Independence Contract Drilling, Inc.
Form 10-K
February 18, 2016

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, 2015

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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer		Accelerated Filer	þ

Non-Accelerated filer (Do not check if a smaller reporting company) Smaller reporting company
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes No þ

The aggregate market value of the registrant's common stock held by non-affiliates of the registrant was approximately $145,926,499 as of June 30, 2015, the last business day of the registrant's most recently completed second fiscal quarter (based on a closing price of $8.87 per share as reported on the New York Stock Exchange and 16,451,691 shares held by non-affiliates).

There were 24,403,659 shares of the registrant's common stock outstanding as of February 12, 2016.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the registrant's 2016 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 sustained decrease in domestic spending by the oil and natural gas exploration and production industry;
- a decline in or substantial volatility of crude oil and natural gas commodity prices;
- 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;
- our backlog of term contracts declining rapidly;
- the current severe market downturn impairing our ability to predict future rig utilization and spot dayrates due to customers delaying or changing their capital budget plans;
- 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 raise funds through debt financing and equity issuances sufficient to maintain financial liquidity and fund our planned capital expenditures;
- 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 revolving 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;
- the potential failure by us to establish and maintain effective internal control over financial reporting; and
- lack of operating history as a contract drilling company.

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 gas properties. We are focused on creating stockholder and customer value through our commitment to operational excellence and our focus on safety. Although we believe the current downturn in oil prices is presenting significant challenges for the drilling industry, we believe that we are well positioned to successfully navigate the downturn due to our premium rigs, operational excellence, commitment to safety, term contract coverage and strong asset base.

Our standardized fleet currently consists of fourteen premium ShaleDriller® rigs. Of these fourteen rigs, twelve are 200 Series rigs equipped with our integrated omni-directional walking system designed specifically to optimize pad drilling for our customers. We also have substantially completed the conversion of one of our non-walking rigs to 200 Series status, which we expect will be available for operations at the end of the first quarter of 2016. We also have the ability to upgrade our remaining non-walking rig to 200 Series status when market conditions improve, but until such time this rig has been decommissioned and we do not intend to market it. Every ShaleDriller® 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 top drives, automated tubular handling systems and blowout preventer (“BOP”) handling systems. Twelve of our fourteen rigs are equipped with bi-fuel capabilities (they 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 predominantly operating in the Permian Basin, and we have one rig operating in the Eaglebine region, however, our rigs have previously operated in the Mid-Continent region and Eagle Ford Shale, as well.

For disclosure concerning financial information on segments and financial information about geographic areas please see "Selected Financial Data."

Industry Trends

Land Rig Replacement Cycle

The increase in horizontal drilling in the U.S. 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. 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 U.S. 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 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. Our rigs have drilled some of the longest horizontal wells to date in the Permian Basin, including a well with a lateral section in excess of 13,980 feet. 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, 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. Twelve of our fourteen 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.

Recent Declines in Oil and Gas Prices and Drilling Activity

Oil prices began to decline in the second half of 2014, declined further during 2015 and have continued to decline 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 has fallen as low as $26.68 during January 2016 (WTI spot price as reported by the United States Energy Information Administration). As a result of the decline in oil prices, our industry is now experiencing an exceptional downturn, and market conditions remain very dynamic and are changing quickly. Although the magnitude as well as the duration of this downturn are not yet known, we believe that 2016 will be an exceptionally challenging year for ICD and our industry.

We believe the vast majority of E&P companies, including our customers, have significantly reduced their 2016 capital spending plans compared to 2015 levels. The initial impact of these spending reductions is evidenced by the published rig counts which have declined more than 60% since their peak in October 2014, and we believe the rig count in the United States may decline further in 2016 until oil and gas prices begin to stabilize and improve.

As a result of this deterioration in market conditions, our customers are principally focused on their most economic wells, drilling to maintain leasehold positions and on maintaining their most cost efficient operations that deliver the overall lowest cost of producing their wells and minimize their capital expenditures. As a result, operators are focusing more of their capital spending on horizontal drilling programs compared to vertical drilling. They also are more focused on utilizing drilling equipment and techniques that optimize costs and efficiency. Thus, we believe this rapid market deterioration 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.

Although we believe that the current market downturn is rapidly increasing the focus of our customers towards the use of premium drilling rigs such as our ShaleDriller®, and that premium operations such as ours have been less affected by the downturn relative to operations conducted by legacy fleets, the rapid pace and level of the market decline has negatively impacted pricing, utilization and contract tenors for premium rigs, including our ShaleDriller® rig. During 2015, our premium drilling fleet operated at 85% utilization, but we do not expect to maintain this level of utilization while this current market downturn continues. As of December 31, 2015, eleven of our twelve 200 series rigs were generating revenue.

Since December 31, 2015,

- One of our rigs operating on a farm out basis ceased operations under its contract. Although this arrangement allows us to recognize revenues and full margins for the duration of the contract, we do not expect this rig to recommence drilling operations in the near term.
- Two of our customers have informed us that they intend to place our rigs operating for them under term contracts on a standby-without-crew basis until market conditions improve. Although these arrangements allow us to continue to recognize revenue and earn expected margins for the durations of these contracts, we do not expect these two rigs to recommence drilling operations in the near term.
- One of our rigs operating under a term contract that expired during the first quarter of 2016 has become idle. We continue to market this rig, however, given current market conditions, we cannot accurately predict when this rig will return to work or that it can operate at profitable levels until market conditions improve.

In addition, two of our rigs operating at December 31, 2015 were operating, in the spot-market, under short-term contracts expiring in March 2016, and we also have several rigs operating under term contracts with terms scheduled to expire during 2016. We expect to market our rigs rolling off contracts in 2016 at substantially lower dayrates than where they historically have operated, and there can be no assurance that these rigs will be contracted or remain operating at profitable levels.

Initial Formation

We were incorporated in November 2011 but did not have meaningful operations until March 2012. In March 2012, we acquired substantially all of the rig manufacturing and intellectual property (the “GES assets”) of Global Energy Services Operating, LLC (“GES”), including GES’ Houston-based manufacturing facility (the “Houston Facility”), which we currently use to construct our rig fleet. The Houston Facility is located on 14.6 acres in northwest Houston. This acquisition provided us with the necessary infrastructure and asset platform required to accelerate the introduction of our ShaleDriller® rig into our target markets and secure initial contracts with key customers. In exchange for the GES assets, we issued 1.6 million shares of our common stock and a warrant to purchase 2.2 million shares of our common stock, which expired unexercised on March 2, 2015, and we assumed approximately $2.1 million of long-term indebtedness from GES. Because we had only limited operations before the GES acquisition and we succeeded them in substantially all of the ongoing rig construction operations of GES, GES is considered our predecessor for accounting purposes.

Contemporaneously with the acquisition of the GES assets, we acquired cash balances and two drilling contracts from Independence Contract Drilling LLC (referred to as “RigAssetCo”) in exchange for approximately 2.4 million shares of our common stock.

As a condition to the completion of these two transactions, we also closed a private placement of shares of our common stock resulting in net proceeds to us of $98.4 million. We used the net proceeds of the private placement primarily to continue the construction of our ShaleDriller® rig fleet and expansion of our operating capacity, and to repay the indebtedness assumed from GES. We refer to the GES and RigAssetCo transactions, together with the private placement of common stock, collectively as the “GES Transaction.”

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 fixed 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. However, throughout 2015, the vast majority of new rig contracts available in the market have been 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 in excess of six months, declined significantly from $152.8 million as of December 31, 2014 to $74.4 million as of December 31, 2015. Approximately $53.3 million of our backlog at December 31, 2015 is expected to be realized during 2016. 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, we currently expect that several of our rigs under term contracts will 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 that we have operating under term contracts during 2016 and beyond.

	Three Months Ending March 31, 2016	Three Months Ending June 30, 2016	Three Months Ending September 30, 2016	Three Months Ending December 31, 2016	2017	2018
Weighted Average Number of Rigs (1)	8.5	6.2	4.5	3.7	1.8	0.2

(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 greater than 6 months, and exclude well-to-well or short-term contracts.

Our Customers

Customers for contract drilling services in the U.S. include major oil and gas companies, independent oil and gas companies as well as numerous small to mid-sized publicly-traded and privately held oil and gas companies. We market our contract drilling services to all such customers. During 2015, our customers representing more than 10% of our revenues were Parsley Energy, LP., Pioneer Natural Resources USA, Inc., Laredo Petroleum, Inc., COG Operating, LLC, a subsidiary of Concho Resources, Inc. and Elevation Resources, LLC. 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, will 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 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 recent decrease in oil prices has caused a reduction in E&P company capital expenditures on exploration, development and production activities, which in turn has resulted in a decreased demand for drilling rigs and downward pricing pressure on drilling rigs in operation.

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 U.S. 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, quality of personnel, efficiency of equipment, 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.

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 U.S. 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 U.S., the Federal Comprehensive Environmental Response Compensation and Liability Act of 1980, as amended (“CERCLA”), and comparable state statutes impose strict liability on:

- owners and operators of sites, and
- persons who disposed of or arranged for the disposal of “hazardous substances” found at sites.

The Federal Resource Conservation and Recovery Act (“RCRA”), as amended, and comparable state statutes govern the disposal of “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, 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 and the Oil Pollution Act of 1990, as amended (the “Oil Pollution Act”), and implementing regulations govern:

- the prevention of discharges, including oil and produced water spills; and

• liability for drainage into waters of the U.S.

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. 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 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 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, 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 state and local regulations, such as the EPA rules issued in April 2012, which add new requirements for the oil and 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 greenhouse gases 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 gas production. Pursuant to President Obama’s Strategy to Reduce Methane Omissions, and as part of the Obama Administration’s efforts to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025. The EPA is expected to propose in the spring of 2016, new regulations that will set methane emission standards for new and modified oil and gas facilities, including production facilities. 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”), 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 U.S., 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 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, 2015, we had approximately 305 employees, including one contract employee, none of whom 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.

Raw Materials, Suppliers and Subcontractors

We use many suppliers of raw materials and services. Although these materials and services have historically been available, there is no assurance that such materials 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 prices have continued and have adversely affected demand for contract drilling services, which could have a material adverse affect on our results of operations and financial condition.

Oil prices began to decline in the second half of 2014, declined further during 2015 and have continued to decline 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 have fallen to as low as $26.68 per barrel during January 2016 (West Texas Intermediate-Cushing, Oklahoma ("WTI") spot price as reported by the United States Energy Information Administration). As a result of the decline in oil prices, our industry is now experiencing an exceptional downturn and market conditions remain very dynamic and are changing quickly. Although the magnitude as well as the duration of this downturn are not yet known, we believe that 2016 will be an exceptionally challenging year for ICD and our industry.

We believe the vast majority of exploration and production companies, including our customers, have significantly reduced their 2016 capital spending plans compared to 2015. The initial impact of these spending reductions is evidenced by the published rig counts, which have declined more than 60% since their peak in October 2014, including an 11% rig count decline since December 31, 2015.

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As a result of this deterioration in market conditions, demand for our contract drilling services has declined. During 2015, our premium drilling fleet operated at 85% utilization, but we do not expect to maintain this level of utilization while this current market downturn continues. As of December 31, 2015, eleven of our twelve 200 series rigs were generating revenue.

Since December 31, 2015,

- One of our rigs operating on a farm out basis ceased operations under its contract. Although this arrangement allows us to recognize revenues and full margins for the duration of the contract, we do not expect this rig to recommence drilling operations in the near term.
- Two of our customers have informed us that they intend to place our rigs operating for them under term contracts on a standby-without-crew basis until market conditions improve. Although these arrangements allow us to continue to recognize revenue and earn expected margins for the durations of these contracts, we do not expect these two rigs to recommence drilling operations in the near term.
- One of our rigs operating under a term contract that expired during the first quarter of 2016 has become idle. We continue to market this rig, however, given current market conditions, we cannot accurately predict when this rig will return to work or that it can operate at profitable levels until market conditions improve.

In addition, two of our rigs operating at December 31, 2015 were operating under short-term contracts expiring in March 2016, and we also have several rigs operating under term contracts with terms scheduled to expire during 2016. We expect to market our rigs rolling off contracts in 2016 at substantially lower dayrates than where they historically have operated, and there can be no assurance that these rigs will be contracted or remain operating at profitable levels. If we are unable to recontract rigs in the spot-market or recontract rigs with expiring term contracts, it would have a material adverse affect on our results of operations and financial condition. In addition, we expect that any rig with an expiring term contract that is recontracted during 2016 will be at dayrates substantially below their current contract rates, which will significantly reduce our profitability and cash flows.

In addition, we currently finance our capital expenditures and operations pursuant to a committed $125.0 million revolving line of credit. A significant portion of our borrowing base is tied to the appraised value of our drilling rigs, which 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 revolving 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 revolving credit facility or cause us to violate one or more of our restrictive covenants, which could have a material adverse affect on our financial condition.

We derive all our revenues from companies in the oil and gas exploration and production industry, a historically cyclical industry with levels of activity that are significantly affected by the levels and volatility in oil and 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 gas companies operating in the U.S., and in particular, the regions where we actively market our contract drilling services. The oil and gas exploration and production industry is a historically cyclical industry characterized by significant changes in the levels of exploration and development activities. Oil and gas prices and market expectations of potential changes in those prices significantly affect the levels of those activities. Worldwide political, regulatory, economic, and military events as well as natural disasters have contributed to oil and 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 U.S. and the regions where we market our contract drilling services, whether resulting from changes in oil and 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 gas, oil and 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 gas prices, including, but not limited to:

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

Oil and natural gas prices have been volatile historically and, we believe, will continue to be so in the future. For example, U.S. Benchmark crude's price per barrel (WTI) was $107.95 on June 20, 2014 and had dropped to $26.68 on January 20, 2016. Future or continued declines and volatility in oil and gas prices, or no improvement in oil and gas prices, from their current levels for an extended period of time, could materially and adversely affect our business, results of operations, financial condition and growth strategy.

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, or a prolonged continuation of current depressed market conditions, could materially and adversely affect our business, results of operations, financial condition and growth strategy.

In addition, if oil and natural gas prices decline further, 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 gas wells in the United States in the regions where we market our rigs. As of December 31, 2015, we have rigs operating or earning revenues from eight different customers, including three customers who have contracted two of our rigs, and 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 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 several rigs operating under short-term contracts in the spot-market, and several rigs operating under long-term contracts with terms expiring during 2016. 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 the term 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. In light of the current downturn in oil prices, we cannot assure that any replacement contract can be obtained for any of rigs operating in the spot-market or with terms expiring while market conditions remain depressed, 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 spot-market or term contracts could have a material and 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 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. For example, during March 2014, we experienced damage to the mast of one of our operating rigs that removed the rig from operations for a period of time, during which we were not compensated. 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 recent 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. Several of our competitors provide a broader array of services and have a stronger presence in more geographic markets.

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. 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. The EPA commenced a study of the potential impacts of hydraulic fracturing on drinking water and issued a draft report for public comment and peer review in June 2015. On October 21, 2011, the EPA announced its intention to propose regulations under the federal Clean Water Act to regulate wastewater discharges from hydraulic fracturing. In March 2015, the U.S. Department of the Interior (the "DOI") published final rules that update existing regulation of hydraulic fracturing activities on federal lands, including requirements for disclosure, wellbore integrity and handling of flowback water. On April 13, 2012, the DOI, the U.S. Department of Energy and the EPA issued a memorandum outlining a multi-agency collaboration on unconventional oil and gas research in response to the White House-entitled "Blueprint for a Secure Energy Future" and the recommendations of the Secretary of Energy Advisory Board Subcommittee on Natural Gas. On March 20, 2015, the U.S. Interior Department's Bureau of Land Management released a final rule regulating hydraulic fracturing activities on Federal and Indian lands. The final rule includes new well-bore integrity requirements, imposes standards for interim storage of recovered waste fluids, and requires notifications and waiting periods for key parts of the fracturing process, which could lead to delays in fracturing and/or drilling operations. The rule also mandates disclosure of the chemicals used in the process. Additionally, on April 7, 2015, the EPA published a proposed rule that would 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 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 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, in particular Mr. Dunn and Mr. Jacob, our Chief Executive Officer and our President and Chief Operating Officer, respectively, 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:

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- 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, 2015, 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 $74.4 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. In addition, we currently expect that several of our rigs under term contracts will realize revenue on a standby-without-crew basis, which allows us to preserve our expected cash margins from the contract but reduces our the overall top line revenues we recognize. 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 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 revolving 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 revolving 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 revolving 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 revolving 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 revolving 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 revolving credit facility would have a material adverse effect on our ability to fund our operations and business strategy.

Our revolving credit facility limits the amounts we can borrow up to a borrowing base amount, 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 revolving credit facility was $98.6 million as calculated as of December 31, 2015, with lender commitments of $125.0 million.

In the future, we may not be able to access adequate funding under our revolving 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.

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. 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 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 and could limit well servicing opportunities. We may not be able to recover some or any of our costs of compliance with these laws and regulations from insurance.
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 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 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, in March 2014 the U.S. Fish & Wildlife Service (the “FWS”) listed the lesser prairie-chicken as threatened However, in September 2015, a federal district court vacated the listing. The Department of Justice has appealed on behalf of FWS. The sage grouse and certain wildflower species, among others, are also 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 gas industry. During 2012, the EPA published rules that include standards to reduce methane emissions associated with oil and gas production. Pursuant to President Obama’s Strategy to Reduce Methane Omissions, and as part of the Obama Administration’s efforts to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025, the EPA is expected to propose in the spring of 2016 new regulations that will set methane emission standards for new and modified oil and gas facilities, including production facilities. In addition, the U.S. 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. 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

Internal projections for our forward-looking cash flows and liquidity are based upon assumptions on future customer activity, market conditions and levels of operation that have become increasingly difficult to estimate and predict.

The extreme industry downturn has required E&P operators to significantly decrease capital budgets, which significantly decreases the number of oil and gas wells they plan to drill, and thus, demand for drilling rigs. In many instances, our customers have not formalized 2016 budgets or have revised them several times as market conditions and oil prices have continued to decline. As a result, our ability to reliably predict future demand for our drilling rigs and services, including our future rig utilization and potential spot-market dayrates, has been impaired. When estimating our future cash flows, future liquidity and ability to fund our planned operating activities, our assumptions concerning future rig utilization in the spot-market and spot-market dayrates are key variables, and if our assumptions regarding these items were to prove incorrect, it could have a material adverse effect on our results of operations and financial condition.

We expect our backlog and term contract base to decline significantly. As a result, a steadily increasing portion of our future cash flow and future rig utilization will come from rigs marketed and operating in the spot-market.

At December 31, 2015, our backlog from term contracts was $74.4 million, of which $53.3 million is scheduled to be realized in 2016. During 2016 we have one rig rolling off a term contract during the first quarter of 2016, three during the second quarter of 2016, and one during the third quarter of 2016. As a result, we expect to only have an average of four rigs earning revenue under term contracts during the last six months of 2016, which compares to an average of nine rigs operating under term contracts during the fourth quarter of 2015. Due to the extreme downturn in market conditions, we do not expect that any of our expiring term contracts will be renewed on a long-term basis. We expect to market all rigs with expiring contracts in the spot-market on a well-to-well or short-term contract basis.

Our forward-looking projections and assumptions regarding our future cash flows and liquidity assume that we are able to successfully maintain a minimum number of rigs operating or earning revenue, which increasingly relies upon assumptions about our ability to successfully operate rigs on a spot-market basis during this period of extremely poor industry conditions. If we are not able to operate rigs in the spot-market at minimum levels assumed in our forward-looking assumptions, it could have a material adverse effect on our results of operations and financial condition.

Spot-market dayrates have declined significantly. We expect our revenue per day and future cash flows to decline as a steadily increasing portion of our future revenues are earned on a spot-market basis.

We expect to experience a steady decline in our average revenue per day during 2016 as term contracts expire and an increasing percentage of our rigs are marketed and operate in the spot-market. At December 31, 2015, the average dayrate in our backlog from term contracts was approximately $25,161, and we expect that spot-market dayrates currently are at a 30% to 40% discount to these rates, and there can be no assurance that spot-market rates will not drop further if current industry conditions persist or become worse. If spot-market dayrates decline or persist at current levels for a protracted period of time, it could have a material adverse effect on our results of operations and financial condition.

The borrowing base under our credit facility is expected to decline during 2016.

At December 31, 2015, the borrowing base under our revolving credit facility was $98.6 million, and we had $35.9 million of availability 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, 2015, the advance percentage utilized to calculate the borrowing base was 73.75%. Under the terms of the revolving credit facility, this advance rate will reduce 1.25% each quarter during 2016 and thereafter.

In addition, since December 31, 2015, the lenders under our revolving credit facility have begun their regularly scheduled reappraisal of our rigs, and given the extreme downturn in market conditions, in particular the decline in oil prices below $30 since December 31, 2015, we currently expect that the appraised forced liquidation value of our eligible rigs to decline between 10% and 20%. Assuming that these revised appraisal values were utilized at December 31, 2015 to calculate our borrowing base, we estimate that our borrowing base would have declined to between $81.6 million and $90.1 million and that our availability under our credit facility would have declined to between $18.9 million and $27.4 million. 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 our rigs or if market conditions continue to decline.

At December 31, 2015, we had eleven rigs that were eligible to be included in the equipment portion of the borrowing base. Looking forward into 2016, as an increasing percentage of our rigs are marketed and operated on a spot-market basis, there is increasing risk that rigs currently included as eligible rigs for purposes of calculating the borrowing base cannot be recontracted and ultimately are removed from the borrowing base, which further reduces availability under our credit facility.

If at any time our borrowing base falls below our outstanding balance under our revolving 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 revolving 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 revolving credit facility is based upon our future cash flows and debt levels that have become increasingly more difficult to predict as the extreme market downturn continues.

Our revolving 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’16: 3.75x; 2Q’16: 4.0x; 3Q’16: 4.25x; 4Q’16: 4.5x; 1Q’17: 4.0x; 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, 2015 the leverage ratio covenant was 3.75x.

The revolving credit facility also requires us to maintain a fixed charge coverage ratio ("FCCR") of not less than 1.1 to 1.0. The FCCR ratio 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 ratio: (1) capital expenditures incurred before November 1, 2015, (2) capital expenditures financed through capital sources other than the revolving credit facility and (3) up to approximately $8.3 million of certain other capital expenditures.

Our compliance with each of these covenants depends significantly upon our level of cash flows in 2016 and beyond, which are based upon factors such as spot dayrates and rig utilization that are increasingly difficult to predict based upon the extreme downturn in market conditions our industry is experiencing. In particular, our ability to comply with our leverage and FCCR ratio covenant in 2017 and beyond is predicated upon market conditions stabilizing in 2016 and beginning to improve throughout 2017. If we are not able to comply with the covenants contained in our revolving 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 comply with the utilization covenant contained in our revolving credit facility is based upon our future rig utilization that has become increasingly more difficult to predict as the extreme market downturn continues and our contract backlog declines.

Our revolving credit facility requires us to maintain a minimum rig utilization covenant of at least 60% in 2016 and 70% in 2017. A rig is considered utilized when it is earning revenue, whether operating, standby or otherwise. Rigs that are “decommissioned” or “under repair” are not considered. At December 31, 2015, our rig utilization percentage under the revolving credit facility was 79.4%, which included our one rig undergoing conversion in the denominator and excluded our remaining 100 Series rig that has been decommissioned pending its conversion. As our backlog of term contracts continues to decline during 2016 and beyond, our ability to comply with this covenant increasingly relies upon our ability to maintain rig operations in the spot-market, which becomes increasingly more difficult to predict while the extreme downturn in market conditions persist of if they become worsen. If we are not able to comply with the covenants contained in our revolving 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 covenants contained in our credit facility, or to cure any such non-compliance would have a material adverse effect on our liquidity and financial condition.

Our revolving credit facility contains a subjective acceleration clause, and a springing lock-box arrangement that is triggered when availability under our revolving credit facility falls below $15 million. Under applicable accounting rules, outstanding balances under our revolving credit facility will be reclassified from long-term to current if this triggering event occurs.

The Credit Facility matures on November 5, 2018. 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) $15.0 million and (B) the lesser of 15% of the borrowing base or 15% 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 $62.7 million in outstanding borrowings under the Credit Facility at December 31, 2015. Remaining availability under the Credit Facility was $35.9 million at December 31, 2015, based on the borrowing base formula, and we are currently in compliance with all covenants under the Credit Facility. Since December 31, 2015, the lenders under our revolving credit facility have begun their regularly scheduled reappraisal of our rigs, and given the extreme downturn in market conditions, in particular the decline in oil prices below $30 since December 31, 2015, we currently expect that the appraised forced liquidation value of our eligible rigs to decline between 10% and 20%. Assuming that these revised appraisal values were utilized at December 31, 2015 to calculate our borrowing base, we estimate that our borrowing base would have declined to between $81.6 million and $90.1 million and that our availability under our credit facility would have declined to between $18.9 million and $27.4 million. 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 our rigs or if market conditions continue to decline.

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 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 the recent 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 revolving 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 $1.0 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.

Existing stockholders continue to hold a significant percentage of our outstanding common stock.

As of February 12, 2016, Sprott Resource Partnership, Lime Rock Partners III, L.P., 4D Global Energy Advisors SAS, Global Energy Services Operating, LLC, Jennison Associates LLC, Prudential Financial, Inc. and FMR LLC each hold or beneficially own more than 10% of our common stock. The existence of significant stockholders may have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in the best interests of our company. Moreover, this concentration of stock ownership may adversely affect the trading price of our common stock to the extent investors perceive a disadvantage in owning stock of a company with significant stockholders.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

We own an approximately 14.4 acre corporate headquarters and rig assembly yard complex located at 11601 North Galayda Street, Houston, TX 77086. The complex includes approximately 18,000 square feet of office space and 76,000 square feet of warehouse space. We have entered into a lease for an additional approximate 0.2 acres of land for equipment and supply storage. We believe that all of our existing properties are suitable for their intended uses and 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 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 are asserted for amounts that may be material should an unfavorable outcome be the result, management does not currently expect that 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 has traded on the New York Stock Exchange under the symbol "ICD" since August 8, 2014 following our initial public offering. Prior to that time, there was no public market for our common stock. 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
2014:		
Period from August 8, 2014 to September 30, 2014	$11.94	$10.87
Fourth Quarter	$11.69	$5.06
2015:		
First Quarter	$6.97	$4.45
Second Quarter	$9.12	$7.01
Third Quarter	$8.28	$4.98
Fourth Quarter	$7.69	$4.96

Holders of Record

As of February 12, 2016, we had 24,403,659 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 revolving 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, 2015 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	3/31/2015	6/30/2015	9/30/2015	12/31/2015
Independence Contract Drilling, Inc.	$100.00	$106.24	$47.20	$63.02	$80.20	$45.03	$45.66
S&P 500 Index	$100.00	$102.11	$106.59	$107.06	$106.81	$99.40	$105.82
Peer Index	$100.00	$93.94	$53.04	$53.51	$56.71	$34.32	$37.97

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., Basic Energy Services, Inc. and C&J Energy Services, Inc.

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

None.

Issuer Purchases of Equity Securities

During the fourth quarter of 2015, we withheld shares of our common stock to satisfy minimum tax withholding obligations in connection with the vesting of certain restricted 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 purchase common shares. The following table provides information relating to our repurchase of shares of common stock during the three months ended December 31, 2015 (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	5,241	$6.33	—	—
November 1 — November 30	—	$—	—	—
December 1 — December 31	7,640	$5.53	—	—

.(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 and that of our accounting predecessor as of and for the periods indicated. Our accounting predecessor was GES Drilling Services (our "predecessor"), a division of Global Energy Services, Inc.

Our selected historical financial data as of and for the periods presented below were derived from our audited financial statements. Our results of operations during 2012 do not include the results of our predecessor prior to its acquisition. Although we did not commence material operations prior to March 2, 2012, we incurred expenses in connection with our private placement and acquisition activities during January and February 2012 prior to the consummation of these transactions.

The selected historical financial data of our predecessor for the period from January 1, 2012 through March 1, 2012 were derived from the audited financial statements of our predecessor. Our predecessor was engaged in a different line of business and you should not evaluate our results based on our predecessor or consider our results and those of our predecessor on a combined basis.

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."

(In thousands, except per share data)	Successor Year Ended December 31, 2015	December 31, 2014	December 31, 2013	December 31, 2012	Predecessor January 1, 2012 through March 1, 2012
Statement of operations data[1]:					
Revenues	$88,418	$70,347	$42,786	$ 15,123	$7,698
Operating costs	52,087	42,654	28,401	15,400	6,973
Selling, general and administrative	14,483	12,222	8,911	7,813	1,383
Depreciation and amortization	21,151	16,181	10,186	5,904	92
Goodwill impairment and other charges[2]	—	30,627	—	—	—
Asset impairments, net of insurance recoveries[3]	2,708	1,711	—	—	—
Loss (gain) on disposition of assets	2,940	19	(55)	—	—
Total cost and expenses	93,369	103,414	47,443	29,117	8,448
Operating loss	(4,951)	(33,067)	(4,657)	(13,994)	(750)
Interest expense	(3,254)	(1,648)	(257)	(10)	(15)
Loss on forgiveness of related party balances[4]	—	—	—		(6,063)
Gain on warrant derivative[5]	—	3,189	1,035	3,655	—
Loss before income taxes	(8,205)	(31,526)	(3,879)	(10,349)	(6,828)
Income tax benefit	(325)	(3,358)	(1,882)	(5,401)	(2,149)
Net loss	$(7,880)	$(28,168)	$(1,997)	$ (4,948)	$(4,679)
Weighted-average number of shares outstanding (basic and diluted)	23,904	17,078	12,179	10,141	
Net loss per share (basic and diluted)	$(0.33)	$(1.65)	$(0.16)	$ (0.49)	
Cash flow data:					
Net cash provided by (used in) operating activities	$27,379	$3,809	$5,997	$ (8,337)	$(3,857)
Net cash used in investing activities	(72,219)	(112,686)	(59,273)	(49,743)	(18)
Net cash provided by (used in) financing activities	39,427	116,904	18,599	95,486	(25)
Balance sheet data:					
Total assets	$314,789	$289,547	$184,968	$ 167,436	
Long-term debt	62,708	—	19,780	—	
Total liabilities	82,052	52,811	40,096	22,736	
Total stockholders' equity	232,737	236,736	144,872	144,700	

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

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

(3) For the year ended December 31, 2015, represents asset impairment expense associated with the impairment of the substructure, mast and various other 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 proceeds. 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 during the three months ended March 31, 2014, net of insurance claim proceeds. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations."

(4) Represents amounts owed to our predecessor by its affiliate that were forgiven in the GES Transaction.

(5) Represents a non-cash gain associated with the decrease in the estimated fair value of the warrant to purchase 2.2 million shares issued to GES in the GES Transaction. 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 10K.

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 newly constructed, technologically advanced, custom designed ShaleDriller® rigs that are specifically engineered and designed to optimize the development of our customers' most technically demanding oil and gas properties. Our first rig began drilling in May 2012.

Our standardized fleet currently consists of fourteen premium ShaleDriller® rigs. Of these fourteen rigs, twelve are 200 Series rigs equipped with our integrated omni-directional walking system designed specifically to optimize pad drilling for our customers. We also have substantially completed the conversion of one of our non-walking rigs to 200 Series status, which we expect will be available for operations at the end of the first quarter of 2016. We also have the ability to upgrade our remaining non-walking rig to 200 Series status when market conditions improve, but until such time this rig has been decommissioned and we do not intend to market it. Every ShaleDriller® 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 top drives, automated tubular handling systems and blowout preventer ("BOP") handling systems. Twelve of our fourteen rigs are equipped with bi-fuel capabilities (they operate on either diesel or a natural gas-diesel blend).

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

In this regard, oil prices declined significantly during the second half of 2014, remained depressed in 2015 and have continued to decline in 2016. The closing price of oil was as high as $106.06 per barrel during the third quarter of 2014, was $37.13 on December 31, 2015 and declined to as low as $26.68 in January 2016 (WTI spot price as reported by the United States Energy Information Administration). As a result of the decline in oil prices, our industry is now experiencing an extreme downturn that has resulted in reduced industry utilization and significant declines in spot-market day rates and opportunities. Market conditions remain very dynamic. Although the magnitude of any additional market declines as well as the duration of this downturn are not yet known, we believe 2016 will continue to be an extremely challenging year for ICD and our industry.

We believe the vast majority of exploration and production companies, including our customers, have significantly reduced their capital spending plans. The initial impact of these spending reductions is evidenced by the active rig count in the United States, which has declined more than 60% since its peak in October 2014 including an 11% rig count decline since December 31, 2015. We believe the active rig count in the United States is likely to decline further during 2016 if oil prices remain at current levels.

As a result of this deterioration in market conditions, our customers are principally focused on their most economic wells, drilling to maintain leasehold positions, and on maintaining their most cost efficient operations that deliver the overall lowest cost of producing their wells and minimize their capital expenditures. As a result, operators are focusing more of their capital spending on horizontal drilling programs compared to vertical drilling. They also are more focused on utilizing drilling equipment and techniques that optimize costs and efficiency. Thus, we believe this rapid market deterioration 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.

Although we believe that the current market downturn is rapidly increasing the focus of our customers towards the use of premium drilling rigs such as our ShaleDriller®, and that premium operations such as ours have been less affected by the downturn relative to operations conducted by legacy fleets, the rapid pace and level of the market decline has negatively impacted pricing, utilization and contract tenors for premium rigs, including our ShaleDriller® rig. During 2015, our premium drilling fleet operated at 85% utilization, but we do not expect to maintain this level of utilization while this current market downturn continues. As of December 31, 2015, eleven of our twelve 200 series rigs were generating revenue.

Since December 31, 2015,

- One of our rigs operating on a farm out basis ceased operations under its contract. Although this arrangement allows us to recognize revenues and full margins for the duration of the contract, we do not expect this rig to recommence drilling operations in the near term.
- Two of our customers have informed us that they intend to place our rigs operating for them under term contracts on a standby-without-crew basis until market conditions improve. Although these arrangements allow us to continue to recognize revenue and earn expected margins for the durations of these contracts, we do not expect these two rigs to recommence drilling operations in the near term.
- One of our rigs operating under a term contract that expired during the first quarter of 2016 has become idle. We continue to market this rig, however, given current market conditions, we cannot accurately predict when this rig will return to work or that it can operate at profitable levels until market conditions improve.

In addition, two of our rigs operating at December 31, 2015 were operating under short-term contracts expiring in March 2016, and we also have several rigs operating under term contracts with terms scheduled to expire during 2016. We expect to market our rigs rolling off contracts in 2016 at substantially lower dayrates than where they historically have operated, and there can be no assurance that these rigs will be contracted or remain operating at profitable levels.

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 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.

Recent Developments

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

During the third quarter of 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 will be 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 decommissioned drilling equipment that is no longer compatible with the converted rig. During the fourth quarter of 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. We have the ability to upgrade this rig when market conditions improve.

Amendment of Revolving Credit Facility

In light of declining market conditions, we amended the Credit Facility on October 20, 2015, to relax certain of our financial covenants in 2016 and 2017. As amended, the Credit Facility requires us to maintain a leverage ratio of net debt to adjusted EBITDA, not to exceed the following in the respective time periods: 1Q’16: 3.75x; 2Q’16: 4.0x; 3Q’16: 4.25x; 4Q’16: 4.5x; 1Q’17: 4.0x; thereafter: 3.0x. The amendment also reduced the minimum rig utilization covenant to 60% in 2016 and 70% in 2017, and provided for the exclusion of certain capital expenditures from consideration in our fixed charge coverage ratio covenant. As of December 31, 2015 the leverage ratio covenant was 3.75x. For additional information regarding our revolving credit facility, please see “Note 7 - Long-Term Debt.”

Initial Public Offering

On August 7, 2014, our registration statement on Form S-1 (File No. 333-196914) (the "Form S-1") was declared effective by the Securities and Exchange Commission (the "SEC") for our IPO, pursuant to which we sold an aggregate of 11,500,000 shares of our common stock at a price to the public of $11.00 per share, which included 1,500,000 shares of our common stock sold pursuant to the exercise by the underwriters in full of their option to purchase additional shares of common stock to cover over-allotments (the "Over-Allotment Option"). Morgan Stanley & Co. LLC, RBC Capital Markets, LLC and Tudor, Pickering, Holt & Co. Securities, Inc. acted as book runners. We completed our IPO of 10,000,000 shares of our common stock on August 13, 2014 and subsequently closed the issuance and sale of the additional 1,500,000 shares of our common stock pursuant to the Over-Allotment Option on August 29, 2014. Our common stock trades on the New York Stock Exchange under the ticker symbol ICD. Net proceeds from the offering were $116.5 million after deducting $7.6 million of underwriting discounts and commissions, as well as legal, accounting, printing and other expenses directly associated with the offering totaling $2.4 million.

Stock Split

On July 14, 2014, our board of directors approved a resolution to effect a 1.57-for-1 stock split of our common stock in the form of a stock dividend. The dividend was distributed on July 24, 2014 to holders of record as of July 21, 2014. The earnings per share information and all common stock information in these financial statements have been retroactively restated for all periods presented to reflect this stock split.

Damage Sustained on Rig 102

In March 2014, one of our non-walking drilling rigs suspended drilling operations due to damage to the rig’s mast and other operating equipment. The cost to repair and replace this equipment was covered by insurance, subject to a deductible. While under repair, we upgraded this rig by adding a substructure and other equipment that included an omni-directional walking system. The cost of the upgrades were not covered by insurance. The repairs and upgrades were completed in October 2014, and the upgraded rig was renamed Rig 208. As a result, in 2014, we recorded an asset impairment charge of $4.7 million, representing an estimate of the damage sustained to the rig, as well as the carrying value of certain items that were discarded as a result of the upgrade. Additionally, we recorded $3.9 million in expected insurance proceeds for which we had received a partial proof of loss from the insurance company. As of December 31, 2014, $2.3 million of insurance proceeds had been collected. During the first quarter of 2015, we received a final payment of $2.9 million from the insurance company, and recognized an additional $1.3 million insurance recovery, representing the excess of the insurance recovery over the total impairment attributable to the damage to the rig.

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 fixed 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. 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.

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 once we complete our current rig conversion, expect all rig construction activities to cease. 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.

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, 2015, 2014 and 2013:

(In thousands, except per share data)	Year Ended December 31, 2015	December 31, 2014	December 31, 2013
Revenues	$88,418	$70,347	$42,786
Costs and expenses			
Operating costs	52,087	42,654	28,401
Selling, general and administrative	14,483	12,222	8,911
Depreciation and amortization	21,151	16,181	10,186
Goodwill impairment and other charges	—	30,627	—
Asset impairments, net of insurance recoveries	2,708	1,711	—
Loss (gain) on disposition of assets	2,940	19	(55)
Total cost and expenses	93,369	103,414	47,443
Operating loss	(4,951)	(33,067)	(4,657)
Interest expense	(3,254)	(1,648)	(257)
Gain on warrant derivative	—	3,189	1,035
Loss before income taxes	(8,205)	(31,526)	(3,879)
Income tax benefit	(325)	(3,358)	(1,882)
Net loss	$(7,880)	$(28,168)	$(1,997)
Other financial and operating data			
Number of completed rigs (end of period) (1)	14	11	7
Rig operating days (2)	3,732	2,944	1,745
Average number of operating rigs (3)	10.22	8.07	4.78
Rig utilization (4)	85.0%	99.7%	96.0%
Average revenue per operating day (5)	$22,921	$22,723	$21,351
Average cost per operating day (6)	$12,857	$12,759	$12,632
Average rig margin per operating day	$10,064	$9,964	$8,719

(1) Number of completed rigs as of December 31, 2015 increased by three compared to the number of completed rigs as of December 31, 2014, reflecting the addition of three newly constructed rigs to our fleet. Number of completed rigs as of December 31, 2014 increased by four compared to the number of completed rigs as of December 31, 2013, reflecting the addition of four newly constructed rigs to our fleet.

(2) Rig operating days represent the number of days that our rigs are earning revenue under a contract.

(3) 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.

(4) Rig utilization is calculated as rig operating days divided by the total number of days our drilling rigs are available during the applicable period. During the third quarter of 2015, we elected to remove two 100 series non-walking rigs from our marketed fleet pending completion of their planned rig conversions to 200 series, pad-optimal status. Rig utilization during the second half of 2015 excludes these two rigs.

(5) Average revenue per operating day represents total contract drilling revenues earned during the period divided by rig operating days in the period. The following revenues are excluded in calculating average revenue per operating day: (i) revenues associated with reimbursement of costs paid by customers of $2.9 million, $3.2 million and $2.4 million during the years ended 2015, 2014 and 2013, respectively, and (ii) direct revenues associated with repair and service and other revenues from third-party drilling contractors of $0.2 million and $3.2 million during the years ended 2014 and 2013, respectively.

(6) 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) costs relating to out-of-pocket costs reimbursed by customers of $2.9 million, $3.2 million and $2.4 million during the years ended 2015, 2014 and 2013, respectively, (ii) non-recurring rentals of drilling equipment of $0.5 million during the year ended 2013, (iii) new crew training costs of $0.8 million, $1.8 million and $1.3 million during the years ended 2015, 2014 and 2013, respectively, (iv) direct operating costs associated with repair and service and other revenues from third-party drilling contractors of $0.1 million and $2.1 million during the years ended 2014 and 2013, respectively, and (v) construction overhead costs expensed due to reduced rig construction activity of $0.5 million during the fourth quarter of 2015.

Comparison of the years ended December 31, 2015 and 2014

Revenues

Revenues for the year ended December 31, 2015 were $88.4 million, representing a 25.7% increase over revenues for the year ended December 31, 2014 of $70.3 million. This increase was primarily related to the addition of three drilling rigs into our operating fleet during 2015, which is reflected in the increase in our average number of operating rigs to 10.22 during 2015 compared to 8.07 during 2014. Average revenue per operating day increased to $22,921 during 2015, compared to $22,723 during 2014.

Operating Costs

Operating costs for the year ended December 31, 2015 were $52.1 million, representing a 22.1% increase over operating costs for the year ended December 31, 2014 of $42.7 million. This increase was primarily related to the addition of three drilling rigs into our operating fleet during 2015 as well as $0.5 million of construction overhead costs that were expensed due to reduced rig construction activity during the fourth quarter of 2015. During the year ended December 31, 2015, our cost per operating day was $12,857, representing a 1% increase compared to 2014 operating cost per day of $12,759.

Selling, General and Administrative Expenses

Selling, general and administrative expenses for the year ended December 31, 2015 were $14.5 million, representing a 18.5% increase over selling, general and administrative expenses for the year ended December 31, 2014 of $12.2 million. This increase primarily relates to $1.0 million in administrative costs incurred for idle rig locations, as well as costs associated with us becoming a public company in August 2014. These public company costs include increased non-cash stock based compensation relating to awards granted at the IPO of $0.4 million, and higher insurance costs, professional fees and other expenses of $0.9 million. The prior year selling, general and administrative expenses included $0.7 million in costs associated with the IPO.

Depreciation and Amortization

Depreciation and amortization for the year ended December 31, 2015 was $21.2 million, representing a 30.7% increase compared to the year ended December 31, 2014. This increase was directly related to the introduction of three new drilling rigs constructed by us in 2015 and a full year of depreciation for rigs constructed during 2014. We begin depreciating our rigs when they commence drilling operations.

Goodwill Impairment and Other Charges

Goodwill impairment and other charges for the year ended December 31, 2014 were $30.6 million. There was no goodwill impairment or other charges in 2015.

The impairments and other charges in December 2014 were deemed necessary due to the significant downturn in industry conditions in late 2014 and related uncertainty regarding demand for our contract drilling services and new rig construction. Based on our analysis of goodwill, we recorded a goodwill impairment of $11.0 million for the year ended December 31, 2014, which represents the impairment of 100% of the goodwill recorded in a business combination. We also accelerated the amortization of our rig manufacturing intellectual property, as we revised the estimate of the remaining useful life from 7.2 years to zero. As a result we recorded additional amortization expense of $19.6 million. This additional amortization expense, as well as our goodwill impairment, were reported in our statement of operations as goodwill impairments and other charges.

Asset Impairments, net of Insurance Recoveries

During the fourth quarter of 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. We have the ability to upgrade this rig when market conditions improve. 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.

In March 2014, one of our non-walking drilling rigs suspended drilling operations due to damage to the rig’s mast and other operating equipment. The cost to repair and replace this equipment was covered by insurance, subject to a deductible. While under repair, we upgraded this rig by adding a substructure and other equipment that included an omni-directional walking system. The cost of the upgrades were not covered by insurance. The repairs and upgrades were completed in October 2014, and the upgraded rig was renamed Rig 208. As a result, in 2014, we recorded an asset impairment charge of $4.7 million, representing an estimate of the damage sustained to the rig, as well as the carrying value of certain items that were discarded as a result of the upgrade. Additionally, we recorded $3.9 million in expected insurance proceeds for which we had received a partial proof of loss from the insurance company. As of December 31, 2014, $2.3 million of insurance proceeds had been collected. During the first quarter of 2015, we received a final payment of $2.9 million from the insurance company, and recognized an additional $1.3 million insurance recovery, representing the excess of the insurance recovery over the total impairment attributable to the damage to the rig.

Loss on Disposition of Assets

A loss on the disposition of assets totaling $2.9 million was recorded for the twelve months ended December 31, 2015 compared to a loss on the disposition of assets totaling $19,000 in the prior year comparable period. During the third quarter of 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 will be 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, 2015 was $3.3 million, as compared to $1.6 million for the year ended December 31, 2014 primarily as a result of increased borrowings under our revolving credit facility. Additionally, as a result of the reduction in the aggregate commitments of our Credit facility amended in October 2015 (see Note 7 - Long-Term Debt), we wrote off $0.4 million of unamortized deferred financing costs associated with the original and amended Credit Facility recorded prior to the October 2015 amendment.

Gain on Warrant Derivative

As part of the consideration paid to GES for their contribution of our rig construction operations and intellectual property, we issued to GES a warrant to purchase 2.2 million shares of common stock. The terms of this warrant contained a feature that would allow the exercise price to be adjusted in the event we issued any shares of common stock at a price below $12.74 per share during the term of the warrant. As a result of this feature, we accounted for the warrant as a derivative liability on our balance sheet and recorded changes in fair value each reporting period through earnings. Based on the closing price of our stock on December 31, 2014 and the short period of time until the expiration of the GES Warrant on March 2, 2015, the warrant had no value as of December 31, 2014, and we recorded a non-cash gain on warrant derivative associated with the changes in fair value of $3.2 million for the year ended December 31, 2014. The warrant expired unexercised March 2, 2015.

Income Tax Benefit

The income tax benefit recorded for the year ended December 31, 2015 amounted to $0.3 million compared to an income tax benefit of $3.4 million for the year ended December 31, 2014. The effective tax rate was 4.0% for the year ended 2015 compared to 10.7% for the year ended 2014. The 2015 benefit related primarily to Texas Margin Tax, as we have recorded a full valuation allowance against our deferred tax assets for federal purposes. The 2014 rate was impacted by a permanent difference associated with the impairment of goodwill and a valuation allowance recorded in 2014 on all of our net deferred tax assets.

Comparison of the years ended December 31, 2014 and 2013

Revenues

Revenues for the year ended December 31, 2014 were $70.3 million, representing a 64.4% increase over revenues for the year ended December 31, 2013 of $42.8 million. This increase was primarily related to the addition of four drilling rigs into our operating fleet during 2014, which is reflected in the increase in our average number of operating rigs to 8.07 during 2014 compared to 4.78 during 2013. Average revenue per operating day increased to $22,723 during 2014, compared to $21,351 during 2013.

Operating Costs

Operating costs for the year ended December 31, 2014 were $42.7 million, representing a 50.2% increase over operating costs for the year ended December 31, 2013 of $28.4 million. This increase was primarily related to the addition of four drilling rigs into our operating fleet during 2014. During the year ended December 31, 2014, our cost per operating day was $12,759, representing a 1% increase compared to 2013 operating cost per day of $12,632.

Selling, General and Administrative Expenses

Selling, general and administrative expenses for the year ended December 31, 2014 were $12.3 million, representing a 38.0% increase over selling, general and administrative expenses for the year ended December 31, 2013 of $8.9 million. This increase primarily relates to costs associated with us becoming a public company in August 2014, including costs associated with increased non-cash stock based compensation relating to awards granted at the IPO, higher executive salaries and other costs associated with maintaining and operating a publicly traded company. In addition, during 2014 we incurred approximately $0.7 million of professional fees and acceleration of vesting of stock-based awards directly associated with the closing of the IPO.

Depreciation and Amortization

Depreciation and amortization for the year ended December 31, 2014 was $16.2 million, representing a 58.9% increase compared to the year ended December 31, 2013 of $10.2 million. This increase was directly related to the introduction of four new drilling rigs constructed by us in 2014 and a full year of depreciation for rigs constructed during 2013. We begin depreciating our rigs when they commence drilling operations.

Goodwill Impairment and Other Charges

Goodwill impairment and other charges for the year ended December 31, 2014 was $30.6 million. There was no goodwill impairment or other charges in 2013.

The impairments and other charges in December 2014 were deemed necessary due to the significant downturn in industry conditions in late 2014 and related uncertainty regarding demand for our contract drilling services and new rig construction. Based on our analysis of goodwill, we recorded a goodwill impairment of $11.0 million for the year ended December 31, 2014, which represents the impairment of 100% of the goodwill recorded in certain contribution transactions completed March 12, 2012. We also accelerated the amortization of our rig manufacturing intellectual property, as we revised the estimate of the remaining useful life from 7.2 years to zero. As a result we recorded additional amortization expense of $19.6 million. This additional amortization expense, as well as our goodwill impairment, were reported in our statement of operations as goodwill impairments and other charges.

Interest Expense

Interest expense for the year ended December 31, 2014 was $1.6 million, as compared to $0.3 million for the year ended December 31, 2013 as a result of increased borrowings under our revolving credit facility. We did not borrow under our original revolving credit facility until July 2013.

Gain on Warrant Derivative
As part of the consideration paid to GES for their contribution of our rig construction operations and intellectual property, we issued to GES a warrant to purchase 2.2 million shares of common stock. The terms of this warrant contained a feature that would allow the exercise price to be adjusted in the event we issued any shares of common stock at a price below $12.74 per share during the term of the warrant. As a result of this feature, we accounted for the warrant as a derivative liability on our balance sheet and recorded changes in fair value each reporting period through earnings. At December 31, 2013, the fair value of the warrant was estimated at $3.2 million, and we recorded a non-cash gain of $1.0 million for the year ended 2013. Based on the closing price of our stock on December 31, 2014 and the short period of time until the expiration of the GES Warrant on March 2, 2015, the warrant had no value as of December 31, 2014, and we recorded a non-cash gain on warrant derivative associated with the changes in fair value of $3.2 million for the year ended December 31, 2014. The warrant expired unexercised March 2, 2015.
Income Tax Benefit
The income tax benefit recorded for the year ended December 31, 2014 amounted to $3.4 million compared to an income tax benefit of $1.9 million for the year ended December 31, 2013. The effective tax rate was 10.7% for the year ended 2014 compared to 48.5% for the year ended 2013 as a result of a permanent difference associated with the impairment of goodwill and a valuation allowance recorded in 2014 on all of our net deferred tax assets.
Liquidity and Capital Resources
Our liquidity as of December 31, 2015 included approximately $35.9 million of availability under our revolving credit facility, $5.3 million of cash and $5.2 million of other net working capital. The aggregate commitments under our revolving credit facility are currently $125 million, and the borrowing base under our credit facility at December 31, 2015, was $98.6 million. Our principal use of capital has been the construction of land drilling rigs and associated equipment and working capital and inventories to support our growing drilling operations. Our first drilling rig was completed and began operating in May 2012. As of December 31, 2015, we had 14 rigs, including twelve completed 200 series ShaleDriller® rigs and two non-walking rigs that are scheduled for conversion. One of these rig conversions has commenced and we have ordered long lead-time items for the second conversion. However, we do not intend to complete the second rig conversion until market conditions improve. Our primary sources of capital to date have been funds received from our initial private placement, our IPO, cash flows from operations and our revolving credit facility.

Our liquidity as of December 31, 2014 included approximately $92.3 million of availability under our revolving credit facility and $10.8 million of cash. As of December 31, 2014, we had eleven completed ShaleDriller® rigs, and three additional rigs under construction.

Initial Public Offering

On August 7, 2014, our registration statement on Form S-1 (File No. 333-196914) was declared effective by the SEC for our IPO pursuant to which we sold an aggregate of 11,500,000 shares of our common stock at a price to the public of $11.00 per share, which included 1,500,000 share of our common stock sold pursuant to the exercise by the underwriters in full of their Over-Allotment Option. We completed our IPO of 10,000,000 shares of our common stock on August 13, 2014 and subsequently closed the issuance and sale of the additional 1,500,000 shares of our common stock pursuant to the Over-Allotment Option on August 29, 2014. Our common stock trades on the New York Stock Exchange under the ticker symbol ICD. Net proceeds from the offering were $116.5 million after deducting $7.6 million of underwriting discounts and commissions, as well as legal, accounting, printing and other expenses directly associated with the offering totaling $2.4 million.

Cash Flows

	Year Ended December 31,		
(in thousands)	2015	2014	2013
Cash flows provided by operating activities	$27,379	$3,809	$5,997

Cash flows used in investing activities	(72,219)	(112,686)	(59,273)
Cash flows provided by financing activities	39,427	116,904	18,599
Net (decrease) increase in cash and cash equivalents	$(5,413)	$8,027	$(34,677)

Net Cash Provided By Operating Activities

Cash provided by operating activities was $27.4 million for the twelve months ended December 31, 2015 compared to cash provided by operating activities of $3.8 million during the same period in 2014. 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, stock-based compensation, deferred taxes and amortization of deferred financing costs. Additionally, changes in working capital items such as accounts receivable, inventory, prepaid expense and accounts payable can significantly affect operating cash flows. Cash flows from operating activities during 2015 were higher as a result of a decrease in net loss, adjusted for non-cash items, of $23.8 million compared to $17.4 million in 2014. In addition, working capital changes increased cash flows from operating activities in 2015 by $3.6 million compared to a reduction of $13.6 million in 2014.

Cash provided by operating activities was $3.8 million for the twelve months ended December 31, 2014 compared to cash provided by operating activities of $6.0 million during the same period in 2013. Cash flows from operating activities during 2014 were lower than 2013 principally due to significant increases in investments in working capital relating to the expansion of our business in 2014.

Net Cash Used In Investing Activities

Cash used in investing activities was $72.2 million for the twelve months ended December 31, 2015 compared to $112.7 million during the same period in 2014. Our primary investing activities relate to the construction of new rigs. Each new rig includes a full complement of drilling tubulars and inventory of spare parts and supplies. In addition, we also maintain an inventory of capital spare rig components and tubulars, which support, our entire rig fleet in the event any critical component of one of our rigs is damaged or requires repair. During 2015, cash payments of $75.5 million for capital expenditures to fund the completion of three ShaleDriller® rigs that had begun construction in 2014 and to begin the conversion of one of our non-walking rigs to a 200 Series rig which will be completed in the first quarter of 2016, 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. During 2014, we spent $115.4 million on capital expenditures to complete an additional four ShaleDriller® rigs, to upgrade one rig with a walking system, to begin the construction of an additional three ShaleDriller® rigs completed in 2015, to increase our inventory of critical spares, and for maintenance capital expenditures on existing rigs. This amount was partially offset by insurance proceeds of $2.0 million and proceeds from the sale of plant, property and equipment of $0.7 million.

Cash used in investing activities was $112.7 million for the twelve months ended December 31, 2014 compared to $59.3 million during the same period in 2013. During 2013, we spent $59.7 million on capital expenditures to fund the completion of three additional ShaleDriller® rigs, to begin construction on two additional rigs, to increase our inventory of critical spares, and for maintenance capital expenditures on existing rigs. This amount was offset by $0.4 million we received from the sale of plant, property and equipment.

Net Cash Provided by Financing Activities

Cash provided by financing activities was $39.4 million for the twelve months ended December 31, 2015 compared to $116.9 million during the same period in 2014. During 2015, we made borrowings under our revolving credit facility of $140.6 million, offset by repayments under our revolving credit facility of $100.4 million, expenditures for deferred financing costs of $0.4 million and the purchase treasury stock of $0.3 million.

Cash provided by financing activities was $116.9 million for the twelve months ended December 31, 2014 compared to $18.6 million during the same period in 2013. During 2014, we received net proceeds from our IPO of $116.5 million and made borrowings under our revolving credit facility of $137.7 million. These proceeds were offset by repayments under our revolving credit facility of $134.9 million and expenditures for deferred financing costs of $2.1 million.

Future Liquidity Requirements

Our liquidity as of December 31, 2015 included approximately $35.9 million of availability under our revolving credit facility, $5.3 million of cash and $5.2 million of other net working capital. The aggregate commitments under our revolving credit facility are currently $125.0 million, and the borrowing base under our credit facility at December 31, 2015 was $98.6 million.

In light of the extreme downturn in market conditions and lack of visibility relating to the timing of any market recovery, we have suspended new build construction activities until market conditions improve. As a result, we intend to complete the one rig conversion we currently have in process, make maintenance capital expenditure required to maintain our operating fleet and complete opportunistic equipment upgrades as market conditions dictate. However, we do not intend to complete the second rig conversion or any new rigs until market conditions improve.

We believe that our cash and cash equivalents, cash flows from operating activities and borrowings available under our revolving credit facility will adequately finance all of our purchase commitments, capital expenditures and other cash requirements over the next 12 months. However, due to the extreme nature of the current industry downturn and lack of forward visibility, and the fact that a larger portion of our assumed future cash flows will be generated from rigs operating in the spot-market, there is increasing risk that our actual rig utilization and actual future cash flows will fall below our internal projections. Based on these conditions, we are evaluating and intend to continue to evaluate a variety of public or private equity or debt financings. Additionally, 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 financings. We cannot predict whether any such financings will be available, or on terms acceptable to us.

In particular, we believe the following facts and circumstances may impact our financial liquidity and operating strategy.

- Declining Customer Capex Budgets and Lack of Forward Visibility. The extreme industry downturn has required E&P operators to significantly decrease capital budgets, which significantly decreases the number of oil and gas wells they plan to drill, and thus, demand for drilling rigs. In many instances, our customers have not formalized 2016 budgets or have revised them several times as market conditions and oil prices have continued to decline. As a result, our ability to reliably predict future demand for our drilling rigs and services, including our future rig utilization and potential spot-market dayrates, has been impaired.

- Declining Backlog and Term Contract Base. At December 31, 2015, our backlog from term contracts was $74.4 million, of which $53.3 million is scheduled to be realized in 2016. During 2016, we have one rig rolling off a term contract during the first quarter of 2016, three during the second quarter of 2016, and one during the third quarter of 2016. Consequently, we expect to have only an average of 4.1 rigs operating under term contracts during the last six months of 2016. Due to the extreme downturn in market conditions, we do not currently expect that any of our expiring term contracts will be renewed on a long-term basis, and that all rigs with expiring contracts will be marketed in the spot-market on a well-to-well or short-term contract basis.

- Declining Borrowing Base. Since December 31, 2015, the lenders under our revolving credit facility have begun their regularly scheduled reappraisal of our rigs, and given the extreme downturn in market conditions, in particular the decline in oil prices below $30 since December 31, 2015, we currently expect that the appraised forced liquidation value of our eligible rigs to decline between 10% and 20%. Assuming that these revised appraisal values were utilized at December 31, 2015 to calculate our borrowing base, we estimate that our borrowing base would have declined to between $81.6 million and $90.1 million and that our availability under our credit facility would have declined to between $18.9 million and $27.4 million. 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 our rigs or if market conditions continue to decline.

At December 31, 2015, we had eleven rigs that were eligible to be included in the equipment portion of the borrowing base. Looking forward into 2016, as an increasing percentage of our rigs are marketed and operated on a spot-market basis, there is increasing risk that rigs currently included as eligible rigs for purposes of calculating the borrowing base cannot be recontracted and ultimately are removed from the borrowing base, which further reduces availability under our credit facility.

If at any time our borrowing base falls below our outstanding balance under our revolving credit facility, 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.

- Covenant Compliance. Our revolving 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’16: 3.75x; 2Q’16: 4.0x; 3Q’16: 4.25x; 4Q’16: 4.5x; 1Q’17: 4.0x; 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, 2015 the leverage ratio covenant was 3.75x.

The revolving credit facility also requires us to maintain a fixed charge coverage ratio ("FCCR") of not less than 1.1 to 1.0. The FCCR ratio 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 ratio: (1) capital expenditures incurred before November 1, 2015, (2) capital expenditures financed through capital sources other than the revolving credit facility and (3) up to approximately $8.3 million of certain other capital expenditures.

Further, our revolving credit facility requires us to maintain a minimum rig utilization covenant of at least 60% in 2016 and 70% in 2017. A rig is considered utilized when it is earning revenue, whether operating, standby or otherwise. Rigs that are “decommissioned” or “under repair” are not considered. At December 31, 2015, our rig utilization percentage under the revolving credit facility was 79.4%. As our backlog of term contracts continues to decline during 2016 and beyond, our ability to comply with this covenant increasingly relies upon our ability to maintain rig operations in the spot-market, which becomes increasingly more difficult to predict while the extreme downturn in market conditions persist of if they worsen.

Our compliance with each of these covenants depends significantly upon our level of cash flows and rig utilization in 2016 and beyond, which are based upon factors that are increasing difficult to predict. In particular, our ability to comply with these covenants in 2017 and beyond is predicated upon market conditions stabilizing in 2016 and beginning to improve throughout 2017. If we are not able to comply with the covenants contained in our revolving 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 covenants contained in our credit facility, or to cure any such non-compliance would have a material adverse effect on our liquidity and financial condition.

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

On May 10, 2013, we entered into a credit agreement (the “Credit Facility”) with a syndicate of financial institutions led by CIT Finance, LLC, that provided for a committed $60.0 million revolving credit facility and an additional uncommitted $20.0 million accordion feature that allowed for future increases in the facility.

In November 2014, we entered into an amended and restated credit agreement (the “Credit Facility”) with a syndicate of financial institutions led by CIT Finance LLC that provided for a committed $155.0 million revolving credit facility and an additional uncommitted $25.0 million accordion feature that allowed for future increases in the facility. On April 23, 2015, we amended the Credit Facility to provide for a springing lock-box arrangement. On October 20, 2015 in light of current market conditions and our reduced capital plans, we entered into an amendment to the Credit Facility to reduce aggregate commitments to $125.0 million and modified certain maintenance covenants.

The obligations under the Credit Facility are secured by all our assets and are unconditionally guaranteed by all of our 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 75% of the appraised forced liquidation value of our eligible, completed and owned drilling rigs. 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 on a semi-annual basis and are subject to upward or downward revisions as a result of market conditions as well as the age of the rig. Beginning on November 5, 2015, the 75% advance rate on our eligible completed and owned drilling rigs decreased by 1.25% per quarter. The Credit Facility matures on November 5, 2018.

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.

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. In light of declining market conditions, we amended the Credit Facility on October 20, 2015, to relax certain of our financial covenants in 2016 and 2017. As amended, the Credit Facility requires us to maintain a leverage ratio of net debt to adjusted EBITDA, as defined, as follows: 1Q’16: 3.75x; 2Q’16: 4.0x; 3Q’16: 4.25x; 4Q’16: 4.5x; 1Q’17: 4.0x; thereafter: 3.0x. The amendment also reduced the minimum rig utilization covenant to 60% in 2016 and 70% in 2017, and provided for the exclusion of certain capital expenditures from consideration in our fixed charge coverage ratio covenant. As of December 31, 2015 the leverage ratio covenant was 3.75x.

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 availability under the Credit Facility falls below the greater of (A) $15.0 million and (B) the lesser of 15% of the borrowing base or 15% 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 $62.7 million in outstanding borrowings under the Credit Facility at December 31, 2015. Remaining availability under the Credit Facility was $35.9 million at December 31, 2015, based on the borrowing base formula, and we are currently in compliance with all covenants under the Credit Facility.

Contractual Obligations

As of December 31, 2015, we had contractual obligations as described below. Our obligations include "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)	2016	2017	2018	2019	2020	Thereafter	Total
Long-term debt	$—	$—	$62,708	$—	$—	$—	$62,708
Interest on long-term debt	3,586	3,587	3,174	—	—	—	10,347
Operating leases	493	282	71	50	—	—	896
Purchase obligations	11,534	9,226	7,233	—	—	—	27,993
Total contractual obligations	$15,613	$13,095	$73,186	$50	$—	$—	$101,944

Our long-term debt as of December 31, 2015 consisted of amounts due under our revolving 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, 2015 under our revolving credit facility. Our operating leases relate primarily to real estate and vehicles.

Our purchase obligations relate primarily to outstanding purchase orders for rig equipment or components ordered but not received. Given the severe nature of the current downturn, and in order to preserve liquidity under our revolving credit facility, we have informed our key vendors that we intend to delay purchases of equipment currently scheduled for delivery in 2016 until market conditions improve. With respect to equipment deliveries scheduled for 2016, we have made progress payments of approximately $7.8 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 and 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.

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.

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. For the years ended December 31, 2015 and 2014, 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 as "Asset impairments, net of insurance recoveries" 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. We have the ability to upgrade this rig when market conditions improve. 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 year ended December 31, 2015, 2014 and 2013 amounted to $0.9 million, $1.0 million and $0.4 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.

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 are material to investors. These arrangements relate to non-cancelable operating leases and unconditional purchase obligations not fully reflected on our balance sheets. See "- Contractual Obligations" for additional information.

Recent Accounting Pronouncements

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.

In May 2014, the Financial Accounting Standards Board (the "FASB") issued an accounting standards update to provide guidance on the recognition of revenue from customers. Under this guidance, 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. This guidance 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. This guidance is effective for interim and annual periods beginning after December 15, 2017. We are currently evaluating the impact this guidance will have on our financial statements.

In June 2014, the FASB issued an accounting standards update to provide guidance on the accounting for share-based payments when the terms of an award provide that a performance target could be achieved after the requisite service period. The guidance requires that a performance target that affects vesting and that could be achieved after the requisite service period is treated as a performance condition. This guidance is effective for interim and annual periods beginning after December 15, 2015. Adoption of this guidance is not expected to have a material impact on our financial statements.

In August 2014, the FASB issued guidance requiring management to perform interim and annual assessments of an entity’s ability to continue as a going-concern within one year of the date the financial statements are issued. The standard also provides guidance on determining when and how to disclose going-concern uncertainties in the financial statements. An entity must provide certain disclosures if there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity’s ability to continue as a going-concern. Management’s evaluation should be based on relevant conditions and events that are known and reasonably knowable at the date that the financial statements are issued. The new guidance applies to all entities and is effective for annual periods ending after December 15, 2016, and interim periods thereafter, with early adoption permitted. We will begin performing the assessments and making the required disclosures, if applicable, beginning at the end of fiscal year 2016.

In April 2015, the FASB issued an accounting standards update intended to simplify the presentation of debt issuance costs. This new guidance requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of the debt liability, consistent with debt discounts. This guidance is effective for public companies for fiscal years beginning after December 15, 2015. This guidance will affect the presentation of deferred issuance costs on the balance sheet but will not have any impact on our results of operations or financial position. Had this guidance been adopted at December 31, 2015 and 2014, respectively, $1.8 million and $2.3 million of debt issuance costs would have been reclassed from "Other long-term assets, net" to reduce "Long-term debt" and "Current portion of long-term debt," respectively.

In July 2015, the FASB issued an accounting standards update requiring an entity to measure inventory at the lower of cost or market. Market could be replacement cost, net realizable value, or net realizable value less an approximately normal profit margin. The amendments do not apply to inventory that is measured using last-in, first-out ("LIFO") or the retail inventory method. The amendments apply to all other inventory, which includes inventory that is measured using first-in, first-out ("FIFO") or average cost. Management should measure in scope inventory at the lower of cost and net realizable value. Net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. Subsequent measurement is unchanged for inventory measured using LIFO or the retail inventory method. This guidance is effective for public companies for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. The amendments should be applied prospectively with earlier application permitted as of the beginning of an interim or annual reporting period. Adoption of this pronouncement is not expected to have a material impact on our financial statements.

In November 2015, the FASB issued an accounting standards update intended to simplify the presentation of deferred income taxes. This new guidance requires that deferred income tax liabilities and assets be classified as noncurrent in a classified statement of financial position. Current Generally Accepted Accounting Principles require an entity to separate deferred income tax liabilities and assets into current and noncurrent amounts in a classified statement of financial position. This guidance is effective for public companies for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. The amendments should be applied prospectively with earlier application permitted as of the beginning of an interim or annual reporting period. We adopted this accounting standard for 2015. Prior periods were not retrospectively adjusted.

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, 2015 included $62.7 million of floating-rate debt attributed to borrowings at an average interest rate of 5.14%. As a result, our annual interest cost in 2015 will fluctuate based on short-term interest rates.

The impact on annual cash flow of a 10% change in the floating-rate (approximately 0.51%) would be approximately $0.3 million annually based on the floating-rate debt and other obligations outstanding at December 31, 2015; 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. Oil prices declined significantly during the second half of 2014, remained depressed in 2015 and have continued to decline in 2016. The closing price of oil was as high as $106.06 per barrel during the third quarter of 2014, was $37.13 on December 31, 2015 and declined to as low as $26.68 in January 2016 (WTI spot price as reported by the United States Energy Information Administration). As a result of the decline in oil prices, our industry is now experiencing an extreme downturn that has resulted in reduced industry utilization and significant declines in spot-market day rates and opportunities. Market conditions remain very dynamic. Although the magnitude of any additional market declines as well as the duration of this downturn are not yet known, we believe 2016 will continue to be an extremely challenging year for ICD and our industry.

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, such as we are currently experiencing, 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

We have audited the accompanying balance sheet of Independence Contract Drilling, Inc. as of December 31, 2015, and the related statements of operations, changes in stockholders' equity, and cash flows for the year then ended. In connection with our audit of the financial statements, we have also audited the financial statement schedule as of and for the year ended December 31, 2015 listed in the accompanying index. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements and schedule. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Independence Contract Drilling, Inc. at December 31, 2015, and the results of its operations and its cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States of America.

Also, in our opinion, the related financial statement schedule as of and for the year ended December 31, 2015, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth within.

/s/ BDO USA, LLP
Houston, Texas
February 18, 2016

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Independence Contract Drilling, Inc.:

In our opinion, the financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Independence Contract Drilling at December 31, 2014, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Houston, TX
March 16, 2015

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

	December 31, 2015	December 31, 2014
Assets		
Cash and cash equivalents	$5,344	$10,757
Accounts receivable, net	18,240	19,127
Inventory	2,317	2,124
Deferred income taxes	—	323
Prepaid expenses and other current assets	3,436	3,969
Total current assets	29,337	36,300
Property, plant and equipment, net	283,378	250,498
Other long-term assets, net	2,074	2,749
Total assets	$314,789	$289,547
Liabilities and Stockholders' Equity		
Liabilities		
Current portion of long-term debt	$—	$22,519
Accounts payable	8,584	21,993
Accrued liabilities	10,206	6,970
Income taxes payable	—	408
Total current liabilities	18,790	51,890
Long-term debt	62,708	—
Other long-term liabilities	361	598
Deferred income taxes	193	323
Total liabilities	82,052	52,811
Commitments and contingencies (Note 12)		
Stockholders' equity		
Common stock, $0.01 par value, 100,000,000 shares authorized; 24,539,937 and 24,540,720 shares issued, respectively; 24,403,659 and 24,455,709 shares outstanding, respectively	244	245
Additional paid-in capital	276,948	272,751
Accumulated deficit	(43,169)	(35,289)
Treasury stock, at cost, 136,278 and 85,011 shares, respectively	(1,286)	(971)
Total stockholders' equity	232,737	236,736
Total liabilities and stockholders' equity	$314,789	$289,547

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

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

	Year Ended December 31,		
	2015	2014	2013
Revenues	$88,418	$70,347	$42,786
Costs and expenses			
Operating costs	52,087	42,654	28,401
Selling, general and administrative	14,483	12,222	8,911
Depreciation and amortization	21,151	16,181	10,186
Goodwill impairment and other charges	—	30,627	—
Asset impairments, net of insurance recoveries	2,708	1,711	—
Loss (gain) on disposition of assets	2,940	19	(55)
Total cost and expenses	93,369	103,414	47,443
Operating loss	(4,951)	(33,067)	(4,657)
Interest expense	(3,254)	(1,648)	(257)
Gain on warrant derivative	—	3,189	1,035
Loss before income taxes	(8,205)	(31,526)	(3,879)
Income tax benefit	(325)	(3,358)	(1,882)
Net loss	$(7,880)	$(28,168)	$(1,997)
Loss per share:			
Basic and Diluted	$(0.33)	$(1.65)	$(0.16)
Weighted average number of common shares outstanding:			
Basic and Diluted	23,904	17,078	12,179

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, 2012	12,309,194	$123	$150,447	$(5,124)	$(746)	$144,700
Restricted stock issued	88,706	1	(1)	—	—	—
Stock-based compensation	—	—	2,169	—	—	2,169
Net loss	—	—	—	(1,997)	—	(1,997)
Balances at December 31, 2013	12,397,900	$124	$152,615	$(7,121)	$(746)	$144,872
Restricted stock issued	576,096	6	(6)	—	—	—
Public offering, net of offering costs of $10,042	11,500,000	115	116,343	—	—	116,458
Purchase of treasury stock	(18,287)	—	—	—	(225)	(225)
Stock-based compensation	—	—	3,799	—	—	3,799
Net loss	—	—	—	(28,168)	—	(28,168)
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

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,		
	2015	2014	2013
Cash flows from operating activities			
Net loss	$(7,880)	$(28,168)	$(1,997)
Adjustments to reconcile net loss to net cash provided by operating activities			
Depreciation and amortization	21,151	16,181	10,186
Goodwill impairment and other charges	—	30,627	—
Asset impairments, net of insurance recoveries	2,708	1,711	—
Stock-based compensation	3,542	3,143	1,751
Gain on warrant derivative	—	(3,189)	(1,035)
Loss (gain) on disposition of assets	2,940	19	(55)
Deferred income taxes	193	(3,742)	(2,043)
Amortization of deferred financing costs	629	668	251
Write-off of deferred financing costs	394	—	—
Bad debt expense	132	123	93
Changes in assets and liabilities			
Accounts receivable	755	(10,161)	(3,802)
Inventory	(263)	(1,356)	(240)
Vendor advances	—	—	(3,977)
Prepaid expenses and other assets	(853)	(1,313)	(856)
Accounts payable and accrued liabilities	4,339	(985)	6,978
Income taxes payable	(408)	251	157
Related party receivable	—	—	586
Net cash provided by operating activities	27,379	3,809	5,997
Cash flows from investing activities			
Purchases of property, plant and equipment	(75,532)	(115,388)	(59,689)
Proceeds from insurance claims	2,899	2,038	—
Proceeds from the sale of assets	414	664	416
Net cash used in investing activities	(72,219)	(112,686)	(59,273)
Cash flows from financing activities			
Borrowings under credit facility	140,610	137,681	36,986
Repayments under credit facility	(100,421)	(134,942)	(17,206)
Initial public offering proceeds, net of offering costs of $10,042	—	116,458	—
Financing costs paid	(447)	(2,068)	(1,181)
Purchase of treasury stock	(315)	(225)	—
Net cash provided by financing activities	39,427	116,904	18,599
Net (decrease) increase in cash and cash equivalents	(5,413)	8,027	(34,677)
Cash and cash equivalents			
Beginning of year	10,757	2,730	37,407
End of year	$5,344	$10,757	$2,730

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 premium 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 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 currently consists of fourteen premium ShaleDriller® rigs. Of these fourteen rigs, twelve are 200 Series rigs equipped with our integrated omni-directional walking system that is specifically designed to optimize pad drilling for our customers. We also are substantially complete with the conversion of one of our non-walking rigs to 200 Series status, which we expect will be available for operations at the end of the first quarter of 2016. We also have the option to upgrade our remaining non-walking rig to 200 Series status when market conditions improve. Every ShaleDriller® 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 top drives, automated tubular handling systems and blowout preventer ("BOP") handling systems. Twelve of our fourteen rigs are equipped with bi-fuel capabilities (they 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 predominantly operating in the Permian Basin, and we have one rig operating in the Eaglebine region, however, our rigs have previously operated in the Mid-Continent region and Eagle Ford Shale, as well.
Our business depends on the level of exploration and production activity by oil and gas companies operating in the U.S., and in particular, the regions where we actively market our contract drilling services. The oil and gas exploration and production industry is a historically cyclical industry characterized by significant changes in the levels of exploration and development activities. Oil and gas prices and market expectations of potential changes in those prices significantly affect the levels of those activities. Worldwide political, regulatory, economic, and military events, as well as natural disasters have contributed to oil and gas price volatility historically, and are likely to continue to do so in the future. Any prolonged reduction in the overall level of exploration and development activities in the U.S. and the regions where we market our contract drilling services, whether resulting from changes in oil and gas prices or otherwise, could materially and adversely affect our business.

Recent Declines in Oil and Gas Prices and Drilling Activity
Oil prices began to decline in the second half of 2014, declined further during 2015 and have continued to decline 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 has fallen as low as $26.68 during January 2016 (WTI spot price as reported by the United States Energy Information Administration). As a result of the decline in oil prices, our industry is now experiencing an exceptional downturn, and market conditions remain very dynamic and are changing quickly. Although the magnitude, as well as the duration, of this downturn are not yet known, we believe that 2016 will be an exceptionally challenging year for ICD and our industry.
We believe the vast majority of E&P companies, including our customers, have significantly reduced their 2016 capital spending plans compared to 2015 levels. The initial impact of these spending reductions is evidenced by the published rig counts which have declined more than 60% since their peak in October 2014, and we believe the rig count in the United States may decline further in 2016 until oil and gas prices begin to stabilize and improve.

As a result of this deterioration in market conditions, our customers are principally focused on their most economic wells, drilling to maintain leasehold positions and on maintaining their most cost efficient operations that deliver the overall lowest cost of producing their wells and minimize their capital expenditures. As a result, operators are focusing more of their capital spending on horizontal drilling programs compared to vertical drilling. They also are more focused on utilizing drilling equipment and techniques that optimize costs and efficiency. Thus, we believe this rapid market deterioration 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.

Although we believe that the current market downturn is rapidly increasing the focus of our customers towards the use of premium drilling rigs such as our ShaleDriller®, and that premium operations such as ours have been less affected by the downturn relative to operations conducted by legacy fleets, the rapid pace and level of the market decline has negatively impacted pricing, utilization and contract tenors for premium rigs, including our ShaleDriller® rig. During 2015, our premium drilling fleet operated at 85% utilization, but we do not expect to maintain this level of utilization while this current market downturn continues. As of December 31, 2015, eleven of our twelve 200 series rigs were generating revenue.

Since December 31, 2015,

- One of our rigs operating on a farm out basis ceased operations under its contract. Although this arrangement allows us to recognize revenues and full margins for the duration of the contract, we do not expect this rig to recommence drilling operations in the near term.

- Two of our customers have informed us that they intend to place our rigs operating for them under term contracts on a standby-without-crew basis until market conditions improve. Although these arrangements allow us to continue to recognize revenue and earn expected margins for the durations of these contracts, we do not expect these two rigs to recommence drilling operations in the near term.

- One of our rigs operating under a term contract that expired during the first quarter of 2016 has become idle. We continue to market this rig, however, given current market conditions, we cannot accurately predict when this rig will return to work or that it can operate at profitable levels until market conditions improve.

In addition, two of our rigs operating at December 31, 2015 were operating under short-term contracts expiring in March 2016, and we also have several rigs operating under term contracts with terms scheduled to expire during 2016. We expect to market our rigs rolling off contracts in 2016 at substantially lower dayrates than where they historically have operated, and there can be no assurance that these rigs will be contracted or remain operating at profitable levels.

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

During the third quarter of 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 will be replaced, including the rig's substructure and various mud system components which are no longer compatible with the converted rig. As a result, we recorded a preliminary estimate of the related disposal loss totaling $2.5 million in "Loss (gain) on disposition of assets." During the fourth quarter we impaired 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. We have the ability to upgrade this rig when market conditions improve.

Amendment of Revolving Credit Facility

In light of declining market conditions, we amended the Credit Facility on October 20, 2015, to relax certain of our financial covenants in 2016 and 2017. As amended, the Credit Facility requires us to maintain a leverage ratio of net debt to adjusted EBITDA, not to exceed the following in the respective time periods: 1Q’16: 3.75x; 2Q’16: 4.0x; 3Q’16: 4.25x; 4Q’16: 4.5x; 1Q’17: 4.0x; thereafter: 3.0x. The amendment also reduced the minimum rig utilization covenant to 60% in 2016 and 70% in 2017, and provided for the exclusion of certain capital expenditures from consideration in our fixed charge coverage ratio covenant. As of December 31, 2015 the leverage ratio covenant was 3.75x. For additional information regarding our revolving credit facility, please see “Note 7 - Long-Term Debt.”

Initial Public Offering

On August 7, 2014, our registration statement on Form S-1 (File No. 333-196914) (the Form S-1) was declared effective by the Securities and Exchange Commission for our initial public offering pursuant to which we sold an aggregate of 11,500,000 shares of our common stock at a price to the public of $11.00 per share, which included 1,500,000 shares of our common stock sold pursuant to the exercise by the underwriters in full of their Over-Allotment Option. We completed our initial public offering of 10,000,000 shares of our common stock on August 13, 2014 and subsequently closed the issuance and sale of the additional 1,500,000 shares of our common stock pursuant to the Over-Allotment Option on August 29, 2014. Our common stock trades on the New York Stock Exchange under the ticker symbol ICD. Net proceeds from the offering were $116.5 million after deducting $7.6 million of underwriting discounts and commissions, as well as legal, accounting, printing and other expenses directly associated with the offering totaling $2.4 million. All of the outstanding borrowings on our revolving credit facility were repaid immediately following the offering.

Stock Split

On July 14, 2014, our board of directors approved a resolution to effect a 1.57-for-1 stock split of our common stock in the form of a stock dividend. The dividend was distributed on July 24, 2014 to holders of record as of July 21, 2014. The earnings per share information and all common stock information in these financial statements have been retroactively restated for all periods presented to reflect this stock split.

Damage Sustained on Rig 102

In March 2014, one of our non-walking drilling rigs suspended drilling operations due to damage to the rig's mast and other operating equipment. The cost to repair and replace this equipment was covered by insurance, subject to a deductible. While under repair, we upgraded this rig by adding a substructure and other equipment that included an omni-directional walking system. The cost of the upgrades were not covered by insurance. The repairs and upgrades were completed in October 2014 and the upgraded rig was renamed Rig 208. As a result, in 2014, we recorded an asset impairment charge of $4.7 million, representing a preliminary estimate of the damage sustained to the rig ($2.9 million), as well as the impairment of certain items that were discarded as a result of the upgrade ($1.8 million). Additionally, we recorded $3.9 million in expected insurance proceeds for which we had received a partial proof of loss from the insurance company. As of December 31, 2014, $2.3 million of insurance proceeds had been collected. During the first quarter of 2015, we received a final payment of $2.9 million from the insurance company, and recognized an additional $1.3 million insurance recovery, representing the excess of the insurance recovery over the total impairment attributable to the damage to the rig.

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 or 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 and $0.1 million as of December 31, 2015 and 2014, respectively.

Inventory

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

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.

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

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	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 do not currently have any capital leases.

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. For the years ended December 31, 2015 and 2014, 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 as "Asset impairments, net of insurance recoveries" 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. We have the ability to upgrade this rig when market conditions improve. 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 years ended December 31, 2015. During the year ended December 31, 2014, we recorded an impairment of $4.7 million associated with the damage to one of our non-walking rigs. We did not record any asset impairment for the year ended December 31, 2013.

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 $0.9 million, $1.0 million, and $0.4 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of the net assets acquired in connection with a business combination. Goodwill is not amortized, but rather tested and assessed for impairment annually or more frequently if certain events or changes in circumstance indicate the carrying amount may exceed fair value. The annual test for goodwill impairment is performed during the fourth quarter of each year and begins with a qualitative assessment of whether it is “more likely than not” that the fair value of our business is less than its carrying value. If the qualitative analysis indicates that it is “more likely than not” that our business’ fair value is less than its carrying value, the resulting goodwill impairment test would consist of a two-step accounting test. The first step of the goodwill impairment test identifies the potential impairment, resulting if the fair value of a reporting unit (including goodwill) is less than its carrying amount. If during testing, it is determined that the fair value of net assets (including goodwill) exceeds its carrying amount, the goodwill of such net assets are not considered impaired and the second step of the goodwill impairment test is not applicable. However, if the fair value of net assets (including goodwill) is less than its carrying amount, we would then proceed to the second step in the goodwill impairment test. The second step includes hypothetically valuing the net assets as if they had been acquired in a business combination. Then, the implied fair value of the net assets’ goodwill is compared to the carrying value of that goodwill. If the carrying value of net assets’ goodwill exceeds the implied fair value of the goodwill, an impairment loss is recognized in an amount equal to the excess, not to exceed the carrying value.

Our analysis of goodwill in 2014 considered the discounted cash flow method, market capitalization and the guideline company method. Based on this analysis, we recorded a goodwill impairment of $11.0 million for the year ended December 31, 2014, which represents the impairment of 100% of our goodwill. This impairment was primarily the result of the significant downturn in industry conditions in late 2014 and the related uncertainty regarding demand for our contract drilling services and new rig construction, as well as the decline in the price of our common stock as of December 31, 2014.

We had no goodwill recorded on our balance sheets as of December 31, 2015 and December 31, 2014.

Intangible Assets

Identifiable intangible assets with determinable lives have historically consisted of drilling contracts and rig manufacturing intellectual property. Intangibles related to the drilling contracts were amortized on a straight-line basis over their estimated useful lives of six months while the identified intangibles related to the rig manufacturing intellectual property were being amortized on a straight-line basis over their estimated useful lives of ten years. Identifiable intangibles are evaluated for impairment at the end of each reporting period if events occur or circumstances change that would more likely than not reduce the fair value of the intangibles below their carrying amounts. During the fourth quarter of 2014, as a result of the significant downturn in industry conditions in late 2014 and the related uncertainty regarding demand for our drilling services and new rig construction, we re-evaluated the cost efficiencies to be realized in future rig construction. As a result of this evaluation, and the economic environment, management reassessed the remaining useful life of our rig manufacturing intellectual property reducing it from 7.2 years, to zero years. As a result of this revised estimate, we recorded additional amortization expense of $19.6 million which was included in "Goodwill impairment and other charges" in the accompanying statements of operations.

Amortization expense recorded in the caption depreciation and amortization in our statement of operations was $2.7 million and $2.7 million for the years ended December 31, 2014 and 2013, respectively.

We had no identifiable intangible assets recorded on our balance sheets as of December 31, 2015 and December 31, 2014.

Financial Instruments and Fair value

In accordance with Accounting Standards Codification 815 “Accounting for Derivative Instruments and Hedging Activities,” as amended, this warrant derivative liability was marked-to-market each reporting period, with a corresponding non-cash gain or loss charged to the current period. 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. Our financial instruments that are subject to fair value measurements are a warrant to purchase approximately 2.2 million shares of our common stock, held by Global Energy Services Operating, LLC ("GES"), which expired unexercised on March 2, 2015, (the "GES Warrant") and long-term debt.

The GES Warrant contained a provision that protected the holder from a decline in the issue price of our common stock, or a “down-round” provision. Down-round provisions reduce the exercise or conversion price of a warrant or convertible instrument if a company either issues equity shares for a price that is lower than the exercise or conversion price of those instruments or issues new warrants or convertible instruments that have a lower exercise or conversion price. As a result of this provision, we accounted for this warrant as a liability. Following our initial public offering completed on August 13, 2014, and the full exercise of the Over-Allotment Option on August 29, 2014, the exercise price of the GES Warrant was reduced from $12.74 per share to $11.37 per share.

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Prior to the completion of our initial public offering on August 13, 2014, the warrant liability was recorded at fair value using Level 3 inputs. Significant Level 3 inputs used to calculate the fair value of the warrant included the estimated share price on the valuation date, expected volatility, risk-free interest rate and management's assumptions regarding the likelihood of a future repricing of these warrants pursuant to the down-round provision. After the initial public offering was completed on August 13, 2014, the warrant liability was recorded at fair value using Level 1 inputs.

As of December 31, 2014, the fair value of the GES Warrant was estimated at zero, and the warrant expired unexercised on March 2, 2015. There was no gain or loss associated with the warrant for the year ended December 31, 2015 and we recorded a non-cash gain on the warrant derivative associated with the changes in fair value of $3.2 million and $1.0 million for the years ended December 31, 2014 and December 31, 2013, respectively.

The following provides a reconciliation of financial liabilities measured at fair value on a recurring basis using Level 3 inputs:

	December 31,	
(in thousands)	2014	2013
Beginning balance	$3,189	$4,224
Issuance of GES warrant	—	—
Gain on warrant derivative	(3,189)	(1,035)
Ending balance	$—	$3,189

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 6.6%. The estimated fair value of our long-term debt totaled $59.7 million and $22.9 million as of December 31, 2015 and 2014, respectively, compared to a carrying amount of $62.7 million and $22.5 million as of December 31, 2015 and 2014, respectively.

Fair value measurements were applied with respect to our non-financial assets and liabilities measured on a nonrecurring basis, which primarily consisted of the fair value of measurements of goodwill, intangibles and property, plant and equipment for impairment purposes. There were no transfers between levels of the hierarchy for the years ended December 31, 2015 and 2014.

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 and 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.

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.

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, impairment of goodwill and intangible assets and the collectibility of accounts receivable.

Recently Issued Accounting Pronouncements

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.

In May 2014, the Financial Accounting Standards Board (the "FASB") issued an accounting standards update to provide guidance on the recognition of revenue from customers. Under this guidance, 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. This guidance 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. This guidance is effective for interim and annual periods beginning after December 15, 2017. We are currently evaluating the impact this guidance will have on our financial statements.

In June 2014, the FASB issued an accounting standards update to provide guidance on the accounting for share-based payments when the terms of an award provide that a performance target could be achieved after the requisite service period. The guidance requires that a performance target that affects vesting and that could be achieved after the requisite service period is treated as a performance condition. This guidance is effective for interim and annual periods beginning after December 15, 2015. Adoption of this guidance is not expected to have a material impact on our financial statements.

In August 2014, the FASB issued guidance requiring management to perform interim and annual assessments of an entity’s ability to continue as a going-concern within one year of the date the financial statements are issued. The standard also provides guidance on determining when and how to disclose going-concern uncertainties in the financial statements. An entity must provide certain disclosures if there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity’s ability to continue as a going-concern. Management’s evaluation should be based on relevant conditions and events that are known and reasonably knowable at the date that the financial statements are issued. The new guidance applies to all entities and is effective for annual periods ending after December 15, 2016, and interim periods thereafter, with early adoption permitted. We will begin performing the assessments and making the required disclosures, if applicable, beginning at the end of fiscal year 2016.

In April 2015, the FASB issued an accounting standards update intended to simplify the presentation of debt issuance costs. This new guidance requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of the debt liability, consistent with debt discounts. This guidance is effective for public companies for fiscal years beginning after December 15, 2015. This guidance will affect the presentation of deferred issuance costs on the balance sheet but will not have any impact on our results of operations or financial position. Had this guidance been adopted at December 31, 2015 and 2014, respectively, $1.8 million and $2.3 million of debt issuance costs would have been reclassed from "Other long-term assets, net" to reduce "Long-term debt" and "Current portion of long-term debt" respectively.

In July 2015, the FASB issued an accounting standards update requiring an entity to measure inventory at the lower of cost or market. Market could be replacement cost, net realizable value, or net realizable value less an approximately normal profit margin. The amendments do not apply to inventory that is measured using last-in, first-out ("LIFO") or the retail inventory method. The amendments apply to all other inventory, which includes inventory that is measured using first-in, first-out ("FIFO") or average cost. Management should measure in scope inventory at the lower of cost and net realizable value. Net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. Subsequent measurement is unchanged for inventory measured using LIFO or the retail inventory method. This guidance is effective for public companies for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. The amendments should be applied prospectively with earlier application permitted as of the beginning of an interim or annual reporting period. Adoption of this pronouncement is not expected to have a material impact on our financial statements.

In November 2015, the FASB issued an accounting standards update intended to simplify the presentation of deferred income taxes. This new guidance requires that deferred income tax liabilities and assets be classified as noncurrent in a classified statement of financial position. Current Generally Accepted Accounting Principles require an entity to separate deferred income tax liabilities and assets into current and noncurrent amounts in a classified statement of financial position. This guidance is effective for public companies for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. The amendments should be applied prospectively with earlier application permitted as of the beginning of an interim or annual reporting period. We adopted this accounting standard for 2015. Prior periods were not retrospectively adjusted.

3. Revision of Prior Year Financial Statements

We revised the classification of long-term debt in our balance sheet as of December 31, 2014 from long-term debt to current portion of long-term debt due to our credit facility including both a required lock-box payment method and a subjective acceleration clause permitting the lenders to declare an event of default in the event of a material adverse change. We amended our credit facility in April 2015 to provide for a springing lock-box arrangement to permit the long-term classification of the debt, subject to the credit facility’s ultimate maturity and our compliance with its terms and conditions. The correction of the misclassification did not affect previously reported net income, total assets, total liabilities or stockholders' equity or cash flows as of and for the years ended December 31, 2014 or 2013. The net impact of the reclassification to the balance sheet at December 31, 2014, was to (i) reduce long-term debt from $22.5 million to zero; and (ii) increase the current portion of long-term debt from zero to $22.5 million, which also increased current liabilities from $29.4 million to $51.9 million. We analyzed the reclassifications under SEC staff guidance and determined that the impact of the reclassification was not material to previously issued financial statements.

4. Inventory

Inventory consisted of the following:

	December 31,	
(in thousands)	2015	2014
Raw materials and purchased components	$2,317	$2,124

We determined that no reserve for obsolescence was needed at December 31, 2015 or December 31, 2014. No inventory obsolescence expense was recognized during the years ended December 31, 2015 and 2014.

5. Property, Plant and Equipment

Property, plant, and equipment consisted of the following:

	December 31,	
(in thousands)	2015	2014
Land	$1,344	$1,344
Buildings	4,115	2,025
Drilling rigs and related equipment	288,094	227,758
Machinery, equipment and other	1,469	1,287
Vehicles	285	266
Software	806	714
Construction in progress	28,313	38,974
Total	$324,426	$272,368
Less: Accumulated depreciation	(41,048)	(21,870)
Total Property, plant and equipment, net	$283,378	$250,498

Repairs and maintenance expense included in operating costs in our statements of operations totaled $10.5 million, $7.4 million and $3.9 million for the years ended December 31, 2015, 2014 and 2013, respectively. Depreciation expense was $21.2 million, $13.4 million, and $7.5 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Amortization expense related to intangible assets recorded in the caption depreciation and amortization in our statements of operations was $0.0 million, $2.7 million and $2.7 million for the years ended December 31, 2015, 2014 and 2013, respectively.

6. Supplemental Balance Sheet and Cash Flow Information

Accrued liabilities consisted of the following:

	December 31,	
(in thousands)	2015	2014
Accrued salaries and other compensation	$2,050	$2,710
Insurance	600	488
Deferred revenues	4,591	1,281
Property, sales and other tax	2,585	1,710
Other	380	781
	$10,206	$6,970

Supplemental cash flow information:

	Year Ended December 31,		
(in thousands)	2015	2014	2013
Supplemental disclosure of cash flow information			
Cash paid during the year for interest	$3,173	$1,907	$196
Cash paid during the year for taxes	135	135	—
Cash received during the year for tax refund	(113)	—	—
Supplemental disclosure of non-cash investing and financing activities			
Stock-based compensation capitalized as property, plant and equipment	654	656	418
Change in property, plant and equipment purchases in accounts payable	(14,750)	17,318	(6,288)

7. Long-Term Debt

On May 10, 2013, we entered into a credit agreement (the “Credit Facility”) with a syndicate of financial institutions led by CIT Finance, LLC, that provided for a committed $60.0 million revolving credit facility and an additional uncommitted$20.0 million accordion feature that allowed for future increases in the facility.

In November 2014, we entered into an amended and restated credit agreement (the “Credit Facility”) with a syndicate of financial institutions led by CIT Finance, LLC, that provided for a committed $155.0 million revolving credit facility and an additional uncommitted $25.0 million accordion feature that allowed for future increases in the facility. On April 23, 2015, we amended the Credit Facility to provide for a springing lock-box arrangement. On October 20, 2015 in light of current market conditions and our reduced capital plans, we entered into an amendment to the Credit Facility to reduce aggregate commitments to $125.0 million and to modify certain maintenance covenants. The obligations under the Credit Facility are secured by all our assets and are unconditionally guaranteed by all of our 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 75% of the appraised forced liquidation value of our eligible, completed and owned drilling rigs. 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 on a semi-annual basis and are subject to upward or downward revisions as a result of market conditions as well as the age of the rig. Beginning on November 5, 2015, the 75% advance rate on our eligible completed and owned drilling rigs decreased by 1.25% per quarter. The Credit Facility matures on November 5, 2018.

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, 2015, the weighted average interest rate on our borrowings was 5.14%.

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 mentioned above, in light of declining market conditions, we amended the Credit Facility on October 20, 2015, to relax certain of our financial covenants in 2016 and 2017. As amended, the Credit Facility requires us to maintain a leverage ratio of net debt to adjusted EBITDA, not to exceed the following in the respective time periods: 1Q’16: 3.75x; 2Q’16: 4.0x; 3Q’16: 4.25x; 4Q’16: 4.5x; 1Q’17: 4.0x; thereafter: 3.0x. The amendment also reduced the minimum rig utilization covenant to 60% in 2016, 70% in 2017 and 75% in 2018, and provided for the exclusion of certain capital expenditures from consideration in our fixed charge coverage ratio covenant. As of December 31, 2015 the leverage ratio covenant was 3.75x.

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 availability under the Credit Facility falls below the greater of (A) $15.0 million and (B) the lesser of 15% of the borrowing base or 15% 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 $62.7 million in outstanding borrowings under the Credit Facility at December 31, 2015. Remaining availability under the Credit Facility was $35.9 million at December 31, 2015, based on the borrowing base formula, and we are currently in compliance with all covenants under the Credit Facility.

8. Income Taxes

The components of the income tax benefit are as follows:

(in thousands)	Year Ended December 31, 2015	2014	2013
Current:			
Federal	$—	$—	$4
State	(518)	384	157
	$(518)	$384	$161
Deferred:			
Federal	$—	$(3,656)	$(1,506)
State	193	(86)	(537)
	$193	$(3,742)	$(2,043)
Income tax benefit	$(325)	$(3,358)	$(1,882)

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

(in thousands)	Year Ended December 31, 2015	2014	2013
Income tax benefit at the statutory federal rate (35%)	$(2,871)	$(11,034)	$(1,358)
Warrant	—	(1,116)	(362)
Goodwill impairment	—	3,852	—
Nondeductible expenses	148	143	243
Valuation allowance	2,261	4,449	—
State taxes, net of federal benefit	(211)	105	(436)
Stock-based compensation and other	348	243	31
Income tax benefit	$(325)	$(3,358)	$(1,882)
Effective tax rate	4.0%	10.7%	48.5%

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)	2015	2014
Deferred income tax assets		
Bad debts	$3	$46
Stock-based compensation	2,740	2,061
Accrued liabilities and other	52	76
Deferred revenue	1,775	667
Net operating losses	17,402	32,199
Total net deferred tax assets	$21,972	$35,049
Deferred income tax liabilities		
Prepaids	$(368)	$(300)
Property, plant and equipment	(15,087)	(30,300)
Total net deferred tax liabilities	$(15,455)	$(30,600)
Valuation allowance	$(6,710)	$(4,449)
Net deferred tax liability	$(193)	$—

At December 31, 2015, we had a total net operating loss ("NOL") carryforward of $49.6 million of federal NOL carryforwards, which begin expiring in 2031. During 2015, we filed amended federal tax returns for 2012 and 2013 to change our method of calculating tax depreciation. This resulted in a reduction of the federal NOL and corresponding deferred income tax asset associated with it. It also resulted in an offsetting decrease in the deferred income tax liability associated with the property, plant and equipment. The net tax effect of these amended returns on our deferred income tax position is zero.

Also 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.

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. 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, 2015, we had no unrecognized tax benefits. We file income tax returns in the U.S. and in various state jurisdictions. With few exceptions, we are subject to U.S. federal, state and local income tax examinations by tax authorities for tax periods 2011 and forward. Our federal and state tax returns for 2011 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. During 2014, 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. We came to the same conclusion as of December 31, 2015. All of our deferred tax liability as of

December 31, 2015 relates to Texas Margin Tax.

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.

9. 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 of 2014. 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 3,454,000 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, 2015, approximately 879,153 shares were available for future awards.

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

	Year Ended December 31,		
(in thousands)	2015	2014	2013
Compensation cost recognized:			
Stock options	$430	$1,133	$1,077
Restricted stock and restricted stock units	3,766	2,666	1,092
Total stock-based compensation	$4,196	$3,799	$2,169

Approximately $0.7 million, $0.7 million and $0.4 million in stock-based compensation was capitalized in connection with rig construction activity during the years ended December 31, 2015, 2014 and 2013, respectively.

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, 2015 or 2014.

No options were exercised during the years ended December 31, 2015, 2014 or 2013. 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 fair value calculations for options granted are based on the following weighted-average assumptions:

	Year Ended December 31, 2013	
Risk-free interest rate	0.83	%
Expected volatility	40	%
Dividend yield	—	
Expected term	5.0 years	

Risk-Free Interest Rate

The risk-free interest rate is based on U.S. Treasury securities with maturities that are the same as the expected term of the option.

Expected Volatility Rate

As we did not have a trading history in 2013, we were required to estimate the potential volatility of our common stock price. The volatility calculation was based on the average volatility of a representative sample of four companies (the “Sample Companies”) that management believes to be engaged in the land contract drilling business. We referred to the average volatility of the Sample Companies because management believed that the average volatility of such companies was a reasonable benchmark to use in estimating the expected volatility of our common stock.

Expected Dividend Yield

We have no plans to pay dividends in the foreseeable future.

Expected Term

The expected term of the options granted represents the period of time that they are expected to be outstanding.

Based on these calculations, the weighted-average fair value per option granted to acquire a share of common stock was $4.08 for options granted during the years ended and December 31, 2013.

The following summary reflects the stock option activity and related information for the year ended December 31, 2015:

	Options	Weighted Average Exercise Price
Outstanding at January 1, 2015	963,196	$12.74
Granted	—	—
Exercised	—	—
Forfeited/expired	(6,543)	12.74
Outstanding at December 31, 2015	956,653	$12.74
Exercisable at December 31, 2015	852,510	$12.74

A summary of our unvested stock options and the changes during the year ended December 31, 2015 is presented below:

	Outstanding	Weighted Average Grant-Date Fair Value
Unvested as of January 1, 2015	360,316	$4.32
Granted	—	—
Vested	(249,630)	4.54
Forfeited/expired	(6,543)	3.36
Unvested as of December 31, 2015	104,143	$3.88

The number of options exercisable at December 31, 2015 was 852,510 with a weighted average remaining contractual life of 6.3 years and a weighted-average exercise price of $12.74 per share.

As of December 31, 2015, the unrecognized compensation cost related to outstanding stock options was $0.2 million. This cost is expected to be recognized over a weighted-average period of 0.5 years. The fair value of options that vested during the years ended December 31, 2015, 2014 and 2013 was $1.1 million, $1.2 million and $0.9 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, 2015, there was $3.5 million of

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total unrecognized compensation cost related to unvested restricted stock awards. That cost is expected to be recognized over a weighted-average period of 0.8 years.
A summary of the status of our restricted stock awards and of changes in restricted stock outstanding for the year ended December 31, 2015 is as follows:

	Shares	Weighted Average Grant Date Fair Value Per Share
Outstanding at January 1, 2015	605,141	$10.82
Granted	—	—
Vested	(202,457)	10.85
Forfeited/expired	(14,419)	11.04
Outstanding at December 31, 2015	388,265	$10.80

Restricted Stock Units
We have granted restricted stock units ("RSUs") to key employees under the 2012 Plan. We have granted three year cliff vesting 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. Vesting of the market-based RSUs is based on our three year total shareholder return ("TSR") as measured against a three year TSR of a defined peer group and vesting of the performance-based RSUs is based on our cumulative EBITDA ("CEBITDA"), 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 CEBITDA 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, 2015, there was $2.3 million of total unrecognized compensation cost related to unvested RSUs. This cost is expected to be recognized over a weighted-average period of 0.8 years.

The assumptions used to value our TSR market-based RSUs granted during the year ended December 31, 2014 were a a risk-free interest rate of 0.08%, an expected volatility of 44.1% and an expected dividend yield of 0.0%. Based on the Monte Carlo simulation, these RSUs were valued at $16.74. There were no such RSU's granted during the year ended December 31, 2015.

A summary of the status of our RSUs as of December 31, 2015, and of changes in RSUs outstanding during the year ended December 31, 2015, is as follows:

	RSUs	Weighted Average Grant-Date Fair Value Per Share
Outstanding at January 1, 2015	516,774	$12.81
Granted	—	—
Vested and converted	(13,634)	11.00
Forfeited/expired	(39,727)	11.49
Outstanding at December 31, 2015	463,413	$12.97

10. Stockholders’ Equity and Loss per Share
As of December 31, 2015, we had a total of 24,403,659 shares of common stock, $0.01 par value, outstanding, including 388,265 shares of restricted stock. We also had 136,278 shares held as treasury stock. Total authorized

common stock is 100,000,000 shares.

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)	2015	2014	2013
Net loss (numerator)	$(7,880)	$(28,168)	$(1,997)
Loss per share:			
Basic and Diluted	$(0.33)	$(1.65)	$(0.16)
Shares (denominator):			
Weighted-average number of shares outstanding-basic	23,904	17,078	12,179
Net effect of dilutive stock options, warrants and restricted stock units	—	—	—
Weighted-average common shares outstanding-diluted	23,904	17,078	12,179

For all years presented, the computation of diluted loss per share excludes the effect of certain outstanding stock options and warrants because their inclusion would be anti-dilutive. The number of options that were excluded from diluted loss per share were 963,196 during each of the years ended December 31, 2015, 2014 and 2013. A warrant to purchase 2,198,000 shares of our common stock was anti-dilutive in each of the years ended December 31, 2015, 2014 and 2013 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 463,413, 516,774, and zero, respectively, for the years ended December 31, 2015, 2014 and 2013, respectively.

11. 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.

12. Commitments and Contingencies

Purchase Commitments

As of December 31, 2015, we had outstanding purchase commitments to a number of suppliers totaling $28.0 million related primarily to the construction of drilling rigs.

Lease Commitments

We lease certain land, equipment and vehicles under non-cancelable operating leases. The minimum rental commitments under non-cancelable operating leases, with lease terms in excess of one year subsequent to December 31, 2015, were as follows:

(in thousands)	
2016	$493
2017	282
2018	71
2019	50
2020	—
Thereafter	—
	$896

Rent expense was $3.6 million, $2.9 million and $2.1 million for the years ended December 31, 2015, 2014 and 2013, respectively.

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.

13. 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 gas prices. We have a number of customers that account for 10% or more of our revenues. 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%). For 2014, these customers included Laredo Petroleum, Inc. (22%), Apache Corporation (21%), COG Operating, LLC, a subsidiary of Concho Resources, Inc. (21%) and BOPCO, L.P. (20%). For 2013, these customers included Apache Corporation (30%), BOPCO, LP (16%), Newfield Exploration Company (11%), W&T Offshore, Inc. (10%) and Anadarko Petroleum Corporation (10%). 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. As of December 31, 2014, Apache Corporation (22%), COG Operating, LLC, a subsidiary of Concho Resources, Inc. (20%), BOPCO, L.P. (18%), Laredo Petroleum, Inc. (16%) and Pioneer Natural Resources USA, Inc. (11%) accounted for 10% or more of our accounts receivable. As of December 31, 2013, Apache Corporation (27%), Laredo Petroleum, Inc. (22%), BOPCO, LP (17%) and Rosetta Resources Operating L.P. (10%) 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, 2015, we had approximately $4.8 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.

14. Related Parties and Other Matters

During 2011, we entered into an asset contribution and share subscription agreement that involved our acquiring certain assets and liabilities from GES and Independence Contract Drilling LLC. One of our directors, was a director of the ultimate parent company of GES as of December 31, 2015, and one of our directors was a director of the ultimate parent company of GES through May 31, 2015. The director who continues to serve as a director of the ultimate parent company of GES is also the director of a fund that owned approximately 36% of the ultimate parent company of GES as of December 31, 2015.

We purchased certain items used in the construction of our drilling rigs from a former affiliate of GES. This vendor was sold by GES to a third party during the second quarter of 2015 and was no longer a related party. Total purchases from the vendor while it was a related party amounted to $1.2 million, $2.2 million and $10,000, during the twelve months ended December 31, 2015, 2014 and 2013, respectively. We had outstanding payables with this vendor totaling $0.5 million and zero as of December 31, 2014 and 2013, respectively.

One of our directors is also a director of one of our vendors from which we purchase oilfield equipment and related supplies. Total purchases from this vendor were $5.1 million and $8.6 million in 2015 and 2014, respectively. We had outstanding payables of $0.1 million and $0.4 million as of December 31, 2015 and 2014, respectively.

During 2015, the son of an executive officer and director of the Company began working in a sales capacity at, and became a minority owner of, a vendor from which we purchase oilfield equipment and related supplies. Total purchases from this vendor during 2015 were $0.1 million and we had outstanding accounts payables of $0.1 million dollars as of December 31, 2015. Prior to 2015, the son of this executive officer and director worked in a sales capacity at a separate vendor from whom we purchase oilfield equipment and related supplies. Total purchases from that vendor were $1.7 million and $0.6 million in 2014 and 2013 respectively. We had outstanding payables with that vendor of $0.6 million and $12,000 as of December 31, 2014 and 2013, respectively.

15. Unaudited Quarterly Financial Data

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

	Year Ended December 31, 2015			
	Quarter Ended			
(in thousands, except for per share data)	March 31	June 30	September 30	December 31
Revenue	$22,306	$21,082	$21,344	$23,686
Operating income (loss)	1,532	160	(2,841)	(3,802)
Income tax (benefit) expense	(155)	95	(326)	61
Net income (loss)	1,375	(652)	(3,377)	(5,226)
Earnings (loss) per share:				
Basic and Diluted	$0.06	$(0.03)	$(0.14)	$(0.22)

	Year Ended December 31, 2014			
	Quarter Ended			
(in thousands, except for per share data)	March 31	June 30	September 30	December 31
Revenue	$13,549	$14,661	$19,123	$23,014
Operating (loss) income	(5,199)	1,444	(672)	(28,640)
Income tax (benefit) expense	(1,885)	667	(352)	(1,788)
Net (loss) income	(3,705)	1,556	(1,413)	(24,606)
Earnings (loss) per share:				
Basic and Diluted	$(0.30)	$0.13	$(0.07)	$(1.00)

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, 2015				
Allowance for doubtful accounts	$129	$132	$(253)	$8
Valuation allowance for deferred tax assets	$4,449	$2,261	$—	$6,710
Year Ended December 31, 2014				
Allowance for doubtful accounts	$93	$123	$(87)	$129
Valuation allowance for deferred tax assets	$—	$4,449	$—	$4,449
Year Ended December 31, 2013				
Allowance for doubtful accounts	$256	$93	$(256)	$93
Valuation allowance for deferred tax assets	$—	$—	$—	$—

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, 2015 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. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

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, 2015. 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, 2015.

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 2016 Annual Meeting of Shareholders, which will be filed with the SEC within 120 business days of December 31, 2015.

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 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 U.S. 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 2016 Annual Meeting of Shareholders, which will be filed with the SEC within 120 business days of December 31, 2015.

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 2016 Annual Meeting of Shareholders, which will be filed with the SEC within 120 business days of December 31, 2015.

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 2016 Annual Meeting of Shareholders, which will be filed with the SEC within 120 business days of December 31, 2015.

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 2016 Annual Meeting of Shareholders, which will be filed with the SEC within 120 business days of December 31, 2015.

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.

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 on this 18th day of February 2016.

INDEPENDENCE CONTRACT DRILLING, INC.

By:	/s/	Byron A. Dunn
	Name:	Byron A. Dunn
	Title:	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 18, 2016	By:	/s/	Byron A. Dunn
		Name:	Byron A. Dunn
		Title:	Chief Executive Officer and Director (Principal Executive Officer)
February 18, 2016	By:	/s/	Philip A. Choyce
		Name:	Philip A. Choyce
		Title:	Senior Vice President, Chief Financial Officer, Treasurer and Secretary (Principal Financial Officer)
February 18, 2016	By:	/s/	Michael J. Harwell
		Name:	Michael J. Harwell
		Title:	Vice President - Finance and Chief Accounting Officer (Principal Accounting Officer)
February 18, 2016	By:	/s/	Thomas R. Bates, Jr.
		Name:	Thomas R. Bates, Jr.
		Title:	Director
February 18, 2016	By:	/s/	Edward S. Jacob, III
		Name:	Edward S. Jacob, III

		Title:	President, Chief Operating Officer and Director
February 18, 2016	By:	/s/ Arthur Einav	
		Name:	Arthur Einav
		Title:	Director
February 18, 2016	By:	/s/ Matthew D. Fitzgerald	
		Name:	Matthew D. Fitzgerald
		Title:	Director
February 18, 2016	By:	/s/ Daniel F. McNease	
		Name:	Daniel F. McNease
		Title:	Director
February 18, 2016	By:	/s/ Tighe A. Noonan	
		Name:	Tighe A. Noonan
		Title:	Director

Glossary of Oil and Natural Gas Terms

Glossary of Oil and 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 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 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	Warrant to Purchase Common Stock of Independence Contract Drilling, Inc., dated March 2, 2012	Incorporated herein by reference to Exhibit 4.2 of the Draft Registration Statement on Form S-1 filed by Independence Contract Drilling, Inc. on May 13, 2014 (377-00611)
4.3	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)
4.4	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	Registration Rights Agreement by and among Independence Contract Drilling, Inc., FBR Capital Markets & Co., Sprott Resource Partnership, Independence Contract Drilling LLC, 4D Global Energy Investments plc and Global Energy Services Operating, LLC, dated March 2, 2012	Incorporated herein by reference to Exhibit 10.4 of the Registration Statement on Form S-1 filed by Independence Contract Drilling, Inc. on June 19, 2014 (Registration No. 333-196914)
10.2	Acknowledgement and Registration Rights Agreement, entered into as of July 17, 2014, by and among Independence Contract Drilling, Inc., FBR Capital Markets & Co., Sprott Resource Partnership, Independence Contract Drilling LLC, and Global Energy Services Operating, LLC	Incorporated herein by reference to Exhibit 10.22 of the Registration Statement on Form S-1 filed by Independence Contract Drilling, Inc. on July 18, 2014 (Registration No. 333-196914)
10.3	Credit Agreement, dated effective as of May 10, 2013, by and 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 10.7 of the Registration Statement on Form S-1 filed by Independence Contract Drilling, Inc. on July 18, 2014 (Registration No. 333-196914)
10.4	First Amendment to Credit Agreement, dated effective as of February 21, 2014, by and among Independence Contract Drilling, Inc., the Lenders	Incorporated herein by reference to Exhibit 10.8 of the Registration Statement on Form S-1 filed by Independence Contract Drilling, Inc. on July 18,

	party thereto and CIT Finance LLC, as Administrative Agent and Collateral Agent, as Issuing Bank and as Swingline Lender	2014 (Registration No. 333-196914)
10.5	Second Amendment to Credit Agreement, dated effective as of May 12, 2014, by and among Independence Contract Drilling, Inc., the Required 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 10.9 of the Registration Statement on Form S-1 filed by Independence Contract Drilling, Inc. on July 18, 2014 (Registration No. 333-196914)
10.6	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)

10.7	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)
10.8	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)
10.9	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)
10.10	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)
10.11	Amended and Restated Executive Employment Agreement between Independence Contract Drilling, Inc. and Edward S. Jacob, III, dated August 13, 2014	Incorporated herein by reference to Exhibit 10.4 of the Quarterly Report on Form 10-Q filed by Independence Contract Drilling, Inc. on September 19, 2014 (File No. 001-36590)
10.12	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)
10.13	Amended and Restated Executive Employment Agreement between Independence Contract Drilling, Inc. and Dave C. Brown, dated August 13, 2014	Incorporated herein by reference to Exhibit 10.5 of the Quarterly Report on Form 10-Q filed by Independence Contract Drilling, Inc. on September 19, 2014 (File No. 001-36590)
10.14	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)
10.15	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)
10.16	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)
10.17	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)
10.18	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)
10.19	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)
10.20	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)
10.21	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	
23.2*	Consent of PricewaterhouseCoopers 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.

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