencing on the third year anniversary date and each year thereafter. In February 2013, we granted an additional 119,320 stock options that vest over four years. No stock options were granted during the years ended December 31, 2017, 2016 or 2015.

No options were exercised during the years ended December 31, 2017, 2016 or 2015. It is our policy that in the future any shares issued upon option exercise will be issued initially from any available treasury shares or otherwise as newly issued shares.

We use the Black-Scholes option pricing model to estimate the fair value of stock options granted to employees and non-employee directors. The fair value of the options is amortized to compensation expense on a straight-line basis over the requisite service periods of the stock awards, which are generally the vesting periods.

The following summary reflects the stock option activity and related information for the year ended December 31, 2017:

	Options	Weighted Average Exercise Price
Outstanding at January 1, 2017	935,720	$ 12.74
Granted	—	—
Exercised	—	—
Forfeited/expired	(252,770)	12.74
Outstanding at December 31, 2017	682,950	$ 12.74
Exercisable at December 31, 2017	682,950	$ 12.74

The number of options exercisable at December 31, 2017 was 682,950 with a weighted average remaining contractual life of 4.3 years and a weighted-average exercise price of $12.74 per share.

As of December 31, 2017, there was no unrecognized compensation cost related to outstanding stock options. The fair value of options that vested during the years ended December 31, 2017, 2016 and 2015 was zero, $0.4 million and $1.1 million, respectively.

Restricted Stock

Restricted stock awards consist of grants of our common stock that vest ratably over three to four years. We recognize compensation expense on a straight-line basis over the vesting period. The fair value of restricted stock awards is determined based on the estimated fair market value of our shares on the grant date. As of December 31, 2017, there was no unrecognized compensation cost related to unvested restricted stock awards.

A summary of the status of our restricted stock awards and of changes in restricted stock outstanding for the year ended December 31, 2017 is as follows:

	Shares	Weighted Average Grant Date Fair Value Per Share
Outstanding at January 1, 2017	147,368	$ 10.67
Granted	—	—
Vested	(144,173)	10.72
Forfeited/expired	(3,195)	8.35
Outstanding at December 31, 2017	—	$ —

Restricted Stock Units

We have granted restricted stock units ("RSUs") to key employees under the 2012 Plan. We have granted three-year time vested RSUs, as well as performance-based and market-based RSUs, where each unit represents the right to receive, at the end of a vesting period, up to two shares of ICD common stock with no exercise price. Exercisability of the market-based RSUs is based on our total shareholder return ("TSR") as measured against the TSR of a defined peer group and vesting of the performance-based RSUs is based on our cumulative EBITDA, safety or uptime performance statistics, as defined in the restricted stock unit agreement, over a three year period. We used a Monte Carlo simulation model to value the TSR market-based RSUs. The fair value of the performance-based RSUs is based on the market price of our common stock on the date of grant. During the restriction period, the RSUs may not be transferred or encumbered, and the recipient does not receive dividend equivalents or have voting rights until the units vest. As of December 31, 2017, there was $2.9 million of total unrecognized compensation cost related to unvested RSUs. This cost is expected to be recognized over a weighted-average period of 0.9 years.

No RSUs were issued during the year ended December 31, 2015.

The assumptions used to value our TSR market-based RSUs granted during the year ended December 31, 2016 were a a risk-free interest rate of 0.93%, an expected volatility of 56.3% and an expected dividend yield of 0.0%. Based on the Monte Carlo simulation, these RSUs were valued at $4.15.
The assumptions used to value our TSR market-based RSUs granted during the year ended December 31, 2017 were a a risk-free interest rate of 1.30%, an expected volatility of 55.5% and an expected dividend yield of 0.0%. Based on the Monte Carlo simulation, these RSUs were valued at $5.62.
A summary of the status of our RSUs as of December 31, 2017, and of changes in RSUs outstanding during the year ended December 31, 2017, is as follows:

	RSUs	Weighted Average Grant-Date Fair Value Per Share
Outstanding at January 1, 2017	1,030,658	$ 7.18
Granted	656,631	5.76
Vested and converted	(350,895)	8.45
Forfeited/expired	(343,074)	9.14
Outstanding at December 31, 2017	993,320	$ 5.11

9. Stockholders' Equity and Loss per Share
As of December 31, 2017, we had a total of 37,985,225 shares of common stock, $0.01 par value, outstanding, including zero shares of restricted stock. We also had 261,694 shares held as treasury stock. Total authorized common stock is 100,000,000 shares.
On April 26, 2016, we completed an underwritten public offering of 13,225,000 shares of common stock at a price to the public of $3.50 per share. We received net proceeds of approximately $42.9 million, after deducting underwriting discounts and commissions and offering expenses.
Basic earnings (loss) per common share ("EPS") are computed by dividing income (loss) available to common stockholders by the weighted-average number of common shares outstanding for the period. Diluted EPS reflects the potential dilution that would occur if securities or other contracts to issue common stock were exercised or converted into common stock. A reconciliation of the numerators and denominators of the basic and diluted losses per share computations is as follows:

	For the Years Ended December 31,		
(in thousands, except for per share data)	2017	2016	2015
Net loss (numerator)	$(24,298)	$(22,178)	$(7,880)
Loss per share:			
Basic and diluted	$(0.64)	$(0.67)	$(0.33)
Shares (denominator):			
Weighted-average number of shares outstanding-basic	37,762	33,118	23,904
Net effect of dilutive stock options, warrants and restricted stock units	—	—	—
Weighted-average common shares outstanding-diluted	37,762	33,118	23,904

For all years presented, the computation of diluted loss per share excludes the effect of certain outstanding stock options, warrants and restricted stock units because their inclusion would be anti-dilutive. The number of options that were excluded from diluted loss per share were 682,950, 935,720, and 956,653 during the years ended December 31, 2017, 2016 and 2015, respectively. A warrant to purchase 2,198,000 shares of our common stock was anti-dilutive in the year ended December 31, 2015 and expired unexercised March 31, 2015. RSUs, which are not participating securities and are excluded from our diluted loss per share because they are anti-dilutive were 993,320, 1,030,658 and 463,413 for the years ended December 31, 2017, 2016 and 2015, respectively.

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10. Segment and Geographical Information
We report one segment because all of our drilling operations are all located in the United States and have similar economic characteristics. We build rigs and engage in land contract drilling for oil and natural gas in the United States. Corporate management administers all properties as a whole rather than as discrete operating segments. Operational data is tracked by rig; however, financial performance is measured as a single enterprise and not on a rig-by-rig basis. Allocation of capital resources is employed on a project-by-project basis across our entire asset base to maximize profitability without regard to individual areas.
11. Commitments and Contingencies
Purchase Commitments
As of December 31, 2017, we had outstanding purchase commitments to a number of suppliers totaling $3.7 million related primarily to the construction of drilling rigs. We have paid deposits of $0.8 million related to these commitments.
Lease Commitments
We lease certain land, equipment and vehicles under non-cancelable operating and capital leases. Future minimum lease payments under operating and capital lease commitments, with lease terms in excess of one year subsequent to December 31, 2017, were as follows:

(in thousands)	
2018	$759
2019	627
2020	306
Thereafter	—
	$1,692

Rent expense was $3.9 million, $2.3 million, and $3.6 million for the years ended December 31, 2017, 2016 and 2015, respectively.
Employment Agreements
We have entered into employment agreements with two key executives, with original terms of three years, that automatically extend a year prior to expiration, provided that neither party has provided a written notice of termination before that date. These agreements provide for aggregate minimum annual cash compensation of $0.8 million and aggregate cash severance payments totaling $2.9 million for termination by ICD without cause, or termination by the employee for good reason, both as defined in the agreements.
Contingencies
Our operations inherently expose us to various liabilities and exposures that could result in third party lawsuits, claims and other causes of action. While we insure against the risk of these proceedings to the extent deemed prudent by our management, we can offer no assurance that the type or value of this insurance will meet the liabilities that may arise from any pending or future legal proceedings related to our business activities. There are no current legal proceedings that we expect will have a material adverse impact on our financial statements.
12. Concentration of Market and Credit Risk
We derive all our revenues from drilling services contracts with companies in the oil and natural gas exploration and production industry, a historically cyclical industry with levels of activity that are significantly affected by the levels and volatility in oil and natural gas prices. We have a number of customers that account for 10% or more of our revenues. For 2017, these customers included GeoSouthern Energy Corporation (33%), Devon Energy (17%), RSP Permian, LLC (16%) and Pioneer Natural Resources USA, Inc. (11%). For 2016, these customers included Parsley Energy, LP (22%), Silver Hill Energy Partners, LLC (17%), Pioneer Natural Resources USA, Inc. (16%) and Anadarko Petroleum Corporation (11%). For 2015, these customers included Parsley Energy, LP (18%), Pioneer Natural Resources USA, Inc. (18%), Laredo Petroleum, Inc. (14%), COG Operating, LLC, a subsidiary of Concho Resources, Inc. (13%) and Elevation Resources, LLC (11%).
As of December 31, 2017, GeoSouthern Energy Corporation (25%), Devon Energy (20%), RSP Permian, LLC (19%), BHP Billiton Petroleum (15%) and Pioneer Natural Resources USA, Inc. (14%) accounted for 10% or more of our accounts

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receivable. As of December 31, 2016, Parsley Energy, LP (20%), Pioneer Natural Resources USA, Inc. (19%), GEP Haynesville, LLC (17%), Energen Corporation (16%), Anadarko Petroleum Corporation (14%) and Silver Hill Energy Partners, LLC (14%) accounted for 10% or more of our accounts receivable. As of December 31, 2015, Devon Energy Corporation (27%), Parsley Energy LP (18%), Pioneer Natural Resources USA, Inc. (17%) and Anadarko Petroleum Corporation (13%) accounted for 10% or more of our accounts receivable.

We compete with large national and multi-national companies that have longer operating histories, greater financial, technical and other resources and greater name recognition than ICD. Our results of operations, cash flows and financial condition may be affected by these factors. Additionally, these factors could impact our ability to obtain additional debt and equity capital required to implement our rig construction and growth strategy, and the cost of that capital.

We have concentrated credit risk for cash by maintaining deposits in major banks, which may at times exceed amounts covered by insurance provided by the United States Federal Deposit Insurance Corporation ("FDIC"). We monitor the financial health of the banks and have not experienced any losses in such accounts and believe we are not exposed to any significant credit risk. As of December 31, 2017, we had approximately $1.9 million in cash and cash equivalents in excess of FDIC limits. Our trade receivables are with a variety of E&P and other oilfield service companies. We perform ongoing credit evaluations of our customers, and we generally do not require collateral. We do occasionally require deposits from customers whose creditworthiness is in question prior to providing services to them.

13. Unaudited Quarterly Financial Data

A summary of our unaudited quarterly financial data is as follows:

	Year Ended December 31, 2017			
	Quarter Ended			
(in thousands, except for per share data)	March 31	June 30	September 30	December 31
Revenue	$20,236	$21,285	$23,445	$25,041
Operating loss	(5,593)	(5,584)	(5,178)	(4,673)
Income tax expense	46	34	30	177
Net loss	(6,269)	(6,304)	(5,980)	(5,745)
Loss per share:				
Basic and diluted	$(0.17)	$(0.17)	$(0.16)	$(0.15)

	Year Ended December 31, 2016			
	Quarter Ended			
(in thousands, except for per share data)	March 31	June 30	September 30	December 31
Revenue	$22,455	$15,155	$14,464	$17,988
Operating income (loss)	567	(3,101)	(6,710)	(9,687)
Income tax expense	4	31	32	135
Net loss	(414)	(4,191)	(7,198)	(10,375)
Loss per share:				
Basic and diluted	$(0.02)	$(0.12)	$(0.19)	$(0.28)

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS

(in thousands)	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Balance at End of Period
Year Ended December 31, 2017:				
Allowance for doubtful accounts	$ 8	$—	$ —	$8
Valuation allowance for deferred tax assets	$ 13,773	$(1,377)	$ —	$12,396
Year Ended December 31, 2016:				
Allowance for doubtful accounts	$ 8	$—	$ —	$8
Valuation allowance for deferred tax assets	$ 6,710	$7,063	$ —	$13,773
Year Ended December 31, 2015:				
Allowance for doubtful accounts	$ 129	$132	$ (253)	$8
Valuation allowance for deferred tax assets	$ 4,449	$2,261	$ —	$6,710

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of the end of the period covered by this Form 10-K. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our 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. Our principal executive officer and principal financial officer have concluded that our current disclosure controls and procedures were effective as of December 31, 2017 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

During the most recent fiscal quarter, there have been no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management’s Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as that term is defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Our management, under the supervision of and with the participation of our Chief Executive Officer and Chief Financial Officer, conducted an evaluation of our internal control over financial reporting as of December 31, 2017. In making this assessment, management used the criteria set forth in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the 2013 framework). Based on this assessment using this criteria, our management determined that our internal control over financial reporting was effective as of December 31, 2017.

Attestation Report of the Independent Registered Public Accounting Firm

Pursuant to the provisions of the JOBS Act, this Annual Report on Form 10-K does not include an attestation report of our independent registered public accounting firm as we are an “emerging growth company.”

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Pursuant to General Instruction G to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2018 Annual Meeting of Shareholders, which will be filed with the SEC within 120 business days of December 31, 2017.

Our board of directors has adopted a Code of Business Conduct and Ethics, which applies to all our officers and employees, a Code of Ethics for Senior Officers of the Company and a Code of Business Conduct and Ethics for Directors, which applies to all our directors. A copy of each of these codes of business conduct and ethics is available on our website at http://icdrilling.investorroom.com. Stockholders may also request a printed copy of either code of business conduct and ethics, free of charge, by contacting us at Independence Contract Drilling, Inc., 11601 N. Galayda Street, Houston, TX 77086 or by telephone at (281) 598-1230 or by emailing Investor.relations@icdrilling.com. Any waiver of any of the codes of business conduct and ethics for executive officers or directors may be made only by our Board or a Board committee to which the Board has delegated that authority and will be promptly disclosed to our stockholders as required by applicable United States federal securities laws and the corporate governance rules of the NYSE. Amendments to either code of business conduct and ethics must be approved by our Board and will be promptly disclosed (other than technical, administrative or non-substantive changes) on our website.

ITEM 11. EXECUTIVE COMPENSATION

Pursuant to General Instruction G to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2018 Annual Meeting of Shareholders, which will be filed with the SEC within 120 business days of December 31, 2017.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Pursuant to General Instruction G to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2018 Annual Meeting of Shareholders, which will be filed with the SEC within 120 business days of December 31, 2017.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Pursuant to General Instruction G to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2018 Annual Meeting of Shareholders, which will be filed with the SEC within 120 business days of December 31, 2017.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Pursuant to General Instruction G to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2018 Annual Meeting of Shareholders, which will be filed with the SEC within 120 business days of December 31, 2017.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) List of filed documents:

(1) Financial Statements

Our Financial Statements and accompanying footnotes are included under Part II, "Item 8. Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

(2) Financial Statement Schedules

Schedule II - Valuation and Qualifying Accounts is included under Part II, "Item 8. Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

(3) Exhibits

The exhibits required by Item 601 of Regulation S-K are listed in subparagraph (b) below.

(b) Exhibits

The exhibits required to be filed pursuant to the requirements of Item 601 of Regulation S-K are set forth in the Exhibit Index accompanying this Annual Report on Form 10-K and are incorporated herein by reference.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this Annual Report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized.

INDEPENDENCE CONTRACT DRILLING, INC.

Date: February 26, 2018 By: /s/ Byron A. Dunn
Name: Byron A. Dunn
Title: President, Chief Executive Officer and Director (Principal Executive Officer)

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Byron A. Dunn and Philip A. Choyce, and each of them, as his true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite or necessary to be done in connection therewith, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report on Form 10-K has been signed by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date:		
February 26, 2018	By: /s/ Byron A. Dunn	
	Name:	Byron A. Dunn
	Title:	President, Chief Executive Officer and Director (Principal Executive Officer)
February 26, 2018	By: /s/ Philip A. Choyce	
	Name:	Philip A. Choyce
	Title:	Executive Vice President, Chief Financial Officer, Treasurer and Secretary (Principal Financial Officer)
February 26, 2018	By: /s/ Michael J. Harwell	
	Name:	Michael J. Harwell
	Title:	Vice President - Finance and Chief Accounting Officer (Principal Accounting Officer)
February 26, 2018	By: /s/ Thomas R. Bates, Jr.	
	Name:	Thomas R. Bates, Jr.
	Title:	Director
February 26, 2018	By: /s/ James D. Crandell	
	Name:	James D. Crandell

Title: Director

February 26, 2018	By:	/s/ Matthew D. Fitzgerald
	Name:	Matthew D. Fitzgerald
	Title:	Director
February 26, 2018	By:	/s/ Daniel F. McNease
	Name:	Daniel F. McNease
	Title:	Director
February 26, 2018	By:	/s/ Tighe A. Noonan
	Name:	Tighe A. Noonan
	Title:	Director

Glossary of Oil and Natural Gas Terms

Glossary of Oil and Natural Gas Terms

AC programmable rig	An AC electric rig with programmable controls.
Basin	A large depression on the Earth's surface in which sediments accumulate and may be a source of oil and natural gas.
Blowout	An uncontrolled flow of reservoir fluids into the wellbore, and in extreme cases to the surface.
BOP	Blowout preventer; a large valve at the top of a well that may be closed to prevent a loss of pressure.
Completion	The process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, abandonment.
Cratering	Caving in of a well that has already been drilled.
Dayrate	The daily fee paid to the drilling contractor, which includes the cost of renting the drilling rig.
Daywork contract	A contract under which the drilling contractor is paid a certain price or rate for work performed as requested by the operator over a 24-hour period, with the price determined by the location, depth and complexity of the well to be drilled, operating conditions, the duration of the contract and the competitive forces of the market.
E&P	Exploration and production.
GHG	Greenhouse gases.
Horizontal drilling	A subset of the more general term "directional drilling," used where the departure of the wellbore from vertical exceeds about 80 degrees.
Hp	Horsepower.
Hydraulic fracturing	A stimulation treatment routinely performed on oil and natural gas wells in low permeability reservoirs.
Pad	Location where well operators perform drilling operations on multiple wells from a single drilling site.
Reservoir	A subsurface body of rock having sufficient permeability to store and transmit fluids.
Rig down	To take apart equipment for storage and portability of the rig.
Rig up	To prepare and assemble the drilling rig for drilling; and to install tools and machinery before drilling is started.
Top drive	A device that turns the drillstring while suspended from the derrick above the rig floor.
Unconventional resource	A term for oil and natural gas that is produced from lower permeability reservoirs by unconventional means, such as horizontal drilling and multistage fracturing.
Utilization	Rig utilization percentage is calculated as rig operating days divided by the total number of days our drilling rigs are available in the applicable period.

Walking rig	A land drilling rig that is capable of lifting legs through hydraulic lifts and moving to a nearby location without having to rig down and disassembling the rig. A “multi-directional” or “omni-directional” walking rig has the ability to walk on either the X or Y axis. A “walking” rig is technologically superior to a “skidding” rig, which requires disconnecting the rig and engaging hydraulic cylinders to push the rig across steel skid beams.
Wellbore	The hole drilled by the bit that is equipped for oil or natural gas production on a completed well. Also called well or borehole.

EXHIBIT INDEX

Exhibit Number	Document Description	Incorporated by Reference Herein
3.1	Amended and Restated Certificate of Incorporation of Independence Contract Drilling, Inc.	Incorporated herein by reference to Exhibit 3.1 of the Current Report on Form 8-K filed by Independence Contract Drilling, Inc. on August 13, 2014 (File No. 001-36590)
3.2	Amended and Restated Bylaws of Independence Contract Drilling	Incorporated herein by reference to Exhibit 3.3 of the Registration Statement on Form S-1 filed by Independence Contract Drilling, Inc. on July 18, 2014 (Registration No. 333-196914)
4.1	Form of Common Stock Certificate	Incorporated herein by reference to Exhibit 4.1 of the Registration Statement on Form S-1 filed by Independence Contract Drilling, Inc. on July 18, 2014 (Registration No. 333-196914)
4.2	Form of Senior Indenture	Incorporated herein by reference to Exhibit 4.1 of the Registration Statement on Form S-3 filed by Independence Contract Drilling, Inc. on September 1, 2015 (File No. 333-206715)
4.3	Form of Subordinated Indenture	Incorporated herein by reference to Exhibit 4.3 of the Registration Statement on Form S-3 filed by Independence Contract Drilling, Inc. on September 1, 2015 (File No. 333-206715)
10.1	Amended and Restated Credit Agreement, dated as of November 5, 2014, among Independence Contract Drilling, Inc., the Lenders Party thereto and CIT Finance LLC as Administrative Agent, Collateral Agent, and Swingline Lender	Incorporated herein by reference to Exhibit 10.1 of the Current Report on Form 8-K filed by Independence Contract Drilling, Inc. on November 6, 2014 (File No. 001-36590)
10.2	First Amendment to Amended and Restated Credit Agreement, dated as of March 4, 2015, by and among Independence Contract Drilling, Inc., the Lenders party thereto and CIT Finance LLC as Administrative Agent and Collateral Agent, as Issuing Bank and as Swingline Lender	Incorporated herein by reference to Exhibit 10.1 of the Current Report on Form 8-K filed by Independence Contract Drilling, Inc. on March 5, 2015 (File No. 001-36590)
10.3	Second Amendment to Amended and Restated Credit Agreement, dated as of April 23, 2015, by and among Independence Contract Drilling, Inc., the Lenders party thereto and CIT Finance LLC as Administrative Agent and Collateral Agent, as Issuing Bank and as Swingline Lender	Incorporated herein by reference to Exhibit 10.2 of the Quarterly Report on Form 10-Q filed by Independence Contract Drilling, Inc. on May 11, 2015 (File No. 001-36590)
10.4	Third Amendment to Amended and Restated Credit Agreement, dated as of October 20, 2015, by and among Independence Contract Drilling, Inc., the Lenders party thereto and CIT Finance LLC as Administrative Agent and Collateral Agent, as Issuing Bank and as Swingline Lender	Incorporated herein by reference to Exhibit 10.1 of the Current Report on Form 8-K filed by Independence Contract Drilling, Inc. on October 21, 2015 (File No. 001-36590)
10.5	Fourth Amendment to Amended and Restated Credit Agreement, dated as of April 14, 2016, by and among	Incorporated herein by reference to Exhibit 10.1 of the Current Report on Form 8-K

	Independence Contract Drilling, Inc., the Lenders party thereto and CIT Finance LLC as Administrative Agent and Collateral Agent, as Issuing Bank and as Swingline Lender	filed by Independence Contract Drilling, Inc. on April 14, 2016 (File No. 001-36590)
10.6	Second Amended and Restated Credit Facility, dated July 14, 2017	Incorporated by reference to the Company's Current Report on Form 8-K (File No. 001-36590) filed July 17, 2017, Exhibit 10.1
10.7†	Amended and Restated Executive Employment Agreement between Independence Contract Drilling, Inc. and Byron A. Dunn, dated August 13, 2014	Incorporated herein by reference to Exhibit 10.2 of the Quarterly Report on Form 10-Q filed by Independence Contract Drilling, Inc. on September 19, 2014 (File No. 001-36590)
10.8†	Amended and Restated Executive Employment Agreement between Independence Contract Drilling, Inc. and Philip A. Choyce, dated August 13, 2014	Incorporated herein by reference to Exhibit 10.3 of the Quarterly Report on Form 10-Q filed by Independence Contract Drilling, Inc. on September 19, 2014 (File No. 001-36590)
10.9†	Second Amendment, dated August 9, 2016, to the Amended and Restated Employment Agreement, dated August 13, 2014, between Independence Contract Drilling, Inc. and Byron A. Dunn.	Incorporated herein by reference to Exhibit 10.1 of the Current Report on Form 8-K filed by Independence Contract Drilling, Inc. on August 10, 2016 (File No. 001-36590)
10.10†	Retirement Agreement dated June 9, 2016, by and between Independence Contract Drilling, Inc. and Edward S. Jacob, III	Incorporated herein by reference to Exhibit 10.1 of the Current Report on Form 8-K filed by Independence Contract Drilling, Inc. on June 10, 2016 (File No. 001-36590)

10.11†	Amended and Restated Independence Contract Drilling, Inc. 2012 Omnibus Incentive Plan, dated August 13, 2014	Incorporated herein by reference to Exhibit 10.1 of the Current Report on Form 8-K filed by Independence Contract Drilling, Inc. on August 13, 2014 (File No. 001-36590)
10.12†	Amendment No. 1 to the Second Amended and Restated Independence Contract Drilling, Inc. 2012 Omnibus Incentive Plan	Incorporated herein by reference to Exhibit 10.1 of the Current Report on Form 8-K filed by Independence Contract Drilling, Inc. on June 24, 2016 (File No. 001-36590)
10.13†	Amendment No. 2 to the Second Amended and Restated Independence Contract Drilling, Inc. 2012 Omnibus Incentive Plan	Incorporated herein by reference to Exhibit 10.12 of the Current Report on Form 10-K filed by Independence Contract Drilling, Inc. on February 28, 2017 (File No. 001-36590)
10.14†	Form of Restricted Stock Award Agreement pursuant to the Amended and Restated Independence Contract Drilling, Inc. 2012 Omnibus Incentive Plan	Incorporated herein by reference to Exhibit 10.15 of the Registration Statement on Form S-1 filed by Independence Contract Drilling, Inc. on July 18, 2014 (Registration No. 333-196914)
10.15†	Form of Nonqualified Stock Option Award Agreement pursuant to the Amended and Restated Independence Contract Drilling, Inc. 2012 Omnibus Incentive Plan	Incorporated herein by reference to Exhibit 10.16 of the Registration Statement on Form S-1 filed by Independence Contract Drilling, Inc. on July 18, 2014 (Registration No. 333-196914)
10.16†	Form of Restricted Stock Award Agreement pursuant to the Independence Contract Drilling, Inc. 2012 Omnibus Incentive Plan	Incorporated herein by reference to Exhibit 10.17 of the Registration Statement on Form S-1 filed by Independence Contract Drilling, Inc. on July 18, 2014 (Registration No. 333-196914)
10.17†	Form of Nonqualified Stock Option Award Agreement pursuant to the Independence Contract Drilling, Inc. 2012 Omnibus Incentive Plan	Incorporated herein by reference to Exhibit 10.18 of the Registration Statement on Form S-1 filed by Independence Contract Drilling, Inc. on July 18, 2014 (Registration No. 333-196914)
10.18†	Form of Performance Unit Award Agreement Total Shareholder Return	Incorporated herein by reference to Exhibit 10.19 of the Registration Statement on Form S-1 filed by Independence Contract Drilling, Inc. on July 18, 2014 (Registration No. 333-196914)
10.19†	Form of Performance Unit Award Agreement Cumulative EBITDA	Incorporated herein by reference to Exhibit 10.20 of the Registration Statement on Form S-1 filed by Independence Contract Drilling, Inc. on July 18, 2014 (Registration No. 333-196914)
10.20†	Form of 2016 TSR Performance Unit Award Agreement	Incorporated herein by reference to Exhibit 10.1 of the Current Report on Form 8-K filed by Independence Contract Drilling, Inc. on February 14, 2017 (File No. 001-36590)
10.21†	Form of 2016 Safety Performance Unit Award Agreement	Incorporated herein by reference to Exhibit 10.2 of the Current Report on Form 8-K filed by Independence Contract Drilling, Inc. on February 14, 2017 (File No. 001-36590)
10.22†	Form of 2016 Utilization Performance Unit Award Agreement	Incorporated herein by reference to Exhibit 10.3 of the Current Report on Form 8-K filed by Independence Contract Drilling, Inc. on February 14, 2017 (File No. 001-36590)
10.23†	Form of Time Based Restricted Stock Unit Agreement	

		Incorporated herein by reference to Exhibit 10.4 of the Current Report on Form 8-K filed by Independence Contract Drilling, Inc. on February 14, 2017 (File No. 001-36590)
10.24†	Form of Director Restricted Stock Unit Agreement	Incorporated herein by reference to Exhibit 10.5 of the Current Report on Form 8-K filed by Independence Contract Drilling, Inc. on February 14, 2017 (File No. 001-36590)
10.25†	Form of Change of Control Agreement	Incorporated herein by reference to Exhibit 10.21 of the Registration Statement on Form S-1 filed by Independence Contract Drilling, Inc. on July 18, 2014 (Registration No. 333-196914)
16.1	Letter from PricewaterhouseCoopers LLP addressed to the Securities and Exchange Commission, dated April 7, 2015	Incorporated by reference herein to Exhibit 16.1 of the Current Report on Form 8-K filed by Independence Contract Drilling, Inc. on April 7, 2015 (File No. 001-36590)
23.1*	Consent of BDO USA, LLP	
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	

31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

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* Filed herewith.

** Furnished, not filed.

† Indicates a management contract or compensatory plan or arrangement filed pursuant to Item 601(b)(10)(iii) of Regulation S-K.