Independence Contract Drilling, Inc.
Form 10-Q
May 03, 2019
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 March 31, 2019
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 x
	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

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

Title of each class	Trading symbol(s)	Name of each exchange where registered
Common Stock, $0.01 par value per share	ICD	New York Stock Exchange

77,078,252 shares of the registrant's Common Stock were outstanding as of April 30, 2019.

INDEPENDENCE CONTRACT DRILLING, INC.
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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;
- 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, 2018. Further, any forward-looking statement speaks only as of the date on which it is made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which the statement is made or to reflect the occurrence of unanticipated events.

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

	March 31, 2019	December 31, 2018
Assets		
Cash and cash equivalents	$12,549	$ 12,247
Accounts receivable, net	42,137	41,987
Inventories	2,738	2,693
Assets held for sale	19,369	19,711
Prepaid expenses and other current assets	5,667	8,930
Total current assets	82,460	85,568
Property, plant and equipment, net	488,472	496,197
Goodwill	1,627	1,627
Deferred tax assets	1,766	—
Other long-term assets, net	2,582	1,470
Total assets	$576,907	$ 584,862
Liabilities and Stockholders’ Equity		
Liabilities		
Current portion of long-term debt	$905	$ 587
Accounts payable	16,174	16,312
Accrued liabilities	21,095	29,219
Total current liabilities	38,174	46,118
Long-term debt	132,610	130,012
Contingent consideration	15,558	15,748
Deferred income taxes, net	—	774
Other long-term liabilities	1,195	677
Total liabilities	187,537	193,329
Commitments and contingencies (Note 13)		
Stockholders’ equity		
Common stock, $0.01 par value, 200,000,000 shares authorized; 77,598,806 shares issued and 77,078,252 shares outstanding	771	771
Additional paid-in capital	503,656	503,446
Accumulated deficit	(112,011)	(109,638)
Treasury stock, at cost, 520,554 shares	(3,046)	(3,046)
Total stockholders’ equity	389,370	391,533
Total liabilities and stockholders’ equity	$576,907	$ 584,862

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

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

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018
Revenues	$60,358	$25,627
Costs and expenses		
Operating costs	39,333	18,926
Selling, general and administrative	4,545	3,479
Merger-related expenses	1,081	—
Depreciation and amortization	11,313	6,591
Asset impairment (insurance recoveries), net	2,018	(35)
Loss (gain) on disposition of assets, net	3,220	(82)
Total costs and expenses	61,510	28,879
Operating loss	(1,152)	(3,252)
Interest expense	(3,761)	(943)
Loss before income taxes	(4,913)	(4,195)
Income tax benefit	(2,540)	(49)
Net loss	$(2,373)	$(4,146)
Loss per share:		
Basic and diluted	$(0.03)	$(0.11)
Weighted average number of common shares outstanding:		
Basic and diluted	75,692	38,124

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

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Independence Contract Drilling, Inc.
Consolidated Statements 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, 2018	77,078,252	$ 771	$ 503,446	$ (109,638)	$ (3,046)	$ 391,533
Common stock issuance costs	—	—	(177)	—	—	(177)
Stock-based compensation	—	—	387	—	—	387
Net loss	—	—	—	(2,373)	—	(2,373)
Balances at March 31, 2019	77,078,252	$ 771	$ 503,656	$ (112,011)	$ (3,046)	$ 389,370

	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	—	—	644	—	—	644
Net loss	—	—	—	(4,146)	—	(4,146)
Balances at March 31, 2018	38,252,765	$ 383	$ 327,162	$ (93,791)	$ (2,219)	$ 231,535

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

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

	Three Months Ended March 31,	
	2019	2018
Cash flows from operating activities		
Net loss	$(2,373)	$(4,146)
Adjustments to reconcile net loss to net cash provided by operating activities		
Depreciation and amortization	11,313	6,591
Asset impairment (insurance recoveries), net	2,018	(35)
Stock-based compensation	387	644
Loss (gain) on disposition of assets, net	3,220	(82)
Deferred income taxes	(2,540)	(49)
Amortization of deferred financing costs	203	90
Bad debt (recovery) expense	(45)	22
Changes in operating assets and liabilities		
Accounts receivable	(105)	1,790
Inventories	(45)	(56)
Prepaid expenses and other assets	843	(386)
Accounts payable and accrued liabilities	(5,271)	(2,371)
Net cash provided by operating activities	7,605	2,012
Cash flows from investing activities		
Purchases of property, plant and equipment	(10,832)	(6,259)
Proceeds from insurance claims	1,000	—
Proceeds from the sale of assets	536	146
Net cash used in investing activities	(9,296)	(6,113)
Cash flows from financing activities		
Borrowings under ABL Credit Facility	2,403	—
Borrowings under CIT Credit Facility	—	13,779
Repayments under CIT Credit Facility	—	(9,100)
Common stock issuance costs	(177)	—
Purchase of treasury stock	—	(350)
RSUs withheld for taxes	—	(95)
Financing costs paid under Term Loan Facility	(5)	—
Financing costs paid under ABL Credit Facility	(12)	—
Payments for finance and capital lease obligations	(216)	(163)
Net cash provided by financing activities	1,993	4,071
Net increase (decrease) in cash and cash equivalents	302	(30)
Cash and cash equivalents		
Beginning of period	12,247	2,533
End of period	$12,549	$2,503
Supplemental disclosure of cash flow information		
Cash paid during the period for interest	$3,514	$848
Supplemental disclosure of non-cash investing and financing activities		
Change in property, plant and equipment purchases in accounts payable	$(1,753)	$(739)
Additions to property, plant and equipment through capital leases	$520	$70
Transfer of assets from held and used to held for sale	$(2,285)	$—

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

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INDEPENDENCE CONTRACT DRILLING, INC.
Notes to Consolidated 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. and its subsidiary.

We provide land-based contract drilling services for oil and natural gas producers targeting unconventional resource plays in the United States. We construct, own and operate a premium fleet comprised of modern, technologically advanced drilling rigs. Our fleet currently includes 32 marketed ShaleDriller® rigs that are specifically engineered and designed to optimize the development of our customers’ most technically demanding oil and gas properties, and two idle ShaleDriller rigs that will enter our marketed fleet when planned upgrades are completed.

Our marketed 32 rig fleet includes 29 AC powered (“AC”) rigs and three 1500-HP ultra-modern SCR rigs. Our two idle rigs that currently are not included in our marketed fleet include one non-walking 1500-HP AC rig and one 1500-HP SCR that will be converted to AC pad-optimal status prior to entering our fleet.

We currently focus our operations on unconventional resource plays located in geographic regions that we can efficiently support from our Houston, Texas and Midland, Texas 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 historically cyclical and 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. As a result, our industry experienced an exceptional downturn, with the U.S. land rig count falling from a high of 1,930 rigs in 2014 to a low of 404 rigs in 2016. In addition to overall rig count decline, pricing for our contract drilling services also substantially declined during this period of time. Although crude oil prices recovered in 2017 and 2018, reaching a high of $77.41 per barrel in the second quarter of 2018, the U.S. land rig count never recovered to its 2014 highs, only reaching 1,083 rigs the week ended December 28, 2018. Similarly, although pricing for our drilling services improved during this period, pricing never reached the rates experienced in 2014.

During the fourth quarter of 2018, oil prices began to decline, reaching a low of $44.48. Although oil prices have recently recovered to over $60.00 in late March 2019, most of our E&P customers have decreased planned capital expenditure budgets with the goal of operating within their cash flows, which they expect to be lower in 2019 unless commodity prices substantially improve. These changes have resulted in softening demand for contract drilling services. Although we believe market conditions for our services have stabilized, we believe this stabilization is predicated on oil prices remaining above a$50 per barrel or higher range. If oil prices were to fall below these levels for any sustainable period, demand and pricing for our contract drilling services could decline and have a material adverse affect on our operations and financial condition.

Sidewinder Merger

On July 18, 2018, ICD, Patriot Saratoga Merger Sub, LLC, a wholly owned subsidiary of ICD (“Merger Sub”), Sidewinder Drilling, LLC (“Sidewinder”) and MSD Credit Opportunity Master Fund, L.P., as Members’ Representative, entered into a definitive merger agreement (the “Merger Agreement”) pursuant to which Merger Sub merged with and into Sidewinder (the “Merger”), with Sidewinder surviving the Merger and becoming a wholly owned subsidiary of the ICD. The

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Merger transaction was completed on October 1, 2018. Pursuant to the terms of the Merger Agreement, Sidewinder Series A members received 36,752,657 shares of ICD common stock in exchange for 100% of the outstanding Series A Common Units of Sidewinder (the “Series A Common Units”). The Merger was accounted for using the acquisition method of accounting with ICD identified as the accounting acquirer.

2. Interim Financial Information

These unaudited consolidated financial statements include the accounts of ICD and its subsidiary, 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, 2018, included in our Annual Report on Form 10-K for the year ended December 31, 2018. 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 months ended March 31, 2019 may not be indicative of results that will be realized for the full year ending December 31, 2019.

Leases

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 are required to recognize (with the exception of leases with terms of 12 months or less) 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.

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 adopted ASU No. 2016-02 and its related amendments (collectively known as ASC 842) effective on January 1, 2019, using the effective date method.

See Note 3 “Leases” for the required disclosures related to the impact of adopting this standard and a discussion of our policies related to leases.

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 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 January 2017, the FASB issued ASU No. 2017-04, Intangibles—Goodwill and Other, which simplifies the subsequent measurement of goodwill by eliminating Step 2 of the goodwill impairment test. In computing the implied fair value of goodwill under Step 2, an entity had to perform procedures to determine the fair value at the impairment testing date of its assets and liabilities (including unrecognized assets and liabilities) following the procedure that would be required in determining the fair value of assets acquired and liabilities assumed in a business combination. Under this new standard, an entity should perform its goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount and then recognize an impairment charge, as necessary, for the amount by which the carrying amount exceeds the reporting unit's fair value, not to exceed the total amount of goodwill allocated to that reporting unit. This guidance is effective for fiscal years beginning after December 15, 2019. We do not believe this new guidance will have a material impact on our consolidated financial statements.

3. Leases

Effective January 1, 2019, we adopted ASC 842. The most significant changes of the new standard are (1) lessees recognize a lease liability and a right-of-use ("ROU") asset for all leases, including operating leases, with an initial term greater than 12 months on their balance sheets and (2) lessees and lessors disclose additional key information about their leasing transactions.

We have elected to implement ASC 842 using the effective date method which recognizes and measures all leases that exist at the effective date, January 1, 2019, using a modified retrospective transition approach. There was no cumulative-effect adjustment required to be recorded in connection with the adoption of the new standard and the reported amount of lease expense and cash flows are substantially unchanged under ASC 842. Comparative periods are presented in accordance with ASC 840 and do not include any retrospective adjustments.

As a Lessor

Our daywork drilling contracts, under which the vast majority of our revenues are derived, contain both a lease component and a service component.

ASU 2018-11 amended ASC 842 to, among other things, provide lessors with a practical expedient to not separate non-lease components from lease components and, instead, to account for those components as a single amount, if the non-lease components otherwise would be accounted for under Topic 606 and both of the following are met:

1) The timing and pattern of transfer of non-lease components and lease components are the same.
2) The lease component, if accounted for separately, would be classified as an operating lease.

If the non-lease component is the predominant component of the combined amount, an entity is required to account for the combined amount in accordance with Topic 606. Otherwise, the entity must account for the combined amount as an operating lease in accordance with Topic 842.

Revenues from our daywork drilling contracts meet both of the criteria above and we have determined both quantitatively and qualitatively that the service component of our daywork drilling contracts is the predominant component. Accordingly, we combine the lease and service components of our daywork drilling contracts and account for the combined amount under Topic 606. See Note 5 - Revenue from Contracts with Customers.

We have multi-year operating and financing leases for corporate office space, field location facilities, land, vehicles and various other equipment used in our operations. We also have a significant number of rentals related to our drilling operations that are day-to-day or month-to-month arrangements. Our multi-year leases have remaining lease terms of greater than one year to 5 years.

As a Lessee

As a practical expedient, a lessee may elect not to apply the recognition requirements in ASC 842 to short-term leases. Instead a lessee may recognize the lease payments in profit or loss on a straight-line basis over the lease term and variable lease payments in the period in which the obligation for those payments is incurred. We have elected to utilize this practical expedient.

We have elected the package of practical expedients permitted in ASC 842. Accordingly, we accounted for our existing capital leases as finance leases under the new guidance, without reassessing whether the contracts contained a lease under ASC 842, whether classification of the capital lease would be different in accordance with ASC 842 and without reassessing any initial costs associated with the lease. As a result, we recognized on January 1, 2019 a lease liability at the carrying amount of the capital lease obligation on December 31, 2018, of $1.2 million and a ROU asset at the carrying amount of the capital lease asset of $1.3 million. Additionally, we accounted for our existing operating leases as operating leases under the new guidance, without reassessing (a) whether the contract contains a lease under ASC 842 or (b) whether classification of the operating lease would be different in accordance with ASC 842. As a result, we recognized on January 1, 2019 a lease liability of $1.7 million, which represents the present value of the remaining lease payments discounted using our incremental borrowing rate of 8.17%, and a ROU asset of $0.9 million, which represents the lease liability of $1.7 million plus any prepaid lease payments, and less any unamortized lease incentives, totaling $0.8 million.

On January 1, 2019, the vehicle leases assumed in the Sidewinder merger were amended to be consistent with our existing vehicle leases, which resulted in a change in the classification from operating leases to finance leases. On the amendment date, we recorded $0.4 million in finance lease obligations and right of use assets.

The components of lease expense were as follows:

(in thousands)	Three Months Ended March 31, 2019
Operating lease expense	$ 125
Short-term lease expense	1,193
Variable lease expense	86
Finance lease cost:	
Amortization of right-of-use assets	$ 265
Interest expense on lease liabilities	32
Total finance lease expense	297
Total lease expenses	$ 1,701

Supplemental cash flow information related to leases is as follows:

(in thousands)	Three Months Ended March 31, 2019
Cash paid for amounts included in measurement of lease liabilities:	
Operating cash flows from operating leases	$ 103
Operating cash flows from finance leases	$ 32
Financing cash flows from finance leases	$ 216
Right-of-use assets obtained or recorded in exchange for lease obligations:	
Operating leases	$ 955

Finance leases	$ 520

Supplemental balance sheet information related to leases is as follows:

(in thousands)	March 31, 2019
Operating leases:	
Operating lease right-of-use assets	$865
Accrued liabilities	$480
Other long-term liabilities	1,196
Total operating lease liabilities	$1,676
Finance leases:	
Property and equipment	$2,523
Accumulated depreciation	(971)
Property and equipment, net	$1,552
Current portion of long-term debt	$905
Long-term debt	679
Total finance lease liabilities	$1,584
Weighted-average remaining lease term	
Operating leases	4.3 years
Finance leases	1.6 years
Weighted-average discount rate	
Operating leases	8.17 %
Finance leases	6.64 %

Maturities of lease liabilities at March 31, 2019 were as follows:

(in thousands)	Operating Leases	Finance Leases
Cash payments in future twelve month periods:		
Year 1	$ 594	$759
Year 2	351	365
Year 3	353	84
Year 4	363	—
Year 5	326	—
Thereafter	—	—
Total cash lease payment	1,987	1,208
Add: expected residual value	—	479
Less: imputed interest	(311)	(103)
Total lease liabilities	$ 1,676	$1,584

As of December 31, 2018, future total obligations on our noncancellable capital and operating leases were $3.7 million in the aggregate, which consisted of the following: $1.4 million in 2019, $1.0 million in 2020, $0.5 million in 2021 and $0.8 million thereafter.

4. Sidewinder Merger

We completed the merger with Sidewinder Drilling LLC on October 1, 2018, through an exchange of 100% of Sidewinder's outstanding voting interests for 36,752,657 shares of ICD common stock, which were valued at $173.1 million at the time of closing. We also assumed $58.5 million of Sidewinder indebtedness in the transaction.

During the three months ended March 31, 2019, we recorded $1.1 million of merger-related expenses comprised primarily of severance, professional fees and various other integration related expenses.

Certain intangible liabilities were recorded in connection with the Sidewinder merger for drilling contracts in place at the closing date of the transaction that had unfavorable contract terms as compared to then current market terms for comparable drilling rigs. The intangible liabilities are amortized to operating revenues over the remaining underlying contract terms. During the three months ended March 31, 2019, $1.0 million of intangible revenue was recognized as a result of this amortization. The remaining balance will be fully amortized by July 2019.

The following table summarizes the components of intangible liabilities, net:

(in thousands)	March 31, 2019	December 31, 2018
Intangible liabilities	$3,123	$ 3,123
Accumulated amortization	(3,077)	(2,044)
Intangible liabilities, net	$46	$ 1,079

5. Revenue from Contracts with Customers

The following table summarizes revenues from our contracts disaggregated by revenue generating activity contained therein for the three months ended March 31, 2019 and 2018:

	Three Months Ended March 31,	
(in thousands)	2019	2018
Dayrate drilling	$56,451	$23,777
Mobilization	1,260	459
Reimbursables	1,604	1,231
Capital modification	10	160
Intangible	1,033	—
Total revenue	$60,358	$25,627

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

(in thousands)	March 31, 2019	December 31, 2018
Receivables, which are included in "Accounts receivable, net"	$ 41,782	$ 41,987
Contract assets	$ —	$ —
Contract liabilities	$ (1,121)	$ (1,374)

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

	Three Months Ended March 31, 2019	
(in thousands)	Contract Assets	Contract Liabilities
Revenue recognized that was included in contract liabilities at beginning of period	$ —	$ 732
Increase in contract liabilities due to cash received, excluding amounts recognized as revenue	$ —	$ (479)
Transferred to receivables from contract assets at beginning of period	$ —	$ —

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 March 31, 2019. The estimated revenue does not include amounts of variable consideration that are constrained.

	Year Ending December 31,			
(in thousands)	2019	2020	2021	Total
Revenue	$ 1,121	$ —	$ —	$ 1,121

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, recorded as "Prepaid expenses and other current assets", amounted to $1.0 million and $1.1 million on our consolidated balance sheets at March 31, 2019 and December 31, 2018, respectively. During the quarter ended March 31, 2019, contract costs increased by $0.5 million and we amortized $0.7 million of contract costs.

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

The fair value of our long-term debt is determined by Level 3 measurements based on quoted market prices and terms for similar instruments, where available, and on the amount of future cash flows associated with the debt, discounted using our current borrowing rate for comparable debt instruments (the Income Method). Based on our evaluation of the risk free rate, the market yield and credit spreads on comparable company publicly traded debt issues, we used an annualized discount rate, including a credit valuation allowance, of 6.9%. The following table summarizes the carrying value and fair value of our long-term debt as of March 31, 2019 and December 31, 2018.

(in thousands)	March 31, 2019		December 31, 2018	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Term Loan Facility	$130,000	$145,773	$130,000	$131,893
ABL Credit Facility	4,969	4,896	2,566	2,258

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.

7. Inventories

All of our inventory as of March 31, 2019 and December 31, 2018 consisted of supplies held for use in our drilling operations.

8. Accrued Liabilities

Accrued liabilities consisted of the following:

(in thousands)	March 31, 2019	December 31, 2018
Accrued salaries and other compensation	$ 8,008	$ 12,379
Insurance	4,674	5,464
Deferred revenues (contract liabilities)	1,121	1,374
Property taxes and other	2,570	3,829
Intangible liability	47	1,079
Interest	3,352	3,318
Operating lease liability - current	480	—
Other	843	1,776
	$ 21,095	$ 29,219

9. Long-term Debt

Our long-term debt consisted of the following:

(in thousands)	March 31, 2019	December 31, 2018
Term Loan Facility due October 1, 2023	$130,000	$130,000
ABL Credit Facility due October 1, 2023	4,969	2,566
Finance and capital lease obligations	1,584	1,235
	136,553	133,801
Less: current portion	(905)	(587)
Less: Term Loan Facility deferred financing costs	(3,038)	(3,202)
Long-term debt	$132,610	$130,012

Credit Facilities

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.

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 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 ABL Credit Facility or other material agreements for indebtedness, and a change of control.

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 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. MSD PCOF Partners IV, LLC (an affiliate of MSD Partners, L.P. "MSD Partners") is the lender of our $130.0 million Term Loan Facility. MSD Partners, together with its affiliate, MSD Capital, L.P. (“MSD Capital”) own approximately 30% of the outstanding shares of the Company’s common stock.

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 “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 ABL Credit Facility is subject to a borrowing base calculated based on 85% of the net amount of our eligible accounts receivable, minus reserves. The 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 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 ABL Credit Facility commitment.

The 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 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 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. We are in compliance with our covenants as of March 31, 2019.

The obligations under the 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. As of March 31, 2019, the weighted-average interest rate on our borrowings was 10.16%. At March 31, 2019, the borrowing base under our ABL Credit Facility was $31.0 million, and we had $23.4 million of availability remaining of our $40.0 million commitment on that date.

10. 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 March 31, 2019, approximately 164,999 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 March 31,	
(in thousands)	2019	2018
Compensation cost recognized:		
Stock options	$—	$—
Restricted stock and restricted stock units	387	644
Total stock-based compensation	$387	$644

No stock-based compensation was capitalized in connection with rig construction activity during the three months ended March 31, 2019 or 2018.

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 three months ended March 31, 2019 or 2018.

A summary of stock option activity and related information for the three months ended March 31, 2019 is as follows:

	Three Months Ended March 31, 2019	
	Options	Weighted Average Exercise Price
Outstanding at January 1, 2019	669,213	$ 12.74
Granted	—	—
Exercised	—	—
Forfeited/expired	—	—
Outstanding at March 31, 2019	669,213	$ 12.74
Exercisable at March 31, 2019	669,213	$ 12.74

The number of options vested at March 31, 2019 was 669,213 with a weighted average remaining contractual life of 3.0 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 March 31, 2019.

Time-based Restricted Stock and Restricted Stock Units

We have granted time-based restricted stock and restricted stock units to key employees under the 2012 Plan.

Time-based Restricted Stock

Time-based restricted stock awards consist of grants of our common stock that vest ratably over three to five 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 March 31, 2019, there was $4.2 million in unrecognized compensation cost related to unvested restricted stock awards. This cost is expected to recognized over a weighted-average period of 2.4 years.

A summary of the status of our time-based restricted stock awards and of changes in our time-based restricted stock awards outstanding for the three months ended March 31, 2019 is as follows:

	Three Months Ended March 31, 2019	
	Shares	Weighted Average Grant-Date Fair Value Per Share
Outstanding at January 1, 2019	1,385,973	$ 3.22
Granted	—	—
Vested	—	—
Forfeited	—	—
Outstanding at March 31, 2019	1,385,973	$ 3.22

Time-based Restricted Stock Units

We have granted three-year time vested restricted stock unit awards where each unit represents the right to receive, at the end of a vesting period, one share of ICD common stock with no exercise price. The fair value of time-based restricted stock unit awards is determined based on the estimated fair market value of our shares on the grant date. As of March 31, 2019, there was $1.6 million of total unrecognized compensation cost related to unvested time-based restricted stock unit awards. This cost is expected to be recognized over a weighted-average period of 1.3 years.

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A summary of the status of our time-based restricted stock unit awards and of changes in our time-based restricted stock unit awards outstanding for the three months ended March 31, 2019 is as follows:

	Three Months Ended March 31, 2019	
	RSUs	Weighted Average Grant-Date Fair Value Per Share
Outstanding at January 1, 2019	409,607	$ 4.79
Granted	—	—
Vested and converted	—	—
Forfeited	—	—
Outstanding at March 31, 2019	409,607	$ 4.79

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

As of March 31, 2019, we had a total of 77,078,252 shares of common stock, $0.01 par value, outstanding. We also had 520,554 shares held as treasury stock. Total authorized common stock is 200,000,000 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 March 31,	
(in thousands, except per share data)	2019	2018
Net loss (numerator):	$(2,373)	$(4,146)
Loss per share:		
Basic and diluted	$(0.03)	$(0.11)
Shares (denominator):		
Weighted average common shares outstanding - basic	75,692	38,124
Weighted average common shares outstanding - diluted	75,692	38,124

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 669,213 and 682,950 during the three months ended March 31, 2019 and 2018, respectively. The number of RSUs, which are not participating securities, that were excluded from our basic and diluted loss per share because they are anti-dilutive, were 409,607 and 1,261,244 for the three months ended March 31, 2019 and 2018, respectively.

12. Income Taxes

Our effective tax rate was 51.7% for the three months ended March 31, 2019, and 1.2% and for the three months ended March 31, 2018. Taxes in both periods relate to Louisiana state income tax and 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.

13. Commitments and Contingencies

Purchase Commitments

As of March 31, 2019, we had outstanding purchase commitments to a number of suppliers totaling $14.4 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 2019.

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.

14. Related Parties

In conjunction with the closing of the Sidewinder Merger on October 1, 2018, we entered into the Term Loan Credit Agreement for an initial term loan in an aggregate principal amount of $130.0 million and a delayed draw term loan facility in an aggregate principal amount of up to $15.0 million. MSD PCOF Partners IV, LLC (an affiliate of MSD Partners) is the lender of our $130.0 million Term Loan Facility. MSD Partners, together with MSD Capital, own approximately 30% of the outstanding shares of the Company's common stock as of March 31, 2019.

We made interest payments on the Term Loan Facility totaling $3.3 million for the three months ended March 31, 2019.

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, 2018, filed with the Securities and Exchange Commission on March 01, 2019 (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. We own and operate a premium fleet comprised of modern, technologically advanced drilling rigs. Our first rig began drilling in May 2012. On October 1, 2018, we completed a merger with Sidewinder Drilling LLC. As a result of this merger, we more than doubled our operating fleet and personnel.

Our rigs currently include 32 marketed ShaleDriller® rigs that are specifically engineered and designed to optimize the development of our customers’ most technically demanding oil and gas properties, and two idle ShaleDriller rigs that will enter our marketed fleet when planned upgrades are completed.

Our marketed 32 rig fleet includes 29 AC powered (“AC”) rigs and three 1500-HP ultra-modern SCR rigs. We plan to convert these three SCR rigs to AC pad-optimal status over the next twelve to 18 months based upon market conditions and customer requirements and the timing of their existing contractual commitments. Our two idle rigs that currently are not included in our marketed fleet include one non-walking 1500-HP AC rig and one 1500-HP SCR rig. We plan to convert both to AC pad-optimal status prior to entering our fleet. We expect both of these rigs to enter our marketed fleet following their upgrade 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 Houston, Texas and Midland, Texas 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, the Mid-Continent and Eaglebine regions as well, and we recently signed a contract to mobilize a rig to the Eagle Ford Shale.

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 historically cyclical and 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.

Emerging Growth Company

We are an emerging growth company (“EGC”) as defined under the Jumpstart Our Business Startups Act of 2012, commonly referred to as the “JOBS Act”. We will remain an EGC for up to five years from the date of the completion of our initial public offering (the “IPO”) on August 13, 2014, or until the earlier of (1) the last day of the fiscal year in which our total annual gross revenues exceed $1.07 billion, (2) the date that we become a “large accelerated filer” as defined in Rule 12b-2 under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), which would occur if the market value of our common equity that is held by non-affiliates is $700 million or more as of the last business day of our most recently completed second fiscal quarter or (3) the date on which we have issued more than $1.0 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 non-binding 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

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. As a result, our industry experienced an exceptional downturn, with the U.S. land rig count falling from a high of 1,930 rigs in 2014 to a low of 404 rigs in 2016. In addition to overall rig count decline, pricing for our contract drilling services also substantially declined during this period of time. Although crude oil prices recovered in 2017 and 2018, reaching a high of $77.41 per barrel in the second quarter of 2018, the U.S. land count never recovered to its 2014 highs, only reaching 1,083 rigs the week ending December 28, 2018. Similarly, although pricing improved during this period, pricing never reached rates experienced in 2014.

During the fourth quarter of 2018, oil prices began to decline, reaching a low of $44.48. Although oil prices have recently recovered to the mid-fifties in February 2019, most of our E&P customers have decreased planned capital expenditure budgets with the goal of operating within their cash flows, which they expect to be lower in 2019 unless commodity prices substantially improve. These changes have resulted in softening demand for contract drilling services. Although we believe market conditions for our services have stabilized, we believe this stabilization is predicated on oil prices remaining above a $50 per barrel or higher range. If oil prices were to fall below these levels for any sustainable period, demand and pricing for our contract drilling services could decline and have a material adverse affect on our operations and financial condition.

Sidewinder Merger

On July 18, 2018, ICD, Patriot Saratoga Merger Sub, LLC, a wholly owned subsidiary of ICD (“Merger Sub”), Sidewinder Drilling, LLC (“Sidewinder”) and MSD Credit Opportunity Master Fund, L.P., as Members’ Representative, entered into a definitive merger agreement (the “Merger Agreement”) pursuant to which Merger Sub merged with and into Sidewinder (the “Merger”), with Sidewinder surviving the Merger and becoming a wholly owned subsidiary of the ICD. The Merger transaction was completed on October 1, 2018. Pursuant to the terms of the Merger Agreement, Sidewinder Series A members received 36,752,657 shares of ICD common stock in exchange for 100% of the outstanding Series A Common Units of Sidewinder (the “Series A Common Units”). The Merger was accounted for using the acquisition method of accounting with ICD identified as the accounting acquirer.

Our Revenues

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

Our Operating Costs

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

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

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. We believe our Risk-Based HSE management system provides the required control, yet needed flexibility, to conduct all activities safely, efficiently and appropriately.
- 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 months ended March 31, 2019 and 2018:

	Three Months Ended	
(In thousands, except per share data)	March 31, 2019	March 31, 2018
Revenues	$60,358	$25,627
Costs and expenses		
Operating costs	39,333	18,926
Selling, general and administrative	4,545	3,479
Merger-related expenses	1,081	—
Depreciation and amortization	11,313	6,591
Asset impairment, net	2,018	(35)
Loss (gain) on disposition of assets, net	3,220	(82)
Total cost and expenses	61,510	28,879
Operating loss	(1,152)	(3,252)
Interest expense	(3,761)	(943)
Loss before income taxes	(4,913)	(4,195)
Income tax benefit	(2,540)	(49)
Net loss	$(2,373)	$(4,146)
Other financial and operating data		
Number of completed rigs (end of period) (1)	32	14
Rig operating days (2)	2,728.1	1,259.4
Average number of operating rigs (3)	30.3	14.0
Rig utilization (4)	94.8 %	100.0 %
Average revenue per operating day (5)	$20,755	$19,055
Average cost per operating day (6)	$13,302	$13,414
Average rig margin per operating day	$7,453	$5,641

(1) Number of marketed rigs as of March 31, 2019 increased by 18 rigs as compared to the number of marketed rigs as of March 31, 2018. Our 15th ShaleDriller rig was completed and commenced operations during the third quarter of 2018 and we acquired 17 marketed rigs and two idle non-operating rigs requiring upgrade as a result of the Sidewinder Merger in the fourth 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.

(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 $2.7 million and $1.6 million during the three months ended March 31, 2019 and 2018, respectively, and revenues associated with the amortization of intangible revenue acquired in the Sidewinder Merger of $1.0 million during the three months ended March 31, 2019.

(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 $2.7 million and $1.6 million during the three months ended March 31, 2019 and 2018,

respectively, (ii) new crew training costs of zero and $25 thousand during the three months ended March 31, 2019 and 2018, respectively and (iii) construction overhead costs expensed due to reduced rig construction activity of $0.3 million and $0.4 million during the three months ended March 31, 2019 and 2018, respectively.

Three Months Ended March 31, 2019 Compared to the Three Months Ended March 31, 2018

Revenues

Revenues for the three months ended March 31, 2019 were $60.4 million, representing a 135.5% increase as compared to revenues of $25.6 million for the three months ended March 31, 2018. This increase was attributable to an increase in operating days to 2,728 days as compared to 1,259 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 the Sidewinder Merger that closed on October 1, 2018. On a revenue per operating day basis, our revenue per day increased by 8.9% to $20,755 during the three months ended March 31, 2019, as compared to revenue per day of $19,055 for the three months ended March 31, 2018. This increase in revenue per day was primarily the result of increased dayrates during the current quarter. Additionally, we recorded revenues of $1.0 million associated with the amortization of intangible revenue acquired in the Sidewinder Merger during the three months ended March 31, 2019.

Operating Costs

Operating costs for the three months ended March 31, 2019 were $39.3 million, representing an 107.8% increase as compared to operating costs of $18.9 million for the three months ended March 31, 2018. This increase was primarily attributable to an increase in operating days to 2,728 days as compared to 1,259 days in the prior year comparable quarter. On a cost per operating day basis, our cost decreased slightly to $13,302 per day during the three months ended March 31, 2019, representing a 0.8% decrease compared to cost per operating day of $13,414 for the three months ended March 31, 2018.

Selling, General and Administrative

Selling, general and administrative expenses for the three months ended March 31, 2019 were $4.5 million, representing a 30.6% increase as compared to selling, general and administrative expense of $3.5 million for the three months ended March 31, 2018. This increase as compared to the prior year comparable quarter primarily relates to the Sidewinder Merger.

Merger-related Expenses

Merger-related expenses of $1.1 million were recorded for the three months ended March 31, 2019 primarily comprised of severance, professional fees and other related expenses.

Depreciation and Amortization

Depreciation and amortization expense for the three months ended March 31, 2019 was $11.3 million, representing a 71.6% increase compared to depreciation and amortization expense of $6.6 million for the three months ended March 31, 2018. This increase relates primarily to the Sidewinder Merger.

Loss (Gain) on Disposition of Assets, net

A loss on the disposition of assets totaling $3.2 million was recorded for the three months ended March 31, 2019. This loss primarily related to the sale of certain surplus assets, acquired in the Sidewinder Merger, at auctions during the quarter.

Assets Impairment (Insurance Recoveries), net

For the three months ended March 31, 2019, we recorded an impairment to assets held for sale of $2.0 million to reflect the proceeds received when these assets were sold at auction in April 2019.

Interest Expense

Interest expense for the three months ended March 31, 2019 was $3.8 million, as compared to $0.9 million for the three months ended March 31, 2018. The increase relates primarily to our new $130.0 term loan facility that was put in place in connection with the Sidewinder Merger.

Income Tax Benefit

The income tax benefit recorded for the three months ended March 31, 2019 amounted to $2.5 million compared to $49.0 thousand for the three months ended March 31, 2018. Our effective tax rates for the three months ended March 31, 2019 and 2018 were 51.7% and 1.2%, respectively. Taxes in both the current and prior period relate to Louisiana state income tax and to Texas margin tax.

Future Liquidity and Capital Resources

Our liquidity as of March 31, 2019 included approximately $23.4 million of availability under our $40.0 million ABL Credit Facility, based on a borrowing base of $31.0 million, a $15.0 million committed accordion under our existing term loan facility, $12.5 million of cash and $31.7 million of other net working capital.

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

Net Cash Provided By Operating Activities

Cash provided by operating activities was $7.6 million for the three months ended March 31, 2019 compared to cash provided by operating activities of $2.0 million during the same period in 2018. 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 three months of 2019 were higher as a result of a decrease in net loss of $1.8 million, adjusted for non-cash items, of $14.6 million for the three months ended March 31, 2019 compared to $7.2 million for non-cash items during the same period in 2018. Working capital changes decreased cash flows from operating activities by $4.6 million for the three months ended March 31, 2019 compared to $1.0 million during the same period in 2018.

Net Cash Used In Investing Activities

Cash used in investing activities was $9.3 million for the three months ended March 31, 2019 compared to cash used in investing activities of $6.1 million during the same period in 2018. During the first three months of 2019, cash payments of $10.8 million for capital expenditures were offset by insurance proceeds of $1.0 million related to the Galayda Facility water damage incurred during Hurricane Harvey and proceeds from the sale of property, plant and equipment of $0.5 million. During the 2018 period, cash payments of $6.3 million for capital expenditures were offset by proceeds from the sale of property, plant and equipment of $0.1 million.

Net Cash Provided by Financing Activities

Cash provided by financing activities was $2.0 million for the three months ended March 31, 2019 compared to cash provided by financing activities of $4.1 million during the same period in 2018. During the first three months of 2019, we made borrowings under our ABL Credit Facility of $2.4 million. These proceeds were offset by common stock issuance costs of $0.2 million, payments for capital lease obligations of $0.2 million and financing costs paid under the Term Loan and ABL Credit Facilities of $5.0 thousand and $12.0 thousand, respectively. During the first three months of 2018 we made borrowings under our Credit Facility of $13.8 million. These proceeds were offset by repayments under our Credit Facility of $9.1 million, the purchase of treasury stock of $0.4 million, restricted stock unit's withheld for taxes paid of $0.1 million, and payments for capital lease obligations of $0.2 million.

Long-term Debt

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.

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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 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 ABL Credit Facility or other material agreements for indebtedness, and a change of control.

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 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. MSD PCOF Partners IV, LLC (an affiliate of MSD Partners) is the lender of our $130.0 million Term Loan Facility. MSD Partners, together with MSD Capital, own approximately 30% of the outstanding shares of the Company's common stock.

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 "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 ABL Credit Facility is subject to a borrowing base calculated based on 85% of the net amount of our eligible accounts receivable, minus reserves. The 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 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 ABL Credit Facility commitment.

The 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 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 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. We are in compliance with our covenants as of March 31, 2019.

The obligations under the 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. As of March 31, 2019, the weighted-average interest rate on our borrowings was 10.16%. At March 31, 2019, the borrowing base under our ABL Credit Facility was $31.0 million, and we had $23.4 million of availability remaining of our $40.0 million commitment on that date.

Additionally, included in our long-term debt are capital leases. These leases generally have initial terms of 36 months and are paid monthly.

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 13 "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 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 January 2017, the FASB issued ASU No. 2017-04, Intangibles—Goodwill and Other, which simplifies the subsequent measurement of goodwill by eliminating Step 2 of the goodwill impairment test. In computing the implied fair value of goodwill under Step 2, an entity had to perform procedures to determine the fair value at the impairment testing date of its assets and liabilities (including unrecognized assets and liabilities) following the procedure that would be required in determining the fair value of assets acquired and liabilities assumed in a business combination. Under this new standard, an entity should perform its goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount and then recognize an impairment charge, as necessary, for the amount by which the carrying amount exceeds the reporting unit's fair value, not to exceed the total amount of goodwill allocated to that reporting unit. This guidance is effective for fiscal years beginning after December 15, 2019. We do not believe this new guidance will have a material impact on our consolidated 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 March 31, 2019 included $135.0 million of floating-rate debt attributed to borrowings at an average interest rate of 10.16%. As a result, our annual interest cost in 2019 will fluctuate based on short-term interest rates.

The impact on annual cash flow of a 10% change in the floating-rate (approximately 11.17%) would be approximately $1.4 million annually based on the floating-rate debt and other obligations outstanding at March 31, 2019; however, there are no assurances that possible rate changes would be limited to such amounts.

Commodity Price Risk

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

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

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. As a result, our industry experienced an exceptional downturn, with the U.S. land rig count falling from a high of 1930 rigs in 2014 to a low of 404 rigs in 2016. In addition to overall rig count decline, pricing for our contract drilling services also substantially declined during this period of time. Although crude oil prices recovered in 2017 and 2018, reaching a high of $77.41 per barrel in the second quarter of 2018, the U.S. land count never recovered to its 2014 highs, only reaching 1,083 rigs the week ending December 28, 2018. Similarly, although pricing improved during this period, pricing never reached rates experienced in 2014.

During the fourth quarter of 2018, oil prices began to decline, reaching a low of $44.48. Although oil prices have recently recovered to the mid-sixties in April 2019, most of our E&P customers have decreased planned capital expenditure budgets with the goal of operating within their cash flows, which they expect to be lower in 2019 unless commodity prices substantially improve. These changes have resulted in softening demand for contract drilling services. Although we believe market conditions for our services have stabilized, we believe this stabilization is predicated on oil prices remaining above a $50 per barrel or higher range. If oil prices were to fall below these levels for any sustainable period, demand and pricing for our contract drilling services could decline and have a material adverse affect on our operations and financial condition.

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, cash flows, 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 March 31, 2019 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, 2018. 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.

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
10.1*	Independence Contract Drilling 2019 Omnibus Incentive Plan, dated as of February 27, 2019
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: May 3, 2019