Independence Contract Drilling, Inc.
Form 10-Q
November 06, 2018
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-Q
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2018
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission File Number: 001-36590
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.)
20475 State Highway 249, Suite 300 Houston, Texas	77070
(Address of principal executive offices)	(Zip code)

(281) 598-1230
(Registrant's telephone number, including area code)

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 x No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ¨	Accelerated filer x
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨
	Emerging growth company x

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. x
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x
75,693,676 shares of the registrant's Common Stock were outstanding as of November 2, 2018.

INDEPENDENCE CONTRACT DRILLING, INC.
Index to Form 10-Q
Part I. FINANCIAL INFORMATION

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

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

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

All forward-looking statements are necessarily only estimates of future results, and there can be no assurance that actual results will not differ materially from expectations, and, therefore, you are cautioned not to place undue reliance on such statements. Any forward-looking statements are qualified in their entirety by reference to the factors discussed throughout this Form 10-Q and Part I, “Item 1A. Risk Factors” of our Annual Report on Form 10-K for the fiscal year ended December 31, 2017. 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.

3

PART I — FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
Independence Contract Drilling, Inc.
Balance Sheets
(Unaudited)
(in thousands, except par value and share amounts)

	September 30, 2018	December 31, 2017
Assets		
Cash and cash equivalents	$ 2,965	$ 2,533
Accounts receivable, net	23,728	18,056
Inventories	3,087	2,710
Assets held for sale	3,898	4,637
Prepaid expenses and other current assets	4,188	2,957
Total current assets	37,866	30,893
Property, plant and equipment, net	277,978	272,388
Other long-term assets, net	1,763	1,364
Total assets	$ 317,607	$ 304,645
Liabilities and Stockholders' Equity		
Liabilities		
Current portion of long-term debt	$ 575	$ 533
Accounts payable	12,573	11,627
Accrued liabilities	8,912	6,969
Total current liabilities	22,060	19,129
Long-term debt	68,631	49,278
Deferred income taxes, net	563	683
Other long-term liabilities	632	73
Total liabilities	91,886	69,163
Commitments and contingencies (Note 11)		
Stockholders' equity		
Common stock, $0.01 par value, 100,000,000 shares authorized; 38,597,447 and 38,246,919 shares issued, respectively; and 38,252,765 and 37,985,225 shares outstanding, respectively	383	380
Additional paid-in capital	328,598	326,616
Accumulated deficit	(101,041)	(89,645)
Treasury stock, at cost, 344,682 and 261,694 shares, respectively	(2,219)	(1,869)
Total stockholders' equity	225,721	235,482
Total liabilities and stockholders' equity	$ 317,607	$ 304,645

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

4

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Revenues	$28,439	$23,445	$79,820	$64,966
Costs and expenses				
Operating costs	18,420	18,247	55,312	48,953
Selling, general and administrative	3,903	2,948	10,877	10,101
Merger expenses	1,933	—	2,376	—
Depreciation and amortization	6,831	6,529	20,001	19,120
Asset impairment, net	431	899	396	1,574
(Gain) loss on disposition of assets, net	(260)	—	(675)	1,573
Total costs and expenses	31,258	28,623	88,287	81,321
Operating loss	(2,819)	(5,178)	(8,467)	(16,355)
Interest expense	(1,168)	(772)	(3,049)	(2,088)
Loss before income taxes	(3,987)	(5,950)	(11,516)	(18,443)
Income tax (benefit) expense	(50)	30	(120)	110
Net loss	$(3,937)	$(5,980)	$(11,396)	$(18,553)
Loss per share:				
Basic and diluted	$(0.10)	$(0.16)	$(0.30)	$(0.49)
Weighted average number of common shares outstanding:				
Basic and diluted	38,253	37,839	38,210	37,688

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

Independence Contract Drilling, Inc.
Statement of Stockholders' Equity
(Unaudited)
(in thousands, except share amounts)

	Common Stock					
	Shares	Amount	Additional Paid-in Capital	Accumulated Deficit	Treasury Stock	Total Stockholders' Equity
Balances at December 31, 2017	37,985,225	$ 380	$ 326,616	$ (89,645)	$ (1,869)	$ 235,482
RSUs vested, net of shares withheld for taxes	350,528	3	(98)	—	—	(95)
Purchase of treasury stock	(82,988)	—	—	—	(350)	(350)
Stock-based compensation	—	—	2,080	—	—	2,080
Net loss	—	—	—	(11,396)	—	(11,396)
Balances at September 30, 2018	38,252,765	$ 383	$ 328,598	$ (101,041)	$ (2,219)	$ 225,721

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

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

	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Cash flows from operating activities		
Net loss	$(11,396)	$(18,553)
Adjustments to reconcile net loss to net cash provided by operating activities		
Depreciation and amortization	20,001	19,120
Asset impairment, net	396	1,574
Stock-based compensation	2,080	3,036
(Gain) loss on disposition of assets, net	(675)	1,573
Amortization of deferred rent	60	—
Deferred income taxes	(120)	110
Amortization of deferred financing costs	290	344
Bad debt expense	22	—
Changes in operating assets and liabilities		
Accounts receivable	(5,694)	(4,343)
Inventories	(116)	(257)
Prepaid expenses and other assets	(1,212)	(1,037)
Accounts payable and accrued liabilities	2,535	655
Net cash provided by operating activities	6,171	2,222
Cash flows from investing activities		
Purchases of property, plant and equipment	(24,804)	(26,975)
Proceeds from insurance claims	257	—
Proceeds from the sale of assets	487	1,088
Net cash used in investing activities	(24,060)	(25,887)
Cash flows from financing activities		
Borrowings under Credit Facility	50,526	38,410
Repayments under Credit Facility	(31,150)	(17,162)
Purchase of treasury stock	(350)	(162)
RSUs withheld for taxes	(95)	(853)
Financing costs paid	(114)	(538)
Payments for capital lease obligations	(496)	(449)
Net cash provided by financing activities	18,321	19,246
Net increase (decrease) in cash and cash equivalents	432	(4,419)
Cash and cash equivalents		
Beginning of period	2,533	7,071
End of period	$2,965	$2,652
Supplemental disclosure of cash flow information		
Cash paid during the period for interest	$2,971	$1,865
Supplemental disclosure of non-cash investing and financing activities		
Change in property, plant and equipment purchases in accounts payable	$(264)	$(3,648)
Additions to property, plant and equipment through capital leases	$515	$822
Additions to property, plant and equipment through tenant allowance on leasehold improvement	$694	$—
Additions to deferred financing costs in accounts payable	$423	$—

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

7

INDEPENDENCE CONTRACT DRILLING, INC.
Notes to Financial Statements
(Unaudited)

1. Nature of Operations and Recent Events

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.

As of September 30, 2018, our rig fleet consisted of 15 premium 200 Series ShaleDriller® rigs, all of which are equipped with integrated omni-directional walking systems specifically designed to optimize pad drilling for our customers. Our 15th ShaleDriller rig commenced operations in the third quarter of 2018.

On October 1, 2018, we acquired all of the outstanding equity interests in Sidewinder Drilling LLC ("Sidewinder") pursuant to a merger of a subsidiary with and into Sidewinder (the “Sidewinder Combination”). See "Sidewinder Merger" below. As a result of the Sidewinder Combination, we added 19 rigs to our rig fleet. Following the Sidewinder Combination, our rig fleet includes 30 AC powered (“AC”) rigs and four 1500hp ultra-modern SCR rigs.

We currently focus our operations on unconventional resource plays located in geographic regions that we can efficiently support from our Texas-based facilities in order to maximize economies of scale. Currently, our rigs are operating in the Permian Basin and the Haynesville Shale; however, our rigs have previously operated in the Eagle Ford Shale and the Mid-Continent and Eaglebine regions as well.

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

Oil and Natural Gas Prices and Drilling Activity

Oil prices declined from a high of $107.95 per barrel in the second quarter of 2014, to a low of $26.19 per barrel in the first quarter of 2016 (West Texas Intermediate - Cushing, Oklahoma (“WTI”) spot price as reported by the United States Energy Information Administration (the “EIA”). Similarly, natural gas prices (as measured at Henry Hub) declined from an average of $4.37 per MMBtu in 2014 to $2.52 per MMBtu in 2016. Oil and natural gas prices have recovered from the lows experienced in 2016, with WTI oil prices reaching a three-year high of $77.41 per barrel in the second quarter of 2018. Similarly, natural gas prices at Henry Hub have averaged $2.97 per MMBtu in 2018 as of October 15, 2018.

Sidewinder Merger

On July 19, 2018, we announced our entry into a definitive merger agreement (the "Merger Agreement") with Patriot Saratoga Merger Sub LLC, a Delaware limited liability company ("Merger Sub") and Sidewinder Drilling LLC, a Delaware limited liability company ("Sidewinder"), pursuant to which Merger Sub merged with and into Sidewinder (the "Sidewinder Merger") and we acquired all of the outstanding equity interests in Sidewinder on October 1, 2018. During the three and nine months ended September 30, 2018, we recorded $1.9 million and $2.4 million, respectively, of merger costs in connection with the Sidewinder Merger comprised primarily of legal and professional fees.

The Sidewinder Merger combined two complementary pad-optimal drilling fleets and operations focused in the Permian Basin, Haynesville region and other basins in Texas and its contiguous states, and will more than double the size of our pad-optimal rig fleet to 34 rigs following modest upgrades to five Sidewinder rigs.

Under the terms of the Merger Agreement, the Sidewinder unitholders received an aggregate of 36,752,657 shares of our common stock, representing approximately 49% of the total outstanding shares immediately following the closing of the transaction.

8

In conjunction with the closing of the Sidewinder Merger on October 1, 2018, we entered into a term loan Credit Agreement (the "Term Loan Credit Agreement") for an initial term loan in an aggregate principal amount of $130.0 million, (the "Term Loan Facility") and (b) a delayed draw term loan facility in an aggregate principal amount of up to $15.0 million (the "DDTL Facility", and together with the Term Loan Facility, the "Term Facilities"). The Term Facilities have a maturity date of October 1, 2023, at which time all outstanding principal under the Term Facilities and other obligations become due and payable in full. Proceeds from the Term Loan Facility were used to repay our existing debt and the Sidewinder debt assumed in the Sidewinder Merger, as well as certain transaction costs.

At our election, interest under the Term Loan Facility is determined by reference at our option to either (i) a "base rate" equal to the higher of (a) the federal funds effective rate plus 0.05%, (b) the London Interbank Offered Rate with an interest period of one month ("LIBOR"), plus 1.0%, and (c) the rate of interest as publicly quoted from time to time by the Wall Street Journal as the "prime rate" in the United States; plus an applicable margin of 6.5%, or (ii) a "LIBOR rate" equal to LIBOR with an interest period of one month, plus an applicable margin of 7.5%.

The Term Loan Credit Agreement contains financial covenants, including a liquidity covenant of $10.0 million and a springing fixed charge coverage ratio covenant of 1.00 to 1.00 that is tested when availability under the New ABL Credit Facility (defined below) and the DDTL Facility is below $5.0 million at any time that a DDTL Facility loan is outstanding. The Term Loan Credit Agreement also contains other customary affirmative and negative covenants, including limitations on indebtedness, liens, fundamental changes, asset dispositions, restricted payments, investments and transactions with affiliates. The Term Loan Credit Agreement also provides for customary events of default, including breaches of material covenants, defaults under the New ABL Credit Facility or other material agreements for indebtedness, and a change of control (as defined).

The obligations under the Term Loan Credit Agreement are secured by a first priority lien on collateral (the "Term Priority Collateral") other than accounts receivable, deposit accounts and other related collateral pledged as first priority collateral ("Priority Collateral") under the New ABL Credit Facility (defined below) and a second priority lien on such Priority Collateral, and are unconditionally guaranteed by all of our current and future direct and indirect subsidiaries.

Additionally, in connection with the closing of the Sidewinder Merger on October 1, 2018, we entered into a $40.0 million revolving Credit Agreement (the "New ABL Credit Facility"), including availability for letters of credit in an aggregate amount at any time outstanding not to exceed $7.5 million. Availability under the New ABL Credit Facility is subject to a borrowing base determined based on 85% of the net amount of our eligible accounts receivable, minus reserves. The New ABL Credit Facility has a maturity date of the earlier of October 1, 2023 or the maturity date of the Term Loan Credit Agreement.

At our election, interest under the New ABL Credit Facility is determined by reference at our option to either (i) a "base rate" equal to the higher of (a) the federal funds effective rate plus 0.05%, (b) LIBOR with an interest period of one month, plus 1.0%, and (c) the prime rate of Wells Fargo, plus in each case, an applicable base rate margin ranging from 1.0% to 1.5% based on quarterly availability, or (ii) a revolving loan rate equal to LIBOR for the applicable interest period plus an applicable LIBOR margin ranging from 2.0% to 2.5% based on quarterly availability. We also pay, on a quarterly basis, a commitment fee of 0.375% (or 0.25% at any time when revolver usage is greater than 50% of the maximum credit) per annum on the unused portion of the New ABL Credit Facility commitment.

The New ABL Credit Facility contains a springing fixed charge coverage ratio covenant of 1.00 to 1.00 that is tested when availability is less than 10% of the maximum credit. The New ABL Credit Facility also contains other customary affirmative and negative covenants, including limitations on indebtedness, liens, fundamental changes, asset dispositions, restricted payments, investments and transactions with affiliates. The New ABL Credit Facility also provides for customary events of default, including breaches of material covenants, defaults under the Term Loan Agreement or other material agreements for indebtedness, and a change of control.

The obligations under the New ABL Credit Facility are secured by a first priority lien on Priority Collateral, which includes all accounts receivable and deposit accounts, and a second priority lien on the Term Priority Collateral, and are unconditionally guaranteed by all of our current and future direct and indirect subsidiaries.

On October 1, 2018, in connection with our entry into the New ABL Credit Facility, we repaid all outstanding borrowings and obligations under our existing Credit Facility, and terminated it.

9

Amendment to Articles of Incorporation

In connection with the Sidewinder Merger, on October 1, 2018, following approval by our shareholders, we amended our certificate of incorporation to increase the authorized number of shares of Common Stock from 100,000,000 shares to 200,000,000 shares.

Change in Plan of Sale of Assets

During the second quarter of 2017, our management committed to a plan to sell our corporate headquarters and rig assembly yard complex located at 11601 North Galayda Street, Houston, Texas (the "Galayda Facility"). This plan of sale was subsequently affected by Hurricane Harvey, which caused substantial water-related damage to the Galayda Facility in August 2017, as well as our entry into a definitive merger agreement with Sidewinder Drilling in July 2018. The following summarizes material financial statement impacts of this plan of sale and associated changes as result of these matters:

- In connection with our initial decision to sell the Galayda Facility, at June 30, 2017, we reclassified an aggregate $4.0 million of land, buildings and equipment from property, plant and equipment to assets held for sale on our balance sheet and recognized a $0.5 million asset impairment charge representing the difference between the carrying value and the fair value, less the costs to sell the related property.
- As a result of water-related damage caused by Hurricane Harvey, in the third quarter of 2017, we recorded an additional impairment on this group of assets totaling $0.6 million.
- Following an evaluation of the Galayda Facility and our operating plans following Hurricane Harvey, during the first quarter of 2018, management changed its plan to sell all of the Galayda Facility assets and decided to improve and utilize a portion of the land and buildings on the property. Based on this decision, which was previously considered unlikely, certain land and buildings at the Galayda Facility were reclassified to assets held and used as of March 31, 2018. Accordingly, we reduced assets held for sale by $2.7 million and increased property, plant and equipment by $2.9 million on our March 31, 2018 balance sheet and recognized a recovery of asset impairment expense of approximately $208 thousand in our statement of operations for the three months ended March 31, 2018.
- During the third quarter of 2018, as a result of the pending merger with Sidewinder Drilling LLC, management decided to again enter into a plan to sell the entire Galayda Facility and entered into an agreement with a third-party buyer to sell the Galayda Facility in “as-is” condition for $3.1 million. As a result, the $2.6 million of property, plant and equipment, representing the portion of the Galayda Facility that was classified as held and used, was reclassified as held for sale on our September 30, 2018 balance sheet and we recognized an impairment charge of $650 thousand representing the difference between the carrying value of the property and the fair value of the property, less costs to sell.

2. Interim Financial Information

These unaudited financial statements include the accounts of ICD, and have been prepared in accordance with accounting principles generally accepted in the United States (“GAAP”). These financial statements should be read along with our audited financial statements for the year ended December 31, 2017, included in our Annual Report on Form 10-K for the year ended December 31, 2017. In management’s opinion, these financial statements contain all adjustments necessary to fairly present our financial position, results of operations, cash flows and changes in stockholders' equity for all periods presented.

As we had no items of other comprehensive income in any period presented, no other components of comprehensive income is presented.

Interim results for the three and nine months ended September 30, 2018 may not be indicative of results that will be realized for the full year ending December 31, 2018.

Revenue and Cost Recognition

In May 2014, the Financial Accounting Standards Board (FASB) issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606) (ASU 2014-09). We adopted ASU 2014-09 and its related amendments (collectively known as ASC 606) effective on January 1, 2018 using the modified retrospective method. While ASC 606 requires additional disclosure of the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers, its adoption did not have a material impact on the measurement or recognition of our revenues. We may recognize demobilization fee revenue earlier in the contract term than we have historically, but demobilization fee revenues are earned very infrequently under our contracts.

See Note 3 "Revenue from Contracts with Customers" for the required disclosures related to the impact of adopting this standard and a discussion of our updated policies related to revenue recognition and accounting for costs to obtain and fulfill a customer contract.

Segment and Geographical Information

Our operations consist of one reportable segment because all of our drilling operations are located in the United States and have similar economic characteristics. 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. Further, the allocation of capital resources is employed on a project-by-project basis across our entire asset base to maximize profitability without regard to individual geographic areas.

Other Matters

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

Recent Accounting Pronouncements

In February 2016, the FASB issued ASU No. 2016-02, Leases, to establish the principles that lessees and lessors shall apply to report useful information to users of financial statements about the amount, timing, and uncertainty of cash flows arising from a lease. Under the new guidance, lessees will be required to recognize (with the exception of short-term leases) at the commencement date, a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term. The provisions of this standard also apply to situations where companies are the lessor and therefore it could impact the accounting and related disclosures for our drilling contracts.

In July 2018, the FASB issued ASU No. 2018-11, Leases: Targeted Improvements, which provides an option to apply the guidance prospectively, and provides a practical expedient allowing lessors to combine the lease and non-lease components of revenues where the revenue recognition pattern is the same and where the lease component, when accounted for separately, would be considered an operating lease. The practical expedient also allows a lessor to account for the combined lease and non-lease components under ASC Topic 606, Revenue from Contracts with Customers, when the non-lease component is the predominant element of the combined components. We are in the process of evaluating the provisions of ASU No. 2018-11, specifically as they relate to our drilling contracts and the practical expedient for combining the lease and non-lease components of revenue, including the determination of which component is predominant.

As a lessee, while we cannot yet quantify the impact at this point, we expect our assets and liabilities to increase as a result of recognizing the right-of-use assets and lease liabilities. We are currently in the process of implementing a lease accounting system for our leases, converting our existing lease data to the new system and implementing relevant internal controls and procedures. We expect to apply this guidance prospectively, effective January 1, 2019.

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

In August 2018, the FASB issued ASU 2018-15, Intangibles - Goodwill and Other - Internal-Use Software: Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract, to align the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. The amendments in the update are effective for public business entities for fiscal years beginning after December 15, 2019, with early adoption permitted. We are currently evaluating the impact this new guidance will have on our financial statements.

3. Revenue from Contracts with Customers

Effective January 1, 2018, we adopted Accounting Standards Codification ("ASC") Revenue from Contracts with Customers ("ASC 606"), using the modified retrospective method. This standard applies to all contracts with customers, except for contracts that are within the scope of other standards, such as leases, insurance, collaborative arrangements and financial instruments. Under ASC 606, an entity recognizes revenue when it transfers control of the promised goods or services to its customer, in an amount that reflects the consideration which the entity expects to receive in exchange for those goods or services. If control transfers to the customer over time, an entity selects a method to measure progress that is consistent with the objective of depicting its performance.

In determining the appropriate amount of revenue to be recognized as we fulfill our obligations under the agreement, the following steps must be performed at contract inception: (i) identification of the promised goods or services in the contract; (ii) determination of whether the promised goods or services are performance obligations, including whether they are distinct in the context of the contract; (iii) measurement of the transaction price, including the constraint on variable consideration; (iv) allocation of the transaction price to the performance obligations; and (v) recognition of revenue when (or as) we satisfy each performance obligation.

Drilling Services

Our revenues are principally derived from contract drilling services and the activities in our drilling contracts, for which revenues may be earned, include: (i) providing a drilling rig and the crews and supplies necessary to operate the rig; (ii) mobilizing and demobilizing the rig to and from the initial and final drill site, respectively; (iii) certain reimbursable activities; (iv) performing rig modification activities required for the contract; and (v) early termination revenues. We account for these integrated services provided under our drilling contracts as a single performance obligation, satisfied over time, that is comprised of a series of distinct time increments. Consideration for activities that are not distinct within the context of our contracts, and that do not correspond to a distinct time increment within the contract term, are allocated across the single performance obligation and recognized ratably in proportion to the actual services performed over the initial term of the contract. If taxes are required to be collected from customers relating to our drilling services, they are excluded from revenue.

Dayrate Drilling Revenue. Our drilling contracts provide that revenue is earned based on a specified rate per day for the activity performed. The majority of revenue earned under daywork contracts is variable, and depends on a rate scale associated with drilling conditions and level of service provided for each fractional-hour time increment over the contract term. Such rates generally include the full operating rate, moving rate, standby rate, and force majeure rate and determination of the rate per time increment is made based on the actual circumstances as they occur. Other variable consideration under these contracts could include reduced revenue related to downtime, delays or moving caps.

Mobilization/Demobilization Revenue. We may receive fees (on either a fixed lump-sum or variable dayrate basis) for the mobilization and demobilization of our rigs. These activities are not considered to be distinct within the context of the contract and therefore, the associated revenue is allocated to the overall performance obligation and recognized ratably over the initial term of the related drilling contract. We record a contract liability for mobilization fees received, which is amortized ratably to revenue as services are rendered over the initial term of the related drilling contract. Demobilization fee revenue expected to be received upon contract completion is estimated as part of the overall transaction price at contract inception and recognized in earnings ratably over the initial term of the contract with an offset to an accretive contract asset.

In our contracts, there is generally significant uncertainty as to the amount of demobilization fee revenue that may ultimately be collected due to contractual provisions which stipulate that certain conditions be present at contract completion for such revenue to be received. For example, the amount collectible may be reduced to zero if the rig has been contracted with a new customer upon contract completion. Accordingly, the estimate for such revenue may be constrained depending on the facts and circumstances pertaining to the specific contract. We assess the likelihood of receiving such revenue based on past experience and knowledge of the market conditions.

Reimbursable Revenues. We receive reimbursements from our customers for the purchase of supplies, equipment and other services provided at their request in accordance with a drilling contract or other agreement. Such reimbursable revenue is variable and subject to uncertainty, as the amounts received and timing thereof is highly dependent on factors outside of our influence. Accordingly, reimbursable revenue is fully constrained and not included in the total transaction price until the uncertainty is resolved, which typically occurs when the related costs are incurred on behalf of a customer. We are generally considered a principal in such transactions and record the associated revenue at the gross amount billed to the customer.

Capital Modification Revenue. From time to time, we may receive fees (on either a fixed lump-sum or variable dayrate basis) from our customers for capital improvements to our rigs to meet their requirements. Such revenue is allocated to the overall performance obligation and recognized ratably over the initial term of the related drilling contract, as these activities are not considered to be distinct within the context of our contracts. We record a contract liability for such fees received up front, and recognize them ratably as contract drilling revenue over the initial term of the related drilling contract.

Early Termination Revenue. Our contracts provide for early termination fees in the event our customers choose to cancel the contract prior to the specified contract term. We record a contract liability for such fees received up front, and recognize them ratably as contract drilling revenue over the initial term of the related drilling contract or until such time that all performance obligations are satisfied.

Disaggregation of Revenue

The following table summarizes revenues from our contracts disaggregated by revenue generating activity contained therein for the three and nine months ended September 30, 2018 and 2017:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2018	2017	2018	2017
Dayrate drilling	$27,552	$22,125	$75,776	$61,369
Mobilization	331	619	1,061	1,586
Reimbursables	555	700	2,788	2,001
Capital modification	1	—	195	—
Other	—	1	—	10
Total revenue	$28,439	$23,445	$79,820	$64,966

Contract Balances

Accounts receivable are recognized when the right to consideration becomes unconditional based upon contractual billing schedules. Payment terms on invoiced amounts are typically 30 days. Contract asset balances could consist of demobilization fee revenue that we expect to receive that is recognized ratably throughout the contract term, but invoiced upon completion of the demobilization activities. Once the demobilization fee revenue is invoiced the corresponding contract asset is transferred to accounts receivable. Contract liabilities include payments received for mobilization fees as well as upgrade activities, which are allocated to the overall performance obligation and recognized ratably over the initial term of the contract.

The following table provides information about receivables, contract assets and contract liabilities related to contracts with customers:

(in thousands)	September 30, 2018	December 31, 2017
Receivables, which are included in "Accounts receivable, net"	$ 23,879	$ 18,028
Contract assets	$ —	$ —
Contract liabilities	$ (1,267)	$ (836)

Significant changes in contract assets and contract liabilities balances during the period are as follows:

(in thousands)	Three Months Ended September 30, 2018		Nine Months Ended September 30, 2018	
	Contract Assets	Contract Liabilities	Contract Assets	Contract Liabilities
Revenue recognized that was included in contract liabilities at beginning of period	$ —	$ 34	$ —	$ 730
Increase in contract liabilities due to cash received, excluding amounts recognized as revenue	$ —	$ (868)	$ —	$ (1,163)
Transferred to receivables from contract assets at beginning of period	$ —	$ —	$ —	$ —

Transaction Price Allocated to the Remaining Performance Obligations

The following table includes estimated revenue expected to be recognized in the future related to performance obligations that are unsatisfied (or partially unsatisfied) as of September 30, 2018. The estimated revenue does not include amounts of variable consideration that are constrained.

(in thousands)	Year Ending December 31,			
	2018	2019	2020	Total
Revenue	$ 428	$ 839	$ —	$ 1,267

The amounts presented in the table above consist only of fixed consideration related to fees for rig mobilizations and demobilizations, if applicable, which are allocated to the drilling services performance obligation as such performance obligation is satisfied. We have elected the exemption from disclosure of remaining performance obligations for variable consideration. Therefore, dayrate revenue to be earned on a rate scale associated with drilling conditions and level of service provided for each fractional-hour time increment over the contract term and other variable consideration such as penalties and reimbursable revenues, have been excluded from the disclosure.

Contract Costs

We capitalize costs incurred to fulfill our contracts that (i) relate directly to the contract, (ii) are expected to generate resources that will be used to satisfy our performance obligations under the contract and (iii) are expected to be recovered through revenue generated under the contract. These costs, which principally relate to rig mobilization costs at the commencement of a new contract, are deferred as a current or noncurrent asset (depending on the length of the contract term), and amortized ratably to contract drilling expense as services are rendered over the initial term of the related drilling contract. Such contract costs amounted to $0.9 million and were recorded as “Prepaid expenses and other current assets” on our balance sheet at September 30, 2018. During the three and nine months ended September 30, 2018, we amortized $0.3 million and $0.9 million of contract costs, respectively.

Costs incurred for the demobilization of rigs at contract completion are recognized as incurred during the demobilization process. Costs incurred for rig modifications or upgrades required for a contract, which are considered to be capital improvements, are capitalized as drilling and other property and equipment and depreciated over the estimated useful life of the improvement.

Impact of ASC 606 on Financial Statement Line Items

The timing of our revenue recognition under ASC 606 is similar to revenue recognition under the previous guidance, except for the recognition of demobilization fee revenue, which we earn infrequently. Such revenue, which was recognized upon completion of a contract under the previous guidance, will now be estimated at contract inception and recognized as contract drilling revenue as the drilling services performance obligation is satisfied, subject to constraint, with an offset to a contract asset. As we had no existing contracts as of January 1, 2018, where we expect to receive a demobilization fee from our customers, there was no cumulative effect of a change in accounting principle required to adjust our January 1, 2018 retained earnings.

4. Financial Instruments and Fair Value

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

Level 1	Unadjusted quoted market prices for identical assets or liabilities in an active market;
Level 2	Quoted market prices for identical assets or liabilities in an active market that have been adjusted for items such as effects of restrictions for transferability and those that are not quoted but are observable through corroboration with observable market data, including quoted market prices for similar assets or liabilities; 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 financial instruments, consisting primarily of cash and cash equivalents, accounts receivable and accounts payable, approximates their fair value due to the short-term nature of such instruments.

The fair value of our Credit Facility debt is determined by Level 3 measurements based 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 6.2%. The fair value of our capital lease obligations is determined using Level 3 measurements using our current incremental borrowing rate. The estimated fair value of our long-term debt, including our capital lease obligations, totaled $72.0 million and $50.6 million as of September 30, 2018 and December 31, 2017, respectively, compared to a carrying amount of $68.6 million and $49.3 million as of September 30, 2018 and December 31, 2017, respectively. The fair value of our assets held for sale is determined using Level 3 measurements.

Fair value measurements are applied with respect to our non-financial assets and liabilities measured on a non-recurring basis, which would consist of measurements primarily of long-lived assets.

5. Inventories

All of our inventory as of September 30, 2018 and December 31, 2017 consisted of supplies held for use in our drilling operations.

6. Accrued Liabilities

Accrued liabilities consisted of the following:

(in thousands)	September 30, 2018	December 31, 2017
Accrued salaries and other compensation	$ 3,686	$ 2,646
Insurance	1,511	507
Deferred revenues (contract liabilities)	1,267	762
Property, sales and other taxes	2,018	2,693
Other	430	361
	$ 8,912	$ 6,969

7. Long-term Debt

Our Long-term Debt consisted of the following:

(in thousands)	September 30, 2018	December 31, 2017
Credit Facility due November 5, 2020	$ 67,917	48,541
Capital lease obligations	1,289	1,270
	69,206	49,811
Less: current portion	(575)	(533)
Long-term debt	$ 68,631	$ 49,278

Credit Facility

Our Credit Facility existing at September 30, 2018, with a maturity date of November 5, 2020, provided for aggregate commitments of $85.0 million (the "Existing Credit Facility"). We had $67.9 million in outstanding borrowings and $17.1 million of remaining availability under the Existing Credit Facility at September 30, 2018. On October 1, 2018, in connection with our entry into the New Term Loan Credit Agreement and New ABL Credit Facility (see Note 1 "Nature of Operations and Recent Events - Merger with Sidewinder Drilling LLC" for further details), we repaid all outstanding borrowings and obligations under the Existing Credit Facility and terminated it.

Borrowings under the Existing Credit Facility were subject to a borrowing base formula that allowed for borrowings of up to 85% of eligible trade accounts receivable not more than 90 days outstanding, plus up to a certain percentage, the "advance rate", of the appraised forced liquidation value of our eligible, completed and owned drilling rigs. As of September 30, 2018, the advance rate was 70%.

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

At our election, interest under the Existing Credit Facility was 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 paid, on a quarterly basis, a commitment fee of 0.50% per annum on the unused portion of the Credit Facility commitment. As of September 30, 2018, the weighted average interest rate on our borrowings was 6.99%.

Capital Lease Obligations

Our capital lease obligations all relate to vehicles that are leased to support our operations. These leases generally have initial terms of 36 months and are paid monthly.

8. Stock-Based Compensation

In March 2012, we adopted the 2012 Omnibus Long-Term Incentive Plan (the "2012 Plan") providing for common stock-based awards to employees and non-employee directors. The 2012 Plan was subsequently amended in August 2014 and June 2016. The 2012 Plan, as amended, permits the granting of various types of awards, including stock options, restricted stock and restricted stock unit awards, and up to 4,754,000 shares were authorized for issuance. Restricted stock and restricted stock units may be granted for no consideration other than prior and future services. The purchase price per share for stock options may not be less than the market price of the underlying stock on the date of grant. Stock options expire ten years after the grant date. We have the right to satisfy option exercises from treasury shares and from authorized but unissued shares. As of September 30, 2018, approximately 1,016,855 shares were available for future awards.

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2018	2017	2018	2017
Compensation cost recognized:				
Stock options	$—	$—	$—	$—
Restricted stock and restricted stock units	718	867	2,080	3,036
Total stock-based compensation	$718	$867	$2,080	$3,036

No stock-based compensation was capitalized in connection with rig construction activity during the three and nine months ended September 30, 2018 or 2017.

Stock Options

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.

There were no stock options granted during the nine months ended September 30, 2018 or 2017.

A summary of stock option activity and related information for the nine months ended September 30, 2018 is as follows:

	Nine Months Ended September 30, 2018	
	Options	Weighted Average Exercise Price
Outstanding at January 1, 2018	682,950	$ 12.74
Granted	—	—
Exercised	—	—
Forfeited/expired	—	—
Outstanding at September 30, 2018	682,950	$ 12.74
Exercisable at September 30, 2018	682,950	$ 12.74

The number of options vested at September 30, 2018 was 682,950 with a weighted average remaining contractual life of 3.6 years and a weighted average exercise price of $12.74 per share. There were no unvested options or unrecognized compensation cost related to outstanding stock options at September 30, 2018.

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 September 30, 2018, there was no unrecognized compensation cost related to unvested restricted stock awards and all previously issued restricted stock awards had vested.

Restricted Stock Units

We have granted restricted stock units ("RSUs") to key employees under the 2012 Plan. We have granted three-year time vested RSUs, as well as performance-based and market-based RSUs, where each unit represents the right to receive, at the end of a vesting period, up to two shares of ICD common stock with no exercise price. Exercisability of the market-based RSUs is based on our three-year total shareholder return ("TSR") as measured against the TSR of a defined peer group and vesting of the performance-based RSUs is based on our cumulative EBITDA, safety or uptime performance statistics, as defined in the restricted stock unit agreement, over a three-year period. We used a Monte Carlo simulation model to value the TSR market-based RSUs. The fair value of the performance-based RSUs is based on the market price of our common stock on the date of grant. During the restriction period, the RSUs may not be transferred or encumbered, and the recipient does not receive dividend equivalents or have voting rights until the units vest. As of September 30, 2018, there was $3.7 million of total unrecognized compensation cost related to unvested RSUs. This cost was expected to be recognized over a weighted average period of 0.9 years, however as a result of the Sidewinder Merger that closed on October 1, 2018, all of these awards were accelerated or forfeited in accordance with the change in control provisions of the RSU's. A non-cash charge of approximately $2.6 million will be recorded in the fourth quarter of 2018.

A summary of the status of our RSUs as of September 30, 2018, and of changes in RSUs outstanding during the nine months ended September 30, 2018, is as follows:

	Nine Months Ended September 30, 2018	
	RSUs	Weighted Average Grant-Date Fair Value Per Share
Outstanding at January 1, 2018	993,320	$ 5.11
Granted	641,041	4.55
Vested and converted	(350,528)	5.03
Forfeited	(57,660)	5.36
Outstanding at September 30, 2018	1,226,173	$ 4.83

9. Stockholders' Equity and Earnings (Loss) per Share

As of September 30, 2018, we had a total of 38,252,765 shares of common stock, $0.01 par value, outstanding. We also had 344,682 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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands, except per share data)	2018	2017	2018	2017
Net loss (numerator):	$(3,937)	$(5,980)	$(11,396)	$(18,553)
Loss per share:				
Basic and diluted	$(0.10)	$(0.16)	$(0.30)	$(0.49)
Shares (denominator):				
Weighted average common shares outstanding - basic	38,253	37,839	38,210	37,688
Weighted average common shares outstanding - diluted	38,253	37,839	38,210	37,688

For all periods presented, the computation of diluted loss per share excludes the effect of certain outstanding stock options and RSUs because their inclusion would be anti-dilutive. The number of options that were excluded from diluted loss per share were 682,950 during the three and nine months ended September 30, 2018 and 2017. RSUs, which are not participating securities and are excluded from our basic and diluted loss per share because they are anti-dilutive, were 1,226,173 for the three and nine months ended September 30, 2018 and 1,038,707 for the three and nine months ended September 30, 2017.

10. Income Taxes

Our effective tax rate was 1.3% and 1.0% for the three and nine months ended September 30, 2018, respectively, and (0.5)% and (0.6)% for the three and nine months ended September 30, 2017, respectively. Taxes in the current year period relate to Louisiana state income tax and Texas margin tax. Taxes in the prior year period relate to Texas margin tax. For federal income tax purposes, we have applied a valuation allowance against any potential deferred tax asset which would have ordinarily resulted.

11. Commitments and Contingencies

Purchase Commitments

As of September 30, 2018, we had outstanding purchase commitments to a number of suppliers totaling $5.8 million, net of deposits previously made, related primarily to the construction of drilling rigs. All of these commitments relate to equipment currently scheduled for delivery in 2018.

Lease Commitments

We have several non-cancelable operating and capital leases primarily for the rental of office space, certain equipment and vehicles. Future minimum lease payments under operating and capital lease commitments, with lease terms in excess of one year subsequent to September 30, 2018, were as follows:

(in thousands)	
2018	$209
2019	1,085
2020	834
2021	478
2022	360
Thereafter	401
	$3,367

As of September 30, 2018, property, plant and equipment on our balance sheet included $1.3 million of equipment under capital lease, which is net of $0.6 million of accumulated amortization. As of December 31, 2017, property, plant and equipment in our balance sheet included $1.3 million of equipment under capital lease, net of $0.5 million of accumulated amortization. This equipment consists entirely of vehicles used in our operations.

Contingencies

We may be the subject of lawsuits and claims arising in the ordinary course of business from time to time. Management cannot predict the ultimate outcome of such lawsuits and claims. While lawsuits and claims are asserted for amounts that may be material should an unfavorable outcome be the result, management does not currently expect that the outcome of any of these known legal proceedings or claims will have a material adverse effect on our financial position or results of operations.

ITEM 2. 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 the financial statements and related notes that are included elsewhere in this Quarterly Report on Form 10-Q and with our audited financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2017, filed with the Securities and Exchange Commission on February 26, 2018 (the “Form 10-K”). 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 those described in the section titled "Cautionary Statement Regarding Forward-Looking Statements" and those set forth under Part 1“Item 1A. Risk Factors” or in other parts of the Form 10-K.

Management Overview

We were incorporated in Delaware on November 4, 2011. We provide land-based contract drilling services for oil and natural gas producers targeting unconventional resource plays in the United States. Our first rig began drilling in May 2012.

As of September 30, 2018, our rig fleet consisted of 15 premium 200 Series ShaleDriller® rigs, all of which are equipped with integrated omni-directional walking systems specifically designed to optimize pad drilling for our customers. Our 15th ShaleDriller rig commenced operations in the third quarter of 2018.

On October 1, 2018, we acquired all of the outstanding equity interests in Sidewinder Drilling LLC (the “Sidewinder Combination”). See "Sidewinder Merger" below. As a result of the Sidewinder Combination, we added 19 rigs to our rig fleet. Following the Sidewinder Combination, our rig fleet includes 30 AC powered (“AC”) rigs and four 1500hp ultra-modern SCR rigs. We plan to convert these four SCR rigs to AC pad-optimal status over the next twelve to 18 months based upon market conditions and customer requirements.

We currently focus our operations on unconventional resource plays located in geographic regions that we can efficiently support from our Texas-based facilities in order to maximize economies of scale. Currently, our rigs are operating in the Permian Basin and the Haynesville Shale; however, our rigs have previously operated in the Eagle Ford Shale and the Mid-Continent and Eaglebine regions as well.

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

Oil prices declined from a high of $107.95 per barrel in the second quarter of 2014, to a low of $26.19 per barrel in the first quarter of 2016 (West Texas Intermediate - Cushing, Oklahoma (“WTI”) spot price as reported by the United States Energy Information Administration (the “EIA”). Similarly, natural gas prices (as measured at Henry Hub) declined from an average of $4.37 per MMBtu in 2014 to $2.52 per MMBtu in 2016. Oil and natural gas prices have recovered from the lows experienced in 2016, with WTI oil prices reaching a three-year high of $77.41 per barrel in the second quarter of 2018. Similarly, natural gas prices at Henry Hub have averaged $2.97 per MMBtu in 2018 as of October 15, 2018.

Demand for our ShaleDriller rigs has improved year over year as market conditions have improved from trough levels in 2016. In addition to improving utilization, contract tenors improved with customers signing term contracts of six to twelve months or longer, and at higher dayrates compared to trough levels, with the potential to move higher if market conditions continue to improve. However, if oil prices were to fall for any sustained period of time, market conditions and demand for our services could deteriorate.

Emerging Growth Company

We are an emerging growth company ("EGC") as defined under the Jumpstart Our Business Startups Act of 2012, commonly referred to as the “JOBS Act”. We will remain an EGC for up to five years from the date of the completion of our initial public offering (the "IPO") on August 13, 2014, or until the earlier of (1) the last day of the fiscal year in which our total annual gross revenues exceed $1.07 billion, (2) the date that we become a "large accelerated filer" as defined in Rule 12b-2

20

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 $1.0 billion in non-convertible debt during the preceding three-year period.

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

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

In addition, Section 107 of the JOBS Act provides that an EGC can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act of 1933, as amended, for complying with new or revised accounting standards. Under this provision, an EGC can delay the adoption of certain accounting standards until those standards would otherwise apply to private companies.

We have not elected to avail ourselves of the extended transition period available to EGCs 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.

Significant Developments

Sidewinder Merger

On July 19, 2018, we announced our entry into a definitive merger agreement (the "Merger Agreement") with Patriot Saratoga Merger Sub LLC, a Delaware limited liability company ("Merger Sub") and Sidewinder Drilling LLC, a Delaware limited liability company ("Sidewinder"), pursuant to which Merger Sub merged with and into Sidewinder (the "Sidewinder Merger") and we acquired all of the outstanding equity interests in Sidewinder on October 1, 2018. During the three and nine months ended September 30, 2018, we recorded $1.9 million and $2.4 million, respectively, of merger costs in connection with the Sidewinder Merger comprised primarily of legal and professional fees.

The Sidewinder Merger combined two complementary pad-optimal drilling fleets and operations focused in the Permian Basin, Haynesville region and other basins in Texas and its contiguous states, and will more than double the size of our pad-optimal rig fleet to 34 rigs following modest upgrades to five Sidewinder rigs.

Under the terms of the Merger Agreement, the Sidewinder unitholders received an aggregate of 36,752,657 shares of our common stock, representing approximately 49% of the total outstanding shares immediately following the closing of the transaction.

In conjunction with the closing of the Sidewinder Merger on October 1, 2018, we entered into a term loan Credit Agreement (the “Term Loan Credit Agreement”) for an initial term loan in an aggregate principal amount of $130.0 million, (the “Term Loan Facility”) and (b) a delayed draw term loan facility in an aggregate principal amount of up to $15.0 million (the “DDTL Facility”, and together with the Term Loan Facility, the “Term Facilities”). The Term Facilities have a maturity date of October 1, 2023, at which time all outstanding principal under the Term Facilities and other obligations become due and payable in full. Proceeds from the Term Loan Facility were used to repay our existing debt and the Sidewinder debt assumed in the Sidewinder Merger, as well as certain transaction costs.

At our election, interest under the Term Loan Facility is determined by reference at our option to either (i) a “base rate” equal to the higher of (a) the federal funds effective rate plus 0.05%, (b) the London Interbank Offered Rate with an interest period of one month (“LIBOR”), plus 1.0%, and (c) the rate of interest as publicly quoted from time to time by the Wall Street Journal as the “prime rate” in the United States; plus an applicable margin of 6.5%, or (ii) a “LIBOR rate” equal to LIBOR with an interest period of one month, plus an applicable margin of 7.5%.

The Term Loan Credit Agreement contains financial covenants, including a liquidity covenant of $10.0 million and a springing fixed charge coverage ratio covenant of 1.00 to 1.00 that is tested when availability under the New ABL Credit Facility (defined below) and the DDTL Facility is below $5.0 million at any time that a DDTL Facility loan is outstanding.

21

The Term Loan Credit Agreement also contains other customary affirmative and negative covenants, including limitations on indebtedness, liens, fundamental changes, asset dispositions, restricted payments, investments and transactions with affiliates. The Term Loan Credit Agreement also provides for customary events of default, including breaches of material covenants, defaults under the New ABL Credit Facility or other material agreements for indebtedness, and a change of control (as defined).

The obligations under the Term Loan Credit Agreement are secured by a first priority lien on collateral (the “Term Priority Collateral”) other than accounts receivable, deposit accounts and other related collateral pledged as first priority collateral (“Priority Collateral”) under the New ABL Credit Facility (defined below) and a second priority lien on such Priority Collateral, and are unconditionally guaranteed by all of our current and future direct and indirect subsidiaries.

Additionally, in connection with the closing of the Sidewinder Merger on October 1, 2018, we entered into a $40.0 million revolving Credit Agreement (the “New ABL Credit Facility”), including availability for letters of credit in an aggregate amount at any time outstanding not to exceed $7.5 million. Availability under the New ABL Credit Facility is subject to a borrowing base determined based on 85% of the net amount of our eligible accounts receivable, minus reserves. The New ABL Credit Facility has a maturity date of the earlier of October 1, 2023 or the maturity date of the Term Loan Credit Agreement.
At our election, interest under the New ABL Credit Facility is determined by reference at our option to either (i) a “base rate” equal to the higher of (a) the federal funds effective rate plus 0.05%, (b) LIBOR with an interest period of one month, plus 1.0%, and (c) the prime rate of Wells Fargo, plus in each case, an applicable base rate margin ranging from 1.0% to 1.5% based on quarterly availability, or (ii) a revolving loan rate equal to LIBOR for the applicable interest period plus an applicable LIBOR margin ranging from 2.0% to 2.5% based on quarterly availability. We also pay, on a quarterly basis, a commitment fee of 0.375% (or 0.25% at any time when revolver usage is greater than 50% of the maximum credit) per annum on the unused portion of the New ABL Credit Facility commitment.

The New ABL Credit Facility contains a springing fixed charge coverage ratio covenant of 1.00 to 1.00 that is tested when availability is less than 10% of the maximum credit. The New ABL Credit Facility also contains other customary affirmative and negative covenants, including limitations on indebtedness, liens, fundamental changes, asset dispositions, restricted payments, investments and transactions with affiliates. The New ABL Credit Facility also provides for customary events of default, including breaches of material covenants, defaults under the Term Loan Agreement or other material agreements for indebtedness, and a change of control.

The obligations under the New ABL Credit Facility are secured by a first priority lien on Priority Collateral, which includes all accounts receivable and deposit accounts, and a second priority lien on the Term Priority Collateral, and are unconditionally guaranteed by all of our current and future direct and indirect subsidiaries.

On October 1, 2018, in connection with our entry into the New ABL Credit Facility, we repaid all outstanding borrowings and obligations under our existing Credit Facility, and terminated it.

In connection with the Sidewinder Merger, we will recognize several significant charges during the fourth quarter of 2018. These charges include non-cash stock based compensation expense of $2.6 million, resulting from the acceleration of certain awards, professional fees of approximately $3.4 million, known compensation and severance arrangements of $6.3 million and $0.9 million of additional interest expense associated with the write-off of deferred financing costs.

Amendment to Articles of Incorporation

In connection with the Sidewinder Merger, on October 1, 2018, following approval by our shareholders, we amended our certificate of incorporation to increase the authorized number of shares of Common Stock from 100,000,000 shares to 200,000,000 shares.

Change in Plan of Sale of Assets

During the second quarter of 2017, our management committed to a plan to sell our corporate headquarters and rig assembly yard complex located at 11601 North Galayda Street, Houston, Texas (the "Galayda Facility"). This plan of sale was subsequently affected by Hurricane Harvey, which caused substantial water-related damage to the Galayda Facility in August 2017, as well as our entry into a definitive merger agreement with Sidewinder Drilling in July 2018. The following summarizes material financial statement impacts of this plan of sale and associated changes as result of these matters:

- In connection with our initial decision to sell Galayda Facility, at June 30, 2017, we reclassified an aggregate $4.0 million of land, buildings and equipment from property, plant and equipment to assets held for sale on our balance sheet and recognized a $0.5 million asset impairment charge representing the difference between the carrying value and the fair value, less the costs to sell the related property.
- As a result of water-related damage caused by Hurricane Harvey, in the third quarter of 2017, we recorded an additional impairment on this group of assets totaling $0.6 million.
- Following an evaluation of the Galayda Facility and our operating plans following Hurricane Harvey, during the first quarter of 2018, management changed its plan to sell all of the Galayda Facility assets and decided to improve and utilize a portion of the land and buildings on the property. Based on this decision, which was previously considered unlikely, certain land and buildings at the Galayda Facility were reclassified to assets held and used as of March 31, 2018. Accordingly, we reduced assets held for sale by $2.7 million and increased property, plant and equipment by $2.9 million on our March 31, 2018 balance sheet and recognized a recovery of asset impairment expense of approximately $208 thousand in our statement of operations for the three months ended March 31, 2018.
- During the third quarter of 2018, as a result of the pending merger with Sidewinder Drilling LLC, management decided to again enter into a plan to sell the entire Galayda Facility and entered into an agreement with a third-party buyer to sell the Galayda Facility in “as-is” condition for $3.1 million. As a result, the $2.6 million of property, plant and equipment, representing the portion of the Galayda Facility that was classified as held and used, was reclassified as held for sale on our September 30, 2018 balance sheet and we recognized an impairment charge of $650 thousand representing the difference between the carrying value of the property and the fair value of the property, less costs to sell.

Our Revenues

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

Our Operating Costs

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

Our operating costs also include costs and expenses associated with construction activities at our Galayda yard location to the extent that construction activities cease or are not continuous. As a result of the significant downturn in industry conditions, we substantially reduced our rig construction activities during the fourth quarter of 2015 and throughout 2016, 2017 and 2018. As a result, we began expensing a portion of our Galayda yard construction costs

during the fourth quarter of 2015 and expect to continue expensing such costs until we resume continuous rig construction activities.
During the three and nine months ended September 30, 2017, our operating costs also included approximately zero and $1.1 million, respectively, of costs associated with the reactivation of idle and standby rigs. These costs included costs associated with recommissioning the rig, the hiring and training of new crews and the purchase of supplies and other

consumables required for the operation of the rigs.

How We Evaluate our Operations

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

- Safety Performance. Maintaining a strong safety record is a critical component of our business strategy. We 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 percentage 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 (defined below) 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 and rig construction costs 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 three and nine months ended September 30, 2018 and 2017:

(In thousands, except per share data)	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Revenues	$28,439	$ 23,445	$79,820	$ 64,966
Costs and expenses				
Operating costs	18,420	18,247	55,312	48,953
Selling, general and administrative	3,903	2,948	10,877	10,101
Merger expenses	1,933	—	2,376	—
Depreciation and amortization	6,831	6,529	20,001	19,120
Asset impairment, net	431	899	396	1,574
(Gain) loss on disposition of assets, net	(260)	—	(675)	1,573
Total cost and expenses	31,258	28,623	88,287	81,321
Operating loss	(2,819)	(5,178)	(8,467)	(16,355)
Interest expense	(1,168)	(772)	(3,049)	(2,088)
Loss before income taxes	(3,987)	(5,950)	(11,516)	(18,443)
Income tax (benefit) expense	(50)	30	(120)	110
Net loss	$(3,937)	$ (5,980)	$(11,396)	$ (18,553)
Other financial and operating data				
Number of completed rigs (end of period) (1)	15	14	15	14
Rig operating days (2)	1,345.1	1,234.7	3,869.2	3,418.9
Average number of operating rigs (3)	14.6	13.4	14.2	12.5
Rig utilization (4)	99.0 %	98.0 %	99.4 %	94.6 %
Average revenue per operating day (5)	$20,538	$ 18,034	$19,687	$ 18,061
Average cost per operating day (6)	$12,986	$ 13,513	$13,141	$ 12,825
Average rig margin per operating day	$7,552	$ 4,521	$6,546	$ 5,236

(1) Our 15th ShaleDriller rig commenced operations during the third quarter of 2018.

(2) Rig operating days represent the number of days our rigs are earning revenue under a contract during the period, including days that standby revenues are earned. During the three and nine months ended September 30, 2018, we did not earn any revenue on a standby basis. During the three and nine months ended September 30, 2017, there were zero and 77.9 operating days in which we earned revenue on a standby basis, respectively, including zero and 69.0 standby-without-crew days, respectively.

(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.

(5) Average revenue per operating day represents total contract drilling revenues earned during the period divided by rig operating days in the period. Excluded in calculating average revenue per operating day are revenues associated with the reimbursement of out-of-pocket costs paid by customers of $0.8 million and $1.2 million during the three months ended September 30, 2018 and 2017, respectively, and $3.6 million and $3.2 million during the nine months ended September 30, 2018 and 2017, respectively.

25

(6) Average cost per operating day represents operating costs incurred during the period divided by rig operating days in the period. The following costs are excluded in calculating average cost per operating day: (i) out-of-pocket costs reimbursed by customers of $0.8 million and $1.2 million during the three months ended September 30, 2018 and 2017, respectively, and $3.6 million and $3.2 million during the nine months ended September 30, 2018 and 2017, respectively, (ii) new crew training costs of zero and zero during the three months ended September 30, 2018 and 2017, respectively, and $0.1 million and $0.1 million during the nine months ended September 30, 2018 and 2017, respectively, (iii) construction overhead costs expensed due to reduced rig construction activity of $0.1 million and $0.4 million during the three months ended September 30, 2018 and 2017, respectively, and $0.7 million and $0.6 million during the nine months ended September 30, 2018 and 2017, respectively, (iv) rig reactivation costs associated with the redeployment of previously stacked rigs, excluding new crew training costs (included in (ii) above), of zero and $1.0 million during the three and nine months ended September 30, 2017, respectively, and (v) out-of-pocket expenses of $0.1 million, net of insurance recoveries, incurred as a result of damage to one of our rig's mast during the nine months ended September 30, 2017.

Three Months Ended September 30, 2018 Compared to the Three Months Ended September 30, 2017

Revenues

Revenues for the three months ended September 30, 2018 were $28.4 million, representing a 21.3% increase as compared to revenues of $23.4 million for the three months ended September 30, 2017. This increase was attributable to an increase in operating days to 1,345 days as compared to 1,235 days in the prior year comparable quarter and higher dayrates as compared to the prior year comparable quarter. The increase in operating days was primarily attributable to our newly constructed 15th ShaleDriller rig commencing operations during the current quarter, and our 14th ShaleDriller rig operating for the entire quarter as compared to a partial quarter in the the prior year quarter. On a revenue per operating day basis, our revenue per day increased by 13.9% to $20,538 during the three months ended September 30, 2018, as compared to revenue per day of $18,034 for the three months ended September 30, 2017. This increase in revenue per day was primarily the result of increased dayrates during the current quarter.

Operating Costs

Operating costs for the three months ended September 30, 2018 were $18.4 million, representing an 0.9% increase as compared to operating costs of $18.2 million for the three months ended September 30, 2017. This increase was attributable to an increase in operating days to 1,345 days as compared to 1,235 days in the prior year comparable quarter. On a cost per operating day basis, our cost decreased to $12,986 per day during the three months ended September 30, 2018, representing a 3.9% decrease compared to cost per operating day of $13,513 for the three months ended September 30, 2017. The decrease in cost per operating day during the three months ended September 30, 2018 was primarily attributable to labor efficiency initiatives and absorption of field overhead costs.

Selling, General and Administrative

Selling, general and administrative expenses for the three months ended September 30, 2018 were $3.9 million, representing a 32.4% increase as compared to selling, general and administrative expense of $2.9 million for the three months ended September 30, 2017. This increase as compared to the prior year comparable quarter primarily relates to higher incentive compensation.

Merger Expenses

Merger expenses of $1.9 million were recorded for the three months ended September 30, 2018 primarily comprised of legal and professional fees related to the Merger Agreement.

Depreciation and Amortization

Depreciation and amortization expense for the three months ended September 30, 2018 was $6.8 million, representing a 4.6% increase compared to depreciation and amortization expense of $6.5 million for the three months ended September 30, 2017. This increase relates primarily to mobilization of our 15th ShaleDriller rig and upgrades and additions to certain rigs in 2017 and 2018.

Asset Impairment, net

Asset impairment expense of $0.4 million was recorded for the three months ended September 30, 2018, as compared to $0.9 million for the three months ended September 30, 2017. See "Change in Plan of Sale of Assets" in Significant Developments in this Management's Discussion and Analysis.

(Gain) Loss on Disposition of Assets, net

A gain on the disposition of assets totaling $0.3 million was recorded for the three months ended September 30, 2018. There were no disposals or sales of assets during the three months ended September 30, 2017. In the current quarter, the gain primarily relates to the sale or disposition of miscellaneous drilling equipment.

Interest Expense

Interest expense for the three months ended September 30, 2018 was $1.2 million, as compared to $0.8 million for the three months ended September 30, 2017. The increase as compared to the prior year comparable quarter was primarily the result of increased average borrowings, as well as an increase in the 30 day LIBOR rate, which drives our borrowing rate of interest, between September 30, 2017 and September 30, 2018. Our interest expense is derived from borrowings under our Credit Facility, which are primarily used to fund our rig construction and rig upgrade activity and general corporate purposes.

Income Tax (Benefit) Expense

The income tax benefit recorded for the three months ended September 30, 2018 amounted to $50.0 thousand compared to an income tax expense of $30.0 thousand for the three months ended September 30, 2017. Our effective tax rates for the three months ended September 30, 2018 and 2017 were 1.3% and (0.5)%, respectively. Taxes in the current year period relate to Louisiana state income tax and to Texas margin tax. Taxes in the prior year period relate to Texas margin tax.

Nine Months Ended September 30, 2018 Compared to the Nine Months Ended September 30, 2017

Revenues

Revenues for the nine months ended September 30, 2018 were $79.8 million, representing a 22.9% increase compared to revenues of $65.0 million for the nine months ended September 30, 2017. This increase was attributable to an increase in operating days to 3,869 days as compared to 3,419 days in the prior year period. The increase in operating days was primarily attributable to our 14th ShaleDriller rig operating during the first nine months of 2018, while still being converted during the first six months of 2017 and commencing operations in the third quarter of 2017, as well as a rig, which was primarily idle during the first six months of 2017, operating at full utilization in the current year period. Additionally, our newly constructed 15th ShaleDriller rig commenced operations during the third quarter of 2018. Revenue per operating day increased to $19,687 during the nine months ended September 30, 2018 compared to revenue per day of $18,061 during the nine months ended September 30, 2017. This increase in revenue per day was primarily the result of increased dayrates during the nine months ended September 30, 2018.

Operating Costs

Operating costs for the nine months ended September 30, 2018 were $55.3 million, representing a 13.0% increase compared to operating costs of $49.0 million for the nine months ended September 30, 2017. This increase was attributable to an increase in operating days to 3,869 days as compared to 3,419 days in the prior year period. The current year increase in operating costs was offset by a reduction in rig reactivation and crew staging costs compared to the prior period which included approximately $1.1 million related to rigs that were reactivated during the first and second quarter of 2017. On a cost per operating day basis, our cost per day increased to $13,141 during the nine months ended September 30, 2018, representing a 2.5% increase compared to cost per day of $12,825 for the nine months ended September 30, 2017. The increase in cost per operating day was primarily due to a decrease in the number of rigs operating on a standby-without-crew basis during the nine months ended September 30, 2018. Rigs on standby-without-crew incur minimal operating costs. There were no standby-without-crew days recorded during the nine months ended September 30, 2018 as compared to 69 standby-without-crew days recorded during the nine months ended September 30, 2017.

Selling, General and Administrative

Selling, general and administrative expenses for the nine months ended September 30, 2018 were $10.9 million, representing a 7.7% increase compared to selling, general and administrative expenses of $10.1 million for the nine months ended September 30, 2017. This increase as compared to the prior year period primarily relates to higher incentive compensation and higher Louisiana franchise tax expense during the nine months ended September 30, 2018.

Merger Expenses

Merger expenses of $2.4 million were recorded for the nine months ended September 30, 2018 primarily comprised of legal and professional fees related to the Merger Agreement.

Depreciation and Amortization

Depreciation and amortization expense for the nine months ended September 30, 2018 was $20.0 million, representing a 4.6% increase compared to depreciation and amortization expense of $19.1 million for the nine months ended September 30, 2017. This increase was primarily due to rig fleet additions and upgrades and additions to certain rigs in 2017 and 2018. We begin depreciating our rigs when they commence drilling operations.

Asset Impairment, net

Asset impairment expense of $0.4 million was recorded for the nine months ended September 30, 2018, as compared to $1.6 million for the nine months ended September 30, 2017. See "Change in Plan of Sale of Assets" in Significant Developments in this Management's Discussion and Analysis.

(Gain) Loss on Disposition of Assets, net

A gain on the disposition of assets totaling $0.7 million was recorded for the nine months ended September 30, 2018 compared to a loss on the disposition of assets totaling $1.6 million in the prior year comparable period. In the current year period, the gain primarily relates to the sale or disposition of miscellaneous drilling equipment. In the prior year period, the loss related primarily to a loss of $0.8 million on the sale of certain assets classified as held for sale and a $0.8 million loss on the disposal of certain rig components associated with the upgrade of three of our rigs to 7,500 psi mud systems.

Interest Expense

Interest expense for the nine months ended September 30, 2018 was $3.0 million compared to interest expense of $2.1 million for the nine months ended September 30, 2017. The increase as compared to the prior year period was primarily the result of increased average borrowings, as well as an increase in the 30 day LIBOR rate, which drives our borrowing rate of interest, between September 30, 2017 and September 30, 2018. Our interest expense is derived from borrowings under our Credit Facility, which are primarily used to fund our rig construction and rig upgrade activity and general corporate purposes.

Income Tax (Benefit) Expense

The income tax benefit recorded for the nine months ended September 30, 2018 amounted to $120.0 thousand compared to an income tax expense of $110.0 thousand for the nine months ended September 30, 2017. The effective tax rates for the nine months ended September 30, 2018 and 2017 were 1.0% and (0.6)%, respectively. Taxes in the current year period relate to Louisiana state income tax and to Texas margin tax. Taxes in the prior year period relate to Texas margin tax.

Liquidity and Capital Resources

Our liquidity as of September 30, 2018 included approximately $17.1 million of our $85.0 million commitment availability under our Credit Facility existing at September 30, 2018, $3.0 million of cash and $12.8 million of other net working capital. As described under "Sidewinder Merger" in Significant Developments in this Management's Discussion and Analysis, on October 1, 2018, we entered into the new Term Loan Credit Agreement and New ABL Credit Facility, and terminated the Credit Facility existing at September 30, 2018. As a result, following September 30, 2018, our liquidity will consist of availability under the New ABL Facility, $15.0 million available pursuant to a committed delayed draw portion of the Term Loan Credit Facility, and cash and other working capital on hand, including working capital acquired in the Sidewinder Combination.

Our principal use of capital has been the construction of drilling rigs and associated equipment and working capital and inventories to support our drilling operations. Our primary sources of capital to date have been funds received from our initial private placement, our IPO, our April 2016 public offering of common stock, and cash flows from operations and our borrowings under credit facilities.

Net Cash Provided By Operating Activities

Cash provided by operating activities was $6.2 million for the nine months ended September 30, 2018 compared to cash provided by operating activities of $2.2 million during the same period in 2017. Factors affecting changes in operating cash flows are similar to those that impact net earnings, with the exception of non-cash items such as depreciation and amortization, impairments, gains or losses on disposals of assets, stock-based compensation, deferred taxes and amortization of deferred financing costs. Additionally, changes in working capital items such as accounts receivable, inventory, prepaid expense and accounts payable can significantly affect operating cash flows. Cash flows from operating activities during the first nine months of 2018 were higher as a result of a decrease in net loss of $7.2 million, adjusted for non-cash items, of $22.1 million for the nine months ended September 30, 2018 compared to $25.8 million for non-cash items during the same period in 2017. Working capital changes decreased cash flows from operating activities by $4.5 million for the nine months ended September 30, 2018 compared to $5.0 million during the same period in 2017.

Net Cash Used In Investing Activities

Cash used in investing activities was $24.1 million for the nine months ended September 30, 2018 compared to cash used in investing activities of $25.9 million during the same period in 2017. During the first nine months of 2018, cash payments of $24.8 million for capital expenditures were offset by proceeds from the sale of property, plant and equipment of $0.5 million. During the 2017 period, cash payments of $27.0 million for capital expenditures were offset by proceeds from the sale of property, plant and equipment of $1.1 million.

Net Cash Provided by Financing Activities

Cash provided by financing activities was $18.3 million for the nine months ended September 30, 2018 compared to cash provided by financing activities of $19.2 million during the same period in 2017. During the first nine months of 2018, we made borrowings under our Credit Facility of $50.5 million. These proceeds were offset by repayments under our Credit Facility of $31.2 million, the purchase of treasury stock of $0.4 million, restricted stock units withheld for taxes paid of $0.1 million, financing costs paid of $0.1 million and payments for capital lease obligations of $0.5 million. During the first nine months of 2017 we made borrowings under our Credit Facility of $38.4 million. These proceeds were offset by repayments under our Credit Facility of $17.2 million, the purchase of treasury stock of $162.0 thousand, restricted stock unit's withheld for taxes paid of $0.9 million, financing costs paid of $0.5 million and payments for capital lease obligations of $0.4 million.

Future Liquidity Requirements

We expect our future capital and liquidity needs to be related to funding capital expenditures for our capital spare inventory and expected upgrades and conversions to rigs acquired in the Sidewinder Combination, operating expenses, maintenance capital expenditures, working capital and general corporate purposes. We believe that our cash and cash equivalents, cash flows from operating activities and availability under our New ABL Credit Facility and DDTL Facility (see "Merger with Sidewinder Drilling LLC" in Significant Developments in this Management's Discussion and Analysis) will adequately finance all of our purchase commitments, capital expenditures and other cash requirements over the next twelve months.

Long-term Debt

Our Credit Facility existing at September 30, 2018, with a maturity date of November 5, 2020, provided for aggregate commitments of $85.0 million (the "Existing Credit Facility"). We had $67.9 million in outstanding borrowings and $17.1 million of remaining availability under the Existing Credit Facility at September 30, 2018. On October 1, 2018, in connection with our entry into the New Term Loan Credit Agreement and New ABL Credit Facility (see Note 1 "Nature of Operations and Recent Events - Merger with Sidewinder Drilling LLC" for further details), we repaid all outstanding borrowings and obligations under the Existing Credit Facility and terminated it.

Borrowings under the Existing Credit Facility were subject to a borrowing base formula that allowed for borrowings of up to 85% of eligible trade accounts receivable not more than 90 days outstanding, plus up to a certain percentage, the "advance rate", of the appraised forced liquidation value of our eligible, completed and owned drilling rigs. As of September 30, 2018, the advance rate was 70%.

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

At our election, interest under the Existing Credit Facility was 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 paid, on a quarterly basis, a commitment fee of 0.50% per annum on the unused portion of the Credit Facility commitment. As of September 30, 2018, the weighted average interest rate on our borrowings was 6.99%.

Additionally, included in our long-term debt are capital leases. These leases generally have initial terms of 36 months and are paid monthly. See Note 7 "Long-term Debt" for additional information.

Other Matters

Off-Balance Sheet Arrangements

We are party to certain arrangements defined as "off-balance sheet arrangements" that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors. These arrangements relate to non-cancelable operating leases and unconditional purchase obligations not fully reflected on our balance sheets (see Note 11 "Commitments and Contingencies" for additional information).

Emerging Growth Company

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

Recent Accounting Pronouncements

In February 2016, the FASB issued ASU No. 2016-02, Leases, to establish the principles that lessees and lessors shall apply to report useful information to users of financial statements about the amount, timing, and uncertainty of cash flows arising from a lease. Under the new guidance, lessees will be required to recognize (with the exception of short-term leases) at the commencement date, a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term. The provisions of this standard also apply to situations where companies are the lessor and therefore it could impact the accounting and related disclosures for our drilling contracts.

In July 2018, the FASB issued ASU No. 2018-11, Leases: Targeted Improvements, which provides an option to apply the guidance prospectively, and provides a practical expedient allowing lessors to combine the lease and non-lease components of revenues where the revenue recognition pattern is the same and where the lease component, when accounted for separately, would be considered an operating lease. The practical expedient also allows a lessor to account for the combined lease and non-lease components under ASC Topic 606, Revenue from Contracts with Customers, when the non-lease component is the predominant element of the combined components. We are in the process of evaluating the provisions of ASU No. 2018-11, specifically as they relate to our drilling contracts and the practical expedient for combining the lease and non-lease components of revenue, including the determination of which component is predominant.

As a lessee, while we cannot yet quantify the impact at this point, we expect our assets and liabilities to increase as a result of recognizing the right-of-use assets and lease liabilities. We are currently in the process of implementing a lease accounting system for our leases, converting our existing lease data to the new system and implementing relevant internal controls and procedures. We expect to apply this guidance prospectively, effective January 1, 2019.

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

In August 2018, the FASB issued ASU 2018-15, Intangibles - Goodwill and Other - Internal-Use Software: Customer’s Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract, to align the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. The amendments in the update are effective for public business entities for fiscal years beginning after December 15, 2019, with early adoption permitted. We are currently evaluating the impact this new guidance will have on our financial statements.

ITEM 3. 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 September 30, 2018 included $67.9 million of floating-rate debt attributed to borrowings at an average interest rate of 6.99%. As a result, our annual interest cost in 2018 will fluctuate based on short-term interest rates.
The impact on annual cash flow of a 10% change in the floating-rate (approximately 0.70%) would be approximately $0.5 million annually based on the floating-rate debt and other obligations outstanding at September 30, 2018; however, as a result of our entry into the New Term Loan Credit Agreement and New ABL Credit Facility as of October 1, 2018 (see Note 1 "Nature of Operations and Recent Events - Merger with Sidewinder Drilling LLC" for further details), our outstanding borrowings and average rate of interest will change and vary from 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 from a high of $107.95 per barrel in the second quarter of 2014, to a low of $26.19 per barrel in the first quarter of 2016. Similarly, natural gas prices declined from an average of $4.37 per MMBtu in 2014 to $2.52 per MMBtu in 2016. Oil and natural gas prices have slowly recovered from the lows experienced in 2016, with WTI oil prices reaching a three-year high of $77.41 per barrel in the second quarter of 2018. Similarly, natural gas prices at Henry Hub have averaged $2.97 per MMBtu in 2018 as of October 15, 2018.
Due to this deterioration and stabilization of commodity prices well below previous highs, our customers are principally focused on their most economic wells, and driving cost and production efficiencies that deliver the most economic wells with the lowest capital costs. As a result of this drive towards production and cost efficiencies, operators are focusing more of their capital spending on horizontal drilling programs compared to vertical drilling, and are more focused on utilizing drilling equipment and techniques that optimize costs and efficiency. Thus, we believe the rapid market deterioration and stabilization of oil prices well below historical highs has significantly accelerated the pace of the ongoing land rig replacement cycle and continued shift to horizontal drilling from multi-well pads utilizing “pad optimal” rig technology.
Demand for our ShaleDriller rigs has improved year over year as market conditions have improved from trough levels in 2016. At September 30, 2018, all 15 of our rigs were under contract and operating. In addition to improving utilization, contract tenors are improving with customers being willing to sign term contracts of six to twelve months or longer, and at higher dayrates compared to trough levels. However, the pace and duration of the current recovery is unknown, and if commodity prices were to fall for any sustained period of time, market conditions and demand for our products and services could deteriorate.
Credit and Capital Market Risk
Our customers may finance their drilling activities through cash flow from operations, the incurrence of debt or the issuance of equity. Any deterioration in the credit and capital markets, as currently being experienced, can make it difficult for our customers to obtain funding for their capital needs. A reduction of cash flow resulting from declines in commodity prices, or a reduction of available financing may result in a reduction in customer spending and the demand for our drilling services. This reduction in spending could have a material adverse effect on our business, financial condition and results of operations.

ITEM 4. 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-Q. 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 September 30, 2018 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.

PART II — OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

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

ITEM 1A. RISK FACTORS

In addition to the other information set forth in this report, you should carefully consider the risks discussed in Part 1, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2017. These risks are not the only risks that we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may materially adversely affect our business, financial condition or results of operations.

Our indebtedness could adversely affect its operations and financial condition.

We incurred additional indebtedness in connection with the Sidewinder Merger and related transactions. As of September 30, 2018, we had indebtedness under our Existing Credit Facility in an aggregate amount of $67.9 million. In connection with the closing of the Sidewinder Merger, we borrowed $130.0 million under a Term Loan Facility to fund the repayment of all of our and Sidewinder’s outstanding indebtedness, and we entered into a $40 million receivables-based New ABL Credit Facility. The Term Loan Credit Agreement also allows us to draw down an additional $15 million of borrowings at any time, subject to certain conditions the (“DDTL Facility” and together with the Term Loan Facility, the “Term Facilities”). As a result, our aggregate debt balance and ability to incur additional debt increased as a result of the Sidewinder Merger.

The Term Loan Facility bears interest at LIBOR plus 750 basis points, which results in an increase in cash interest payments over and above interest rates contained in our existing borrowing arrangements. Both the Term Loan Facility and ABL Credit Facility contain customary covenants, including covenants that limit our ability to pay dividends, make acquisitions, make certain investments and incur additional indebtedness.

Our indebtedness after giving effect to the Sidewinder Merger could have important consequences, including but not limited to:

- limiting our operational flexibility due to the covenants contained in our debt agreements;
- limiting our ability to invest operating cash flow in our business due to debt service requirements;
- limiting our ability to pay quarterly dividends or to repurchase shares;
- limiting our ability to obtain additional financing;
- limiting our ability to compete with companies that are not as highly leveraged and that may be better positioned to withstand economic downturns;
- increasing our vulnerability to economic downturns, changing market conditions and changes in the radio broadcast industry;
- limiting our flexibility in planning for, or reacting to, changes in its business or industry; and
- to the extent that our debt is subject to floating interest rates, increasing our vulnerability to fluctuations in market interest rates.

Our ability to meet our expenses and debt service obligations will depend on the factors described above, as well as our future financial performance, which will be affected by financial, business, economic and other factors, the success of product and marketing innovation and pressure from competitors. If we do not generate enough cash to pay our debt service obligations, we may be required to refinance all or part of our existing debt, sell assets, borrow more money or raise equity. We cannot assure you that we will be able to, at any given time, refinance our debt, sell assets, borrow more money or raise equity on terms acceptable to us or at all.

If the representations and warranties made to us by Sidewinder or others in connection with the Merger Agreement were inaccurate, we could incur losses or financial obligations.

If we were to discover that there were inaccuracies in the representations and warranties made to us by Sidewinder pursuant to the Merger Agreement were inaccurate, we will not have any post-closing rights to indemnification from Sidewinder or its members, and we could incur substantial losses or financial obligations, which could materially adversely affect our financial condition or harm our business. Similarly, any inaccuracies in the representations and warranties made to us by other parties to the Stockholders' Agreement entered into in connection with the Sidewinder Merger could materially adversely affect our financial condition or harm our business.

We may be unable to integrate operations successfully or realize anticipated benefits from the Sidewinder Merger.

Realizing any of the anticipated benefits of the Sidewinder Merger, including additional revenue opportunities, involves a number of challenges. The failure to meet these integration challenges could seriously harm our results of operations and the market price of our common stock may decline as a result.

Realizing the benefits of the transaction will depend in part on the integration of technology, operations, personnel and sales activity of the two companies. These integration activities are complex and time-consuming, and we may encounter unexpected difficulties or incur unexpected costs, including:

- challenges in combining the cultural and management teams of two different companies
- challenges in combining rig product offerings, including integration of the underlying technology, and sales and marketing activities;
- our inability to achieve the cost savings and operating synergies anticipated in the transaction, which would prevent us from achieving the positive earnings gains expected as a result of the transaction;
- diversion of management attention from ongoing business concerns to integration matters;
- difficulties in consolidating and rationalizing information technology platforms and administrative infrastructures;
- complexities in managing a larger company than before the completion of transaction;
- difficulties in the assimilation of the personnel and the integration of two business cultures;
- challenges in demonstrating to our customers and to customers of Sidewinder that the transaction will not result in adverse changes in product and technology offerings, customer service standards or business focus; and
- possible cash flow interruption or loss of revenue as a result of change of ownership transitional matters.

We may not successfully integrate operations in a timely manner, and we may not realize the anticipated net reductions in costs and expenses and other benefits and synergies of the Sidewinder Merger to the extent, or in the timeframe, anticipated. In addition to the integration risks discussed above, our ability to realize the benefits and synergies of the Sidewinder Merger could be adversely impacted by practical or legal constraints on our ability to combine operations. If our management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer and our results of operations and financial condition may be harmed.

The market price of our common stock could decline as a result of the large number of shares eligible for sale after the Sidewinder Merger.

A substantial number of additional shares of our common stock are eligible for resale in the public market. Current stockholders of the Company and former shareholders of Sidewinder may not wish to continue to invest in the operations of the combined business after the Sidewinder Merger, or for other reasons, may wish to dispose of some or all of their interests in the Company after the Sidewinder Merger. Sales of substantial numbers of shares of both the newly issued and the existing shares of our common stock in the public market following the Sidewinder Merger could adversely affect the market price of such shares.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

Exhibit Number	Description
2.1	Agreement and Plan of Merger, dated as of July 18, 2018, by and among Independence Contract Drilling, Inc., Patriot Saratoga Merger Sub LLC, and Sidewinder Drilling, LLC. (Incorporated by reference to the Company's Current Report on Form 8-K (File No. 001-36590) filed on October 2, 2018, Exhibit 2.1)
3.1	Certificate of Amendment to the Amended and Restated Certificate of Incorporation of Independence Contract Drilling, Inc. (Incorporated by reference to the Company's Current Report on Form 8-K (File No. 001-36590) filed on October 2, 2018, Exhibit 3.1)
3.2	Amended and Restated Certificate of Incorporation of Independence Contract Drilling, Inc. (Incorporated by reference to the Company's Current Report on Form 8-K (File No. 001-36590) filed August 13, 2014, Exhibit 3.1)
3.3	Amended and Restated Bylaws of Independence Contract Drilling, Inc. (Incorporated by reference to the Company's Registration Statement on Form S-1 (File No. 333-196914) filed July 18, 2014, Exhibit 3.3)
10.1	Amended and Restated Stockholders' Agreement, dated as of October 1, 2018, by and among Independence Contract Drilling, Inc. and the Member Parties thereto. (Incorporated by reference to the Company's Current Report on Form 8-K (File No. 001-36590) filed on October 2, 2018, Exhibit 10.1)
10.2	Credit Agreement, dated as of October 1, 2018, by and among Wells Fargo Bank, National Association, as Agent, the Lenders party thereto, Independence Contract Drilling, Inc., Patriot Saratoga Merger Sub, LLC, and ICD Operating LLC, as Borrowers, the Lenders party thereto, and U.S. Bank National Association, as Agent. (Incorporated by reference to the Company's Current Report on Form 8-K (File No. 001-36590) filed on October 2, 2018, Exhibit 10.2)
10.3	Credit Agreement, dated as of October 1, 2018, by and among Independence Contract Drilling, Inc. and Patriot Saratoga Merger Sub, LLC, as initial Borrowers, and (following the consummation of the Merger) Independence Contract Drilling, Inc. and ICD Operating LLC, each as Borrower, the Lenders party thereto, and U.S. Bank National Association, as Agent. (Incorporated by reference to the Company's Current Report on Form 8-K (File No. 001-36590) filed on October 2, 2018, Exhibit 10.3)
10.4	Voting and Support Agreement, dated as of July 18, 2018, by and among Independence Contract Drilling, Inc., and the directors and officers party there. (Incorporated by reference to the Company's Current Report on Form 8-K (File No. 001-36590) filed on October 2, 2018, Exhibit 10.2)
10.5	Executive Employment Agreement, dated as of July 18, 2018, by and among Independence Contract Drilling, Inc., and J. Anthony Gallegos, Jr. (Incorporated by reference to the Company's Current Report on Form 8-K (File No. 001-36590) filed on July , 2018, Exhibit 10.3)
31.1*	Certification by Chief Executive Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act

31.2*	Certification by Chief Financial Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act
32.1*	Certification of Chief Executive Officer pursuant to 18 U.S.C Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.CAL*	XBRL Calculation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document

101.INS*	XBRL Instance Document
101.LAB*	XBRL Labels Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.SCH*	XBRL Schema Document

*Filed with this report

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

INDEPENDENCE CONTRACT DRILLING, INC.

By: /s/ J. Anthony Gallegos, Jr.
Name: J. Anthony Gallegos, Jr.
Title: President and Chief Executive Officer (Principal Executive Officer)

By: /s/ Philip A. Choyce
Name: Philip A. Choyce
Title: Executive Vice President, Chief Financial Officer, Treasurer and Secretary (Principal Financial Officer)

By: /s/ Michael J. Harwell
Name: Michael J. Harwell
Title: Vice President - Finance and Chief Accounting Officer (Principal Accounting Officer)

Date: November 6, 2018