DIAMOND OFFSHORE

2018 ANNUAL REPORT

BLOCK-CHAIN

BEST-IN-CLASS OPERATIONAL PERFORMANCE

SIM-STACK®

THOUGHT LEADERSHIP

SAFETY

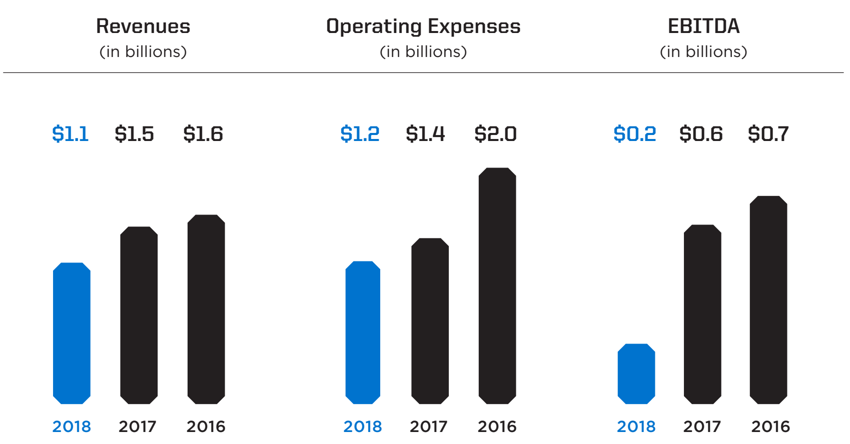
DIAMOND DIFFERENCE

INNOVATION

OVERVIEW

FINANCIAL HIGHLIGHTS

(dollars in millions)	2018	2017	2016
Revenue	$ 1,083	$ 1,486	$ 1,600
Depreciation & Amortization	332	349	382
Operating Expenses	1,195	1,362	1,957
Earnings Before Interest, Taxes, Depreciation & Amortization (EBITDA)	247	572	703
Net (Loss) Income	(180)	18	(373)
Capital Expenditures	222	140	653
Cash and Investments	$ 454	$ 376	$ 156
Drilling & Other Property & Equipment, Net	5,184	5,262	5,727
Total Assets	6,036	6,251	6,372
Long-term Debt	1,974	1,972	1,981
Shareholders' Equity	3,585	3,774	3,750



COMPANY PROFILE

Diamond Offshore is a leader in offshore drilling, providing contract drilling services to the energy industry around the globe with a total fleet of 17 offshore drilling rigs, consisting of 13 semisubmersible rigs and four dynamically positioned drillships.

Diamond Offshore's headquarters are in Houston, Texas. Primary regional offices are located in Brazil, the United Kingdom and Australia, with local offices in other countries as required to support operations. Approximately 2,300 people work for the Company onboard our rigs and in our offices. Diamond Offshore's common stock is listed on the New York Stock Exchange under the symbol "DO."

TO OUR SHAREHOLDERS

MARC EDWARDS
President and
Chief Executive Officer

Oil and gas prices remained depressed throughout 2018. After reaching multi-year highs in early October, U.S. crude prices ended the year down 25% on the back of rising output from North American shale oil and fears an economic slowdown could weaken oil demand.

Despite significantly improved cash flows, our clients remained largely focused on short-cycle investments, including shale and other onshore programs. As a result, offshore rig utilization and dayrates remained at trough levels.

Despite those challenging conditions, in 2018 Diamond Offshore added $647 million to our backlog, began the reactivation of two rigs, set new company records for operational performance and safety, and added two new innovations to our portfolio of differentiating technologies.

LEADING INNOVATION

Throughout the year, Diamond Offshore continued our focus on innovation and thought leadership to improve efficiency, customer service and safety across the offshore industry.

In April 2018, we introduced our Sim-Stack® service, the industry's first cybernetic blowout preventer (BOP) service. Using a highly sophisticated and complex virtual replica of a BOP system, this new service performs advanced digitalization, simulation and data fusion to improve efficiencies, lower non-productive time and reduce the cost of deepwater drilling.

With our Sim-Stack service, we can continuously and accurately assess BOP status and regulatory compliance after a single or multiple component failure has been identified. When issues arise, Sim-Stack immediately provides critical feedback, without human bias. With this information, we can determine a proper course of action while providing a third-party statement of fact to the operator and regulatory bodies. Whereas the traditional process can take days or even weeks to reach consensus, with Sim-Stack, this can now be accomplished in a few hours or less.

An analysis of how our Sim-Stack service would have performed on past unplanned stack pulls suggests that utilization of Sim-Stack has the potential to reduce our subsea non-productive time by upwards of 35%.

Within just six months of deployment on our drillships in the Gulf of Mexico, Sim-Stack enabled us to avoid four unplanned stack pulls, which resulted in the preservation of an estimated $9 million of lost dayrate.

We are working to implement this service on other rigs in our global fleet over the coming quarters.

In June 2018, we launched our Blockchain Drilling™ service, the first publicly disclosed blockchain technology application in upstream oil and gas. In blockchain, "blocks" – or digital pieces of data – store information about transactions and about the participants in those transactions. Blockchain is distributed – meaning it creates a shared system of record, or ledger, among participants. It is scalable – therefore, massive amounts of data can be recorded and shared. And blockchain data is immutable – as a result, it can be recorded and distributed, but not edited.

When applied to offshore drilling, blockchain technology enables all participants in the entire value chain to plan, track and report across the well construction and drilling lifecycle. Providing our oil and gas operator clients with 24/7 access to this information drives efficiencies and enables them to lower the total cost of ownership.

In addition, our Blockchain Drilling service has the potential to eliminate invoicing waste and automate invoice reconciliation. And it can improve logistics and safety by optimizing marine traffic and reducing the number of crane lifts onboard the rig.

We began collecting data onto a blockchain platform from each of our drillships in the fourth quarter of 2018 and plan to have this capability available across the fleet in the coming year.

OPERATIONAL PERFORMANCE

We constantly look for innovative ways to reduce downtime while enhancing operational efficiencies for our customers.

I am pleased to report that in 2018 we set a new Company benchmark and delivered significant improvements in unplanned subsea downtime, where subsea reliability exceeded surface reliability – making it a first in the history of the Company.

Through ongoing process improvement efforts, we continued to set new drilling efficiency benchmarks on our drillships, without sacrificing safety. One of our drillships completed a well in 48 days versus the planned 70 days. Another drilled and completed a well 54 days ahead of schedule. And yet another reached 28,000 feet after only 38 days.

Diamond Offshore drilled three of the four most cost-effective wells in the Gulf of Mexico based on time-to-depth, and as a result, helped to deliver a large offshore deepwater project $1.2 billion under budget and six months ahead of schedule. This type of performance is best-in-class and only further reinforces Diamond Offshore's already strong reputation across our client base.

We will continue to pursue ways to make offshore drilling more economic for our clients while best positioning Diamond Offshore for the eventual market recovery.

SAFETY PERFORMANCE

Operating safely is of paramount importance, and 2018 was our safest year on record.

We delivered the lowest total recordable incident rate (TRIR) and highest number of zero incident operation (ZIO) days in Company history.

I attribute our success in this area to the talent and commitment of our operational and technical teams, our culture of safety and our safety-enhancing services such as Sim-Stack, whose underlying technology received designation as a STAR (Safety, Technology and Review) initiative from the regulator in the Gulf of Mexico as being one of the industry's best available and safest technologies.

I am also pleased to report that for the second consecutive year, Diamond Offshore was recognized by the International Association of Drilling Contractors for having the best safety performance in the North Sea in the floating-rig, under-100-million-man-hours category.

CONTRACT ACTIVITY

Despite the continued market downturn, our ability to create differentiation in a traditionally commoditized market enabled us to secure $647 million in net additional backlog in 2018.

During the year, we secured an additional five years of backlog for our drillships, the asset class that is most distressed, with major operators BP and Anadarko – and at rates significantly above the prevailing market. We are unique among our peers in that we are the only major offshore player with all its sixth- and seventh-generation assets under contract.

When we released our first quarter 2018 results, we announced plans to reactivate the cold-stacked *Ocean Endeavor* after being awarded a contract that will keep the rig working in the North Sea for at least two years. When we released our full year 2018 results, we announced plans to upgrade and reactivate a second rig, the *Ocean Onyx*, which will work for Beach Energy for a one-year contract offshore Australia. Following the upgrade, the *Ocean Onyx's* operational life will be extended for many years.

We see the reactivation of these two formerly cold-stacked assets as a positive sign that operators are reinvigorating their drilling programs in anticipation of an eventual oil and gas industry rebound. We also view this as a vote of confidence in Diamond Offshore in what is still an oversupplied and highly competitive market.

FINANCIAL RESULTS

For the full year 2018, we reported a net loss of $180 million, or $(1.31) per diluted share, compared to net income of $18 million, or $0.13 per diluted share, in 2017. Contract drilling revenue was $1.1 billion compared to $1.5 billion in 2017.

Given the uncertainty around the timing of the recovery, in October 2018, we proactively improved our liquidity position by establishing a $950 million credit facility, which matures in fourth quarter 2023. This new facility, combined with our existing credit facility, provides us with over $1.25 billion of liquidity until 2020.

SUMMARY

2018 was another tough year in the floater drilling market. Nevertheless, we stayed our strategic course, developing and deploying innovation to lower the total cost of ownership for operators in offshore drilling while setting new Company records for safety and operational performance.

We believe the moored market has hit bottom. 2018 saw tightening and modest improvements in both North Sea and non-harsh markets, resulting in incremental dayrate increases. Clients are looking to lock in capacity for 2020 and beyond.

We believe the dynamically-positioned (DP) floater market has also bottomed, as have DP dayrates. But we don't expect these dayrates to recover before the next decade, as the DP segment is still suffering from significant oversupply.

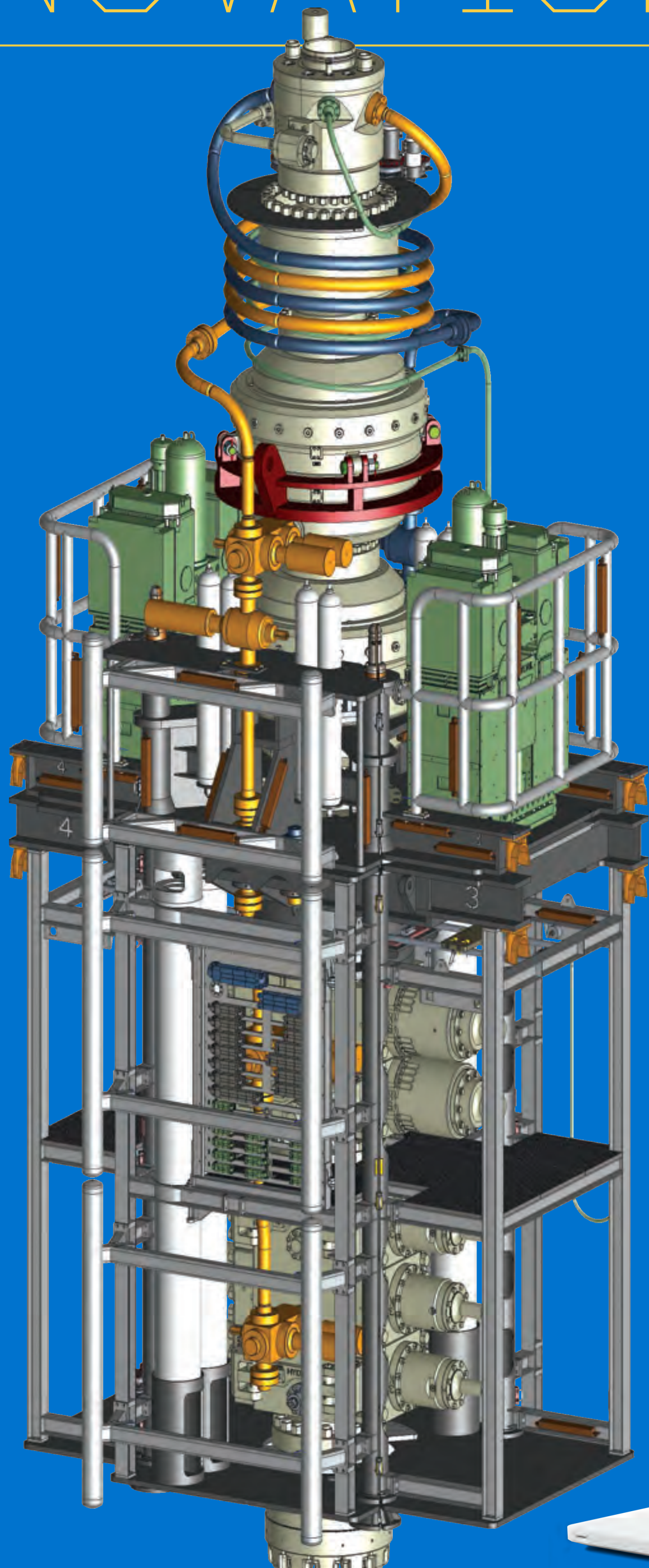
With a solid backlog, a superior balance sheet and strong liquidity, we are well positioned for sustainable success in the eventual market recovery.

We will continue to invest our capital conservatively, but have the financial means to act quickly on strategic opportunities should they present themselves. We are confident the long-term fundamentals of the oil and gas industry – and particularly the deepwater drilling sector – remain intact. Oil and gas operators will eventually resume their essential deepwater campaigns – and we will be ready when they do.

Thank you for your continued confidence in Diamond Offshore.

Marc Edwards
President and Chief Executive Officer

INNOVATION



SIM-STACK® SERVICE

The industry's first cybernetic blowout preventer (BOP) service to continuously assess status and regulatory compliance to immediately determine course of action when issues arise.

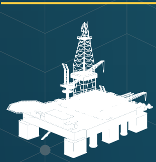
→ Replicates BOP hydraulic and electrical conditions and removes human bias to accelerate decision making

→ Improves subsea efficiency, reduces cost of deepwater drilling and reduces BOP pulls

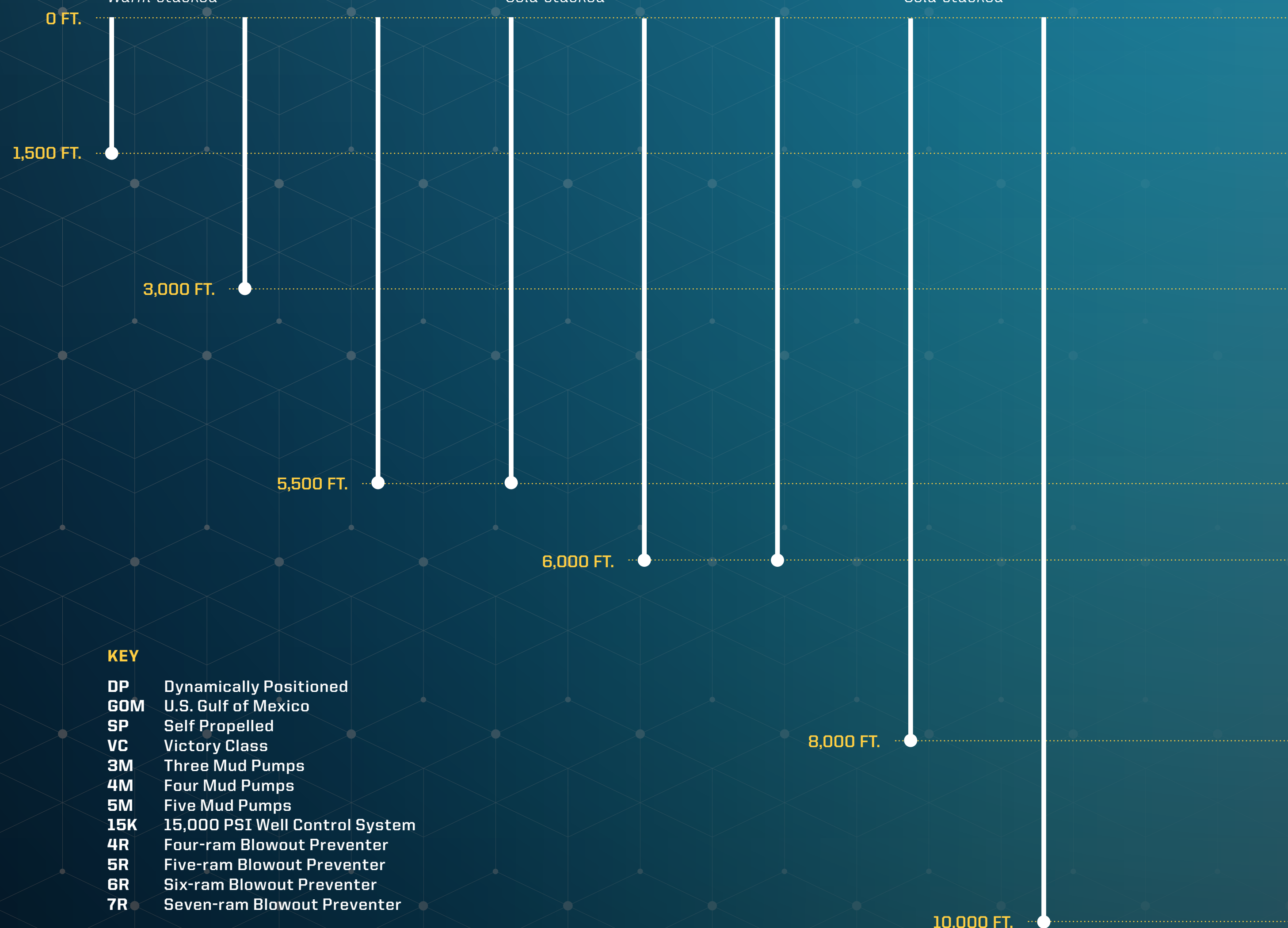
→ A robust training tool to develop next-generation subsea BOP expertise

→ The underlying technology received the U.S. Bureau of Safety and Environmental Enforcement's (BSEE) STAR designation for being one of the industry's best available and safest technologies

THE FLEET



OCEAN GUARDIAN	OCEAN PATRIOT	OCEAN VALIANT	OCEAN AMERICA	OCEAN ONYX	OCEAN APEX	OCEAN ROVER	OCEAN VALOR
1,500 Ft.	3,000 Ft.	5,500 Ft.	5,500 Ft.	6,000 Ft.	6,000 Ft.	8,000 Ft.	10,000 Ft.
15K; 3M; 5R	15K; 3M; 5R	SP; 15K; 3M; 4R	SP; 15K; 3M; 5R	VC; 15K; 4M; 5R	VC; 15K; 4M; 5R	VC; 15K; 4M; 5R	DP; 15K; 4M; 6R
UK	UK	UK	Malaysia	Singapore	Australia	Malaysia	Brazil
Warm-stacked			*Cold-stacked*			*Cold-stacked*	



KEY

DP	Dynamically Positioned
GOM	U.S. Gulf of Mexico
SP	Self Propelled
VC	Victory Class
3M	Three Mud Pumps
4M	Four Mud Pumps
5M	Five Mud Pumps
15K	15,000 PSI Well Control System
4R	Four-ram Blowout Preventer
5R	Five-ram Blowout Preventer
6R	Six-ram Blowout Preventer
7R	Seven-ram Blowout Preventer

RATED WATER DEPTH

For semisubmersible rigs and drillships, the indicated depth reflects the operating water depth capacity for each drilling unit. In many cases, individual rigs are capable of achieving, or have achieved, greater water depths. In all cases, floating rigs are capable of working successfully at greater depths than their rated water depth. On a case-by-case basis, a greater depth capacity may be achieved by providing additional equipment.

As of February 1, 2019

OCEAN MONARCH	10,000 Ft.	VC; 15K;	4M; 5R	Australia
OCEAN GREATWHITE	10,000 Ft.	DP; 15K;	4M; 6R	UK
OCEAN ENDEAVOR	10,000 Ft.	VC; 15K;	4M; 5R	UK
OCEAN COURAGE	10,000 Ft.	DP; 15K;	4M; 6R	Brazil
OCEAN CONFIDENCE	10,000 Ft.	DP; 15K;	4M; 6R	Canary Islands *Cold-stacked*
OCEAN BLACKRHINO	12,000 Ft.	DP; 15K;	5M; 7R	GOM
OCEAN BLACKLION	12,000 Ft.	DP; 15K;	5M; 7R	GOM
OCEAN BLACKHORNET	12,000 Ft.	DP; 15K;	5M; 7R	GOM
OCEAN BLACKHAWK	12,000 Ft.	DP; 15K;	5M; 7R	GOM

12,000 FT.

LEADERSHIP

BOARD OF DIRECTORS

James S. Tisch
Chairman of the Board,
Diamond Offshore Drilling, Inc.
President & Chief Executive Officer,
Loews Corporation

Marc Edwards
President & Chief Executive Officer,
Diamond Offshore Drilling, Inc.

Charles L. Fabrikant
Executive Chairman,
SEACOR Holdings Inc.

Paul G. Gaffney II
President Emeritus,
Monmouth University

Edward Grebow
Managing Director,
Lakewood Advisors, LLC

Kenneth I. Siegel
Senior Vice President,
Loews Corporation

Clifford M. Sobel
Managing Partner,
Valor Capital Group, LLC

Andrew H. Tisch
Co-Chairman of the Board,
Loews Corporation

EXECUTIVE OFFICERS

Marc Edwards
President & Chief Executive Officer

Ronald Woll
Executive Vice President
& Chief Commercial Officer

Scott Kornblau
Senior Vice President
& Chief Financial Officer

David L. Roland
Senior Vice President,
General Counsel & Secretary

Tommy Roth
Senior Vice President,
Worldwide Operations

Beth G. Gordon
Vice President
& Controller

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2018

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from __________ to __________

Commission file number 1-13926

DIAMOND OFFSHORE DRILLING, INC.

(Exact name of registrant as specified in its charter)

Delaware **(State or other jurisdiction of incorporation or organization)**	**76-0321760** **(I.R.S. Employer Identification No.)**

15415 Katy Freeway
Houston, Texas 77094
(Address and zip code of principal executive offices)

(281) 492-5300
(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock, $0.01 par value per share	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☒	Accelerated filer ☐
Non-accelerated filer ☐	Smaller reporting company ☐
	Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter.

As of June 30, 2018	$1,341,545,587

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

As of February 8, 2019	Common Stock, $0.01 par value per share	137,438,353 shares

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement relating to the 2019 Annual Meeting of Stockholders of Diamond Offshore Drilling, Inc., which will be filed within 120 days of December 31, 2018, are incorporated by reference in Part III of this report.

DIAMOND OFFSHORE DRILLING, INC.
FORM 10-K for the Year Ended December 31, 2018

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PART I

Item 1. Business.

General

Diamond Offshore Drilling, Inc. provides contract drilling services to the energy industry around the globe with a fleet of 17 offshore drilling rigs, consisting of four drillships and 13 semisubmersible rigs. Three of these rigs are currently cold stacked. We are currently reactivating and preparing for future contracts for the *Ocean Endeavor* and *Ocean Onyx*, both of which were cold stacked in 2016. *See* "– Our Fleet – *Fleet Status*" and "– Our Fleet – *Fleet Enhancements and Additions.*"

Unless the context otherwise requires, references in this report to "Diamond Offshore," "we," "us" or "our" mean Diamond Offshore Drilling, Inc. and our consolidated subsidiaries. Diamond Offshore Drilling, Inc. was incorporated in Delaware in 1989.

Our Fleet

Our fleet enables us to offer services in the floater market on a worldwide basis. A floater rig is a type of mobile offshore drilling rig that floats and does not rest on the seafloor. This asset class includes self-propelled drillships and semisubmersible rigs.

Semisubmersible rigs are comprised of an upper working and living deck resting on vertical columns connected to lower hull members. Such rigs operate in a "semi-submerged" position, remaining afloat, off bottom, in a position in which the lower hull is approximately 55 feet to 90 feet below the water line and the upper deck protrudes well above the surface. Semisubmersibles hold position while drilling by use of a series of small propulsion units or thrusters that provide dynamic positioning, or DP, to keep the rig on location, or with anchors tethered to the sea bed. Although DP semisubmersibles are self-propelled, such rigs may be moved long distances with the assistance of tug boats. Non-DP, or moored, semisubmersibles require tug boats or the use of a heavy lift vessel to move between locations.

A drillship is an adaptation of a maritime vessel that is designed and constructed to carry out drilling operations by means of a substructure with a moon pool centrally located in the hull. Drillships are typically self-propelled and are positioned over a drillsite through the use of a DP system similar to those used on semisubmersible rigs.

Fleet Status

The following table presents additional information regarding our floater fleet at February 1, 2019:

Rig Type and Name	Rated Water Depth (in feet)[a]	Attributes	Year Built/ Redelivered [b]	Current Location [c]	Customer [d]
DRILLSHIPS (4):					
Ocean BlackLion	12,000	DP; 7R; 15K	2015	GOM	Hess Corporation
Ocean BlackRhino	12,000	DP; 7R; 15K	2014	GOM	Hess Corporation
Ocean BlackHornet	12,000	DP; 7R; 15K	2014	GOM	Anadarko
Ocean BlackHawk	12,000	DP; 7R; 15K	2014	GOM	Anadarko
SEMISUBMERSIBLES (13):					
Ocean GreatWhite	10,000	DP; 6R; 15K	2016	North Sea/U.K.	Contract Preparation/ Siccar Point
Ocean Valor	10,000	DP; 6R; 15K	2009	Brazil	Petrobras
Ocean Courage	10,000	DP; 6R; 15K	2009	Brazil	Petrobras
Ocean Confidence	10,000	DP; 6R; 15K	2001/2015	Canary Islands	Cold Stacked
Ocean Monarch	10,000	15K	2008	Australia	Warm Stacked/ Exxon/Cooper
Ocean Endeavor	10,000	15K	2007	North Sea/U.K.	Reactivation/Contract Preparation/Shell
Ocean Rover	8,000	15K	2003	Malaysia	Cold Stacked
Ocean Apex	6,000	15K	2014	Singapore	Contract Preparation/ Woodside
Ocean Onyx	6,000	15K	2013	Singapore	Reactivation/ Upgrades/Beach Energy
Ocean America	5,500	15K	1988	Malaysia	Cold Stacked
Ocean Valiant	5,500	15K	1988	North Sea/U.K.	Total
Ocean Patriot	3,000	15K	1983	North Sea/U.K.	Apache
Ocean Guardian	1,500	15K	1985	North Sea/U.K.	Warm Stacked

Attributes

DP = Dynamically Positioned/Self-Propelled

6R = Six ram blow out preventer

7R = 2 Seven ram blow out preventers

15K = 15,000 psi well control system

(a) Rated water depth for drillships and semisubmersibles reflects the maximum water depth in which a floating rig has been designed for drilling operations. However, individual rigs are capable of drilling, or have drilled, in marginally greater water depths depending on various conditions (such as salinity of the ocean, weather and sea conditions).

(b) Represents year rig was built and originally placed in service or year rig was redelivered with significant enhancements that enabled the rig to be classified within a different floater category than originally constructed.

(c) GOM means U.S. Gulf of Mexico.

(d) For ease of presentation in this table, customer names have been shortened or abbreviated. Warm-stacked is used to describe a rig that is idled (not contracted) and maintained in a "ready" state with a full crew to enable the rig to be quickly placed into service when contracted. Cold-stacked is used to describe an idled rig for which steps have been taken to preserve the rig and reduce certain costs, such as crew costs and maintenance expenses. Depending on the amount of time that a rig is cold-stacked, significant expenditures may be required to return the rig to a "ready" state.

Fleet Enhancements and Additions.

Our long-term strategy is to upgrade our fleet to meet customer demand for advanced, efficient and high-tech rigs by acquiring or building new rigs when possible to do so at attractive prices. Our most recent fleet enhancement cycle was completed in 2016, with the delivery of the *Ocean GreatWhite*. During 2018, we began reactivation of the *Ocean Endeavor*. The rig is currently in the U.K., where it is completing its reactivation and is undergoing contract preparation activities in advance of its upcoming contract in the second quarter of 2019. In addition, in late 2018, we initiated the reactivation and upgrade of the *Ocean Onyx* to increase the rig's marketability by expanding its lower deck load, reducing rig motion response and making other technologically desirable enhancements sought by our customers. The *Ocean Onyx* has been moved to Singapore, where we expect its upgrade to be completed in the later part of 2019.

We continue to evaluate further rig acquisition and enhancement opportunities as they arise. However, we can provide no assurance whether, or to what extent, we will continue to make rig acquisitions or enhancements to our fleet. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – *Sources and Uses of Cash – Rig Reactivation, Upgrade and Other Capital Expenditures*" in Item 7 of this report.

Markets

The principal markets for our offshore contract drilling services are:

- the Gulf of Mexico, including the United States, or U.S., and Mexico;
- South America, principally offshore Brazil, and Trinidad and Tobago;
- Australia and Southeast Asia, including Malaysia, Indonesia, Myanmar and Vietnam;
- Europe, principally offshore the United Kingdom, or U.K., and Norway;
- East and West Africa; and
- the Mediterranean.

We actively market our rigs worldwide. From time to time, our fleet operates in various other markets throughout the world. See Note 18 "Segments and Geographic Area Analysis" to our Consolidated Financial Statements in Item 8 of this report.

Offshore Contract Drilling Services

Our contracts to provide offshore drilling services vary in their terms and provisions. We typically obtain our contracts through a competitive bid process, although it is not unusual for us to be awarded drilling contracts following direct negotiations. Our drilling contracts generally provide for a basic dayrate regardless of whether or not drilling results in a productive well. Drilling contracts generally also provide for reductions in rates during periods when the rig is being moved or when drilling operations are interrupted or restricted by equipment breakdowns, adverse weather conditions or other circumstances. Under dayrate contracts, we generally pay the operating expenses of the rig, including wages and the cost of incidental supplies. Historically, dayrate contracts have accounted for the majority of our revenues. In addition, from time to time, our dayrate contracts may also provide for the ability to earn an incentive bonus from our customer based upon performance.

The duration of a dayrate drilling contract is generally tied to the time required to drill a single well or a group of wells, in what we refer to as a well-to-well contract, or a fixed period of time, in what we refer to as a term contract. Our drilling contracts may be terminated by the customer in the event the drilling unit is destroyed or lost, or if drilling operations are suspended for an extended period of time as a result of a breakdown of equipment or, in some cases, due to events beyond the control of either party to the contract. Certain of our contracts also permit the customer to terminate the contract early by giving notice; in most circumstances this requires the payment of an early termination fee by the customer. The contract term in many instances may also be extended by the customer exercising options for the drilling of additional wells or for an additional length of time, generally subject to mutually agreeable terms and rates at the time of the extension. In periods of decreasing demand for offshore rigs, drilling contractors may prefer longer term contracts to preserve dayrates at existing levels and ensure utilization, while customers may prefer shorter contracts that allow them to more quickly obtain the benefit of declining dayrates. Moreover, drilling contractors may accept lower dayrates in a declining market in order to obtain longer-term contracts and add backlog. See "Risk Factors – *We may not be able to renew or replace expiring contracts for our rigs*" and "Risk Factors – *Our business involves numerous operating hazards that could expose us to significant losses and significant damage claims. We are not fully insured against all of these risks and our contractual indemnity provisions may not fully protect us,*" in Item 1A of this report, which are incorporated herein by reference. For a discussion of our contract backlog, see "Management's Discussion and Analysis of Financial Condition and Results of Operations – Contract Drilling Backlog" in Item 7 of this report, which is incorporated herein by reference.

Customers

We provide offshore drilling services to a customer base that includes major and independent oil and gas companies and government-owned oil companies. During 2018, 2017 and 2016, we performed services for 13, 14 and 18 different customers, respectively. During 2018, 2017 and 2016, our most significant customers were as follows:

	Percentage of Annual Consolidated Revenues		
Customer	**2018**	**2017**	**2016**
Anadarko	33.8%	24.9%	22.4%
Hess Corporation	25.0%	16.0%	7.7%
Petróleo Brasileiro S.A.	15.8%	18.9%	17.9%
BP	10.5%	15.8%	9.0%

No other customer accounted for 10% or more of our annual total consolidated revenues during 2018, 2017 or 2016. See "Risk Factors – *Our industry is highly competitive, with oversupply of drilling rigs and intense price competition*" and "Risk Factors – *Our customer base is concentrated"* in Item 1A of this report, which are incorporated herein by reference.

As of January 1, 2019, our contract backlog was $2.0 billion attributable to 12 customers. All four of our drillships are currently contracted to work in the GOM. As of January 1, 2019, contract backlog attributable to our expected operations in the GOM was $471.0 million, $372.0 million, $217.0 million and $36.0 million for the years 2019, 2020, 2021 and 2022, respectively, all of which was attributable to three customers. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – Contract Drilling Backlog" in Item 7 of this report. See "Risk Factors – *We can provide no assurance that our drilling contracts will not be terminated early or that our current backlog of contract drilling revenue will be ultimately realized*" in Item 1A of this report, which is incorporated herein by reference.

Competition

Based on industry data, as of the date of this report, there are approximately 760 mobile drilling rigs (drillships, semi-submersibles and jack-up rigs) in service worldwide, including approximately 240 floater rigs. Despite consolidation in previous years, the offshore contract drilling industry remains highly competitive with numerous industry participants, none of which at the present time has a dominant market share. Some of our competitors may have greater financial or other resources than we do.

Drilling contracts are traditionally awarded on a competitive bid basis. Price is typically the primary factor in determining which qualified contractor is awarded a job. Customers may also consider rig availability and location, a drilling contractor's operational and safety performance record, and condition and suitability of equipment. We believe we compete favorably with respect to these factors.

We compete on a worldwide basis, but competition may vary significantly by region at any particular time. See "—Markets." Competition for offshore rigs generally takes place on a global basis, as these rigs are highly mobile and may be moved, although at a cost that may be substantial, from one region to another. It is characteristic of the offshore drilling industry to move rigs from areas of low utilization and dayrates to areas of greater activity and relatively higher dayrates. The current oversupply of offshore drilling rigs also intensifies price competition. See "Risk Factors – *Our industry is highly competitive, with oversupply of drilling rigs and intense price competition*" in Item 1A of this report, which is incorporated herein by reference.

Governmental Regulation

Our operations are subject to numerous international, foreign, U.S., state and local laws and regulations that relate directly or indirectly to our operations, including regulations controlling the discharge of materials into the environment, requiring removal and clean-up under some circumstances, or otherwise relating to the protection of the environment, and may include laws or regulations pertaining to climate change, carbon emissions or energy use. See "Risk Factors – *We are subject to extensive domestic and international laws and regulations that could significantly limit our business activities and revenues and increase our costs*" and "Risk Factors – *Regulation of greenhouse gases and climate change could have a negative impact on our business*" in Item 1A of this report, which are incorporated herein by reference.

Employees

As of December 31, 2018, we had approximately 2,300 workers, including international crew personnel furnished through independent labor contractors.

Executive Officers of the Registrant

We have included information on our executive officers in Part I of this report in reliance on General Instruction G(3) to Form 10-K. Our executive officers are elected annually by our Board of Directors and serve at the discretion of our Board of Directors until their successors are duly elected and qualified, or until their earlier death, resignation, disqualification or removal from office. Information with respect to our executive officers is set forth below.

Name	Age as of January 31, 2019	Position
Marc Edwards	58	President and Chief Executive Officer and Director
Ronald Woll	51	Executive Vice President and Chief Commercial Officer
David L. Roland	57	Senior Vice President, General Counsel and Secretary
Thomas Roth	63	Senior Vice President – Worldwide Operations
Scott Kornblau	47	Senior Vice President and Chief Financial Officer
Beth G. Gordon	63	Vice President and Controller

Marc Edwards has served as our President and Chief Executive Officer and as a Director since March 2014. Mr. Edwards previously served as a member of the Executive Committee and as Senior Vice President of the Completion and Production Division at Halliburton Company, a global diversified oilfield services company, from January 2010 to February 2014.

Ronald Woll has served as our Executive Vice President and Chief Commercial Officer since January 1, 2019. Mr. Woll previously served as Senior Vice President and Chief Commercial Officer from June 2014 until December 2018. Mr. Woll served as Senior Vice President – Supply Chain at Halliburton Company from January 2011 through June 2014.

David L. Roland has served as our Senior Vice President, General Counsel and Secretary since September 2014. From April 2004 until joining us in 2014, Mr. Roland served as Senior Vice President, General Counsel and Corporate Secretary of ION Geophysical Corporation, a NYSE-listed geophysical company.

Thomas Roth has served as our Senior Vice President – Worldwide Operations since December 2016. Mr. Roth previously served as Vice President of the Boots & Coots Product Service Line at Halliburton Company from July 2013 to September 2015. Mr. Roth also served as Boots & Coots Global Operations Manager at Halliburton Company from August 2011 to July 2013.

Scott Kornblau has served as our Senior Vice President and Chief Financial Officer since July 2018. Mr. Kornblau previously served as our Vice President, Acting Chief Financial Officer and Treasurer since December 2017, Vice President and Treasurer since January 2017 and Treasurer since July 2007.

Beth G. Gordon has served as our Vice President and Controller since January 2017 and previously served as our Controller since April 2000.

Access to Company Filings

We are subject to the informational requirements of the Securities Exchange Act of 1934, as amended, or the Exchange Act, and accordingly file annual, quarterly and current reports on Forms 10-K, 10-Q and 8-K, respectively, any amendments to those reports, proxy statements and other information with the United States Securities and Exchange Commission, or SEC. Our SEC filings are available to the public from the SEC's Internet site at www.sec.gov or from our Internet site at www.diamondoffshore.com. Our website provides a hyperlink to a third-party SEC filings website where these reports may be viewed and printed at no cost as soon as reasonably practicable after we have electronically filed such material with, or furnished it to, the SEC. The preceding Internet addresses and all other Internet addresses referenced in this report are for information purposes only and are not intended to be a hyperlink. Accordingly, no information found or provided at such Internet addresses or at our website in general (or at other websites linked to our website) is intended or deemed to be incorporated by reference in this report.

Item 1A. Risk Factors.

Our business is subject to a variety of risks and uncertainties. If any of these risks or uncertainties actually occur, our business, financial condition, results of operations and cash flows, and the trading prices of our securities, may be materially and adversely affected. You should carefully consider these risks when evaluating us and our securities. The following is a description of the most significant risks and uncertainties facing us; however, these risks and uncertainties are not the only ones facing our company. We are also subject to a variety of risks that affect many other companies generally, as well as additional risks and uncertainties not known to us or that, as of the date of this report, we believe are not as significant as the risks described below.

The worldwide demand for drilling services has historically been dependent on the price of oil and, as a result of low oil prices, demand has continued to be depressed in 2018.

Demand for our drilling services depends in large part upon the oil and natural gas industry's offshore exploration and production activity and expenditure levels, which are directly affected by oil and gas prices and market expectations of potential changes in oil and gas prices. Commencing in the second half of 2014, oil prices declined significantly, resulting in a sharp decline in the demand for offshore drilling services, including services that we provide, and adversely affecting our results of operations and cash flows compared to years before the decline. The continuation of low oil prices would have a material adverse effect on many of our customers and, therefore, on demand for our services and on our financial condition, results of operations and cash flows.

Oil prices have been, and are expected to continue to be, volatile and are affected by numerous factors beyond our control, including:

- worldwide supply and demand for oil and gas;
- the level of economic activity in energy-consuming markets;

- the worldwide economic environment and economic trends, including recessions and the level of international trade activity;
- the ability of the Organization of Petroleum Exporting Countries, or OPEC, to set and maintain production levels and pricing;
- the level of production in non-OPEC countries, including U.S. domestic onshore oil production;
- civil unrest and the worldwide political and military environment, including uncertainty or instability resulting from an escalation or additional outbreak of armed hostilities involving the Middle East, Russia, other oil-producing regions or other geographic areas or further acts of terrorism in the U.S. or elsewhere;
- the cost of exploring for, developing, producing and delivering oil and gas, both onshore and offshore;
- the discovery rate of new oil and gas reserves;
- the rate of decline of existing and new oil and gas reserves and production;
- available pipeline and other oil and gas transportation and refining capacity;
- the ability of oil and gas companies to raise capital;
- weather conditions, including hurricanes, which can affect oil and gas operations over a wide area;
- natural disasters or incidents resulting from operating hazards inherent in offshore drilling, such as oil spills;
- the policies of various governments regarding exploration and development of their oil and gas reserves;
- international sanctions on oil-producing countries, or the lifting of such sanctions;
- technological advances affecting energy consumption, including development and exploitation of alternative fuels or energy sources;
- laws and regulations relating to environmental or energy security matters, including those addressing alternative energy sources or the risks of global climate change;
- domestic and foreign tax policy; and
- advances in exploration and development technology.

Although, historically, higher sustained commodity prices have generally resulted in increases in offshore drilling projects, short-term or temporary increases in the price of oil and gas will not necessarily result in an increase in offshore drilling activity or an increase in the market demand for our rigs. The timing of commitment to offshore activity in a cycle depends on project deployment times, reserve replacement needs, availability of capital and alternative options for resource development, among other things. Timing can also be affected by availability, access to, and cost of equipment to perform work.

Our business depends on the level of activity in the offshore oil and gas industry, which has been cyclical and is significantly affected by many factors outside of our control.

Demand for our drilling services depends upon the level of offshore oil and gas exploration, development and production in markets worldwide, and those activities depend in large part on oil and gas prices, worldwide demand for oil and gas and a variety of political and economic factors. The level of offshore drilling activity is adversely affected when operators reduce or defer new investment in offshore projects, reduce or suspend their drilling budgets or reallocate their drilling budgets away from offshore drilling in favor of other priorities, such as shale or other land-based projects, which could reduce demand for our rigs. As a result, our business and the oil and gas industry in general are subject to cyclical fluctuations.

As a result of the cyclical fluctuations in the market, there have been periods of lower demand, excess rig supply and lower dayrates, followed by periods of higher demand, shorter rig supply and higher dayrates. We cannot predict the timing or duration of such fluctuations. Periods of lower demand or excess rig supply, which have occurred in the recent past and are continuing, intensify the competition in the industry and often result in periods of lower utilization and lower dayrates. During these periods, our rigs may not obtain contracts for future work and may be idle for long periods of time or may be able to obtain work only under contracts with lower dayrates or less favorable terms. Additionally, prolonged periods of low utilization and dayrates could also result in the recognition of further impairment charges on certain of our drilling rigs if future cash flow estimates, based upon information available to management at the time, indicate that the carrying value of these rigs may not be recoverable. See "–*We may incur additional asset impairments and/or rig retirements as a result of reduced demand for certain offshore drilling rigs*."

Our industry is highly competitive, with oversupply of drilling rigs and intense price competition.

The offshore contract drilling industry is highly competitive with numerous industry participants. Some of our competitors may be larger companies, have larger or more technologically advanced fleets and have greater financial or other resources than we do. The drilling industry has experienced consolidation and may experience additional consolidation, which could create additional large competitors. Drilling contracts are traditionally awarded on a competitive bid basis. Price is typically the primary factor in determining which qualified contractor is awarded a job; however, rig availability and location, a drilling contractor's safety record and the quality and technical capability of service and equipment are also considered.

New rig construction and upgrades of existing drilling rigs, cancelation or termination of drilling contracts and established rigs coming off contract have contributed to the current oversupply of drilling rigs, intensifying price competition. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – Market Overview" in Item 7 of this report.

We can provide no assurance that our drilling contracts will not be terminated early or that our current backlog of contract drilling revenue will be ultimately realized.

Our customers may terminate our drilling contracts under certain circumstances, such as the destruction or loss of a drilling rig, our suspension of drilling operations for a specified period of time as a result of a breakdown of major equipment, excessive downtime for repairs, failure to meet minimum performance criteria (including customer acceptance testing) or, in some cases, due to other events beyond the control of either party.

In addition, some of our drilling contracts permit the customer to terminate the contract after specified notice periods, often by tendering contractually specified termination amounts, which may not fully compensate us for the loss of the contract. During depressed market conditions, such as those currently in effect, certain customers have utilized such contract clauses to seek to renegotiate or terminate a drilling contract or claim that we have breached provisions of our drilling contracts in order to avoid their obligations to us under circumstances where we believe we are in compliance with the contracts. Additionally, because of depressed commodity prices, restricted credit markets, economic downturns, changes in priorities or strategy or other factors beyond our control, a customer may no longer want or need a rig that is currently under contract or may be able to obtain a comparable rig at a lower dayrate. For these reasons, customers may seek to renegotiate the terms of our existing drilling contracts, terminate our contracts without justification or repudiate or otherwise fail to perform their obligations under our contracts. As a result of such contract renegotiations or terminations, our contract backlog may be adversely impacted. We might not recover any compensation (or any recovery we obtain may not fully compensate us for the loss of the contract) and we may be required to idle one or more rigs for an extended period of time. Each of these results could have a material adverse effect on our financial condition, results of operations and cash flows. See "– *Our industry is highly competitive, with oversupply of drilling rigs and intense price competition*" and "Management's Discussion and Analysis of Financial Condition and Results of Operations – Contract Drilling Backlog" in Item 7 of this this report.

We may not be able to renew or replace expiring contracts for our rigs.

As of the date of this report, all of our current customer contracts will expire between 2019 and 2022. Some of our drilling rigs are not currently contracted for continuous utilization between contracts and are being actively marketed for these uncontracted periods. Our ability to renew or replace expiring contracts or obtain new contracts, and the terms of any such contracts, will depend on various factors, including market conditions and the specific needs of our customers, at such times. Given the historically cyclical and highly competitive nature of our industry, we may not be able to renew or replace the contracts or we may be required to renew or replace expiring contracts or obtain new contracts at dayrates that are below existing dayrates, or that have terms that are less favorable to us than our existing contracts. Moreover, we may be unable to secure contracts for these rigs. Failure to secure contracts for a rig may result in a decision to cold stack the rig, which puts the rig at risk for impairment and may competitively disadvantage the rig as many customers, during the most recent market downturn, have expressed a preference for ready or "warm" stacked rigs over cold-stacked rigs.

We may incur additional asset impairments and/or rig retirements as a result of reduced demand for certain offshore drilling rigs.

The current oversupply of drilling rigs in the offshore drilling market has resulted in numerous rigs being idled and in some cases retired and/or scrapped. We evaluate our property and equipment for impairment whenever changes in circumstances indicate that the carrying amount of an asset may not be recoverable, and we could incur additional impairment charges related to the carrying value of our drilling rigs. Impairment write-offs could result if, for example, any of our rigs become obsolete or commercially less desirable due to changes in technology, market demand or market expectations or their carrying values become excessive due to the condition of the rig, cold stacking the rig, the expectation of cold stacking the rig in the near future, contracted backlog of less than one year for a rig, a decision to retire or scrap the rig, or spending in excess of budget on a new-build construction project or major rig upgrade. We utilize an undiscounted probability-weighted cash flow analysis in testing an asset for potential impairment, reflecting management's assumptions and estimates regarding the appropriate risk-adjusted dayrate by rig, future industry conditions and operations and other factors. Asset impairment evaluations are, by their nature, highly subjective. The use of different estimates and assumptions could result in materially different carrying values of our assets, which could impact the need to record an impairment charge and the amount of any charge taken. Since 2012, we have retired and sold 28 drilling rigs and recorded impairment losses aggregating $1.7 billion, including $27.2 million recognized in 2018. Historically, the longer a drilling rig remains cold stacked, the higher the cost of reactivation and, depending on the age, technological obsolescence and condition of the rig, the lower the likelihood that the rig will be reactivated at a future date. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Estimates – *Property, Plant and Equipment*" in Item 7 of this report and Note 3 "Asset Impairments" to our Consolidated Financial Statements in Item 8 of this report.

We can provide no assurance that our assumptions and estimates used in our asset impairment evaluations will ultimately be realized or that the current carrying value of our property and equipment will ultimately be realized.

Changes in tax laws and policies, effective income tax rates or adverse outcomes resulting from examination of our tax returns could adversely affect our financial results.

Tax laws and regulations are highly complex and subject to interpretation and disputes. We conduct our worldwide operations through various subsidiaries in a number of countries throughout the world. As a result, we are subject to highly complex tax laws, regulations and income tax treaties within and between the countries in which we operate as well as countries in which we may be resident, which may change and are subject to interpretation. In addition, in several of the international locations in which we operate, certain of our wholly-owned subsidiaries enter into agreements with each other to provide specialized services and equipment in support of our foreign operations. In such cases, we apply an intercompany transfer pricing methodology to determine the arm's length amount to be charged for providing the services and equipment. In most cases, there are alternative transfer pricing methodologies that could be applied to these transactions and, if applied, could result in different chargeable amounts.

As a result, we determine our income tax expense based on our interpretation of the applicable tax laws and regulations in effect in each jurisdiction for the period during which we operate and earn income. Our overall effective tax rate could be adversely affected by lower than anticipated earnings in countries where we have lower statutory rates and higher than anticipated earnings in countries where we have higher statutory rates, by changes in the valuation of our deferred tax assets and liabilities or by changes in tax laws, tax treaties, regulations, accounting principles or interpretations thereof in one or more countries in which we operate. In addition, changes in laws, treaties and regulations and the interpretation of such laws, treaties and regulations may put us at risk for future tax assessments and liabilities which could be substantial.

Our income tax returns are subject to review and examination. We do not recognize the benefit of income tax positions we believe are more likely than not to be disallowed upon challenge by a tax authority. If any tax authority successfully challenges any tax position taken or any of our intercompany transfer pricing policies, or if the terms of certain income tax treaties are interpreted in a manner that is adverse to us or our operations, or if we lose a material tax dispute in any country, our effective tax rate on our worldwide earnings could increase substantially.

Our consolidated effective income tax rate may vary substantially from one reporting period to another.

Our consolidated effective income tax rate is impacted by the mix between our domestic and international pre-tax earnings or losses, as well as the mix of the international tax jurisdictions in which we operate. We cannot provide any assurance as to what our consolidated effective income tax rate will be in the future due to, among other factors, uncertainty regarding the nature and extent of our business activities in any particular jurisdiction in the future and the tax laws of such jurisdictions, as well as potential changes in U.S. and foreign tax laws, regulations or treaties or the interpretation or enforcement thereof, changes in the administrative practices and precedents of tax authorities or any reclassification or other matter (such as changes in applicable accounting rules) that increases the amounts we have provided for income taxes or deferred tax assets and liabilities in our consolidated financial statements. This variability may cause our consolidated effective income tax rate to vary substantially from one reporting period to another.

Our customer base is concentrated.

We provide offshore drilling services to a customer base that includes major and independent oil and gas companies and government-owned oil companies. During 2018, two of our customers in the GOM and our three largest customers in the aggregate accounted for 59% and 75%, respectively, of our annual total consolidated revenues. In addition, the number of customers we have performed services for has declined from 35 in 2014 to 13 in 2018. The loss of a significant customer could have a material adverse impact on our financial condition, results of operations and cash flows, especially in a declining market where the number of our working drilling rigs is declining along with the number of our active customers. In addition, if a significant customer experiences liquidity constraints or other financial difficulties, or elects to terminate one of our drilling contracts, it could materially adversely affect our utilization rates in the affected market and also displace demand for our other drilling rigs as the resulting excess supply enters the market. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – Contract Drilling Backlog" in Item 7 of this report.

We may be subject to litigation and disputes that could have a material adverse effect on us.

We are, from time to time, involved in litigation and disputes. These matters may include, among other things, contract disputes, personal injury claims, environmental claims or proceedings, asbestos and other toxic tort claims, employment and tax matters, claims of infringement of patent and other intellectual property rights, and other litigation that arises in the ordinary course of our business. We cannot predict with certainty the outcome or effect of any dispute, claim or other litigation matter, and there can be no assurance as to the ultimate outcome of any litigation. We may not have insurance for litigation or claims that may arise, or if we do have insurance coverage it may not be sufficient, insurers may not remain solvent, other claims may exhaust some or all of the insurance available to us or insurers may interpret our insurance policies such that they do not cover losses for which we make claims or may otherwise dispute claims made. Litigation may have a material adverse effect on us because of potential adverse outcomes, defense costs, the diversion of our management's resources and other risk factors inherent in litigation or relating to the claims that may arise.

Our contract drilling expense includes fixed costs that will not decline in proportion to decreases in rig utilization and dayrates.

Our contract drilling expense includes all direct and indirect costs associated with the operation, maintenance and support of our drilling equipment, which is often not affected by changes in dayrates and utilization. During periods of reduced revenue and/or activity, certain of our fixed costs will not decline and often we may incur additional operating costs, such as fuel and catering costs, for which the customer generally reimburses us when a rig is under contract. During times of reduced utilization, reductions in costs may not be immediate as we may incur additional costs associated with cold stacking a rig (particularly if we cold stack a newer rig, such as a drillship or other DP semisubmersible rig, for which cold-stacking costs are typically substantially higher than for an older non-DP rig), or we may not be able to fully reduce the cost of our support operations in a particular geographic region due to the need to support the remaining drilling rigs in that region. Accordingly, a decline in revenue due to lower dayrates and/or utilization may not be offset by a corresponding decrease in contract drilling expense.

Contracts for our drilling rigs are generally fixed dayrate contracts, and increases in our operating costs could adversely affect our profitability on those contracts.

Our contracts for our drilling rigs generally provide for the payment of an agreed dayrate per rig operating day, although some contracts do provide for a limited escalation in dayrate due to increased operating costs we incur on the project. Over the term of a drilling contract, our operating costs may fluctuate due to events beyond our control. In addition, equipment repair and maintenance expenses vary depending on the type of activity the rig is performing, the age and condition of the equipment and general market factors impacting relevant parts, components and services. The gross margin that we realize on these fixed dayrate contracts will fluctuate based on variations in our operating costs over the terms of the contracts. In addition, for contracts with dayrate escalation clauses, we may not be able to fully recover increased or unforeseen costs from our customers.

We are subject to extensive domestic and international laws and regulations that could significantly limit our business activities and revenues and increase our costs.

Certain countries are subject to restrictions, sanctions and embargoes imposed by the U.S. government or other governmental or international authorities. These restrictions, sanctions and embargoes may prohibit or limit us from participating in certain business activities in those countries. Our operations are also subject to numerous local, state and federal laws and regulations in the U.S. and in foreign jurisdictions concerning the containment and disposal of hazardous materials, the remediation of contaminated properties and the protection of the environment. Laws and regulations protecting the environment have become increasingly stringent, and may in some cases impose "strict liability," rendering a person liable for environmental damage without regard to negligence or fault on the part of that person. Failure to comply with such laws and regulations could subject us to civil or criminal enforcement action, for which we may not receive contractual indemnification or have insurance coverage, and could result in the issuance of injunctions restricting some or all of our activities in the affected areas. We may be required to make significant expenditures for additional capital equipment or inspections and recertifications thereof to comply with existing or new governmental laws and regulations. It is also possible that these laws and regulations may in the future add significantly to our operating costs or result in a reduction in revenues associated with downtime required to install such equipment or may otherwise significantly limit drilling activity.

In addition, these laws and regulations require us to perform certain regulatory inspections, which we refer to as a special survey. For most of our rigs, these special surveys are due every five years, although the inspection interval for our North Sea rigs is two-and-one-half years. Our operating income is negatively impacted during these special surveys. These special surveys are generally performed in a shipyard and require scheduled downtime, which can negatively impact operating revenue. Operating expenses increase as a result of these special surveys due to the cost to mobilize the rigs to a shipyard, and inspection, repair and maintenance costs. Repair and maintenance activities may result from the special survey or may have been previously planned to take place during this mandatory downtime. The number of rigs undergoing a special survey will vary from year to year, as well as from quarter to quarter. Operating income may also be negatively impacted by intermediate surveys, which are performed at interim periods between special surveys. Although an intermediate survey normally does not require shipyard time, the survey may require some downtime for the rig. We can provide no assurance as to the exact timing and/or duration of downtime associated with regulatory inspections, planned rig mobilizations and other shipyard projects.

In addition, the offshore drilling industry is dependent on demand for services from the oil and gas exploration industry and, accordingly, can be affected by changes in tax and other laws relating to the energy business generally. Governments in some countries are increasingly active in regulating and controlling the ownership of concessions, the exploration for oil and gas and other aspects of the oil and gas industry. The modification of existing laws or regulations or the adoption of new laws or regulations curtailing exploratory or developmental drilling for oil and gas for economic, environmental or other reasons could limit drilling opportunities.

U.S. federal, state, foreign and international laws and regulations address oil spill prevention and control and impose a variety of obligations on us related to the prevention of oil spills and liability for damages resulting from such spills. Some of these laws and regulations have significantly expanded liability exposure across all segments of the oil and gas industry. For example, the United States Oil Pollution Act of 1990 imposes strict and, with limited exceptions, joint and several liability upon each responsible party for oil removal costs and a variety of public and private damages. Failure to comply with such laws and regulations could subject us to civil or criminal enforcement action, for which we may not receive contractual indemnification or have insurance coverage, and could result in the issuance of injunctions restricting some or all of our activities in the affected areas. In addition, legislative and regulatory developments may occur that could substantially increase our exposure to liabilities that might arise in connection with our operations.

Regulation of greenhouse gases and climate change could have a negative impact on our business.

Governments around the world are increasingly considering and adopting laws and regulations to address climate change issues. Lawmakers and regulators in the U.S. and other jurisdictions where we operate have focused increasingly on restricting the emission of carbon dioxide, methane and other “greenhouse” gases. This may result in new environmental regulations that may unfavorably impact us, our suppliers and our customers. In addition, efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues and impose reductions of hydrocarbon-based fuels. We may be exposed to risks related to new laws, regulations, treaties or international agreements pertaining to climate change, greenhouse gases, carbon emissions or energy use that could decrease the use of oil or natural gas, thus reducing demand for hydrocarbon-based fuel and our drilling services. Governments may also pass laws or regulations incentivizing or mandating the use of alternative energy sources, such as wind power and solar energy, which may reduce demand for oil and natural gas and our drilling services. Such laws, regulations, treaties or international agreements could result in increased compliance costs or additional operating restrictions, which may have a negative impact on our business, and could adversely affect our operations by limiting drilling opportunities.

If we, or our customers, are unable to acquire or renew permits and approvals required for drilling operations, we may be forced to delay, suspend or cease our operations.

Oil and natural gas exploration and production operations require numerous permits and approvals for us and our customers from governmental agencies in the areas in which we operate or expect to operate. Obtaining all necessary permits and approvals may necessitate substantial expenditures to comply with the requirements of these permits and approvals, future changes to these permits or approvals, or any adverse change in the interpretation of existing permits and approvals. In addition, such regulatory requirements and restrictions could also delay or curtail our operations.

Our business involves numerous operating hazards that could expose us to significant losses and significant damage claims. We are not fully insured against all of these risks and our contractual indemnity provisions may not fully protect us.

Our operations are subject to the significant hazards inherent in drilling for oil and gas offshore, such as blowouts, reservoir damage, loss of production, loss of well control, unstable or faulty sea floor conditions, fires and natural disasters such as hurricanes. The occurrence of any of these types of events could result in the suspension of drilling operations, damage to or destruction of the equipment involved and injury or death to rig personnel and damage to producing or potentially productive oil and gas formations, oil spillage, oil leaks, well blowouts and extensive uncontrolled fires, any of which could cause significant environmental damage. In addition, offshore drilling operations are subject to marine hazards, including capsizing, grounding, collision and loss or damage from severe weather. Operations also may be suspended because of machinery breakdowns, abnormal drilling conditions, failure of suppliers or subcontractors to perform or supply goods or services or personnel shortages. Any of the foregoing events could result in significant damage or loss to our properties and assets or the properties and assets of others, injury or death to rig personnel or others, significant loss of revenues and significant damage claims against us.

Our drilling contracts with our customers provide for varying levels of indemnity and allocation of liabilities between our customers and us with respect to the hazards and risks inherent in, and damages or losses arising out of, our operations, and we may not be fully protected. Our contracts are individually negotiated, and the levels of indemnity and allocation of liabilities in them can vary from contract to contract depending on market conditions, particular customer requirements and other factors existing at the time a contract is negotiated. We may incur liability for significant losses or damages under such provisions.

Additionally, the enforceability of indemnification provisions in our contracts may be limited or prohibited by applicable law or such provisions may not be enforced by courts having jurisdiction, and we could be held liable for substantial losses or damages and for fines and penalties imposed by regulatory authorities. The indemnification provisions in our contracts may be subject to differing interpretations, and the laws or courts of certain jurisdictions may enforce such provisions while other laws or courts may find them to be unenforceable. The law with respect to the enforceability of indemnities varies from jurisdiction to jurisdiction and is unsettled under certain laws that are applicable to our contracts. There can be no assurance that our contracts with our customers, suppliers and subcontractors will fully protect us against all hazards and risks inherent in our operations. There can also be no assurance that those parties with contractual obligations to indemnify us will be financially able to do so or will otherwise honor their contractual obligations.

We maintain liability insurance, which generally includes coverage for environmental damage; however, because of contractual provisions and policy limits, our insurance coverage may not adequately cover our losses and claim costs. In addition, certain risks and contingencies related to pollution, reservoir damage and environmental risks are generally not fully insurable. Also, we do not typically purchase loss-of-hire insurance to cover lost revenues when a rig is unable to work. There can be no assurance that we will continue to carry the insurance we currently maintain, that our insurance will cover all types of losses or that we will be able to maintain adequate insurance in the future at rates we consider to be reasonable or that we will be able to obtain insurance against some risks.

We are self-insured for physical damage to rigs and equipment caused by named windstorms in the GOM. This results in a higher risk of material losses that are not covered by third party insurance contracts. In addition, certain of our shore-based facilities are located in geographic regions that are susceptible to damage or disruption from hurricanes and other weather events. Future hurricanes or similar natural disasters that impact our facilities, our personnel located at those facilities or our ongoing operations may negatively affect our financial position and operating results.

If an accident or other event occurs that exceeds our insurance coverage limits or is not an insurable event under our insurance policies, or is not fully covered by contractual indemnity, it could result in a significant loss to us.

We must make substantial capital and operating expenditures to reactivate, build, maintain and upgrade our drilling fleet.

Our business is highly capital intensive and dependent on having sufficient cash flow and/or available sources of financing in order to fund our capital expenditure requirements. Our expenditures could increase as a result of changes in offshore drilling technology; the cost of labor and materials; customer requirements; the cost of replacement parts for existing drilling rigs; the geographic location of the rigs; and industry standards. Changes in offshore drilling technology, customer requirements for new or upgraded equipment and competition within our industry may require us to make significant capital expenditures in order to maintain our competitiveness. In addition, changes in governmental regulations, safety or other equipment standards, as well as compliance with standards imposed by maritime self-regulatory organizations, may require us to make additional unforeseen capital expenditures. As a result, we may be required to take our rigs out of service for extended periods of time, with corresponding losses of revenues, in order to make such alterations or to add such equipment. In addition, we believe the operating expenditures required to reactivate a cold-stacked rig and return the rig to drilling service are substantial. Depending on the length of time that a rig has been cold-stacked, we may incur significant costs to restore the rig to drilling capability, which may also include capital expenditures due to the possible technological obsolescence of the rig. In the future, market conditions may not justify these expenditures or enable us to operate our older rigs profitably during the remainder of their economic lives. We can provide no assurance that we will have access to adequate or economical sources of capital to fund our capital and operating expenditures.

Significant portions of our operations are conducted outside the U.S. and involve additional risks not associated with U.S. domestic operations.

Our operations outside the U.S. accounted for approximately 41%, 58% and 69% of our total consolidated revenues for 2018, 2017 and 2016, respectively, and include, or have included, operations in South America, Australia and Southeast Asia, Europe, East and West Africa, the Mediterranean and Mexico. Because we operate in various regions throughout the world, we are exposed to a variety of risks inherent in international operations, including risks of war or conflicts; political and economic instability and disruption; civil disturbance; acts of piracy, terrorism or other assaults on property or personnel; corruption; possible economic and legal sanctions (such as possible restrictions against countries that the U.S. government may consider to be state sponsors of terrorism); changes in global monetary and trade policies, laws and regulations; fluctuations in currency exchange rates; restrictions on currency exchange; controls over the repatriation of income or capital; and other risks. We may not have insurance coverage for these risks, or we may not be able to obtain adequate insurance coverage for such events at reasonable rates. Our operations may become restricted, disrupted or prohibited in any country in which any of these risks occur.

In June 2016, the U.K. voted to withdraw from the European Union, commonly referred to as Brexit. The impact of Brexit and the future relationship between the U.K. and the European Union are uncertain for companies that do business in the U.K. and the overall global economy. Approximately 9% of our total revenues for the year ended December 31, 2018 were generated in the U.K. Brexit, or similar events in other jurisdictions, could depress economic activity or impact global markets, including foreign exchange and securities markets, which may have an adverse impact on our business and operations as a result of changes in currency exchange rates, tariffs, treaties and other regulatory matters.

We are also subject to the following risks in connection with our international operations:

- kidnapping of personnel;
- seizure, expropriation, nationalization, deprivation, malicious damage or other loss of possession or use of property or equipment;
- renegotiation or nullification of existing contracts;
- disputes and legal proceedings in international jurisdictions;
- changing social, political and economic conditions;
- imposition of wage and price controls, trade barriers, export controls or import-export quotas;
- difficulties in collecting accounts receivable and longer collection periods;
- fluctuations in currency exchange rates and restrictions on currency exchange;
- regulatory or financial requirements to comply with foreign bureaucratic actions;
- restriction or disruption of business activities;
- limitation of our access to markets for periods of time;
- travel limitations or operational problems caused by public health threats or changes in immigration policies;
- difficulties in supplying, repairing or replacing equipment or transporting personnel in remote locations;
- difficulties in obtaining visas or work permits for our employees on a timely basis; and
- changing taxation policies and confiscatory or discriminatory taxation.

We are also subject to the regulations of the U.S. Treasury Department's Office of Foreign Assets Control and other U.S. laws and regulations governing our international operations in addition to domestic and international anti-bribery laws and sanctions, trade laws and regulations, customs laws and regulations, and other restrictions imposed by other governmental or international authorities. Failure to comply with these laws and regulations could result in criminal and civil penalties, economic sanctions, seizure of shipments and/or the contractual withholding of monies owed to us, among other things. We have operated and may in the future operate in parts of the world where strict compliance with anti-corruption and anti-bribery laws may conflict with local customs and practices. Any failure to comply with the U.S. Foreign Corrupt Practices Act, the U.K. Bribery Act 2010 or other anti-corruption laws due to our own acts or omissions or the acts or omissions of others, including our partners, agents or vendors, could subject us to substantial fines, sanctions, civil and/or criminal penalties and curtailment of operations in certain jurisdictions. In addition, international contract drilling operations are subject to various laws and regulations in countries in which we operate, including laws and regulations relating to the equipping and operation of drilling rigs; import-export quotas or other trade barriers; repatriation of foreign earnings or capital; oil and gas exploration and development; local content requirements; taxation of offshore earnings and earnings of expatriate personnel; and use and compensation of local employees and suppliers by foreign contractors.

Any significant cyber attack or other interruption in network security or the operation of critical information technology systems could materially disrupt our operations and adversely affect our business.

Our business has become increasingly dependent upon information technologies, computer systems and networks, including those maintained by us and those maintained and provided to us by third parties (for example, “software-as-a-service” and cloud solutions), to conduct day-to-day operations, and we are placing greater reliance on information technology to help support our operations and increase efficiency in our business functions. We are dependent upon our information technology and infrastructure, including operational and financial computer systems, to process the data necessary to conduct almost all aspects of our business. Computer, telecommunications and other business facilities and systems could become unavailable or impaired from a variety of causes including, among others, storms and other natural disasters, terrorist attacks, utility outages, theft, design defects, human error or complications encountered as existing systems are maintained, repaired, replaced or upgraded. In addition, it has been reported that known or unknown entities or groups have mounted so-called “cyber attacks” on businesses and other organizations solely to disable or disrupt computer systems, disrupt operations and, in some cases, steal data. Cybersecurity risks and threats to such systems continue to grow and may be difficult to anticipate, prevent, discover or mitigate. A breach or failure of our computer systems or networks, or those of our customers, vendors or others with whom we do business, could materially disrupt our business operations and our customers’ operations and could result in the alteration, loss, theft or corruption of data or unauthorized release of confidential, proprietary or sensitive data concerning our company, business activities, employees, customers or vendors. Any such breach or failure could have a material adverse effect on our operations, business or reputation.

Acts of terrorism, piracy and political and social unrest could affect the markets for drilling services, which may have a material adverse effect on our results of operations.

Acts of terrorism and social unrest, brought about by world political events or otherwise, have caused instability in the world’s financial and insurance markets in the past and may occur in the future. Such acts could be directed against companies such as ours. In addition, acts of terrorism, piracy and social unrest could lead to increased volatility in prices for crude oil and natural gas and could adversely affect the market for offshore drilling services. Insurance premiums could increase and coverage may be unavailable in the future. Government regulations may effectively preclude us from engaging in business activities in certain countries. These regulations could be amended to cover countries where we currently operate or where we may wish to operate in the future.

We rely on third-party suppliers, manufacturers and service providers to secure and service equipment, components and parts used in rig operations, conversions, upgrades and construction.

Our reliance on third-party suppliers, manufacturers and service providers to provide equipment and services exposes us to volatility in the quality, price and availability of such items. Certain components, parts and equipment that we use in our operations may be available only from a small number of suppliers, manufacturers or service providers. The failure of one or more third-party suppliers, manufacturers or service providers to provide equipment, components, parts or services, whether due to capacity constraints, production or delivery disruptions, price increases, quality control issues, recalls or other decreased availability of parts and equipment, is beyond our control and could materially disrupt our operations or result in the delay, renegotiation or cancellation of drilling contracts, thereby causing a loss of contract drilling backlog and/or revenue to us, as well as an increase in operating costs and an increased risk of additional asset impairments.

Additionally, our suppliers, manufacturers and service providers could be negatively impacted by current industry conditions or global economic conditions. If certain of our suppliers, manufacturers or service providers were to experience significant cash flow issues, become insolvent or otherwise curtail or discontinue their business as a result of such conditions, it could result in a reduction or interruption in supplies, equipment or services available to us and/or a significant increase in the price of such supplies, equipment and services,.

Our debt levels may limit our liquidity and flexibility in obtaining additional financing and in pursuing other business opportunities.

Our business is highly capital intensive and dependent on having sufficient cash flow and/or available sources of financing in order to fund our capital expenditure requirements. As of December 31, 2018, we had outstanding approximately $2.0 billion of senior notes, maturing at various times from 2023 through 2043. As of February 8, 2019, we had no borrowings outstanding under our $325 million revolving credit facility maturing in 2020 or our $950 million revolving credit facility maturing in October 2023, and an aggregate $1.275 billion available under both such credit facilities, subject to their respective terms, to meet our short-term liquidity requirements. At various times in 2019, $100 million of the commitments under our $325 million revolving credit facility will mature, and the remaining $225 million of commitments will mature in October 2020.We may incur additional indebtedness in the future and borrow from time to time under our revolving credit facilities to fund working capital, capital expenditures or other needs, subject to compliance with their covenants. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – *Sources and Uses of Cash – Credit Agreements*" in Item 7 of this report and Note 10 "Credit Agreements and Senior Notes" to our Consolidated Financial Statements in Item 8 of this report.

Our ability to meet our debt service obligations is dependent upon our future performance, which is unpredictable. High levels of indebtedness could have negative consequences to us, including:

- we may have difficulty satisfying our obligations with respect to our outstanding debt;
- we may have difficulty obtaining financing in the future for working capital, capital expenditures, acquisitions or other purposes;
- we may need to use a substantial portion of our available cash flow from operations to pay interest and principal on our debt, which would reduce the amount of money available to fund working capital requirements, capital expenditures, the payment of dividends and other general corporate or business activities;
- our vulnerability to the effects of general economic downturns, adverse industry conditions and adverse operating results could increase;
- our flexibility in planning for, or reacting to, changes in our business and in our industry in general could be limited;
- we may not have the ability to pursue business opportunities that become available to us;
- our amount of debt and the amount we must pay to service our debt obligations could place us at a competitive disadvantage compared to our competitors that have less debt; and
- our customers may react adversely to our significant debt level and seek alternative service providers.

In addition, our failure to comply with the restrictive covenants in our debt instruments could result in an event of default that, if not cured or waived, could have a material adverse effect on our business. Among other things, these covenants:

- require us to maintain a specified ratio of our consolidated indebtedness to total capitalization;
- require us to maintain a specified ratio of (A) the aggregate value of certain of our rigs to (B) the aggregate value of substantially all rigs owned by us;
- require us to maintain a specified ratio of (A) the aggregate value of certain of our marketed rigs to (B) the sum of the commitments under our $950 million revolving credit facility, plus certain outstanding loans, letter of credit exposures and other indebtedness; and
- limit the ability of our subsidiaries to incur debt.

In August 2018, S&P Global Ratings, or S&P, downgraded our corporate credit rating to B from B+, and Moody's Investor Services, or Moody's, downgraded our corporate credit rating to B2 from Ba3. In October 2018, Moody's downgraded our senior unsecured notes credit rating to B3 from B2. The rating outlook from both S&P and Moody's remains negative. These credit ratings are below investment grade and could raise our cost of financing. As a consequence, we may not be able to issue additional debt in amounts and/or with terms that we consider to be reasonable. One or more of these occurrences could limit our ability to pursue other business opportunities.

Our revolving credit facilities bear interest at variable rates, based on our corporate credit rating and market interest rates. If market interest rates increase, our cost to borrow under our revolving credit facilities may also increase. Although we may employ hedging strategies such that a portion of the aggregate principal amount outstanding under our credit facilities would effectively carry a fixed rate of interest, any hedging arrangement put in place may not offer complete protection from this risk.

Changes in accounting principles and financial reporting requirements could adversely affect our results of operations or financial condition.

We are required to prepare our financial statements in accordance with accounting principles generally accepted in the U.S., or GAAP, as promulgated by the Financial Accounting Standards Board. It is possible that future accounting standards that we are required to adopt could change the current accounting treatment that we apply to our consolidated financial statements and that such changes could have a material adverse effect on our results of operations and financial condition. For a description of recent accounting standards that we have not yet adopted and, if known, our estimates of their expected impact, see Note 1 "General Information – *Recent Accounting Pronouncements Not Yet Adopted"* to the Consolidated Financial Statements included under Item 8 of this report.

Failure to obtain and retain highly skilled personnel could hurt our operations.

We require highly skilled personnel to operate and provide technical services and support for our business. A well-trained, motivated and adequately-staffed work force has a positive impact on our ability to attract and retain business. As a result, our future success depends on our continuing ability to identify, hire, develop, motivate and retain skilled personnel for all areas of our organization. To the extent that demand for drilling services and/or the size of the active worldwide industry fleet increases, shortages of qualified personnel could arise, creating upward pressure on wages and difficulty in staffing and servicing our rigs. Our continued ability to compete effectively depends on our ability to attract new employees and to retain and motivate our existing employees. Heightened competition for skilled personnel could materially and adversely limit our operations and further increase our costs.

We are controlled by a single stockholder, which could result in potential conflicts of interest.

Loews Corporation, which we refer to as Loews, beneficially owned approximately 53% of our outstanding shares of common stock as of February 8, 2019, and is in a position to control actions that require the consent of stockholders, including the election of directors, amendment of our Restated Certificate of Incorporation and any merger or sale of substantially all of our assets. In addition, three officers of Loews serve on our Board of Directors. We have also entered into a services agreement and a registration rights agreement with Loews, and we may in the future enter into other agreements with Loews.

Loews is a holding company, with principal subsidiaries (in addition to us) consisting of CNA Financial Corporation, an 89%-owned subsidiary engaged in commercial property and casualty insurance; Boardwalk Pipeline Partners, LP, a wholly-owned subsidiary engaged in the transportation and storage of natural gas and natural gas liquids; Loews Hotels & Co, a wholly-owned subsidiary engaged in the operation of a chain of hotels; and Consolidated Container Company LLC, a 99%-owned subsidiary providing packaging solutions to end markets such as beverage, food and household chemicals. It is possible that potential conflicts of interest could arise in the future for our directors who are also officers of Loews with respect to a number of areas relating to the past and ongoing relationships of Loews and us, including tax and insurance matters, financial commitments and sales of common stock pursuant to registration rights or otherwise. Although the affected directors may abstain from voting on matters in which our interests and those of Loews are in conflict so as to avoid potential violations of their fiduciary duties to stockholders, the presence of potential or actual conflicts could affect the process or outcome of Board deliberations.

Item 1B. Unresolved Staff Comments.

Not applicable.

Item 2. Properties.

We own an office building in Houston, Texas, where our corporate headquarters are located. We also own offices and other facilities in New Iberia, Louisiana, Aberdeen, Scotland, Macae, Brazil and Ciudad del Carmen, Mexico. Additionally, we currently lease various office, warehouse and storage facilities in Australia, Louisiana, Malaysia, Singapore and the U.K. to support our offshore drilling operations.

Item 3. Legal Proceedings.

See information with respect to legal proceedings in Note 12 "Commitments and Contingencies" to our Consolidated Financial Statements in Item 8 of this report.

Item 4. Mine Safety Disclosures.

Not applicable.

PART II

Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Market Information and Holders of Record

Our common stock is listed on the New York Stock Exchange, or NYSE, under the symbol "DO."

As of February 8, 2019, there were approximately 138 holders of record of our common stock. This number represents registered stockholders and does not include stockholders who hold their shares through an institution.

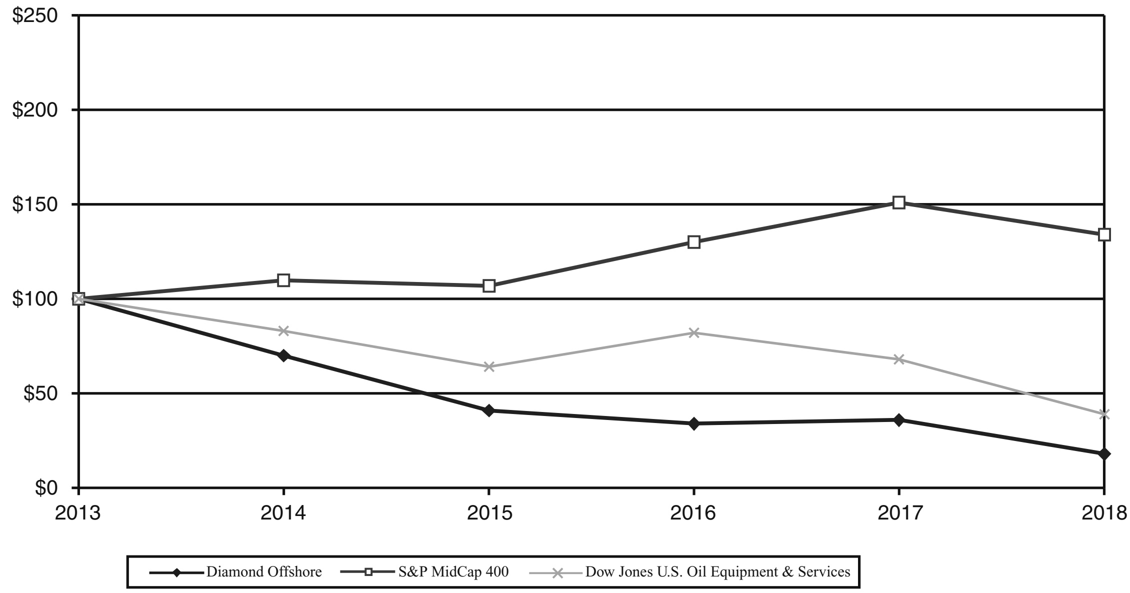
Dividend Policy

We pay dividends at the discretion of our Board of Directors, or Board. Any determination to declare a dividend, as well as the amount of any dividend that may be declared, will be based on the Board's consideration of our financial position, earnings, earnings outlook, capital spending plans, outlook on current and future market conditions and business needs, contractual obligations and other factors that our Board considers relevant at that time. The Board's dividend policy may change from time to time, but there can be no assurance that we will declare any cash dividends at all or in any particular amounts. We have not paid a dividend to stockholders since 2015.

Cumulative Total Stockholder Return

The following graph shows the cumulative total stockholder return for our common stock, the Standard & Poor's MidCap 400 Index and the Dow Jones U.S. Oil Equipment & Services index over the five-year period ended December 31, 2018.

Comparison of Five-Year Cumulative Total Return (1)



	Dec. 31, 2013	Dec. 31, 2014	Dec. 31, 2015	Dec. 31, 2016	Dec. 31, 2017	Dec. 31, 2018
Diamond Offshore	$100	70	41	34	36	18
S&P MidCap 400 Index	$100	110	107	130	151	134
Dow Jones U.S. Oil Equipment & Services	$100	83	64	82	68	39

(1) Total return assuming reinvestment of dividends. Assumes $100 invested on December 31, 2013 in our common stock and the two published indices.

Unregistered Sales of Equity Securities and Use of Proceeds.

Items 2(a) and 2(b) are not applicable.

(c) During the three months ended December 31, 2018, in connection with the vesting of restricted stock units held by our officers and certain of our employees, which were awarded under an equity incentive compensation plan, we acquired shares of our common stock in satisfaction of tax withholding obligations that were incurred on the vesting date. The date of acquisition, number of shares and average effective acquisition price per share were as follows:

Issuer Purchases of Equity Securities

Period	Total Number of Shares Acquired	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October 1, 2018 through October 31, 2018	79	$20.10	N/A	N/A
November 1, 2018 through November 30, 2018	—	—	N/A	N/A
December 1, 2018 through December 31, 2018	1,176	$12.60	N/A	N/A
Total	1,255	$20.86	N/A	N/A

Item 6. Selected Financial Data.

The following table sets forth certain historical consolidated financial data relating to Diamond Offshore. We prepared the selected consolidated financial data from our consolidated financial statements as of and for the periods presented. The selected consolidated financial data below should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 and our Consolidated Financial Statements (including the Notes thereto) in Item 8 of this report.

	As of and for the Year Ended December 31,				
	2018	2017	2016	2015	2014
	(In thousands, except per share and ratio data)				
Income Statement Data:					
Total revenues	$1,083,215[1]	$1,485,746	$1,600,342	$2,419,393	$2,814,671
Operating (loss) income	(112,183)[2]	123,879[2]	(356,884)[2]	(294,074)[2]	572,562[2]
Net (loss) income	(180,272)	18,346	(372,503)	(274,285)	387,011
Net (loss) income per share:					
Basic	(1.31)	0.13	(2.72)	(2.00)	2.82
Diluted	(1.31)	0.13	(2.72)	(2.00)	2.81
Balance Sheet Data:					
Drilling and other property and equipment, net	$5,184,222[2]	$5,261,641[2]	$5,726,935[2]	$6,378,814[2]	$6,945,953[2]
Total assets	6,035,694	6,250,570	6,371,877	7,149,894[3]	8,005,398[3]
Long-term debt (excluding current maturities)[4]	1,973,922	1,972,225	1,980,884	1,979,778[3]	1,978,635[3]
Other Financial Data:					
Capital expenditures, excluding accruals	$ 222,406	$ 139,581	$ 652,673	$ 830,655	$2,032,764[4]
Cash dividends declared per share	—	—	—	0.50	3.50

(1) On January 1, 2018, we adopted Financial Accounting Standards Board Accounting Standards Update, or ASU, No. 2014-09, *Revenue from Contracts with Customers* (Topic 606), or ASU 2014-09, which superseded previous revenue recognition requirements in ASU Topic 605, Revenue Recognition. Under the new guidance, revenue is recognized when a customer obtains control of promised goods or services and in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. We adopted ASU 2014-09, and its related amendments, or collectively Topic 606, using the modified retrospective implementation method, and, accordingly, have applied the five-step method outlined in Topic 606 for determining when and how revenue is recognized to all contracts that were not completed as of the date of adoption. Revenues for reporting periods beginning after January 1, 2018 are presented under Topic 606, while prior period amounts have not been adjusted and continue to be reported under the previous revenue recognition guidance. See Note 1—"General Information—*Changes in Accounting Principles*—Revenue Recognition" and Note 2 "Revenue from Contracts with Customers" to our Consolidated Financial Statements in Item 8 of this report for a discussion of the impact of adopting Topic 606.

(2) During 2018, 2017, 2016, 2015 and 2014 we recorded impairment losses aggregating $27.2 million, $99.3 million, $678.1 million, $860.4 million and $109.5 million, respectively, to write down certain of our drilling rigs and related equipment with indicators of impairment to their estimated recoverable amounts. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – *2018 Compared to 2017 – Impairment of Assets*" and "Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – *2017 Compared to 2016 – Impairment of Assets*" in Item 7 and Note 3 "Asset Impairments" to our Consolidated Financial Statements in Item 8 of this report for a discussion of these impairments.

(3) Historical data for the years ended December 31, 2015 and 2014 has been restated to reflect the effect thereon of the adoption on January 1, 2016 of an accounting standard that requires debt issuance costs associated with our senior notes to be presented in the balance sheet as a reduction in the related long-term debt. Prior to the adoption of this accounting standard, debt issuance costs associated with our senior notes were presented as “Prepaid expenses and other current assets” and “Other assets” in our Consolidated Balance Sheets.

(4) See Note 10 “Credit Agreements and Senior Notes” to our Consolidated Financial Statements included in Item 8 of this report for a discussion of changes to our long-term debt.

Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.

The following discussion should be read in conjunction with Item 1A, “Risk Factors” and our Consolidated Financial Statements (including the Notes thereto) in Item 8 of this report.

We provide contract drilling services to the energy industry around the globe with a fleet of 17 offshore drilling rigs, consisting of four drillships and 13 semisubmersible rigs.

Market Overview

Over the past five years, crude oil prices have been volatile, reaching a high of $115 per barrel in 2014 but dropping to $55 per barrel by the end of 2014. In 2015, oil prices continued to decline, closing at $37 per barrel at the end of the year, and continuing to fall to a low of $28 per barrel during 2016 before recovering to nearly $57 per barrel by the end of 2016. While the price of crude oil continued to fluctuate in 2017 and 2018, as of the date of this report, the current spot price for Brent crude was in the $60 per barrel range. As a result of this volatility in commodity price and its uncertain future, the offshore drilling industry has experienced a substantial decline in demand for its services, as well as a significant decline in dayrates for contract drilling services. Although demand and offshore utilization increased during 2018, with industry-wide floater utilization averaging near 60% at the end of 2018 based on analyst reports, dayrates remain low as the increase in oil prices from earlier lows has not yet resulted in significantly higher dayrates. If dayrates increase, offshore drillers with more available floaters and/or unpriced options for currently committed rigs will be better positioned to take advantage of the market recovery as it materializes.

Tendering activity has also increased. During 2018 and continuing into 2019, there has been an increase in contract tenders for late 2019 and 2020 project commencements, primarily for work in the North Sea and Australia floater markets. Industry analysts also predict that there will be additional opportunities in the West Africa market in the near term. Reflective of the uncertainty in the market, many of these tenders have been limited to single-well jobs, with options for future wells. Although some geographic areas appear to be improving, other markets show little or no sign of recovery at this time.

From a supply perspective, industry analysts have reported that during 2018, the global supply of floater rigs decreased for the fourth consecutive year, with 20 floaters being scrapped during the year. Based on these reports, over 200 drilling rigs, including 119 floaters, have been retired since 2014. However, the offshore floater market remains oversupplied, as there are drilling rigs across all water depth categories that are not contracted or that are cold stacked as of the date of this report. Industry reports also indicate that there remain approximately 40 newbuild floaters on order with scheduled deliveries in 2019 and 2020, most of which have not yet been contracted for future work. In addition, several rig reactivations were announced during 2018 and in early 2019, including the ongoing reactivations of our *Ocean Endeavor* and *Ocean Onyx* that have been brought out of cold stack to fulfill newly-acquired contracts. These factors provide for a continued, challenging offshore drilling market in the near term.

See “– Contract Drilling Backlog” for future commitments of our rigs during 2019 through 2022.

Contract Drilling Backlog

Contract drilling backlog, as presented below, includes only firm commitments (typically represented by signed contracts) and is calculated by multiplying the contracted operating dayrate by the firm contract period. Our calculation also assumes full utilization of our drilling equipment for the contract period (excluding scheduled shipyard and survey days); however, the amount of actual revenue earned and the actual periods during which revenues are earned will be different than the amounts and periods shown in the tables below due to various factors. Utilization rates, which generally approach 92-98% during contracted periods, can be adversely impacted by downtime due to various operating factors including, but not limited to, weather conditions and unscheduled repairs and maintenance. Contract drilling backlog excludes revenues for mobilization, demobilization, contract preparation and customer reimbursables. No revenue is generally earned during periods of downtime for regulatory surveys. Changes in our contract drilling backlog between periods are generally a function of the performance of work on term contracts, as well as the extension or modification of existing term contracts and the execution of additional contracts. In addition, under certain circumstances, our customers may seek to terminate or renegotiate our contracts, which could adversely affect our reported backlog.

See "Risk Factors — *We can provide no assurance that our drilling contracts will not be terminated early or that our current backlog of contract drilling revenue will be ultimately realized*" in Item 1A of this report, which is incorporated herein by reference.

The backlog information presented below does not, nor is it intended to, align with the disclosures related to revenue expected to be recognized in the future related to unsatisfied performance obligations, which are presented in Note 2 "Revenue from Contracts with Customers" to our Consolidated Financial Statements in Item 8 of this report. Contract drilling backlog includes only future dayrate revenue as described above, while the disclosure in Note 2 excludes dayrate revenue and only reflects expected future revenue for mobilization, demobilization and capital modifications to our rigs, which are related to non-distinct promises within our signed contracts.

The following table reflects our contract drilling backlog as of January 1, 2019 (based on information available at that time), October 1, 2018 (the date reported in our Quarterly Report on Form 10-Q for the quarter ended September 30, 2018), and January 1, 2018 (the date reported in our Annual Report on Form 10-K for the year ended December 31, 2017) (in thousands).

	January 1, 2019[1]	October 1, 2018[1]	January 1, 2018
Contract Drilling Backlog	$1,973,000	$2,040,000	$2,417,000

(1) Contract drilling backlog as of January 1, 2019 and October 1, 2018 excludes a future gross margin commitment totaling $135.0 million payable by a customer in the form of a guarantee of gross margin to be earned on future contracts or by direct payment, pursuant to terms of an existing contract.

The following table reflects the amount of our contract drilling backlog by year as of January 1, 2019 (in thousands).

	For the Years Ending December 31,				
	Total	2019	2020	2021	2022
Contract Drilling Backlog [1]	$1,973,000	$886,000	$798,000	$253,000	$36,000

(1) Contract drilling backlog as of January 1, 2019 excludes future gross margin commitments of $30.0 million for 2019, $30.0 million for 2020 and an aggregate of $75.0 million for the 2021 through 2023 period payable by a customer in the form of a guarantee of gross margin to be earned on future contracts or by direct payment at the end of each of the three respective periods, pursuant to terms of an existing contract.

The following table reflects the percentage of rig days committed by year as of January 1, 2019. The percentage of rig days committed is calculated as the ratio of total days committed under contracts, as well as scheduled shipyard, survey and mobilization days for all rigs in our fleet, to total available days (number of rigs, including cold-stacked rigs, multiplied by the number of days in a particular year).

	For the Years Ending December 31,			
	2019	2020	2021	2022
Rig Days Committed (1)	67%	59%	18%	2%

(1) As of January 1, 2019, includes approximately 855 and 125 currently known, scheduled days for contract preparation, reactivation of rigs, mobilization of rigs, surveys and extended repair and maintenance projects for the years 2019 and 2020, respectively.

Important Factors That May Impact Our Operating Results, Financial Condition or Cash Flows

Operating Income. Our operating income is primarily a function of contract drilling revenue earned less contract drilling expenses incurred or recognized. The two most significant variables affecting our contract drilling revenue are the dayrates earned and utilization rates achieved by our rigs, each of which is a function of rig supply and demand in the marketplace. These factors are not entirely within our control and are difficult to predict. We generally recognize revenue from dayrate drilling contracts as services are performed. Consequently, when a rig is idle, no dayrate is earned and revenue will decrease as a result.

Effective January 1, 2018, we adopted Accounting Standards Update, or ASU, No. 2014-09, *Revenue from Contracts with Customers* (Topic 606), or ASU 2014-09, which supersedes the revenue recognition requirements in ASU Topic 605, Revenue Recognition. Under the new guidance, revenue is recognized when a customer obtains control of promised goods or services and in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. Revenues for reporting periods beginning after January 1, 2018 are presented under ASU 2014-09, while prior period amounts have not been adjusted and continue to be reported under the previous revenue recognition guidance.

Revenue recognition under ASU 2014-09 differs from our previous revenue recognition pattern only as it relates to demobilization revenue. Such revenue, which was previously recognized upon completion of a contract, is now estimated at contract inception and recognized, to the extent not constrained, ratably over the initial term of the contract under the new revenue recognition guidance. See "– Critical Accounting Estimates" and Note 1 "General Information—*Changes in Accounting Principles* - Revenue Recognition" and Note 2 "Revenue from Contracts with Customers" to our Consolidated Financial Statements in Item 8 of this report.

Revenue is affected by the acquisition or disposal of rigs, rig mobilizations, required surveys and shipyard projects. In connection with certain drilling contracts, we may receive fees for the mobilization and demobilization of equipment. In addition, some of our drilling contracts require downtime before the start of the contract to prepare the rig to meet customer requirements for which we may or may not be compensated. We recognize these fees ratably as services are performed over the initial term of the related drilling contracts. We defer mobilization and contract preparation fees received (on either a lump-sum or dayrate basis), as well as direct and incremental costs associated with the mobilization of equipment and contract preparation activities, and amortize each, on a straight-line basis, over the term of the related drilling contracts. As noted above, demobilization revenue expected to be received upon contract completion is estimated and is also recognized ratably over the initial term of the contract.

Operating income also fluctuates due to varying levels of contract drilling expenses. Our operating expenses represent all direct and indirect costs associated with the operation and maintenance of our drilling equipment, which generally are not affected by changes in dayrates and short-term reductions in utilization. For instance, if a rig is to be idle for a short period of time, few decreases in operating expenses may actually occur since the rig is typically maintained in a prepared or "warm-stacked" state with a full crew. In addition, when a rig is idle, we are responsible for certain operating expenses such as rig fuel and supply boat costs, which are typically costs of our customer when a rig is under contract. However, if a rig is expected to be idle for an extended period of time, we may reduce the size of a rig's crew and take steps to "cold stack" the rig, which lowers expenses and partially offsets the impact on operating income. The cost of cold stacking a rig can vary depending on the type of rig. The cost of cold stacking a drillship, for example, is typically substantially higher than the cost of cold stacking a jack-up rig or an older floater rig.

The principal components of our operating costs are, among other things, direct and indirect costs of labor and benefits, repairs and maintenance, freight, regulatory inspections, boat and helicopter rentals and insurance. Labor and repair and maintenance costs represent the most significant components of our operating expenses. In general, our labor costs increase primarily due to higher salary levels, rig staffing requirements and costs associated with labor regulations in the geographic regions in which our rigs operate. In addition, the costs associated with training employees can be significant. Costs to repair and maintain our equipment fluctuate depending upon the type of activity the drilling unit is performing, as well as the age and condition of the equipment and the regions in which our rigs are working. See "– Contractual Cash Obligations – *Pressure Control by the Hour®*."

Regulatory Surveys and Planned Downtime. Our operating income is negatively impacted when we perform certain regulatory inspections, which we refer to as a special survey, that are due every five years for most of our rigs. The inspection interval for our North Sea rigs is two-and-one-half years. Operating revenue decreases because these special surveys are generally performed during scheduled downtime in a shipyard. Operating expenses increase as a result of these special surveys due to the cost to mobilize the rigs to a shipyard, inspection costs incurred and repair and maintenance costs, which are recognized as incurred. Repair and maintenance activities may result from the special survey or may have been previously planned to take place during this mandatory downtime. The number of rigs undergoing a special survey will vary from year to year, as well as from quarter to quarter.

During 2019, we expect to spend approximately 855 days for contract preparation, reactivation of rigs, mobilization of rigs, upgrades and surveys, including approximately 60 days for contract preparation for the *Ocean GreatWhite* and an aggregate of 425 days for reactivation activities and contract preparation for the *Ocean Endeavor* and *Ocean Onyx* prior to their contract commencements. We also expect to spend an aggregate of 230 days for special surveys and rig upgrades for the *Ocean BlackHawk*, *Ocean BlackHornet* and *Ocean BlackRhino,* 60 days for a special survey for the *Ocean Courage* and an aggregate of 80 days for the mobilization of the *Ocean Apex* and the *Ocean Monarch*. We can provide no assurance as to the exact timing and/or duration of downtime associated with these projects. See " – Contract Drilling Backlog."

Physical Damage and Marine Liability Insurance. We are self-insured for physical damage to rigs and equipment caused by named windstorms in the U.S. Gulf of Mexico, as defined by the relevant insurance policy. If a named windstorm in the U.S. Gulf of Mexico causes significant damage to our rigs or equipment, it could have a material adverse effect on our financial condition, results of operations and cash flows. Under our current insurance policy, which renewed effective May 1, 2018, we carry physical damage insurance for certain losses other than those caused by named windstorms in the U.S. Gulf of Mexico for which our deductible for physical damage is $25.0 million per occurrence. We do not typically retain loss-of-hire insurance policies to cover our rigs.

In addition, we carry marine liability insurance covering certain legal liabilities, including coverage for certain personal injury claims, and generally covering liabilities arising out of or relating to pollution and/or environmental risk. We believe that the policy limit for our marine liability insurance is within the range that is customary for companies of our size in the offshore drilling industry and is appropriate for our business. Our deductibles for marine liability coverage related to insurable events arising due to named windstorms in the U.S. Gulf of Mexico are $25.0 million for the first occurrence, with no aggregate deductible, and vary in amounts ranging between $25.0 million and, if aggregate claims exceed certain thresholds, up to $100.0 million for each subsequent occurrence, depending on the nature, severity and frequency of claims that might arise during the policy year. Our deductibles for other marine liability coverage, including personal injury claims not related to named windstorms in the U.S. Gulf of Mexico, are $10.0 million for the first occurrence and vary in amounts ranging between $5.0 million and, if aggregate claims exceed certain thresholds, up to $100.0 million for each subsequent occurrence, depending on the nature, severity and frequency of claims that might arise during the policy year.

Impact of Changes in Tax Laws or Their Interpretation. We operate through our various subsidiaries in a number of jurisdictions throughout the world. As a result, we are subject to highly complex tax laws, treaties and regulations in the jurisdictions in which we operate, which may change and are subject to interpretation. Changes in laws, treaties and regulations and the interpretation of such laws, treaties and regulations may put us at risk for future tax assessments and liabilities which could be substantial and could have a material adverse effect on our financial condition, results of operations and cash flows.

Critical Accounting Estimates

Our significant accounting policies are included in Note 1 “General Information” to our Consolidated Financial Statements in Item 8 of this report. Judgments, assumptions and estimates by our management are inherent in the preparation of our financial statements and the application of our significant accounting policies. We believe that our most critical accounting estimates are as follows:

Property, Plant and Equipment. We carry our drilling and other property and equipment at cost, less accumulated depreciation. Maintenance and routine repairs are charged to income currently while replacements and betterments that upgrade or increase the functionality of our existing equipment and that significantly extend the useful life of an existing asset, are capitalized. Significant judgments, assumptions and estimates may be required in determining whether or not such replacements and betterments meet the criteria for capitalization and in determining useful lives and salvage values of such assets. Changes in these judgments, assumptions and estimates could produce results that differ from those reported. During the years ended December 31, 2018 and 2017, we capitalized $243.6 million and $69.4 million, respectively, in replacements and betterments of our drilling fleet.

We evaluate our property and equipment for impairment whenever changes in circumstances indicate that the carrying amount of an asset may not be recoverable (such as, but not limited to, cold stacking a rig, the expectation of cold stacking a rig in the near term, contracted backlog of less than one year for a rig, a decision to retire or scrap a rig, or excess spending over budget on a newbuild, construction project or major rig upgrade). We utilize an undiscounted probability-weighted cash flow analysis in testing an asset for potential impairment. Our assumptions and estimates underlying this analysis include the following:

- dayrate by rig;
- utilization rate by rig if active, warm stacked or cold stacked (expressed as the actual percentage of time per year that the rig would be used at certain dayrates);
- the per day operating cost for each rig if active, warm stacked or cold stacked;
- the estimated annual cost for rig replacements and/or enhancement programs;
- the estimated maintenance, inspection or other reactivation costs associated with a rig returning to work;
- salvage value for each rig; and
- estimated proceeds that may be received on disposition of each rig.

Based on these assumptions, we develop a matrix for each rig under evaluation using multiple utilization/ dayrate scenarios, to each of which we have assigned a probability of occurrence. We arrive at a projected probability-weighted cash flow for each rig based on the respective matrix and compare such amount to the carrying value of the asset to assess recoverability.

The underlying assumptions and assigned probabilities of occurrence for utilization and dayrate scenarios are developed using a methodology that examines historical data for each rig, which considers the rig's age, rated water depth and other attributes and then assesses its future marketability in light of the current and projected market environment at the time of assessment. Other assumptions, such as operating, maintenance, inspection and reactivation costs, are estimated using historical data adjusted for known developments, cost projections for re-entry of rigs into the market and future events that are anticipated by management at the time of the assessment.

Management's assumptions are necessarily subjective and are an inherent part of our asset impairment evaluation, and the use of different assumptions could produce results that differ from those reported. Our methodology generally involves the use of significant unobservable inputs, representative of a Level 3 fair value measurement, which may include assumptions related to future dayrate revenue, costs and rig utilization, quotes from rig brokers, the long-term future performance of our rigs and future market conditions. Management's assumptions involve uncertainties about future demand for our services, dayrates, expenses and other future events, and management's expectations may not be indicative of future outcomes. Significant unanticipated changes to these assumptions could materially alter our analysis in testing an asset for potential impairment. For example, changes in market conditions that exist at the measurement date or that are projected by management could affect our key assumptions. Other events or circumstances that could affect our assumptions may include, but are not limited to, a further sustained decline in oil and gas prices, cancelations of our drilling contracts or contracts of our competitors, contract modifications, costs to comply with new governmental regulations, capital expenditures required due to advances in offshore drilling technology, growth in the global oversupply of oil and geopolitical events, such as lifting sanctions on oil-producing nations. Should actual market conditions in the future vary significantly from market conditions used in our projections, our assessment of impairment would likely be different.

During 2018, 2017 and 2016, we recorded impairment losses of $27.2 million, $99.3 million and $678.1 million, respectively. See "– Results of Operations *–2018 Compared to 2017 – Impairment of Assets*" and "– Results of Operations *–2017 Compared to 2016 – Impairment of Assets*" and Note 3 "Asset Impairments" to our Consolidated Financial Statements in Item 8 of this report.

Personal Injury Claims. Under our current insurance policies, which renewed effective May 1, 2018, our deductibles for marine liability insurance coverage with respect to personal injury claims not related to named windstorms in the U.S. Gulf of Mexico, which primarily result from Jones Act liability in the Gulf of Mexico, are $10.0 million for the first occurrence, with no aggregate deductible, and vary in amounts ranging between $5.0 million and, if aggregate claims exceed certain thresholds, up to $100.0 million for each subsequent occurrence, depending on the nature, severity and frequency of claims that might arise during the policy year. Our deductibles for personal injury claims arising due to named windstorms in the U.S. Gulf of Mexico are $25.0 million for the first occurrence, with no aggregate deductible, and vary in amounts ranging between $25.0 million and, if aggregate claims exceed certain thresholds, up to $100.0 million for each subsequent occurrence, depending on the nature, severity and frequency of claims that might arise during the policy year. The Jones Act is a federal law that permits seamen to seek compensation for certain injuries during the course of their employment on a vessel and governs the liability of vessel operators and marine employers for the work-related injury or death of an employee. We engage outside consultants to assist us in estimating our aggregate liability for personal injury claims based on our historical losses and utilizing various actuarial models.

The models used in estimating our aggregate reserve for personal injury claims include actuarial assumptions such as:

- claim emergence, or the delay between occurrence and recording of claims;

- settlement patterns, or the rates at which claims are closed;
- development patterns, or the rate at which known cases develop to their ultimate level;
- average, potential frequency and severity of claims; and
- effect of re-opened claims.

The eventual settlement or adjudication of these claims could differ materially from our estimated amounts due to uncertainties such as:

- the severity of personal injuries claimed;
- significant changes in the volume of personal injury claims;
- the unpredictability of legal jurisdictions where the claims will ultimately be litigated;
- inconsistent court decisions; and
- the risks and lack of predictability inherent in personal injury litigation.

Income Taxes. We account for income taxes in accordance with accounting standards that require the recognition of the amount of taxes payable or refundable for the current year and an asset and liability approach in recognizing the amount of deferred tax liabilities and assets for the future tax consequences of events that have been currently recognized in our financial statements or tax returns. In each of our tax jurisdictions we recognize a current tax liability or asset for the estimated taxes payable or refundable on tax returns for the current year and a deferred tax asset or liability for the estimated future tax effects attributable to temporary differences and carryforwards. Deferred tax assets are reduced by a valuation allowance, if necessary, which is determined by the amount of any tax benefits that, based on available evidence, are not expected to be realized under a "more likely than not" approach. We make judgments regarding future events and related estimates especially as they pertain to the forecasting of our effective tax rate, the potential realization of deferred tax assets such as net operating loss carryforwards, utilization of foreign tax credits, and exposure to the disallowance of items deducted on tax returns upon audit.

In several of the international locations in which we operate, certain of our wholly-owned subsidiaries enter into agreements with other of our wholly-owned subsidiaries to provide specialized services and equipment in support of our foreign operations. We apply a transfer pricing methodology to determine the arm's length amount to be charged for providing the services and equipment, and utilize outside consultants to assist us in the development of such transfer pricing methodologies. In most cases, there are alternative transfer pricing methodologies that could be applied to these transactions and, if applied, could result in different chargeable amounts.

Results of Operations

Our operating results for contract drilling services are dependent on three primary metrics or key performance indicators: revenue-earning days, rig utilization and average daily revenue. The following table presents these three key performance indicators and other comparative data relating to our revenues and operating expenses (in thousands, except days, daily amounts and percentages).

	Year Ended December 31,		
	2018	2017	2016
REVENUE-EARNING DAYS [(1)]			
Floaters	3,192	3,865	3,645
Jack-ups	—	282	149
UTILIZATION [(2)]			
Floaters	51%	48%	41%
Jack-ups	—	61%	8%
AVERAGE DAILY REVENUE [(3)]			
Floaters	$ 329,400	$ 370,100	$ 410,200
Jack-ups	—	74,900	202,700
REVENUE RELATED TO CONTRACT DRILLING SERVICES	$1,059,973	$1,451,219	$1,525,214
REVENUE RELATED TO REIMBURSABLE EXPENSES	23,242	34,527	75,128
TOTAL REVENUES	$1,083,215	$1,485,746	$1,600,342
CONTRACT DRILLING EXPENSE, EXCLUDING DEPRECIATION	$ 722,834	$ 801,964	$ 772,173
REIMBURSABLE EXPENSES	$ 22,917	$ 33,744	$ 58,058
OPERATING (LOSS) INCOME			
Contract drilling services, net	$ 337,139	$ 649,255	$ 753,041
Reimbursable expenses, net	325	783	17,070
Depreciation	(331,789)	(348,695)	(381,760)
General and administrative expense	(85,351)	(74,505)	(63,560)
Bad debt recovery	—	—	265
Impairment of assets	(27,225)	(99,313)	(678,145)
Restructuring and separation costs	(5,041)	(14,146)	—
(Loss) gain on disposition of assets	(241)	10,500	(3,795)
Total Operating (Loss) Income	$ (112,183)	$ 123,879	$ (356,884)
Other income (expense):			
Interest income	8,477	2,473	768
Interest expense, net of amounts capitalized	(123,240)	(113,528)	(89,934)
Foreign currency transaction gain	(379)	(1,128)	(11,522)
Loss on early extinguishment of senior notes	—	(35,366)	—
Other, net	700	2,230	(10,727)
Loss before income tax benefit	(226,625)	(21,440)	(468,299)
Income tax benefit	46,353	39,786	95,796
NET (LOSS) INCOME	$ (180,272)	$ 18,346	$ (372,503)

(1) A revenue-earning day is defined as a 24-hour period during which a rig earns a dayrate after commencement of operations and excludes mobilization, demobilization and contract preparation days.

(2) Utilization is calculated as the ratio of total revenue-earning days divided by the total calendar days in the period for all specified rigs in our fleet (including three, five and ten cold-stacked floater rigs at December 31, 2018, 2017 and 2016, respectively).
(3) Average daily revenue is defined as total contract drilling revenue for all of the specified rigs in our fleet per revenue-earning day.

2018 Compared to 2017

We recorded a net loss of $180.3 million in 2018 compared to net income of $18.3 million in 2017. The $198.6 million decrease in net results was primarily due to lower revenue from our contract drilling services and higher interest expense and certain other charges. These negative factors were partially offset by the favorable impact of reduced depreciation expense and a lower impairment charge in 2018, combined with the absence of a $35.4 million loss on the early extinguishment of our senior notes in 2017. Contract drilling services contributed operating income of $337.1 million in 2018, compared to operating income of $649.3 million in 2017, reflecting the challenging contract drilling market during 2018.

Operating Results. Contract drilling revenue decreased $391.2 million during 2018 compared to 2017, primarily due to 955 fewer revenue-earning days ($334.0 million), combined with the effect of lower average daily revenue earned ($65.6 million). Revenue-earning days decreased during 2018, primarily due to fewer revenue-earning days for previously-owned rigs that operated during 2017 (437 days), incremental downtime for planned shipyard projects, including associated mobilization days (392 days), incremental downtime attributable to the warm stacking of rigs between contracts (86 days) and an increase in non-productive days (40 days). Average daily revenue decreased during 2018 compared to 2017, primarily due to lower dayrates earned by several of our rigs as a result of the renegotiation of existing contracts under mutually favorable terms and new contracts at lower dayrates than previously contracted during 2017. The decrease in revenue was partially offset by $8.4 million in loss-of-hire insurance proceeds received during 2018 related to contract terminations for two jack-up rigs in a prior year.

Contract drilling expense, excluding depreciation, decreased $79.1 million during 2018 compared to 2017, primarily due to reduced costs for currently cold-stacked and previously-owned rigs, which had incurred contract drilling expense in 2017 ($52.4 million), combined with decreased costs for our current rig fleet ($26.7 million). The decrease in contract drilling expense for our current fleet resulted from lower labor and personnel costs, agency fees, shorebase support costs and overheads, primarily as a result of our continuing cost control initiatives, including termination of our Brazilian agency agreement at the end of 2017, and the deferral of costs associated with contract preparation activities for rigs as they prepare for new contracts in 2019. These reductions were partially offset by increased costs for repairs and maintenance, inspections and equipment rentals. Depreciation expense decreased $16.9 million in 2018 compared to 2017, primarily due to a lower asset base in 2018 as a result of the sale of rigs and asset impairments.

General and administrative expense increased $10.8 million during 2018 compared to 2017, primarily due to a $17.5 million charge for settlement of a previously pending legal claim, partially offset by the favorable effect of lower administrative payroll costs resulting from restructuring initiatives.

Impairment of Assets. During the second quarter of 2018, we recorded an impairment loss of $27.2 million to recognize a reduction in fair value (less costs to sell) of the *Ocean Scepter*, a jack-up rig that was reported in "Assets held for sale" in our audited Consolidated Balance Sheets at December 31, 2017 and which was sold in July 2018. In 2017, we recorded an aggregate impairment loss of $99.3 million with respect to the carrying values of three rigs. See "– Critical Accounting Estimates – *Property, Plant and Equipment*" and Note 1 "General Information – *Assets Held for Sale*" and Note 3 "Asset Impairments" to our Consolidated Financial Statements in Item 8 of this report.

Restructuring and Separation Costs. During the fourth quarter of 2017, our management approved and initiated a plan to restructure our worldwide operations, which also included a reduction in workforce at our corporate facilities and onshore bases. As a result, we recognized $14.1 million in 2017 in restructuring and other employee separation related costs, including $11.5 million related to a negotiated termination of our agency agreement in Brazil. During 2018, we recognized $5.0 million in restructuring and other employee separation related costs for additional workforce reduction in 2018.

Interest Expense, Net of Amounts Capitalized. Interest expense increased $9.7 million during 2018 compared to 2017, primarily as a result of interest charges related to foreign customs and payroll tax assessments ($4.0 million) combined with incremental interest expense associated with our senior notes issued in August 2017 ($6.5 million) and amendment of our credit facility in October 2018 ($1.9 million). See "– Liquidity and Capital Resources – *Sources and Uses of Cash – Credit Agreements*" and Note 10 "Credit Agreements and Senior Notes" to our Consolidated Financial Statements in Item 8 of this report. These incremental interest costs were partially offset by the reversal of accrued interest on assessments due to the expiration of statutes of limitations on non-income based taxes in certain tax jurisdictions.

Loss on Extinguishment of Senior Notes. During the third quarter of 2017, we recorded a $35.4 million loss on extinguishment of $500.0 million aggregate principal amount of our senior notes that were to mature in 2019. See Note 10 "Credit Agreements and Senior Notes" to our Consolidated Financial Statements in Item 8 of this report.

Income Tax Benefit. During 2018 and 2017, we recorded net income tax benefits of $46.4 million and $39.8 million, respectively, on net losses of $226.6 million and $21.4 million, respectively. The variance in the income tax benefit recognized between years is due to differences in the mix of our domestic and international pre-tax earnings and losses, including asset impairments taken during both 2018 and 2017 in various jurisdictions, as well as discrete tax items recorded in each period as a result of, among other things, tax audits or assessments and filed or amended tax returns.

As a result of the Tax Cuts and Jobs Act, commonly referred to as the Tax Reform Act, which was signed into law on December 22, 2017, we recorded an incremental income tax expense of $1.1 million in 2017, consisting of (i) a $75.4 million charge related to the immediate deemed repatriation of the previously deferred accumulated earnings of our non-U.S. subsidiaries and (ii) a $74.3 million benefit resulting from the remeasurement of our net U.S. deferred tax liability at the lower corporate income tax rate. Subsequently, in 2018, the U.S. Department of the Treasury and the Internal Revenue Service, or IRS, issued additional guidance which clarified certain tax positions taken in 2017 pursuant to the Tax Reform Act. Consequently, we reversed a $43.3 million liability for an uncertain tax position related to the deemed repatriation of accumulated non-U.S. earnings in 2017. In addition, based on proposed regulations issued by the IRS in the fourth quarter of 2018, which we believe may impact the utilization of certain tax attributes to offset the deemed repatriation of non-U.S. earnings, we recorded an uncertain tax position in the amount of $20.1 million. See Note 16 "Income Taxes" to our Consolidated Financial Statements in Item 8 of this report.

2017 Compared to 2016

During 2017, we recorded net income of $18.3 million, compared to a net loss of $372.5 million in 2016. Our net results for 2017 increased $390.8 million compared to 2016, primarily due to lower impairment charges and a reduction in depreciation expense. These favorable factors were partially offset by lower contract drilling results, higher interest expense and a lower tax benefit recorded in 2017, combined with a $35.4 million loss on early extinguishment of our senior notes. Contract drilling services contributed operating income of $649.3 million in 2017, compared to operating income of $753.0 million in 2016.

Operating Results. Contract drilling revenue decreased $74.0 million during 2017 compared to 2016, primarily as a result of a lower average daily revenue earned ($216.0 million), partially offset by the favorable impact of an aggregate 353 incremental revenue-earning days ($142.0 million). Average daily revenue decreased primarily due to several of our rigs having worked under new contracts in 2017 at lower dayrates than those previously contracted. Revenue-earning days increased during 2017, primarily due to incremental revenue-earning days for the *Ocean GreatWhite* (351 days), which began its first contract during the first quarter of 2017, less planned downtime for shipyard projects (211 days) and fewer days attributable to the warm stacking of rigs between contracts (164 days). These favorable impacts were partially offset by fewer revenue-earning days related to cold-stacked and sold rigs that worked in 2016 (344 days) and an increase in non-productive days (31 days). Total revenue in 2016 also included $14.6 million in net reimbursable revenue earned by the *Ocean Endeavor* upon completion of its demobilization from the Black Sea.

Contract drilling expense, excluding depreciation, increased $29.8 million in 2017 compared to 2016, reflecting higher amortized rig mobilization expense ($25.4 million) and incremental costs associated with the Pressure Control by the Hour® program, or the PCbtH program, on our drillships ($27.8 million), partially offset by lower repair and maintenance costs ($15.2 million) and a net reduction in other rig operating and overhead costs ($8.2 million). Depreciation expense decreased $33.1 million compared to 2016, primarily due to a lower depreciable asset base, as a result of asset impairments in 2016 and 2017.

General and administrative expense increased $10.9 million in 2017 compared to 2016, primarily due to higher administrative payroll costs and incremental advisory and consulting costs incurred in relation to various corporate initiatives.

Interest Expense, Net of Amounts Capitalized. Interest expense increased $23.6 million during 2017 compared to 2016, primarily as a result of a $20.7 million reduction in interest capitalized during 2017 due to the completion of construction projects in 2016. Interest expense for 2017 also included incremental interest expense associated with our newly-issued senior notes and subsequent redemption of existing senior notes ($4.0 million), which was partially offset by reduced interest expense associated with lower borrowings under our revolving credit agreement ($2.8 million).

Impairment of Assets. During 2017, we recorded an aggregate impairment charge of $99.3 million related to three drilling rigs. During 2016, we recognized an aggregate impairment charge of $678.1 million with respect to the carrying values of eight drilling rigs, including related rig spares and supplies. See "– Critical Accounting Estimates – *Property, Plant and Equipment*" and Note 3 "Asset Impairments" to our Consolidated Financial Statements in Item 8 of this report.

Restructuring and Separation Costs. During 2017, our management approved and initiated a plan to restructure our worldwide operations, which also included a reduction in workforce at our corporate facilities and onshore bases. As a result, during 2017, we recognized $14.1 million in restructuring and other employee separation related costs, including $11.5 million related to a negotiated termination of our agency agreement in Brazil.

Gain on Disposition of Assets. During 2017, we sold five floaters and one jack-up rig for scrap and recognized an aggregate pre-tax gain of $8.9 million on the sale of these rigs. In 2016, we sold four floaters and four jack-ups for a net pre-tax loss of $4.0 million.

Other, net. During 2016, we sold our investment in privately-placed corporate bonds for a total recognized loss of $12.1 million.

Income Tax Benefit. During 2017 and 2016, we recorded net income tax benefits of $39.8 million and $95.8 million, respectively, on net pre-tax losses of $21.4 million and $468.3 million, respectively. The variance in the income tax benefit recognized between years is due to differences in the mix of our domestic and international pre-tax earnings and losses, including asset impairments taken during both 2017 and 2016 in various jurisdictions, as well as discrete tax items recorded in each period as a result of, among other things, tax audits or assessments and filed or amended tax returns.

In addition, as a result of the Tax Reform Act, we recorded incremental income tax expense of $1.1 million in 2017. During 2016, we recorded a $43.0 million reduction in income tax expense, primarily related to our Egyptian tax liability for uncertain tax positions related to the devaluation of the Egyptian Pound. See Note 16 "Income Taxes" to our Consolidated Financial Statements in Item 8 of this report.

Liquidity and Capital Resources

We principally rely on our cash flows from operations and cash reserves to meet our liquidity needs. We may also utilize borrowings under our credit agreements that provide for maximum borrowings of up to $1.275 billion, all of which was available to us as of February 8, 2019. See "– *Sources and Uses of Cash – Credit Agreements*." In addition, as of January 1, 2019, our contractual backlog was $2.0 billion, of which $0.9 billion is expected to be realized during 2019.

Previously, we have asserted that the earnings of our foreign subsidiaries were indefinitely reinvested to finance our foreign activities, and, as such, these earnings were not available to our stockholders or to finance our domestic activities. As a result of the Tax Reform Act and the deemed repatriation of the accumulated earnings of our foreign subsidiaries in 2017, we have determined that we will no longer permanently reinvest our foreign earnings. Accordingly, our earnings and cash are available to finance both our domestic and foreign activities. We expect to record the withholding income tax impact associated with the potential distribution of earnings of our foreign subsidiaries; however, we have not provided income tax on the outside basis difference of our international subsidiaries as management does not intend to dispose of these subsidiaries and structuring alternatives exist to mitigate any potential liability should a disposition take place.

At December 31, 2018, we had cash available for current operations of $154.1 million and investments in U.S. Treasury bills of $299.8 million, all of which matured at various times during January 2019.

We have historically invested a significant portion of our cash flows in the enhancement of our drilling fleet. The amount of cash required to meet our capital commitments is determined by evaluating the need to upgrade our rigs to meet specific customer requirements and our ongoing rig equipment enhancement/replacement programs. We make periodic assessments of our capital spending programs based on current and expected industry conditions and make adjustments to them if required.

Based on our cash available and contractual backlog, we believe our 2019 capital spending and debt service requirements will be funded from our cash and cash equivalents, future operating cash flows and borrowings under our credit agreements, as needed. See "– *Sources and Uses of Cash – Rig Reactivation, Upgrade and Other Capital Expenditures*."

Depending on market conditions, we may, from time to time, purchase shares of our common stock in the open market or otherwise. We did not purchase any shares of our outstanding common stock during 2018, 2017 or 2016.

We may, from time to time, issue debt or equity securities, or a combination thereof, to finance capital expenditures, the acquisition of assets and businesses or for general corporate purposes. Our ability to access the capital markets by issuing debt or equity securities will be dependent on our results of operations, our current financial condition, current credit ratings, current market conditions and other factors beyond our control.

Sources and Uses of Cash

During 2018, our primary sources of cash were $232.1 million generated by operating activities and proceeds of $70.1 million from the disposition of assets, primarily from the sale of the *Ocean Victory* and *Ocean Scepter*. Excluding a net $296.0 million investment in U.S. Treasury bills, we funded capital expenditures of $222.4 million during 2018 and incurred $5.7 million in fees associated with our credit facilities.

Cash Flow from Operations. Cash flow from operations for 2018 decreased $261.8 million compared to 2017, primarily due to lower cash receipts for contract drilling services ($312.2 million), partially offset by a net decrease in cash expenditures for contract drilling services and other working capital requirements ($8.3 million) and lower income tax payments, net of refunds ($42.2 million). The decrease in cash flow from operations in 2018, compared to 2017, is primarily the result of reduced demand for our contract drilling services, which continued into 2018, partially offset by our cost control initiatives.

Rig Reactivation, Upgrades and Other Capital Expenditures. As of the date of this report, we expect capital expenditures in 2019 to be approximately $340 million to $360 million. Projects for 2019 include (i) $110 million in capitalized costs associated with the reactivation and upgrade of the *Ocean Onyx*, (ii) approximately $20 million associated with the reactivation of the *Ocean Endeavor*, and (iii) other capital expenditures under our capital maintenance and replacement programs, including equipment upgrades for the *Ocean BlackHawk* and *Ocean BlackHornet*.

Credit Agreements. In October 2018, we amended our existing 5-year revolving credit agreement, reducing the maximum availability under the agreement to $325.0 million, of which $40.0 million of the commitments mature in March 2019, $60.0 million of the commitments mature in October 2019 and $225.0 million of the commitments mature in October 2020. Concurrently, we entered into a new senior 5-year revolving credit agreement in the amount of $950.0 million that may be used for general corporate purposes, including investments, acquisitions and capital expenditures. The new facility, which matures in October 2023, provides for a swingline subfacility of $100.0 million and a letter of credit subfacility in the amount of $250.0 million. As of December 31, 2018, there were no amounts outstanding under the credit agreements.

We are subject to various restrictive covenants and borrowing limitations under our credit agreements, and repayment of borrowings under our credit agreements is subject to acceleration upon the occurrence of an event of default.

Senior Notes. As of December 31, 2018, we had an aggregate $2.0 billion in long-term, unsecured senior notes outstanding which will mature at various times beginning in 2023 through 2043.

See Note 10 “Credit Agreements and Senior Notes” to our Consolidated Financial Statements in Item 8 of this report, which is incorporated herein by reference.

Credit Ratings

In August 2018, S&P Global Ratings, or S&P, downgraded our corporate credit rating to B from B+, and Moody’s Investor Services, or Moody’s, downgraded our corporate credit rating to B2 from Ba3. In October 2018, Moody’s downgraded our senior unsecured notes credit rating to B3 from B2. The rating outlook from both S&P and Moody’s remains negative. These credit ratings are below investment grade and could raise our cost of financing. As a consequence, we may not be able to issue additional debt in amounts and/or with terms that we consider to be reasonable. One or more of these occurrences could limit our ability to pursue other business opportunities.

Contractual Cash Obligations

The following table sets forth our contractual cash obligations at December 31, 2018 (in thousands).

		Payments Due By Period			
Contractual Obligations[(1)]	**Total**	**Less than 1 year**	**1 – 3 years**	**4 – 5 years**	**After 5 years**
Long-term debt (principal and interest)	$3,831,313	$113,063	$226,125	$476,125	$3,016,000
PCbtH program	485,000	65,000	130,000	130,000	160,000
Property leases	3,172	2,093	1,079	—	—
Total obligations	$4,319,485	$180,156	$357,204	$606,125	$3,176,000

(1) The above table excludes $81.6 million of total net unrecognized tax benefits related to uncertain tax positions as of December 31, 2018. Due to the high degree of uncertainty regarding the timing of future cash outflows associated with the liabilities recognized in these balances, we are unable to make reasonably reliable estimates of the period of cash settlement with the respective taxing authorities.

Pressure Control by the Hour®. In 2016, we entered into a ten-year agreement with a subsidiary of GE Oil & Gas, or GE, to provide services with respect to certain blowout preventer and related well control equipment on our four drillships. Such services include management of maintenance, certification and reliability with respect to such equipment. In connection with the services agreement with GE, we sold the equipment to a GE affiliate for an aggregate $210.0 million and are leasing back such equipment over separate ten-year operating leases. Collectively, we refer to the services agreement with GE and the lease agreements with the GE affiliate as the "PCbtH program." See Note 13 "Sale and Leaseback Transactions" to our Consolidated Financial Statements in Item 8 of this report.

Except for our contractual requirements under the PCbtH program discussed above, we had no other purchase obligations for major rig upgrades or any other significant obligations at December 31, 2018, except for those related to our direct rig operations, which arise during the normal course of business.

Other Commercial Commitments – Letters of Credit

We were contingently liable as of December 31, 2018 in the amount of $25.7 million under certain performance, tax, VAT and customs bonds and letters of credit. Agreements relating to approximately $17.1 million of tax and customs bonds can require collateral at any time. As of December 31, 2018, we had not been required to make any collateral deposits with respect to these agreements. The remaining agreements cannot require collateral except in events of default. Banks have issued letters of credit on our behalf securing certain of these bonds. The table below provides a list of these obligations in U.S. dollar equivalents and their time to expiration (in thousands).

		For the Years Ending December 31,		
	Total	**2019**	**2020**	**2021**
Other Commercial Commitments				
Customs bonds	$ 9,243	$ 8,954	$106	$ 183
Tax bonds	9,119	5,814	—	3,305
Performance bonds	7,100	1,000	—	6,100
Other	229	229	—	—
Total obligations	$25,691	$15,997	$106	$9,588

Off-Balance Sheet Arrangements

At December 31, 2018 and 2017, we had no off-balance sheet debt or other off-balance sheet arrangements.

Other

Operations Outside the U.S. Our operations outside the U.S. accounted for approximately 41%, 58% and 69% of our total consolidated revenues for the years ended December 31, 2018, 2017 and 2016, respectively. See "Risk Factors – *Significant portions of our operations are conducted outside the U.S. and involve additional risks not associated with U.S. domestic operations*" in Item 1A of this report.

Currency Risk. Some of our subsidiaries conduct a portion of their operations in the local currency of the country where they conduct operations, resulting in foreign currency exposure. Currency environments in which we currently have or previously had significant business operations include Australia, Brazil, Egypt, Malaysia, Mexico, Trinidad and Tobago and the U.K., creating exposure to certain monetary assets and liabilities denominated in currencies other than the U.S. dollar. These assets and liabilities are revalued based on currency exchange rates at the end of the reporting period.

To reduce our currency exchange risk, we may, if possible, arrange for a portion of our international contracts to be payable to us in local currency in amounts equal to our estimated operating costs payable in local currency, with the balance of the contract payable in U.S. dollars. At present, however, only a limited number of our contracts are payable both in U.S. dollars and the local currency. Historically, to the extent that we have not been able to cover our local currency operating costs with customer payments in the local currency, we have also utilized foreign currency forward exchange, or FOREX, contracts to reduce our currency exchange risk. As of the date of this report, we currently have no outstanding FOREX contracts. We record currency transaction gains and losses and gains and losses arising from the settlement of our FOREX contracts that have been designated as cash flow hedges as “Foreign currency transaction (loss) gain” and “Contract drilling, excluding depreciation” expense, respectively, in our Consolidated Statements of Operations. The revaluation of liabilities denominated in currencies other than the U.S. dollar related to foreign income taxes, including deferred tax assets and liabilities and uncertain tax positions, is reported as a component of “Income tax benefit” in our Consolidated Statements of Operations.

Forward-Looking Statements

We or our representatives may, from time to time, either in this report, in periodic press releases or otherwise, make or incorporate by reference certain written or oral statements that are “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. All statements other than statements of historical fact are, or may be deemed to be, forward-looking statements. Forward-looking statements include, without limitation, any statement that may project, indicate or imply future results, events, performance or achievements, and may contain or be identified by the words “expect,” “intend,” “plan,” “predict,” “anticipate,” “estimate,” “believe,” “should,” “could,” “may,” “might,” “will,” “will be,” “will continue,” “will likely result,” “project,” “forecast,” “budget” and similar expressions. In addition, any statement concerning future financial performance (including, without limitation, future revenues, earnings or growth rates), ongoing business strategies or prospects, and possible actions taken by or against us, which may be provided by management, are also forward-looking statements as so defined. Statements made by us in this report that contain forward-looking statements may include, but are not limited to, information concerning our possible or assumed future results of operations and statements about the following subjects:

- market conditions and the effect of such conditions on our future results of operations;
- sources and uses of and requirements for financial resources and sources of liquidity;
- contractual obligations and future contract negotiations;
- interest rate and foreign exchange risk;
- operations outside the United States;
- business strategy;
- growth opportunities;
- competitive position including, without limitation, competitive rigs entering the market;
- expected financial position;
- cash flows and contract backlog;
- future amounts payable by a customer in the form of a guarantee of gross margin to be earned on future contracts or by direct payment, pursuant to terms of an existing contract, including the timing and revenue associated therewith;

- idling drilling rigs or reactivating stacked rigs;
- outcomes of litigation and legal proceedings;
- declaration and payment of dividends;
- financing plans;
- market outlook;
- tax planning and effects of the Tax Reform Act;
- debt levels and the impact of changes in the credit markets and credit ratings for our debt;
- budgets for capital and other expenditures;
- timing and duration of required regulatory inspections for our drilling rigs;
- timing and cost of completion of capital projects;
- delivery dates and drilling contracts related to capital projects or rig acquisitions;
- the reactivation of and future contracts for the *Ocean Endeavor* and *Ocean Onyx*;
- plans and objectives of management;
- scrapping retired rigs;
- purchasing or constructing rigs;
- asset impairments and impairment evaluations;
- our internal controls and internal control over financial reporting;
- performance of contracts;
- purchases of our securities;
- compliance with applicable laws; and
- availability, limits and adequacy of insurance or indemnification.

These types of statements are based on current expectations about future events and inherently are subject to a variety of assumptions, risks and uncertainties, many of which are beyond our control, that could cause actual results to differ materially from those expected, projected or expressed in forward-looking statements. These risks and uncertainties include, among others, the following:

- those described under "Risk Factors" in Item 1A;
- general economic and business conditions and trends, including recessions and adverse changes in the level of international trade activity;
- worldwide supply and demand for oil and natural gas;
- changes in foreign and domestic oil and gas exploration, development and production activity;
- oil and natural gas price fluctuations and related market expectations;
- the ability of OPEC to set and maintain production levels and pricing, and the level of production in non-OPEC countries;
- policies of various governments regarding exploration and development of oil and gas reserves;
- inability to obtain contracts for our rigs that do not have contracts;
- the cancellation of contracts included in our reported contract backlog;

- advances in exploration and development technology;
- the worldwide political and military environment, including, for example, in oil-producing regions and locations where our rigs are operating or are in shipyards;
- casualty losses;
- operating hazards inherent in drilling for oil and gas offshore;
- the risk that dividends may not be declared or paid;
- the risk of physical damage to rigs and equipment caused by named windstorms in the U.S. Gulf of Mexico;
- industry fleet capacity;
- market conditions in the offshore contract drilling industry, including, without limitation, dayrates and utilization levels;
- competition;
- changes in foreign, political, social and economic conditions;
- risks of international operations, compliance with foreign laws and taxation policies and seizure, expropriation, nationalization, deprivation, malicious damage or other loss of possession or use of equipment and assets;
- risks of potential contractual liabilities pursuant to our various drilling contracts in effect from time to time;
- customer or supplier bankruptcy, liquidation or other financial difficulties;
- the ability of customers and suppliers to meet their obligations to us and our subsidiaries;
- collection of receivables;
- foreign exchange and currency fluctuations and regulations, and the inability to repatriate income or capital;
- risks of war, military operations, other armed hostilities, sabotage, piracy, cyber attack, terrorist acts and embargoes;
- changes in offshore drilling technology, which could require significant capital expenditures in order to maintain competitiveness;
- reallocation of drilling budgets away from offshore drilling in favor of other priorities such as shale or other land-based projects;
- regulatory initiatives and compliance with governmental regulations including, without limitation, regulations pertaining to climate change, greenhouse gases, carbon emissions or energy use;
- compliance with and liability under environmental laws and regulations;
- uncertainties surrounding deepwater permitting and exploration and development activities;
- potential changes in accounting policies by the Financial Accounting Standards Board, the Securities and Exchange Commission, or SEC, or regulatory agencies for our industry which may cause us to revise our financial accounting and/or disclosures in the future, and which may change the way analysts measure our business or financial performance;
- development and exploitation of alternative fuels;
- customer preferences;

- risks of litigation, tax audits and contingencies and the impact of compliance with judicial rulings and jury verdicts;
- cost, availability, limits and adequacy of insurance;
- invalidity of assumptions used in the design of our controls and procedures and the risk that material weaknesses may arise in the future;
- business opportunities that may be presented to and pursued or rejected by us;
- the results of financing efforts;
- adequacy and availability of our sources of liquidity;
- risks resulting from our indebtedness;
- public health threats;
- negative publicity; and
- impairments of assets.

The risks and uncertainties included here are not exhaustive. Other sections of this report and our other filings with the SEC include additional factors that could adversely affect our business, results of operations and financial performance. Given these risks and uncertainties, investors should not place undue reliance on forward-looking statements. Forward-looking statements included in this report speak only as of the date of this report. We expressly disclaim any obligation or undertaking to release publicly any updates or revisions to any forward-looking statement to reflect any change in our expectations or beliefs with regard to the statement or any change in events, conditions or circumstances on which any forward-looking statement is based. In addition, in certain places in this report, we may refer to reports published by third parties that purport to describe trends or developments in energy production or drilling and exploration activity. While we believe that each of these reports is reliable, we have not independently verified the information included in such reports. We specifically disclaim any responsibility for the accuracy and completeness of such information and undertake no obligation to update such information.

New Accounting Pronouncements

For a discussion of recent accounting pronouncements, which are not yet effective, and their effect on our financial position, results of operations and cash flows, see Note 1 "General Information—*Recent Accounting Pronouncements Not Yet Adopted*" to our Consolidated Financial Statements in Item 8 of this report.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

The information included in this Item 7A is considered to constitute "forward-looking statements" for purposes of the statutory safe harbor provided in Section 27A of the Securities Act and Section 21E of the Exchange Act. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – Forward-Looking Statements" in Item 7 of this report.

Our measure of market risk exposure represents an estimate of the change in fair value of our financial instruments. Market risk exposure is presented for each class of financial instrument held by us at December 31, 2018 and 2017, assuming immediate adverse market movements of the magnitude described below. We believe that the various rates of adverse market movements represent a measure of exposure to loss under hypothetically assumed adverse conditions. The estimated market risk exposure represents the hypothetical loss to future earnings and does not represent the maximum possible loss or any expected actual loss, even under adverse conditions, because actual adverse fluctuations would likely differ. In addition, since our investment portfolio is subject to change based on our portfolio management strategy as well as in response to changes in the market, these estimates are not necessarily indicative of the actual results that may occur.

Exposure to market risk is managed and monitored by our senior management. Senior management approves the overall investment strategy that we employ and has responsibility to ensure that the investment positions are consistent with that strategy and the level of risk acceptable to us. We may manage risk by buying or selling instruments or entering into offsetting positions.

Interest Rate Risk. We have exposure to interest rate risk arising from changes in the level or volatility of interest rates. Our investments in marketable securities are in fixed maturity securities. We monitor our sensitivity to interest rate risk by evaluating the change in the value of our financial assets and liabilities due to fluctuations in interest rates. The evaluation is performed by applying an instantaneous change in interest rates by varying magnitudes on a static balance sheet to determine the effect such a change in rates would have on the recorded market value of our investments and the resulting effect on stockholders' equity. The analysis provides the sensitivity of the market value of our financial instruments to selected changes in market rates and prices which we believe are reasonably possible over a one-year period.

The sensitivity analysis estimates the change in the market value of our interest sensitive assets and liabilities that were held on December 31, 2018 and 2017, due to instantaneous parallel shifts in the yield curve of 100 basis points, with all other variables held constant.

The interest rates on certain types of assets and liabilities may fluctuate in advance of changes in market interest rates, while interest rates on other types may lag behind changes in market rates. Accordingly, the analysis may not be indicative of, is not intended to provide, and does not provide a precise forecast of the effect of changes in market interest rates on our earnings or stockholders' equity. Further, the computations do not contemplate any actions we could undertake in response to changes in interest rates.

Our long-term debt, as of December 31, 2018 and 2017, is denominated in U.S. dollars. Our existing debt has been issued at fixed rates, and as such, interest expense would not be impacted by interest rate shifts. The impact of a 100-basis point increase in interest rates on fixed rate debt would result in a decrease in market value of $94.9 million and $145.1 million as of December 31, 2018 and 2017, respectively. A 100-basis point decrease would result in an increase in market value of $108.6 million and $168.9 million as of December 31, 2018 and 2017, respectively.

We are also subject to risk exposure related to the variable interest rates charged on our revolving credit agreements, which are calculated on a base rate as defined in the respective credit agreement.

Our marketable securities at December 31, 2018, included investments in U.S. Treasury bills with a fair value of $299.8 million. The impact of a 100-basis point increase in interest rates would result in a decrease in market value of these securities of $0.1 million, while a 100-basis point decrease in interest rates would result in an increase in market value of $0.1 million at December 31, 2018. We had no such investments outstanding as of December 31, 2017.

Item 8. Financial Statements and Supplementary Data.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of Diamond Offshore Drilling, Inc. and Subsidiaries

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Diamond Offshore Drilling, Inc. and subsidiaries (the "Company") as of December 31, 2018 and 2017, the related consolidated statements of operations, comprehensive income or loss, stockholders' equity, and cash flows, for each of the three years in the period ended December 31, 2018, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 13, 2019, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 13, 2019

We have served as the Company's auditor since 1989.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of Diamond Offshore Drilling, Inc. and Subsidiaries

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Diamond Offshore Drilling, Inc. and subsidiaries (the "Company") as of December 31, 2018, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2018, of the Company and our report dated February 13, 2019, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 13, 2019

DIAMOND OFFSHORE DRILLING, INC.
AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(In thousands, except share and per share data)

	December 31, 2018	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 154,073	$ 376,037
Marketable securities	299,849	—
Accounts receivable, net of allowance for bad debts	168,620	256,730
Prepaid expenses and other current assets	163,396	157,625
Assets held for sale	—	96,261
Total current assets	785,938	886,653
Drilling and other property and equipment, net of accumulated depreciation	5,184,222	5,261,641
Other assets	65,534	102,276
Total assets	$6,035,694	$6,250,570
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 43,933	$ 38,755
Accrued liabilities	172,228	154,655
Taxes payable	20,685	29,878
Total current liabilities	236,846	223,288
Long-term debt	1,973,922	1,972,225
Deferred tax liability	104,380	167,299
Other liabilities	135,893	113,497
Total liabilities	2,451,041	2,476,309
Commitments and contingencies (Note 12)	—	—
Stockholders' equity:		
Preferred stock (par value $0.01, 25,000,000 shares authorized, none issued and outstanding)	—	—
Common stock (par value $0.01, 500,000,000 shares authorized; 144,383,662 shares issued and 137,438,353 shares outstanding at December 31, 2018; 144,085,292 shares issued and 137,227,782 shares outstanding at December 31, 2017)	1,444	1,441
Additional paid-in capital	2,018,143	2,011,397
Retained earnings	1,769,415	1,964,497
Accumulated other comprehensive gain (loss)	21	(5)
Treasury stock, at cost (6,945,309 and 6,857,510 shares of common stock at December 31, 2018 and 2017, respectively)	(204,370)	(203,069)
Total stockholders' equity	3,584,653	3,774,261
Total liabilities and stockholders' equity	$6,035,694	$6,250,570

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

DIAMOND OFFSHORE DRILLING, INC.
AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share data)

	Year Ended December 31, 2018	2017	2016
Revenues:			
Contract drilling	$1,059,973	$1,451,219	$1,525,214
Revenues related to reimbursable expenses	23,242	34,527	75,128
Total revenues	1,083,215	1,485,746	1,600,342
Operating expenses:			
Contract drilling, excluding depreciation	722,834	801,964	772,173
Reimbursable expenses	22,917	33,744	58,058
Depreciation	331,789	348,695	381,760
General and administrative	85,351	74,505	63,560
Impairment of assets	27,225	99,313	678,145
Bad debt recovery	—	—	(265)
Restructuring and separation costs	5,041	14,146	—
Loss (gain) on disposition of assets	241	(10,500)	3,795
Total operating expenses	1,195,398	1,361,867	1,957,226
Operating (loss) income	(112,183)	123,879	(356,884)
Other income (expense):			
Interest income	8,477	2,473	768
Interest expense, net of amounts capitalized	(123,240)	(113,528)	(89,934)
Loss on extinguishment of senior notes	—	(35,366)	—
Foreign currency transaction loss	(379)	(1,128)	(11,522)
Other, net	700	2,230	(10,727)
Loss before income tax benefit	(226,625)	(21,440)	(468,299)
Income tax benefit	46,353	39,786	95,796
Net (loss) income	$ (180,272)	$ 18,346	$ (372,503)
(Loss) earnings per share:			
Basic	$ (1.31)	$ 0.13	$ (2.72)
Diluted	$ (1.31)	$ 0.13	$ (2.72)
Weighted-average shares outstanding:			
Shares of common stock	137,399	137,213	137,168
Dilutive potential shares of common stock	—	52	—
Total weighted-average shares outstanding	137,399	137,265	137,168

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

DIAMOND OFFSHORE DRILLING, INC.
AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME OR LOSS
(In thousands)

	Year Ended December 31,		
	2018	**2017**	**2016**
Net (loss) income	$(180,272)	$18,346	$(372,503)
Other comprehensive gains (losses), net of tax:			
Derivative financial instruments:			
Reclassification adjustment for gain included in net (loss) income	(6)	(6)	(5)
Investments in marketable securities:			
Unrealized holding gain (loss) on investments	69	—	(6,559)
Reclassification adjustment for (gain) loss included in net (loss) income	(37)	—	11,600
Total other comprehensive gain (loss)	26	(6)	5,036
Comprehensive (loss) income	$(180,246)	$18,340	$(367,467)

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

DIAMOND OFFSHORE DRILLING, INC.
AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In thousands, except number of shares)

	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Gains (Losses)	Treasury Stock		Total Stockholders' Equity
	Shares	Amount				Shares	Amount	
January 1, 2016	143,978,877	$1,440	$1,999,634	$2,319,136	$(5,035)	6,820,171	$(202,405)	$4,112,770
Net loss	—	—	—	(372,503)	—	—	—	(372,503)
Anti-dilution adjustment	—	—	—	132	—	—	—	132
Stock-based compensation, net of tax	18,880	—	4,880	—	—	7,923	(181)	4,699
Net loss on derivative financial instruments	—	—	—	—	(5)	—	—	(5)
Net gain on investments	—	—	—	—	5,041	—	—	5,041
December 31, 2016	143,997,757	$1,440	$2,004,514	$1,946,765	$ 1	6,828,094	$(202,586)	$3,750,134
Impact of change in accounting principle	—	—	634	(634)	—	—	—	—
Adjusted balance at January 1, 2017	143,997,757	$1,440	$2,005,148	$1,946,131	$ 1	6,828,094	$(202,586)	$3,750,134
Net income	—	—	—	18,346	—	—	—	18,346
Anti-dilution adjustment	—	—	—	20	—	—	—	20
Stock-based compensation, net of tax	87,535	1	6,249	—	—	29,416	(483)	5,767
Net loss on derivative financial instruments	—	—	—	—	(6)	—	—	(6)
December 31, 2017	144,085,292	$1,441	$2,011,397	$1,964,497	$ (5)	6,857,510	$(203,069)	$3,774,261
Impact of change in accounting principle	—	—	—	(14,812)	—	—	—	(14,812)
Adjusted balance at January 1, 2018	144,085,292	$1,441	$2,011,397	$1,949,685	$ (5)	6,857,510	$(203,069)	$3,759,449
Net loss	—	—	—	(180,272)	—	—	—	(180,272)
Anti-dilution adjustment	—	—	—	2	—	—	—	2
Stock options exercised	3,773	—	—	—	—	—	—	—
Stock-based compensation, net of tax	294,597	3	6,746	—	—	87,799	(1,301)	5,448
Net loss on derivative financial instruments	—	—	—	—	(6)	—	—	(6)
Net gain on investments	—	—	—	—	32	—	—	32
December 31, 2018	144,383,662	$1,444	$2,018,143	$1,769,415	$ 21	6,945,309	$(204,370)	$3,584,653

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

**DIAMOND OFFSHORE DRILLING, INC.
AND SUBSIDIARIES**

**CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)**

	Year Ended December 31,		
	2018	2017	2016
Operating activities:			
Net (loss) income	$ (180,272)	$ 18,346	$(372,503)
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Depreciation	331,789	348,695	381,760
Loss on impairment of assets	27,225	99,313	678,145
Loss on extinguishment of senior notes	—	35,366	—
Restructuring and separation costs	1,478	14,146	—
Loss (gain) on disposition of assets	241	(10,500)	3,795
Loss on sale of marketable securities, net	—	—	12,146
Deferred tax provision	(75,993)	(72,127)	(106,263)
Stock-based compensation expense	6,749	6,250	4,880
Contract liabilities, net	183	8,676	(29,108)
Contract assets, net	(6,221)	—	—
Deferred contract costs, net	22,765	46,337	(20,155)
Other assets, noncurrent	(1,307)	(326)	(4,914)
Other liabilities, noncurrent	(3,217)	(963)	(31)
Other	1,560	7,708	5,691
Changes in operating assets and liabilities:			
Accounts receivable	87,970	(11,049)	159,098
Prepaid expenses and other current assets	6,211	(1,291)	6,187
Accounts payable and accrued liabilities	(7,587)	19,803	(71,085)
Taxes payable	20,484	(14,576)	(1,089)
Net cash provided by operating activities	232,058	493,808	646,554
Investing activities:			
Capital expenditures (including rig construction)	(222,406)	(139,581)	(652,673)
Proceeds from disposition of assets, net of disposal costs	70,067	15,196	221,722
Proceeds from sale and maturities of marketable securities	1,600,000	35	4,614
Purchase of marketable securities	(1,895,997)	—	—
Net cash used in investing activities	(448,336)	(124,350)	(426,337)
Financing activities:			
Redemption of senior notes	—	(500,000)	—
Payment of debt extinguishment costs	—	(34,395)	—
Proceeds from issuance of senior notes	—	496,360	—
Repayment of short-term borrowings, net	—	(104,200)	(182,389)
Debt issuance costs and arrangement fees	(5,651)	(7,263)	(215)
Other	(35)	(156)	(408)
Net cash used in financing activities	(5,686)	(149,654)	(183,012)
Net change in cash and cash equivalents	(221,964)	219,804	37,205
Cash and cash equivalents, beginning of year	376,037	156,233	119,028
Cash and cash equivalents, end of year	$ 154,073	$ 376,037	$ 156,233

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

**DIAMOND OFFSHORE DRILLING, INC.
AND SUBSIDIARIES**

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. General Information

Diamond Offshore Drilling, Inc. provides contract drilling services to the energy industry around the globe with a fleet of 17 offshore drilling rigs, consisting of four drillships and 13 semisubmersible rigs. Unless the context otherwise requires, references in these Notes to "Diamond Offshore," "we," "us" or "our" mean Diamond Offshore Drilling, Inc. and our consolidated subsidiaries. We were incorporated in Delaware in 1989.

As of February 8, 2019, Loews Corporation, or Loews, owned approximately 53% of the outstanding shares of our common stock.

Principles of Consolidation

Our consolidated financial statements include the accounts of Diamond Offshore Drilling, Inc. and our wholly-owned subsidiaries after elimination of intercompany transactions and balances.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with accounting principles generally accepted in the United States, or U.S., or GAAP, requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimated.

Changes in Accounting Principles

Revenue Recognition. In May 2014, the Financial Accounting Standards Board, or FASB, issued Accounting Standards Update, or ASU, No. 2014-09, *Revenue from Contracts with Customers* (Topic 606), or ASU 2014-09, which superseded the revenue recognition requirements in ASU Topic 605, Revenue Recognition. Under the new guidance, revenue is recognized when a customer obtains control of promised goods or services and in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services.

We adopted ASU 2014-09 and its related amendments, or collectively Topic 606, effective January 1, 2018 using the modified retrospective implementation method. Accordingly, we have applied the five-step method outlined in Topic 606 for determining when and how revenue is recognized to all contracts that were not completed as of the date of adoption. Revenues for reporting periods beginning after January 1, 2018 are presented under Topic 606, while prior period amounts have not been adjusted and continue to be reported under the previous revenue recognition guidance. For contracts that were modified before the effective date, we have considered the modification guidance within the new standard and determined that the revenue recognized and contract balances recorded prior to adoption for such contracts were not impacted. While Topic 606 requires additional disclosure of the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers, its adoption has not had a material impact on the measurement or recognition of our revenues.

Our adoption of ASU 2014-09 represents a change in accounting principle and therefore, we have recorded the cumulative effect of adopting Topic 606 as an increase to opening retained earnings on January 1, 2018. This adjustment represents an accrual for the earned portion of demobilization revenue expected to be received for contracts not completed as of December 31, 2017, which was not recordable under previous revenue recognition guidance until completion of the demobilization activities. See Note 2.

Income Taxes. In October 2016, the FASB issued ASU No. 2016-16, *Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory,* or ASU 2016-16. ASU 2016-16 amended the guidance in Topic 740 with respect to the accounting for the income tax consequences of intra-entity transfers of assets other than inventory. We have evaluated our historical intra-group transactions for impact under the provisions of ASU 2016-16 and adopted the guidance thereof effective January 1, 2018 using the modified retrospective approach. We recorded the $17.4 million cumulative effect of applying the new standard as a decrease to opening retained earnings with an offset to deferred income tax liability. See Note 16.

The aggregate impact of the changes in accounting principles, as discussed above, to our Consolidated Balance Sheets on January 1, 2018 was as follows (in thousands):

	Retained Earnings	Prepaid Expenses and Other Current Assets	Other Assets	Deferred Tax Liability
Balance as of January 1, 2018 before adoption	$1,964,497	$157,625	$102,276	$167,299
Adjustments for adoption of:				
Topic 606	2,589	610	2,107	128
ASU 2016-16	(17,401)	—	—	17,401
Balance as of January 1, 2018 after adoption	$1,949,685	$158,235	$104,383	$184,828

Other Recently Adopted Accounting Pronouncements

In August 2018, the FASB issued ASU No. 2018-13, *Fair Value Measurement (Topic 820): Disclosure Framework – Changes to the Disclosure Requirements for Fair Value Measurement*, or ASU 2018-13. ASU 2018-13 modified the disclosure requirements for fair value measurements, including the (i) removal of certain disclosure requirements regarding transfers between Levels 1 and 2 of the fair value hierarchy and timing thereof and the valuation processes for Level 3 fair value measurements and (ii) a requirement to provide additional information regarding the range and weighted average of significant unobservable inputs used to develop Level 3 fair value measurements. We early adopted the disclosure modifications in ASU 2018-13.

In February 2018, the FASB issued ASU No. 2018-02, Income Statement – Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income, or ASU 2018-02. ASU 2018-02 provides for entities to make a one-time election to reclassify the income tax effects of the Tax Cuts and Jobs Act enacted in December 2017, or the Tax Reform Act, on items within accumulated other comprehensive income to retained earnings. The guidance of ASU 2018-02 is effective for fiscal years beginning after December 15, 2018, including interim periods within that reporting period. Early adoption of ASU 2018-02 is permitted. We early adopted ASU 2018-02 and have reclassified the effect of the change in the U.S. federal corporate income tax rate on deferred tax-related items remaining in accumulated other comprehensive loss. The impact of adoption of ASU 2018-02 was not significant.

In August 2016, the FASB issued ASU No. 2016-15, *Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments*, or ASU 2016-15. ASU 2016-15 provides specific guidance on eight cash flow classification issues not specifically addressed by GAAP: debt prepayment or debt extinguishment costs; settlement of zero-coupon debt instruments; contingent consideration payments; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies; distributions from equity method investees; beneficial interests in securitization transactions; and separately identifiable cash flows and application of the predominance principle. The adoption of ASU 2016-15 did not have a significant impact on the presentation of cash receipts and cash payments within our consolidated statements of cash flows.

Recent Accounting Pronouncements Not Yet Adopted

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842), or ASU 2016-02, which (i) requires lessees to recognize a right of use asset and a lease liability on the balance sheet for virtually all leases, (ii) updates previous accounting standards for lessors to align certain requirements with the updates to lessee accounting standards and the revenue recognition accounting standards and (iii) requires enhanced disclosure of qualitative and quantitative information about the entity's leasing arrangements. This update is effective for annual and interim periods beginning after December 15, 2018, with early adoption permitted. We adopted ASU 2016-02 effective January 1, 2019 and elected the optional transition method whereby initial application of the new standard begins on the date of adoption and comparative periods are not restated. This transition method allows for the initial recognition of a cumulative effect adjustment to retained earnings in the year of adoption, however, we do not expect that such an adjustment will be required based on our analysis of current lease arrangements. We also expect to elect the transition practical expedient package available in the ASU whereby we will not reassess (i) whether any of our expired or existing contracts contain a lease, (ii) the classification for any expired or existing leases and (iii) initial direct costs for any existing leases.

During our evaluation of ASU 2016-02, we concluded that our drilling contracts contain a lease component based on the updated definition of a lease. Our typical drilling contracts qualify for a practical expedient, which is available to lessors under certain circumstances, to combine the lease and non-lease components and account for the combined component in accordance with the accounting treatment for the predominant component. We intend to apply this practical expedient and will combine the lease and service components of our standard drilling contracts and continue to account for the combined component under Topic 606, *Revenue from Contracts with Customers*.

With respect to leases whereby we are the lessee, we expect to recognize lease liabilities and offsetting right of use assets of between $120 million and $130 million, primarily related to certain leased subsea equipment. However, we are still finalizing our evaluation of the overall impact.

Cash and Cash Equivalents

We consider short-term, highly liquid investments that have an original maturity of three months or less and deposits in money market mutual funds that are readily convertible into cash to be cash equivalents.

The effect of exchange rate changes on cash balances held in foreign currencies was not material for the years ended December 31, 2018, 2017 and 2016.

Provision for Bad Debts

We record a provision for bad debts on a case-by-case basis when facts and circumstances indicate that a customer receivable may not be collectible. In establishing these reserves, we consider historical and other factors that predict collectability, including write-offs, recoveries and the monitoring of credit quality. Such provision is reported as a component of "Operating expense" in our Consolidated Statements of Operations. See Note 4.

Assets Held for Sale

We reported the $96.3 million carrying value of two of our rigs, the *Ocean Scepter* and *Ocean Victory*, as "Assets held for sale" in our Consolidated Balance Sheets at December 31, 2017. The *Ocean Victory,* which had a carrying value of $1.2 million, was sold in January 2018. The *Ocean Scepter* was sold in July 2018, subsequent to recognizing an additional impairment loss in the second quarter of 2018. As both rigs had previously been impaired, the aggregate net pre-tax gain on the sale of these rigs during the year ended December 31, 2018 was not significant. See Note 3.

Drilling and Other Property and Equipment

We carry our drilling and other property and equipment at cost, less accumulated depreciation. Maintenance and routine repairs are charged to income currently while replacements and betterments that upgrade or increase the functionality of our existing equipment and that significantly extend the useful life of an existing asset are capitalized. Significant judgments, assumptions and estimates may be required in determining whether or not such replacements and betterments meet the criteria for capitalization and in determining useful lives and salvage values of such assets. Changes in these judgments, assumptions and estimates could produce results that differ from those reported. During the years ended December 31, 2018 and 2017, we capitalized $243.6 million and $69.4 million, respectively, in replacements and betterments of our drilling fleet.

Costs incurred for major rig upgrades and/or the construction of rigs are accumulated in construction work-in-progress, with no depreciation recorded on the additions, until the month the upgrade or newbuild is completed and the rig is placed in service. Upon retirement or sale of a rig, the cost and related accumulated depreciation are removed from the respective accounts and any gains or losses are included in our results of operations as "(Gain) loss on disposition of assets." Depreciation is recognized up to applicable salvage values by applying the straight-line method over the remaining estimated useful lives from the year the asset is placed in service. Drilling rigs and equipment are depreciated over their estimated useful lives ranging from 3 to 30 years.

Capitalized Interest

We capitalize interest cost for rig construction and other qualifying projects. A reconciliation of our total interest cost to "Interest expense, net of amounts capitalized" as reported in our Consolidated Statements of Operations is as follows (in thousands):

	For the Year Ended December 31,		
	2018	**2017**	**2016**
Total interest cost including amortization of debt issuance costs	$123,816	$113,618	$110,748
Capitalized interest	(576)	(90)	(20,814)
Total interest expense as reported	$123,240	$113,528	$ 89,934

Impairment of Long-Lived Assets

We evaluate our property and equipment for impairment whenever changes in circumstances indicate that the carrying amount of an asset may not be recoverable (such as, but not limited to, cold stacking a rig, the expectation of cold stacking a rig in the near term, contracted backlog of less than one year for a rig, a decision to retire or scrap a rig, or excess spending over budget on a newbuild, construction project or major rig upgrade). We utilize an undiscounted probability-weighted cash flow analysis in testing an asset for potential impairment. Our assumptions and estimates underlying this analysis include the following:

- dayrate by rig;
- utilization rate by rig if active, warm stacked or cold stacked (expressed as the actual percentage of time per year that the rig would be used at certain dayrates);
- the per day operating cost for each rig if active, warm stacked or cold stacked;
- the estimated annual cost for rig replacements and/or enhancement programs;
- the estimated maintenance, inspection or other reactivation costs associated with a rig returning to work;
- salvage value for each rig; and
- estimated proceeds that may be received on disposition of each rig.

Based on these assumptions, we develop a matrix for each rig under evaluation using multiple utilization/dayrate scenarios, to each of which we have assigned a probability of occurrence. We arrive at a projected probability-weighted cash flow for each rig based on the respective matrix and compare such amount to the carrying value of the asset to assess recoverability.

The underlying assumptions and assigned probabilities of occurrence for utilization and dayrate scenarios are developed using a methodology that examines historical data for each rig, which considers the rig's age, rated water depth and other attributes and then assesses its future marketability in light of the current and projected market environment at the time of assessment. Other assumptions, such as operating, maintenance, inspection and reactivation costs, are estimated using historical data adjusted for known developments, cost projections for re-entry of rigs into the market and future events that are anticipated by management at the time of the assessment.

Management's assumptions are necessarily subjective and are an inherent part of our asset impairment evaluation, and the use of different assumptions could produce results that differ from those reported. Our methodology generally involves the use of significant unobservable inputs, representative of a Level 3 fair value measurement, which may include assumptions related to future dayrate revenue, costs and rig utilization, quotes from rig brokers, the long-term future performance of our rigs and future market conditions. Management's assumptions involve uncertainties about future demand for our services, dayrates, expenses and other future events, and management's expectations may not be indicative of future outcomes. Significant unanticipated changes to these assumptions could materially alter our analysis in testing an asset for potential impairment. For example, changes in market conditions that exist at the measurement date or that are projected by management could affect our key assumptions. Other events or circumstances that could affect our assumptions may include, but are not limited to, a further sustained decline in oil and gas prices, cancelations of our drilling contracts or contracts of our competitors, contract modifications, costs to comply with new governmental regulations, capital expenditures required due to advances in offshore drilling technology, growth in the global oversupply of oil and geopolitical events, such as lifting sanctions on oil-producing nations. Should actual market conditions in the future vary significantly from market conditions used in our projections, our assessment of impairment would likely be different. See Note 3.

Fair Value of Financial Instruments

We believe that the carrying amount of our current financial instruments approximates fair value because of the short maturity of these instruments. See Note 8.

Debt Issuance Costs

Deferred costs associated with our credit facilities are presented in "Other assets" in our Consolidated Balance Sheets at December 31, 2018 and 2017 and amortized as interest expense over the respective terms of the credit facilities. During 2018, we paid $5.7 million in debt issuance and arrangement fees in connection with our credit facilities. Deferred costs associated with our senior notes are presented in our Consolidated Balance Sheets at December 31, 2018 and 2017 as a reduction in the related long-term debt and are amortized over the respective terms of the related debt. See Note 10.

Income Taxes

We account for income taxes in accordance with accounting standards that require the recognition of the amount of taxes payable or refundable for the current year and an asset and liability approach in recognizing the amount of deferred tax liabilities and assets for the future tax consequences of events that have been currently recognized in our financial statements or tax returns. In each of our tax jurisdictions we recognize a current tax liability or asset for the estimated taxes payable or refundable on tax returns for the current year and a deferred tax asset or liability for the estimated future tax effects attributable to temporary differences and carryforwards.

Deferred tax assets are reduced by a valuation allowance, if necessary, which is determined by the amount of any tax benefits that, based on available evidence, are not expected to be realized under a "more likely than not" approach. Deferred tax assets and liabilities are classified as noncurrent in a classified statement of financial position. We make judgments regarding future events and related estimates especially as they pertain to the forecasting of our effective tax rate, the potential realization of deferred tax assets such as utilization of foreign tax credits, and exposure to the disallowance of items deducted on tax returns upon audit.

We record interest related to accrued unrecognized tax positions in "Interest expense, net of amounts capitalized" and recognize penalties associated with uncertain tax positions in "Income tax benefit" in our Consolidated Statements of Operations. Liabilities for uncertain tax positions, including any penalty, are denominated in the currency of the related tax jurisdiction and are revalued for changes in currency exchange rates. The revaluation of such liabilities for uncertain tax positions is reported in "Income tax benefit" in our Consolidated Statements of Operations. See Note 16.

Treasury Stock

In connection with the vesting of restricted stock units held by certain individuals, we acquired 87,799 and 29,416 shares of our common stock during 2018 and 2017, respectively (valued at $1.3 million in 2018 and $0.5 million in 2017), in satisfaction of tax withholding obligations that were incurred on the vesting date. See Note 5.

Depending on market conditions, we may, from time to time, purchase shares of our common stock in the open market or otherwise. We account for the purchase of treasury stock using the cost method, which reports the cost of the shares acquired in "Treasury stock" as a deduction from stockholders' equity in our Consolidated Balance Sheets. We did not repurchase any shares of our outstanding common stock during 2018, 2017 or 2016.

Comprehensive (Loss) Income

Comprehensive (loss) income is the change in equity of a business enterprise during a period from transactions and other events and circumstances except those transactions resulting from investments by owners and distributions to owners. Comprehensive (loss) income for the three years ended December 31, 2018, 2017 and 2016 includes net (loss) income and unrealized holding gains and losses on marketable securities and financial derivatives designated as cash flow accounting hedges. See Note 11.

Foreign Currency

Our functional currency is the U.S. dollar. Transactions incurred in currencies other than the U.S. dollar are subject to gains or losses due to fluctuations in those currencies. We report foreign currency transaction gains and losses as "Foreign currency transaction (loss) gain" in our Consolidated Statements of Operations. The revaluation of assets and liabilities related to foreign income taxes, including deferred tax assets and liabilities and uncertain tax positions, including any penalty, is reported in "Income tax benefit (expense)" in our Consolidated Statements of Operations.

2. Revenue from Contracts with Customers

The activities that primarily drive the revenue earned from our drilling contracts include (i) providing a drilling rig and the crew and supplies necessary to operate the rig, (ii) mobilizing and demobilizing the rig to and from the drill site and (iii) performing rig preparation activities and/or modifications required for the contract. Consideration received for performing these activities may consist of dayrate drilling revenue, mobilization and demobilization revenue, contract preparation revenue and reimbursement revenue. We account for these integrated services provided within our drilling contracts as a single performance obligation satisfied over time and comprised of a series of distinct time increments in which we provide drilling services.

Consideration for activities that are not distinct within the context of our contracts and do not correspond to a distinct time increment within the contract term are allocated across the single performance obligation and recognized ratably over the initial term of the contract (which is the period we estimate to be benefited from the corresponding activities and generally ranges from two to 60 months). Consideration for activities that correspond to a distinct time increment within the contract term is recognized in the period when the services are performed. The total transaction price is determined for each individual contract by estimating both fixed and variable consideration expected to be earned over the term of the contract. See below for further discussion regarding the allocation of the transaction price to the remaining performance obligations.

The amount estimated for variable consideration may be constrained (reduced) and is only included in the transaction price to the extent that it is probable that a significant reversal of previously recognized revenue will not occur throughout the term of the contract. When determining if variable consideration should be constrained, management considers whether there are factors outside of our control that could result in a significant reversal of revenue as well as the likelihood and magnitude of a potential reversal of revenue. These estimates are re-assessed each reporting period as required.

Dayrate Drilling Revenue. Our drilling contracts generally provide for payment on a dayrate basis, with higher rates for periods when the drilling unit is operating and lower rates or zero rates for periods when drilling operations are interrupted or restricted. The dayrate invoices billed to the customer are typically determined based on the varying rates applicable to the specific activities performed on an hourly basis. Such dayrate consideration is allocated to the distinct hourly increment it relates to within the contract term, and therefore, recognized in line with the contractual rate billed for the services provided for any given hour.

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

In some contracts, there is uncertainty as to the likelihood and amount of expected demobilization revenue to be received. For example, contractual provisions may require that a rig demobilize a certain distance before the demobilization revenue is payable or the amount may vary dependent upon whether or not the rig has additional contracted work within a certain distance from the wellsite. Therefore, the estimate for such revenue may be constrained, as described above, depending on the facts and circumstances pertaining to the specific contract. We assess the likelihood of receiving such revenue based on our past experience and knowledge of market conditions.

Contract Preparation Revenue. Some of our drilling contracts require downtime before the start of the contract to prepare the rig to meet customer requirements. At times, we may be compensated by the customer for such work (on either a fixed lump-sum or variable dayrate basis). These activities are not considered to be distinct within the context of the contract. We record a contract liability for contract preparation fees received, which is amortized ratably to contract drilling revenue over the initial term of the related drilling contract.

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

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

Contract Balances

Accounts receivable are recognized when the right to consideration becomes unconditional based upon contractual billing schedules. Payment terms on invoiced amounts are typically 30 days. Contract asset balances consist primarily of demobilization revenue that we expect to receive and is recognized ratably throughout the contract term, but invoiced upon completion of the demobilization activities. Once the demobilization revenue is invoiced, the corresponding contract asset is transferred to accounts receivable. Contract assets may also include amounts recognized in advance of amounts invoiced due to the blending of rates when a contract has operating dayrates that increase over the initial contract term. Contract liabilities include payments received for mobilization as well as rig preparation and upgrade activities which are allocated to the overall performance obligation and recognized ratably over the initial term of the contract. Contract liabilities may also include amounts invoiced in advance of amounts recognized due to the blending of rates when a contract has operating dayrates that decrease over the initial contract term.

Contract balances are netted at a contract level, such that deferred revenue for mobilization, contract preparation and capital modifications (contract liabilities) is netted with any accrued demobilization revenue (contract asset) for each applicable contract.

The following table provides information about receivables, contract assets and contract liabilities from our contracts with customers (in thousands):

	December 31, 2018	January 1, 2018
Trade receivables	$160,478	$247,453
Current contract assets (1)	6,832	611
Noncurrent contract assets (1)	2,107	2,107
Current contract liabilities (deferred revenue) (1)	(2,803)	(11,371)
Noncurrent contract liabilities (deferred revenue) (1)	(17,723)	(8,972)

(1) Contract assets and contract liabilities may reflect balances that have been netted together on a contract basis. Net current contract asset and liability balances are included in "Prepaid expenses and other current assets" and "Accrued liabilities," respectively, and net noncurrent contract asset and liability balances are included in "Other assets" and "Other liabilities," respectively, in our Consolidated Balance Sheets as of December 31, 2018.

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

	Net Contract Balances
Contract assets at January 1, 2018	$ 2,718
Contract liabilities at January 1, 2018	(20,343)
Net balance at January 1, 2018	(17,625)
Decrease due to amortization of revenue that was included in the beginning contract liability balance	19,026
Increase due to cash received, excluding amounts recognized as revenue during the period	(19,353)
Increase due to revenue recognized during the period but contingent on future performance	7,114
Decrease due to transfer to receivables during the period	(893)
Adjustments	144
Net balance at December 31, 2018	$(11,587)
Contract assets at December 31, 2018	$ 8,939
Contract liabilities at December 31, 2018	(20,526)

Deferred Contract Costs

Certain direct and incremental costs incurred for upfront preparation, initial mobilization and modifications of contracted rigs represent costs of fulfilling a contract as they relate directly to a contract, enhance resources that will be used in satisfying our performance obligations in the future and are expected to be recovered. Such costs are deferred and amortized ratably to contract drilling expense as services are rendered over the initial term of the related drilling contract. Such deferred contract costs in the amount of $70.0 million and $13.1 million are reported in "Prepaid expenses and other current assets" and "Other assets," respectively, in our Consolidated Balance Sheets at December 31, 2018. During the year ended December 31, 2018, the amount of amortization of such costs was $67.7 million. There was no impairment loss in relation to capitalized costs.

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

Transaction Price Allocated to Remaining Performance Obligations

The following table reflects revenue expected to be recognized in the future related to unsatisfied performance obligations as of December 31, 2018 (in thousands):

		For the Years Ending December 31,			
	2019	2020	2021	2022	Total
Mobilization and contract preparation revenue	$ 5,671	$ 391	$ 511	$ 83	$ 6,656
Capital modification revenue	10,441	4,725	—	—	15,166
Other deferred revenue	—	7,626	9,799	—	17,425
Total	$16,112	$12,742	$10,310	$ 83	$39,247

The revenue included above consists primarily of expected fixed mobilization and upgrade revenue for both wholly and partially unsatisfied performance obligations as well as expected variable mobilization and upgrade revenue for partially unsatisfied performance obligations, which has been estimated for purposes of allocating across the entire corresponding performance obligations. Revenue expected to be recognized in the future related to the blending of rates when a contract has operating dayrates that decrease over the initial contract term is also included. The amounts are derived from the specific terms within drilling contracts that contain such provisions, and the expected timing for recognition of such revenue is based on the estimated start date and duration of each respective contract based on information known at December 31, 2018. The actual timing of recognition of such amounts may vary due to factors outside of our control. We have applied the disclosure practical expedient in Accounting Standards Codification 606-10-50-14A(b) and have not included estimated variable consideration related to wholly unsatisfied performance obligations or to distinct future time increments within our contracts, including dayrate revenue.

Impact of Topic 606 on Financial Statement Line Items

Our revenue recognition pattern under Topic 606 is similar to revenue recognition under the previous guidance, except for the recognition of demobilization revenue. Such revenue, which was recognized upon completion of a contract under the previous guidance, is now estimated at contract inception and recognized ratably as contract drilling revenue over the initial term of the contract with an offset to a contract asset under Topic 606.

The following tables summarize the impacts of adopting Topic 606 on our selected Consolidated Balance Sheets, Consolidated Statements of Operations and Consolidated Statements of Cash Flows information, as of and for the year ended December 31, 2018 (in thousands, except per share data):

	December 31, 2018		
	Balances as reported	**Adjustments**	**Balances without adoption of Topic 606**
Consolidated Balance Sheets			
Prepaid and other current assets	$ 163,396	$(3,785)	$ 159,611
Other assets	65,534	(2,107)	63,427
Deferred tax liability	104,380	(795)	103,585
Retained earnings	1,769,415	(5,097)	1,764,318
Consolidated Statements of Operations			
Contract drilling revenues	$1,059,973	$(3,174)	$1,056,799
Income tax benefit	46,353	666	47,019
Loss per share, basic and diluted	(1.31)	(0.02)	(1.33)
Consolidated Statements of Cash Flows			
Cash flow from operating activities:			
Net loss	$ (180,272)	$(2,508)	$ (182,780)
Adjustments to reconcile net loss to net cash			
Deferred tax provision	(75,993)	(666)	(76,659)
Contract assets, net	(6,221)	3,174	(3,047)

3. Asset Impairments

2018 Impairment. During 2018, we recorded an impairment loss of $27.2 million to recognize a reduction in fair value of the *Ocean Scepter*. We estimated the fair value of the impaired rig using a market approach based on a signed agreement to sell the rig, less estimated costs to sell. We consider this valuation approach to be a Level 3 fair value measurement due to the level of estimation involved as the sale had not yet been completed at the time of our analysis.

At December 31, 2018, we evaluated one drilling rig with indicators of impairment. Based on our assumptions and analysis at that time, we determined that the undiscounted probability-weighted cash flow of the rig was in excess of its carrying value. As a result, we concluded that no impairment of the rig had occurred at December 31, 2018.

As of December 31, 2018, there were 12 rigs in our drilling fleet not previously written down to scrap, for which there were no current indicators that their carrying amounts may not be recoverable and, thus, were not evaluated for impairment. If market fundamentals in the offshore oil and gas industry deteriorate further or a projected market recovery is further delayed, we may be required to recognize additional impairment losses in future periods.

2017 Impairments. During 2017, we evaluated ten of our drilling rigs with indicators of impairment and determined that the carrying values of three rigs were impaired (we collectively refer to these three rigs as the 2017 Impaired Rigs).

We estimated the fair value of two of the 2017 Impaired Rigs using an income approach, whereby the fair value of each rig was estimated based on a calculation of the rig’s future net cash flows. These calculations utilized significant unobservable inputs, including estimated proceeds that may be received on ultimate disposition of each rig. The fair value of the remaining 2017 Impaired Rig was estimated using a market approach, which required us to estimate the value that would be received for the rig in the principal or most advantageous market for that rig in an orderly transaction between market participants. This estimate was primarily based on an indicative bid to purchase the rig at that time, as well as our evaluation of other market data points. Our fair value estimates were representative of Level 3 fair value measurements due to the significant level of estimation involved and the lack of transparency as to the inputs used.

We recorded aggregate impairment losses of $99.3 million for the year ended December 31, 2017 related to our 2017 Impaired Rigs.

2016 Impairments. During 2016, we evaluated 15 of our drilling rigs with indications that their carrying amounts may not be recoverable. Based on our assumptions and analyses at that time, we determined that the carrying values of eight of these rigs were impaired, including one rig that had been previously impaired in a prior year. We collectively refer to these eight rigs as the 2016 Impaired Rigs.

We estimated the fair value of the 2016 Impaired Rigs using an income approach, as described above. Our fair value estimates were representative of Level 3 fair value measurements due to the significant level of estimation involved and the lack of transparency as to the inputs used. During 2016, we recorded an impairment loss of $670.0 million related to our 2016 Impaired Rigs.

See Notes 1 and 8.

4. Supplemental Financial Information

Consolidated Balance Sheets Information

Accounts receivable, net of allowance for bad debts, consists of the following (in thousands):

	December 31, 2018	December 31, 2017
Trade receivables	$160,478	$247,453
Value added tax receivables	13,237	14,067
Related party receivables	174	205
Other	190	464
	174,079	262,189
Allowance for bad debts	(5,459)	(5,459)
Total	$168,620	$256,730

An analysis of the changes in our provision for bad debts for each of the three years ended December 31, 2018, 2017 and 2016 is as follows (in thousands):

	For the Year Ended December 31, 2018	2017	2016
Allowance for bad debts, beginning of year	$5,459	$5,459	$5,724
Bad debt recovery	—	—	(265)
Allowance for bad debts, end of year	$5,459	$5,459	$5,459

See Note 8 for a discussion of our policy regarding uncollectible accounts.

Prepaid expenses and other current assets consist of the following (in thousands):

	December 31, 2018	December 31, 2017
Deferred contract costs	$ 70,021	$ 51,297
Prepaid taxes	54,412	67,212
Rig spare parts and supplies	20,256	28,383
Current contract assets	6,832	—
Prepaid BOP Lease	3,873	3,873
Prepaid insurance	2,742	3,091
Other	5,260	3,769
Total	$163,396	$157,625

Accrued liabilities consist of the following (in thousands):

	December 31, 2018	December 31, 2017
Payroll and benefits	$ 47,564	$ 46,560
Rig operating expenses	42,323	48,894
Accrued capital project/upgrade costs	37,379	3,698
Interest payable	28,234	28,234
Personal injury and other claims	5,544	5,699
Deferred revenue	2,803	11,371
Other	8,381	10,199
Total	$172,228	$154,655

Consolidated Statements of Cash Flows Information

Noncash investing activities excluded from the Consolidated Statements of Cash Flows and other supplemental cash flow information is as follows (in thousands):

	December 31, 2018	December 31, 2017	December 31, 2016
Accrued but unpaid capital expenditures at period end	$ 37,234	$ 3,698	$ 60,308
Common stock withheld for payroll tax obligations (1)	1,301	483	181
Cash interest payments (2)	113,063	97,096	105,987
Cash income taxes paid (refunded), net:			
Foreign	9,286	43,999	48,931
U.S. federal	(7,389)	—	(31,151)
State	2	94	1

(1) Represents the cost of 87,799, 29,416 and 7,923 shares of common stock withheld to satisfy the payroll tax obligation incurred as a result of the vesting of restricted stock units in 2018, 2017 and 2016, respectively. These costs are presented as a deduction from stockholders' equity in "Treasury stock" in our Consolidated Balance Sheets at December 31, 2018, 2017 and 2016, respectively.

(2) Interest payments, net of amounts capitalized, were $112.5 million, $97.0 million and $86.1 million for the years ended December 31, 2018, 2017 and 2016, respectively.

5. Stock-Based Compensation

We have an Equity Incentive Compensation Plan, or Equity Plan, for our officers, independent contractors, employees and non-employee directors, which is designed to encourage stock ownership by such persons, thereby aligning their interests with those of our stockholders. Under the Equity Plan, we may grant both time-vesting and performance-vesting awards, which are earned on the achievement of certain performance criteria. The following types of awards may be granted under the Equity Plan:

- Stock options (including incentive stock options and nonqualified stock options);
- Stock appreciation rights, or SARs;
- Restricted stock;
- Restricted stock units, or RSUs;
- Performance shares or units; and
- Other stock-based awards (including dividend equivalents).

A maximum of 7,500,000 shares of our common stock is available for the grant or settlement of awards under the Equity Plan, subject to adjustment for certain business transactions and changes in capital structure. Vesting conditions and other terms and conditions of awards under the Equity Plan are determined by our Board of Directors or the compensation committee of our Board of Directors, subject to the terms of the Equity Plan. RSUs may be issued with performance-vesting or time-vesting features. Except for RSUs issued to our CEO, RSUs are not participating securities, and the holders of such awards have no right to receive regular dividends if or when declared.

In March 2016, the FASB issued ASU No. 2016-09, *Compensation—Stock Compensation (Topic 718)*, or ASU 2016-09, which requires that all excess tax benefits and tax deficiencies be recognized in the income statement as discrete tax items when share-based awards vest or are settled and also provides for a policy election to either estimate the number of awards expected to vest or account for forfeitures when they occur. We have elected to account for forfeitures of share-based awards in the period in which such forfeitures occur and adopted ASU 2016-09 on January 1, 2017 using a modified retrospective approach. The adoption of ASU 2016-09 resulted in a $0.6 million reduction in opening retained earnings. The impact to our Consolidated Balance Sheets is as follows (in thousands):

	Retained Earnings	Additional Paid-in Capital
Balance as of January 1, 2017 before adoption	$1,946,765	$2,004,514
Adjustment for making election to account for forfeitures as they occur	(634)	634
Balance as of January 1, 2017 after adoption	$1,946,131	$2,005,148

All other requirements of ASU 2016-09, where applicable, have been applied prospectively as of January 1, 2017.

Total compensation cost recognized for all awards under the Equity Plan (or its predecessor) for the years ended December 31, 2018, 2017 and 2016 was $6.8 million, $8.7 million and $7.0 million, respectively. Tax benefits recognized for the years ended December 31, 2018, 2017 and 2016 related thereto were $0.8 million, $2.6 million and $2.4 million, respectively. As of December 31, 2018 there was $8.0 million of total unrecognized compensation cost related to non-vested awards under the Equity Plan, which we expect to recognize over a weighted average period of two years.

Time-Vesting Awards

SARs. Currently, SARs awarded under the Equity Plan generally vest immediately and expire in ten years. The exercise price per share of SARs awarded under the Equity Plan may not be less than the fair market value of our common stock on the date of grant.

The fair value of SARs granted under the Equity Plan (or its predecessor) during each of the years ended December 31, 2018, 2017 and 2016 was estimated using the Black Scholes pricing model with the following weighted average assumptions:

	Year Ended December 31,		
	2018	2017	2016
Expected life of SARs (in years)	7	7	7
Expected volatility	32.10%	31.70%	45.79%
Dividend yield	—	—	.60% [(1)]
Risk free interest rate	2.56%	2.09%	1.46%

(1) Represents dividend yield related to January 2016 grant of SARs prior to our decision in early 2016 to discontinue paying dividends.

The expected life of SARs is based on historical data as is the expected volatility. The dividend yield is based on the current approved regular dividend rate in effect and the current market price at the time of grant. Risk free interest rates are determined using the U.S. Treasury yield curve at time of grant with a term equal to the expected life of the SARs.

A summary of SARs activity under the Equity Plan as of December 31, 2018 and changes during the year then ended is as follows:

	Number of Awards	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value (In Thousands)
Awards outstanding at January 1, 2018	1,262,114	$60.16		
Granted	40,500	$18.22		
Exercised	(23,000)	$15.89		
Forfeited	(1,100)	$42.41		
Expired	(249,432)	$82.65		
Awards outstanding at December 31, 2018	1,029,082	$54.07	4.1	$—
Awards exercisable at December 31, 2018	1,029,082	$54.07	4.1	$—

The weighted-average grant date fair values per share of awards granted during the years ended December 31, 2018, 2017 and 2016 were $7.11, $5.61 and $9.32, respectively. The total intrinsic value of awards exercised during the years ended December 31, 2018, 2017 and 2016 was $0.1 million, $0 and $0, respectively. The total fair value of awards vested during the years ended December 31, 2018, 2017 and 2016 was $0.7 million, $1.2 million and $2.2 million, respectively.

Restricted Stock Units. RSUs are contractual rights to receive shares of our common stock in the future if the applicable vesting conditions are met. In 2018, 2017 and 2016, we granted an aggregate of 135,759, 276,085 and 183,076 time-vesting RSUs, respectively. One-half of each annual grant will vest two years from the date of grant and the remaining 50% will vest three years from the date of grant, conditioned upon continued employment through the applicable vesting date. The fair value of time-vesting RSUs granted under the Equity Plan was estimated based on the fair market value of our common stock on the date of grant.

A summary of activity for time-vesting RSUs under the Equity Plan as of December 31, 2018 and changes during the year then ended is as follows:

	Number of Awards	Weighted-Average Grant Date Fair Value Per Share
Nonvested awards at January 1, 2018	471,289	$19.15
Granted	135,759	$14.58
Vested	(131,418)	$23.00
Forfeited	(53,571)	$18.55
Nonvested awards at December 31, 2018	422,059	$16.57

The total fair value of time-vesting RSUs vested during the years ended December 31, 2018 and 2017 was $1.9 million and $1.1 million, respectively. No time-vesting RSUs vested during the year ended December 31, 2016.

Performance-Vesting Awards

Restricted Stock Units. In 2018, 2017 and 2016, we granted an aggregate of 194,563, 370,616 and 248,188 performance-vesting RSUs, respectively, which will vest upon achievement of certain performance goals as set forth in the individual award agreements over the three-year performance period beginning on January 1 in the year of grant. The shares of our common stock to be received upon the vesting of the performance-vesting RSUs will be delivered no later than March 15 of the year following completion of the three-year performance period. The fair value of performance-vesting RSUs granted under the Equity Plan to employees was estimated based on the fair market value of our common stock on the date of grant.

A summary of activity for performance-vesting RSUs under the Equity Plan as of December 31, 2018 and changes during the year then ended is as follows:

	Number of Awards	Weighted-Average Grant Date Fair Value Per Share
Nonvested awards at January 1, 2018	727,856	$20.28
Granted	194,563	$14.58
Vested	(164,271)	$26.21
Forfeited	(16,175)	$17.78
Nonvested awards at December 31, 2018	741,973	$17.53

The total grant date fair value of the performance-vesting RSUs that vested during the years ended December 31, 2018, 2017 and 2016 was $2.5 million, $0.3 million and $0.4 million, respectively.

6. Earnings (Loss) Per Share

A reconciliation of the numerators and the denominators of the basic and diluted per-share computations follows (in thousands, except per share data):

	Year Ended December 31,		
	2018	2017	2016
Net (loss) income – basic and diluted (numerator):	$(180,272)	$ 18,346	$(372,503)
Weighted-average shares – basic (denominator):	137,399	137,213	137,168
Dilutive effect of stock-based awards	—	52	—
Weighted-average shares including conversions – diluted (denominator):	137,399	137,265	137,168
(Loss) earnings per share:			
Basic	$ (1.31)	$ 0.13	$ (2.72)
Diluted	$ (1.31)	$ 0.13	$ (2.72)

The following table sets forth the share effects of stock-based awards excluded from the computation of earnings (loss) per share, as the inclusion of such potentially dilutive shares would have been antidilutive for the periods presented (in thousands).

	Year Ended December 31,		
	2018	2017	2016
Employee and director:			
Stock options	—	—	7
SARs	1,133	1,315	1,505
RSUs	1,153	757	704

7. Marketable Securities

We report our investments as current assets in our Consolidated Balance Sheets in “Marketable securities,” representing the investment of cash available for current operations. See Note 8.

Our investments in marketable securities are classified as available for sale and are summarized as follows (in thousands):

	December 31, 2018		
	Amortized Cost	Unrealized Gain	Market Value
U.S. Treasury bills (due within one year)	$299,813	$36	$299,849

Proceeds from maturities of U.S. Treasury bills were $1.6 billion in 2018. There were no sales of U.S. Treasury bills during 2018.

8. Financial Instruments and Fair Value Disclosures

Concentrations of Credit and Market Risk

Financial instruments that potentially subject us to significant concentrations of credit or market risk consist primarily of periodic temporary investments of excess cash, trade accounts receivable and investments in debt securities, including mortgage-backed securities. We generally place our excess cash investments in U.S.

government backed short-term money market instruments through several financial institutions. At times, such investments may be in excess of the insurable limit. We periodically evaluate the relative credit standing of these financial institutions as part of our investment strategy.

Concentrations of credit risk with respect to our trade accounts receivable are limited primarily due to the entities comprising our customer base. Since the market for our services is the offshore oil and gas industry, this customer base consists primarily of major and independent oil and gas companies and government-owned oil companies. Based on our current customer base and the geographic areas in which we operate, as well as the number of rigs currently working in these areas, we do not believe that we have any significant concentrations of credit risk at December 31, 2018.

In general, before working for a customer with whom we have not had a prior business relationship and/or whose financial stability may be uncertain to us, we perform a credit review on that company. Based on that analysis, we may require that the customer present a letter of credit, prepay or provide other credit enhancements. We record a provision for bad debts on a case-by-case basis when facts and circumstances indicate that a customer receivable may not be collectible. Historically, losses on our trade receivables have been infrequent occurrences.

Fair Values

Fair value is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. The fair value hierarchy prescribed by GAAP requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. There are three levels of inputs that may be used to measure fair value:

Level 1 Quoted prices for identical instruments in active markets. Level 1 assets include short-term investments such as money market funds, U.S. Treasury bills and Treasury notes. Our Level 1 assets at December 31, 2018 consisted of cash held in money market funds of $135.8 million and investments in U.S. Treasury bills of $299.8 million. Our Level 1 assets at December 31, 2017 consisted of cash held in money market funds of $337.1 million and time deposits of $20.9 million.

Level 2 Quoted market prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model-derived valuations in which all significant inputs and significant value drivers are observable in active markets. Level 2 assets and liabilities may include residential mortgage-backed securities, corporate bonds purchased in a private placement offering and over-the-counter foreign currency forward exchange contracts. We had no Level 2 assets or liabilities at December 31, 2018 or 2017.

Level 3 Valuations derived from valuation techniques in which one or more significant inputs or significant value drivers are unobservable. Level 3 assets and liabilities generally include financial instruments whose value is determined using pricing models, discounted cash flow methodologies, or similar techniques, as well as instruments for which the determination of fair value requires significant management judgment or estimation or for which there is a lack of transparency as to the inputs used. Our Level 3 assets at December 31, 2017 consisted of nonrecurring measurements of certain of our drilling rigs for which we recorded an impairment loss during 2017. We had no Level 3 assets as of December 31, 2018. See Notes 1 and 3.

Certain of our assets and liabilities are required to be measured at fair value on a recurring basis in accordance with GAAP. In addition, certain assets and liabilities may be recorded at fair value on a nonrecurring basis. Generally, we record assets at fair value on a nonrecurring basis as a result of impairment charges. We recorded impairment charges related to certain of our drilling rigs, which were measured at fair value on a nonrecurring basis in 2018 and 2017 and have presented the aggregate loss in “Impairment of assets” in our Consolidated Statements of Operations for the years ended December 31, 2018 and 2017.

Assets measured at fair value are summarized below (in thousands).

	December 31, 2018				
	Fair Value Measurements Using				
	Level 1	Level 2	Level 3	Assets at Fair Value	Total Losses for Year Ended (1)
Recurring fair value measurements:					
Assets:					
Short-term investments	$435,671	$—	$—	$435,671	
Nonrecurring fair value measurements:					
Assets:					
Impaired assets	$ —	$—	$—	$ —	$27,225

(1) Represents impairment loss of $27.2 million recognized during 2018 related to a drilling rig whose carrying value was impaired and was subsequently sold. See Notes 1 and 3.

	December 31, 2017				
	Fair Value Measurements Using				
	Level 1	Level 2	Level 3	Assets at Fair Value	Total Losses for Year Ended (1)
Recurring fair value measurements:					
Assets:					
Short-term investments	$358,019	$—	$ —	$358,019	
Nonrecurring fair value measurements:					
Assets:					
Impaired assets (2)	$ —	$—	$97,261	$ 97,261	$99,313

(1) Represents aggregate impairment loss of $99.3 million recognized during 2017 related to our 2017 Impaired Rigs. See Note 3.

(2) Represents the total book value as of December 31, 2017 of three drilling rigs, which were written down to their estimated fair value during 2017. Of the total fair value, $96.3 million and $1.0 million were reported as “Assets held for sale” and “Drilling and other property and equipment, net of accumulated depreciation,” respectively, in our Consolidated Balance Sheets at December 31, 2017. See Notes 1 and 3.

We believe that the carrying amounts of our other financial assets and liabilities (excluding long-term debt), which are not measured at fair value in our Consolidated Balance Sheets, approximate fair value based on the following assumptions:

- *Cash and cash equivalents* — The carrying amounts approximate fair value because of the short maturity of these instruments.
- *Accounts receivable and accounts payable* — The carrying amounts approximate fair value based on the nature of the instruments.

We consider our senior notes, including current maturities, to be Level 2 liabilities under the GAAP fair value hierarchy and, accordingly, the fair value of our senior notes was derived using a third-party pricing service at December 31, 2018 and 2017. We perform control procedures over information we obtain from pricing services and brokers to test whether prices received represent a reasonable estimate of fair value. These procedures include the review of pricing service or broker pricing methodologies and comparing fair value estimates to actual trade activity executed in the market for these instruments occurring generally within a 10-day window of the report date. Fair values and related carrying values of our senior notes (see Note 10) are shown below (in millions).

	December 31, 2018		December 31, 2017	
	Fair Value	Carrying Value	Fair Value	Carrying Value
3.45% Senior Notes due 2023	$185.0	$249.5	$223.1	$249.4
7.875% Senior Notes due 2025	415.0	496.8	523.1	496.5
5.70% Senior Notes due 2039	305.0	497.2	405.0	497.2
4.875% Senior Notes due 2043	416.3	748.9	547.5	748.9

We have estimated the fair value amounts by using appropriate valuation methodologies and information available to management. Considerable judgment is required in developing these estimates, and accordingly, no assurance can be given that the estimated values are indicative of the amounts that would be realized in a free market exchange.

9. Drilling and Other Property and Equipment

Cost and accumulated depreciation of drilling and other property and equipment are summarized as follows (in thousands):

	December 31,	
	2018	2017
Drilling rigs and equipment	$ 8,210,824	$ 7,971,406
Land and buildings	63,757	63,309
Office equipment and other	91,819	82,691
Cost	8,366,400	8,117,406
Less accumulated depreciation	(3,182,178)	(2,855,765)
Drilling and other property and equipment, net	$ 5,184,222	$ 5,261,641

During the years ended December 31, 2018 and 2017, we recognized impairment losses of $27.2 million and $99.3 million, respectively. See Note 3.

10. Credit Agreements and Senior Notes

Credit Agreements

In September 2012, we entered into a syndicated 5-year revolving credit agreement, which, as amended as of August 18, 2016, provided for a $1.5 billion senior unsecured revolving credit facility for general corporate purposes. On October 2, 2018, we entered into Amendment No. 6 and Consent to Credit Agreement and Successor Agency Agreement, or the Amendment, which amended our 5-year revolving credit agreement, dated as of September 28, 2012, as amended (we refer to such credit agreement, as amended by the Amendment, as the $325 Million Credit Facility). Among other things, the Amendment reduced the aggregate principal amount of commitments under the credit facility to $325.0 million, of which $40.0 million of the commitments mature on March 17, 2019, $60.0 million of the commitments mature on October 22, 2019 and $225.0 million of the commitments mature on October 22, 2020. The entire amount of the $325 Million Credit Facility is available, subject to its terms, for revolving loans.

On October 2, 2018, Diamond Offshore Drilling, Inc., or DODI, as the U.S. borrower, and our subsidiary Diamond Foreign Asset Company, or DFAC, as the foreign borrower, entered into a senior 5-year revolving credit agreement with a syndicate of lenders and Wells Fargo Bank, National Association, as administrative agent (we refer to such credit agreement as the $950 Million Credit Facility). The maximum amount of borrowings available under the $950 Million Credit Facility is $950.0 million and may be used for general corporate purposes, including investments, acquisitions and capital expenditures. The $950 Million Credit Facility, which matures on October 2, 2023, provides for a swingline subfacility of $100.0 million and a letter of credit subfacility of $250.0 million.

The entire amount of borrowings available under the $950 Million Credit Facility is available for loans to DFAC, and a portion of such amount is available for loans to DODI, based on a ratio as specified in the $950 Million Credit Facility. The obligations of DODI and DFAC under the $950 Million Credit Facility are each guaranteed by certain subsidiaries of DODI and DFAC, respectively, and 65% of the equity interest in DFAC is pledged as collateral.

The $950 Million Credit Facility includes restrictions on borrowing if, after giving effect to any such borrowings and the application of the proceeds thereof, the aggregate amount of available cash, as defined in the $950 Million Credit Facility, would exceed $500.0 million. In addition, the ability to borrow revolving loans under the $950 Million Credit Facility is conditioned on there being no unused commitments to advance loans under the $325 Million Credit Facility.

We refer to the $325 Million Credit Facility and $950 Million Credit Facility collectively as the Credit Agreements. At December 31, 2018, we had no borrowings outstanding under the Credit Agreements. At February 8, 2019, we had no borrowings outstanding under the Credit Agreements and an aggregate $1.275 billion available under the Credit Agreements, subject to their respective terms.

Covenants

The $325 Million Credit Facility contains customary covenants, including, but not limited to, maintenance of a ratio of consolidated indebtedness to total capitalization, as defined in the $325 Million Credit Facility, of not more than 60% at the end of each fiscal quarter, as well as limitations on liens; mergers, consolidations, liquidation and dissolution; changes in lines of business; swap agreements; transactions with affiliates; and subsidiary indebtedness.

The $950 Million Credit Facility contains certain financial covenants, including (i) maintenance of a ratio of consolidated indebtedness to total capitalization not to exceed 60% at the end of each fiscal quarter, (ii) maintenance of a ratio of (A) the aggregate value of certain rigs directly wholly owned by the borrowers and subsidiary guarantors to (B) the aggregate value of substantially all rigs owned by us of not less than 80% at the end of each fiscal quarter and (iii) maintenance of a ratio of (A) the sum of the aggregate value of all marketed rigs, as defined in the $950 Million Credit Facility, wholly owned directly by DFAC and certain foreign guarantors, as specified in the $950 Million Credit Facility, plus the value of the *Ocean Valiant* at any time when it is a marketed rig owned by a guarantor to (B) the sum of commitments under the $950 Million Credit Facility, the outstanding loans and letter of credit exposures under the $325 Million Credit Facility plus certain other indebtedness of DFAC and certain foreign guarantors, as specified in the $950 Million Credit Facility, of not less than 3:00 to 1:00 at the end of each fiscal quarter.

The $950 Million Credit Facility also contains additional covenants generally applicable to DODI and its subsidiaries that we consider usual and customary for an agreement of this type, including a limit on the payment of dividends if certain minimum cash balances are not maintained.

The Credit Agreements provide for customary events of default including, among others, a cross-default provision with respect to DODI's and its subsidiaries' other indebtedness in excess of $100.0 million. At December 31, 2018, we were in compliance with all covenant requirements under the Credit Agreements.

Interest Rates and Fees

Revolving loans under the Credit Agreements bear interest, at our option, at a rate per annum based on either an alternate base rate, or ABR, or a Eurodollar Rate, as defined in the applicable Credit Agreement, plus the applicable interest margin for an ABR loan or a Eurodollar loan (determined based on our credit ratings). Swingline loans under the $950 Million Credit Facility bear interest, at our option, at a rate per annum equal to (i) the ABR plus the applicable interest margin for ABR loans or (ii) the daily one-month Eurodollar Rate plus the applicable interest margin for Eurodollar loans.

Under the Credit Agreements, we also pay, based on our current long-term credit ratings, and as applicable, other customary fees including, but not limited to, a commitment fee on the unused commitments under each of the Credit Agreements and a fronting fee to the issuing bank for each letter of credit. Participation fees for letters of credit are dependent upon the type of letter of credit issued.

The following summarizes the interest rate margins and fees payable under the Credit Agreements, based on our current long-term credit ratings:

	$325 Million Credit Facility	$950 Million Credit Facility
Revolving Loans:		
ABR	0.25% over the greater of (i) the prime rate, (ii) the federal funds rate plus 0.50% and (iii) the daily one-month Eurodollar Rate plus 1.00%	3.00% over the greater of (i) the prime rate, (ii) the federal funds rate plus 0.50% and (iii) the daily one-month Eurodollar Rate plus 1.00%
Eurodollar	1.25% over specified LIBOR	4.00% over specified LIBOR
Swingline Loans	N/A	At our option, at a rate per annum equal to (i) the ABR plus the applicable interest margin for ABR loans or (ii) the daily one-month Eurodollar Rate plus the applicable interest margin for Eurodollar loans
Letter of credit participation fees:		
Performance letters of credit	N/A	2.00% per annum
All other letters of credit	N/A	4.00% per annum
Commitment fee on unused commitments under credit agreement	0.20% per annum	0.70% per annum

Favorable changes in our current credit ratings could lower the interest rate margins and fees that we pay under the Credit Agreements; however, current interest rates and fees under the $325 Million Credit Facility will apply should there be any further downgrade in our credit ratings. A downgrade in our credit ratings would increase the interest rate margins and fees that we pay under the $950 Million Credit Facility.

Senior Notes

At December 31, 2018, our senior notes were comprised of the following debt issues (dollars in millions):

Debt Issue	Principal Amount	Maturity Date	Interest Rate Coupon	Interest Rate Effective	Semiannual Interest Payment Dates
3.45% Senior Notes due 2023	$250.0	November 1, 2023	3.45%	3.50%	May 1 and November 1
7.875% Senior Notes due 2025	$500.0	August 15, 2025	7.875%	8.00%	February 15 and August 15
5.70% Senior Notes due 2039	$500.0	October 15, 2039	5.70%	5.75%	April 15 and October 15
4.875% Senior Notes due 2043	$750.0	November 1, 2043	4.875%	4.89%	May 1 and November 1

At December 31, 2018 and 2017, the carrying value of our senior notes, net of unamortized discount and debt issuance costs, was as follows (in thousands):

	December 31, 2018	December 31, 2017
3.45% Senior Notes due 2023	$ 248,455	$ 248,162
7.875% Senior Notes due 2025	490,491	489,420
5.70% Senior Notes due 2039	493,139	492,971
4.875% Senior Notes due 2043	741,837	741,672
Total senior notes, net	$1,973,922	$1,972,225

As of December 31, 2018, the aggregate annual maturity of our senior notes, excluding net unamortized discounts and debt issuance costs of $7.5 million and $18.5 million, respectively, was as follows (in thousands):

Year Ending December 31,	Aggregate Principal Amount
2019	$ —
2020	—
2021	—
2022	—
2023	250,000
Thereafter	1,750,000
Total maturities of senior notes	$2,000,000

Notes Redemption. In August 2017, we redeemed all of our outstanding 5.875% senior notes due 2019, or 2019 Notes, for a redemption price of $543.0 million in the aggregate, including accrued and unpaid interest to the date of redemption. We accounted for the redemption as an extinguishment of debt and reported a corresponding loss of $35.4 million in our Consolidated Statements of Operations.

Senior Notes Due 2025. In August 2017, we issued $500.0 million aggregate principal amount of unsecured 7.875% senior notes due 2025, or 2025 Notes, and received net proceeds of $489.1 million after deduction of underwriter discounts, commissions and expenses. We used the net proceeds from the 2025 Notes, together with cash on hand, to fund the redemption of our previously outstanding 2019 Notes. The 2025 Notes are unsecured obligations of DODI, and rank equally in right of payment to all of its existing and future senior indebtedness, and are structurally subordinated to all existing and future obligations of our subsidiaries. We have the right to redeem some or all of the 2025 Notes at any time or from time to time, on at least 15 days but not more than 60 days prior written notice, at the applicable redemption price specified in the governing indenture, plus accrued and unpaid interest to, but excluding, the date of redemption.

Senior Notes Due 2023 and 2043. Our 3.45% Senior Notes due 2023 and 4.875% Senior Notes due 2043 are unsecured and unsubordinated obligations of DODI, and rank equally in right of payment to all of its existing and future unsecured and unsubordinated indebtedness, and are effectively subordinated to all existing and future obligations of our subsidiaries. We have the right to redeem all or a portion of these notes for cash at any time or from time to time, on at least 15 days but not more than 60 days prior written notice, at a make-whole redemption price specified in the governing indenture (if applicable) plus accrued and unpaid interest to, but excluding, the date of redemption.

Senior Notes Due 2039. Our 5.70% Senior Notes due 2039 are unsecured and unsubordinated obligations of DODI, and rank equally in right of payment to all of its existing and future unsecured and unsubordinated indebtedness, and are effectively subordinated to all existing and future obligations of our subsidiaries. We have the right to redeem all or a portion of these notes for cash at any time or from time to time, on at least 15 days but not more than 60 days prior written notice, at the redemption price specified in the governing indenture plus accrued and unpaid interest to the date of redemption.

The 2025 Notes, 3.45% Senior Notes due 2023, 4.875% Senior Notes due 2043 and 5.70% Senior Notes due 2039 contain customary covenants including limitations on liens, mergers, consolidations and certain sales of assets and on entering into sale and lease-back transactions covering a drilling rig or drillship, as specified in each governing indenture.

11. Other Comprehensive Income (Loss)

The following table sets forth the components of "Other comprehensive gain (loss)" and the related income tax effects thereon for the three years ended December 31, 2018 and the cumulative balances in "Accumulated other comprehensive gain (loss)," or AOCGL, by component at December 31, 2018, 2017 and 2016 (in thousands).

	Unrealized Gain (Loss) on		
	Derivative Financial Instruments	Marketable Securities	Total AOCGL
Balance at January 1, 2016	6	(5,041)	(5,035)
Change in other comprehensive loss before reclassifications, after tax of $0 and $2	—	(6,559)	(6,559)
Reclassification adjustments for items included in Net Loss, after tax of $3 and $0	(5)	11,600	11,595
Total other comprehensive (loss) income	(5)	5,041	5,036
Balance at December 31, 2016	1	—	1
Reclassification adjustments for items included in Net Loss, after tax of $2 and $0	(6)	—	(6)
Total other comprehensive loss	(6)	—	(6)
Balance at December 31, 2017	(5)	—	(5)
Change in other comprehensive gain before reclassifications, after tax of $0 and $(8)	—	69	69
Reclassification adjustments for items included in Net Loss, after tax of $2 and $4	(6)	(37)	(43)
Total other comprehensive (loss) income	(6)	32	26
Balance at December 31, 2018	$ (11)	$ 32	$ 21

The following table presents the line items in our Consolidated Statements of Operations affected by reclassification adjustments out of AOCGL (in thousands).

Major Components of AOCGL	Year Ended December 31, 2018	2017	2016	Consolidated Statements of Operations Line Items
Derivative financial instruments:				
Unrealized gain on Treasury Lock Agreements	$ (8)	$ (8)	$ (8)	Interest expense
	2	2	3	Income tax expense (benefit)
	$ (6)	$ (6)	$ (5)	Net of tax
Marketable securities:				
Unrealized (gain) loss on marketable securities	$(41)	$—	$11,600	Other, net
	4	—	—	Income tax expense
	$(37)	$—	$11,600	Net of tax

12. Commitments and Contingencies

Various claims have been filed against us in the ordinary course of business, including claims by offshore workers alleging personal injuries. With respect to each claim or exposure, we have made an assessment, in accordance with GAAP, of the probability that the resolution of the matter would ultimately result in a loss. When we determine that an unfavorable resolution of a matter is probable and such amount of loss can be determined, we record a liability for the amount of the estimated loss at the time that both of these criteria are met. Our management believes that we have recorded adequate accruals for any liabilities that may reasonably be expected to result from these claims.

Patent Litigation. On August 30, 2017, an affiliate of Transocean Ltd., or Transocean, an offshore drilling contractor, filed a lawsuit against us and one of our subsidiaries in the United States District Court for the Southern District of Texas, alleging that we infringed certain United States patents previously owned by Transocean or its affiliates or employees pertaining to certain dual-activity drilling operations. The lawsuit alleged that we infringed the patents by the unauthorized sale, offer for sale, and importation and use of four of our drilling rigs (*Ocean BlackHawk*, *Ocean BlackHornet*, *Ocean BlackRhino* and *Ocean BlackLion*). On June 1, 2018, we filed petitions with the Patent Trial and Appeal Board to challenge the validity of each of the Transocean patents through an administrative process referred to as an *Inter Partes* Review. In September 2018, we reached an agreement with Transocean to settle the lawsuit and the *Inter Partes* Review on mutually agreeable terms, and both proceedings were dismissed in October 2018. We expensed the settlement charge during the year ended December 31, 2018.

Asbestos Litigation. We are one of several unrelated defendants in lawsuits filed in Louisiana state courts alleging that defendants manufactured, distributed or utilized drilling mud containing asbestos and, in our case, allowed such drilling mud to have been utilized aboard our drilling rigs. The plaintiffs seek, among other things, an award of unspecified compensatory and punitive damages. The manufacture and use of asbestos-containing drilling mud had already ceased before we acquired any of the drilling rigs addressed in these lawsuits. We believe that we are not liable for the damages asserted in the lawsuits pursuant to the terms of our 1989 asset purchase agreement with Diamond M Corporation. We are unable to estimate our potential exposure, if any, to these lawsuits at this time but do not believe that our ultimate liability, if any, resulting from this litigation will have a material effect on our consolidated financial condition, results of operations or cash flows.

Other Litigation. We have been named in various other claims, lawsuits or threatened actions that are incidental to the ordinary course of our business, including a claim by one of our customers in Brazil, Petróleo Brasileiro S.A., or Petrobras, that it will seek to recover from its contractors, including us, any taxes, penalties, interest and fees that it must pay to the Brazilian tax authorities for our applicable portion of withholding taxes related to Petrobras' charter agreements with its contractors. We intend to defend these matters vigorously; however, litigation is inherently unpredictable, and the ultimate outcome or effect of any claim, lawsuit or action cannot be predicted with certainty. As a result, there can be no assurance as to the ultimate outcome of any litigation matter. Any claims against us, whether meritorious or not, could cause us to incur significant costs and expenses and require significant amounts of management and operational time and resources. In the opinion of our management, no pending or known threatened claims, actions or proceedings against us are expected to have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Personal Injury Claims. Under our current insurance policies, which renewed effective May 1, 2018, our deductibles for marine liability insurance coverage with respect to personal injury claims not related to named windstorms in the U.S. Gulf of Mexico, which primarily result from Jones Act liability in the U.S. Gulf of Mexico, are $10.0 million for the first occurrence, with no aggregate deductible, and vary in amounts ranging between $5.0 million and, if aggregate claims exceed certain thresholds, up to $100.0 million for each subsequent occurrence, depending on the nature, severity and frequency of claims that might arise during the policy year. Our deductibles for personal injury claims arising due to named windstorms in the U.S. Gulf of Mexico are $25.0 million for the first occurrence, with no aggregate deductible, and vary in amounts ranging between $25.0 million and, if aggregate claims exceed certain thresholds, up to $100.0 million for each subsequent occurrence, depending on the nature, severity and frequency of claims that might arise during the policy year.

The Jones Act is a federal law that permits seamen to seek compensation for certain injuries during the course of their employment on a vessel and governs the liability of vessel operators and marine employers for the work-related injury or death of an employee. We engage outside consultants to assist us in estimating our aggregate liability for personal injury claims based on our historical losses and utilizing various actuarial models. We allocate a portion of the aggregate liability to “Accrued liabilities” based on an estimate of claims expected to be paid within the next twelve months with the residual recorded as “Other liabilities.” At December 31, 2018, our estimated liability for personal injury claims was $27.9 million, of which $5.2 million and $22.7 million were recorded in “Accrued liabilities” and “Other liabilities,” respectively, in our Consolidated Balance Sheets. At December 31, 2017, our estimated liability for personal injury claims was $30.9 million, of which $5.2 million and $25.7 million were recorded in “Accrued liabilities” and “Other liabilities,” respectively, in our Consolidated Balance Sheets. The eventual settlement or adjudication of these claims could differ materially from our estimated amounts due to uncertainties such as:

- the severity of personal injuries claimed;
- significant changes in the volume of personal injury claims;
- the unpredictability of legal jurisdictions where the claims will ultimately be litigated;
- inconsistent court decisions; and
- the risks and lack of predictability inherent in personal injury litigation.

Purchase Obligations. At December 31, 2018, we had no purchase obligations for major rig upgrades or any other significant obligations, except for those related to our direct rig operations, which arise during the normal course of business.

Operating Leases. We lease office and yard facilities, housing, office equipment and vehicles under operating leases, which expire at various times through the year 2022. Total rent expense amounted to $3.1 million, $3.9 million and $5.5 million for the years ended December 31, 2018, 2017 and 2016, respectively. Future minimum rental payments under leases are approximately $2.1 million and $0.8 million for 2019 and 2020, respectively, and an aggregate of $0.3 million for the years 2021 through 2022.

In addition, we lease certain blowout preventer equipment, or BOP, and related well control equipment under ten-year operating leases. See Note 13.

Letters of Credit and Other. We were contingently liable as of December 31, 2018 in the amount of $25.7 million under certain customs, performance, tax and VAT bonds and letters of credit. Agreements relating to approximately $17.1 million of customs and tax bonds can require collateral at any time. As of December 31, 2018, we had not been required to make any collateral deposits with respect to these agreements. The remaining agreements cannot require collateral except in events of default. On our behalf, banks have issued letters of credit securing certain of these bonds.

13. Sale and Leaseback Transactions

In February 2016, we entered into a ten-year agreement with a subsidiary of GE Oil & Gas, or GE, to provide services with respect to certain blowout preventer and related well control equipment, or Well Control Equipment, on our four drillships. Such services include management of maintenance, certification and reliability with respect to such equipment.

In connection with the contractual services agreement with GE, we completed four sale and leaseback transactions with another GE affiliate during 2016 with respect to the Well Control Equipment on our four drillships. As a result of these transactions, we received an aggregate of $210.0 million in proceeds from the sale of the Well Control Equipment, which was less than the carrying value of the equipment. The resulting difference was recorded as prepaid rent with no gain or loss recognized on the transactions. The prepaid rent will be amortized over the respective terms of the operating leases. Future commitments under the operating leases and contractual services agreements are estimated to be approximately $65.0 million per year or an estimated

$485.0 million in the aggregate over the remaining term of the agreements. During the years ended December 31, 2018, 2017 and 2016, we recognized $65.1 million, $61.7 million and $34.0 million, respectively, in aggregate expense related to the Well Control Equipment leases and contractual services agreements.

14. Related-Party Transactions

Transactions with Loews. We are party to a services agreement with Loews, or the Services Agreement, pursuant to which Loews performs certain administrative and technical services on our behalf. Such services include personnel, internal auditing, accounting, and cash management services, in addition to advice and assistance with respect to preparation of tax returns and obtaining insurance. Under the Services Agreement, we are required to reimburse Loews for (i) allocated personnel costs (such as salaries, employee benefits and payroll taxes) of the Loews personnel actually providing such services and (ii) all out-of-pocket expenses related to the provision of such services. The Services Agreement may be terminated at our option upon 30 days' notice to Loews and at the option of Loews upon six months' notice to us. In addition, we have agreed to indemnify Loews for all claims and damages arising from the provision of services by Loews under the Services Agreement unless due to the gross negligence or willful misconduct of Loews. We were charged $0.6 million, $1.0 million and $1.0 million by Loews for these support functions during the years ended December 31, 2018, 2017 and 2016, respectively.

Transactions with Other Related Parties. We hire marine vessels and helicopter transportation services at the prevailing market rate from subsidiaries of SEACOR Holdings Inc., SEACOR Marine Holdings Inc. and Era Group Inc. We paid $0.4 million, $0.1 million and $0.7 million for the hire of such vessels and such services during the years ended December 31, 2018, 2017 and 2016, respectively. A member of our Board of Directors serves as the Chief Executive Officer and Executive Chairman of the Board of Directors of SEACOR Holdings Inc., the Non-Executive Chairman of the Board of Directors of SEACOR Marine Holdings Inc. and the Non-Executive Chairman of the Board of Directors of Era Group Inc.

15. Restructuring and Separation Costs

In late 2017, in response to expectations that a recovery of the offshore drilling market would not occur in the near term, combined with changes to the size and composition of our drilling fleet since 2015, we reviewed our global cost and organizational structure, including the way in which we market our services in certain countries. As a result, our management approved and initiated a reduction in workforce at our onshore bases and corporate facilities, as well as the negotiation of a termination of our agency agreement in Brazil, also referred to as the 2017 Reduction Plan. We incurred $14.1 million in restructuring and employee separation related costs during 2017, including $11.5 million related to the termination of our Brazilian agency agreement. During 2018, we incurred an additional $5.0 million in severance and related costs for redundant employees identified in 2018 in connection with the 2017 Reduction Plan and paid $12.4 million in previously accrued costs.

At December 31, 2018, accrued costs associated with the 2017 Reduction Plan were $1.5 million, all of which is payable in 2019.

16. Income Taxes

Effective January 1, 2018, we adopted ASU 2016-16, which required us to record the income tax consequences of two historical intra-entity transfers of rigs, for which previous accounting guidance precluded us from recognizing such income tax effects. We adopted the new accounting guidance using the modified retrospective approach, whereby we recorded the $17.4 million cumulative effect of applying the new standard as an adjustment to opening retained earnings with an offset to a deferred income tax liability.

Additionally, in response to our interpretation of the Tax Reform Act, which was signed into law in late December 2017, we recorded a provisional net tax expense of $1.1 million during the fourth quarter of 2017, which included a charge relating to the one-time mandatory repatriation of previously deferred earnings of certain non-U.S. subsidiaries that are owned either wholly or partially by our U.S. subsidiaries, inclusive of the utilization of certain tax attributes offset by a provisional liability for uncertain tax positions related to such attributes. Due to the timing of the enactment of the Tax Reform Act, there has been and continues to be a significant amount of uncertainty as to the appropriate application of a number of the underlying provisions, pending further guidance and clarification from the relevant authorities. In 2018, the U.S. Department of the Treasury and Internal Revenue Service, or IRS, issued additional guidance which we believe clarified certain of our tax positions taken in 2017 and, consequently, during the first quarter of 2018, we reversed a $43.3 million liability for an uncertain tax position related to the deemed repatriation of accumulated non-U.S. earnings. During the fourth quarter of 2018, the IRS issued further proposed regulations that may impact the utilization of certain tax attributes used to offset the deemed mandatory repatriation, for which we recorded an uncertain tax position in the amount of $20.1 million. Consequently, our revised net tax benefit associated with the Tax Reform Act is $20.3 million, which now consists of (i) a $52.2 million charge relating to the one-time mandatory repatriation of previously deferred earnings of certain non-US subsidiaries that are owned either wholly or partially by our U.S. subsidiaries, inclusive of the utilization of certain tax attributes offset by a liability for uncertain tax positions related to such attributes and (ii) a $72.5 million credit resulting from the determination and re-measurement of our net U.S. deferred tax liabilities at the lower corporate income tax rate.

The Securities and Exchange Commission's Staff Accounting Bulletin No. 118, or SAB 118, allowed companies to report the income tax effects of the Tax Reform Act as a provisional amount based on a reasonable estimate, subject to adjustment during a reasonable measurement period, not to exceed twelve months, until the accounting and analysis under Topic 740 is complete. Although further guidance and clarification from the relevant authorities is expected to continue into 2019, in accordance with SAB 118's twelve month measurement period, we have completed our analysis of the income tax effect of the Tax Reform Act including (i) the mandatory, deemed repatriation aspect of the Tax Reform Act, (ii) the amount of deferred tax assets and liabilities subject to the income tax rate change from 35% to 21%, (iii) the ability to more likely than not realize the benefit of deferred tax assets, including net operating losses and foreign tax credits, and (iv) our position with regard to the permanent reinvestment of non-U.S. earnings, and, consequently, we recorded a net tax benefit of $21.0 million in 2018.

Our income tax expense is a function of the mix between our domestic and international pre-tax earnings or losses, as well as the mix of international tax jurisdictions in which we operate. Certain of our rigs are owned and operated, directly or indirectly, by DFAC. The deferred foreign earnings of our international subsidiaries were deemed to be repatriated under the Tax Reform Act, and our management has determined that we will no longer permanently reinvest foreign earnings. As of December 2018, we recorded $0.5 million for the withholding income tax impact associated with the potential distribution of DFAC's earnings. We have not provided income tax on the outside basis difference of our international subsidiaries as management does not intend to dispose of these subsidiaries and structuring alternatives exist to mitigate any potential liability should a disposition take place. The potential unrecorded tax liability associated with the outside basis difference is approximately $116 million.

The components of income tax expense (benefit) are as follows (in thousands):

	Year Ended December 31,		
	2018	2017	2016
Federal – current	$ 20,107	$ 6,994	$ 230
State – current	2	95	(60)
Foreign – current	9,531	25,252	10,297
Total current	29,640	32,341	10,467
Federal – deferred	(75,279)	(85,066)	(108,274)
Foreign – deferred	(714)	12,939	2,011
Total deferred	(75,993)	(72,127)	(106,263)
Total	$(46,353)	$(39,786)	$ (95,796)

The difference between actual income tax expense and the tax provision computed by applying the statutory federal income tax rate to income before taxes is attributable to the following (in thousands):

	Year Ended December 31,		
	2018	2017	2016
(Loss) income before income tax expense:			
U.S.	$(266,855)	$(241,178)	$(146,037)
Foreign	40,230	219,738	(322,262)
	$(226,625)	$ (21,440)	$(468,299)
Expected income tax benefit at federal statutory rate	$ (47,591)	$ (7,504)	$(163,905)
Effect of tax rate changes	1,763	(74,294)	—
Mandatory repatriation of earnings pursuant to Tax Reform Act	—	94,194	—
Effect of foreign operations	15	(42,102)	48,573
Valuation allowance	11,929	(41,492)	62,400
Uncertain tax positions, settlements and adjustments relating to prior years	(15,777)	31,726	(34,666)
Other	3,308	(314)	(8,198)
Income tax benefit	$ (46,353)	$ (39,786)	$ (95,796)

Deferred Income Taxes. Significant components of our deferred income tax assets and liabilities are as follows (in thousands):

	December 31,	
	2018	2017
Deferred tax assets:		
Net operating loss carryforwards, or NOLs	$ 209,679	$ 133,298
Foreign tax credits	43,225	27,623
Disallowed interest deduction	16,248	—
Worker's compensation and other current accruals	8,375	10,330
U.K. depreciation deduction	—	52,800
Anticipatory deductions and credits	2,438	13,111
Deferred deductions	10,481	14,483
Other	3,942	3,748
Total deferred tax assets	294,388	255,393
Valuation allowance	(174,970)	(169,224)
Net deferred tax assets	119,418	86,169
Deferred tax liabilities:		
Property, plant and equipment	(212,251)	(236,038)
Mobilization	(11,012)	(17,192)
Other	(535)	(238)
Total deferred tax liabilities	(223,798)	(253,468)
Net deferred tax liability	$(104,380)	$(167,299)

Net Operating Loss Carryforwards. As of December 31, 2018, we recorded a deferred tax asset of $209.7 million for the benefit of NOL carryforwards, comprised of $96.9 million related to our U.S. losses and $112.8 million related to our international operations. Approximately $111.6 million of this deferred tax asset relates to NOL carryforwards that have an indefinite life. The remaining $98.1 million relates to NOL carryforwards in several of our foreign subsidiaries, as well as in the U.S. Unless utilized, the NOL carryforwards will expire between 2021 and 2028.

Foreign Tax Credits. As of December 31, 2018, we recorded a deferred tax asset of $43.2 million for the benefit of foreign tax credits in the U.S., all of which will expire, unless utilized, between 2020 to 2027.

Interest Deduction Carryforward. The Tax Reform Act signed into law in 2017 imposed new limitations to Code Section 163(j), restricting the ability to deduct interest paid or accrued on indebtedness. As of December 2018, we recorded a deferred tax asset for the benefit of the interest deduction carryforward in the amount of $16.2 million. The interest carryforward has an indefinite life.

Valuation Allowances. We record a valuation allowance to derecognize a portion of our deferred tax assets, which we do not expect to be ultimately realized. During the years ended December 31, 2018, 2017 and 2016, we established valuation allowances related to net operating losses, foreign tax credits and other deferred tax assets of $35.2 million, $37.9 million and $77.5 million, respectively. During the years ended December 31, 2018, 2017 and 2016, we released valuation allowances in various jurisdictions of $23.3 million, $79.4 million and $13.5 million, respectively. The valuation allowance was also reduced by a $6.2 million adjustment to retained earnings at January 1, 2018 in connection with our adoption of ASU 2016-16. See Note 1 "General Information – *Changes in Accounting Principles* – Income Taxes."

As of December 31, 2018, valuation allowances of $98.8 million, $42.3 million, $16.2 million and $17.7 million have been recorded for our NOLs, foreign tax credits, interest deduction carryforward and other deferred tax assets, respectively, for which the tax benefits are not likely to be realized.

Unrecognized Tax Benefits. Our income tax returns are subject to review and examination in the various jurisdictions in which we operate, and we are currently contesting various tax assessments. We accrue for income tax contingencies, or uncertain tax positions, that we believe are not likely to be realized. A rollforward of the beginning and ending amount of unrecognized tax benefits, excluding interest and penalties, is as follows (in thousands):

	For the Year Ended December 31,		
	2018	2017	2016
Balance, beginning of period	$(81,864)	$(34,970)	$(53,952)
Additions for current year tax positions	(2,906)	(51,260)	(4,233)
Additions for prior year tax positions	(20,943)	(2,938)	(1,020)
Reductions for prior year tax positions	49,175	623	19,661
Reductions related to statute of limitation expirations	595	6,681	4,574
Balance, end of period	$(55,943)	$(81,864)	$(34,970)

The $20.9 million addition for prior year tax positions in 2018 is primarily due to recent proposed regulations issued to clarify the use of certain tax attributes against the deemed, mandatory repatriation provision of the Tax Reform Act. The $49.2 million reduction for prior year tax positions in 2018 is primarily due to clarification issued by the IRS in regard to tax attributes available to offset the deemed, mandatory repatriation. The $51.3 million addition for current year tax positions for 2017 is primarily attributable to a provisional liability associated with the use of tax attributes in conjunction with the deemed, mandatory repatriation provision of the Tax Reform Act. The $19.7 million reduction for prior year tax positions in 2016 resulted primarily from the devaluation of the Egyptian Pound.

At December 31, 2018, $1.2 million, $7.5 million and $72.2 million of the net liability for uncertain tax positions were reflected in "Other assets," "Deferred tax liability" and "Other liabilities," respectively. At December 31, 2017, $2.3 million, $51.3 million and $52.9 million of the net liability for uncertain tax positions were reflected in "Other assets," "Deferred tax liability" and "Other liabilities," respectively. Of the net unrecognized tax benefits at December 31, 2018, 2017 and 2016, all $81.6 million, $101.9 million and $36.0 million, respectively, would affect the effective tax rates if recognized.

At December 31, 2018, the amount of accrued interest and penalties related to uncertain tax positions was $3.2 million and $16.3 million, respectively. At December 31, 2017, the amount of accrued interest and penalties related to uncertain tax positions was $3.1 million and $15.1 million, respectively.

We record interest related to accrued uncertain tax positions in interest expense and recognize penalties associated with uncertain tax positions in tax expense. Interest expense (benefit) recognized during the years ended December 31, 2018, 2017 and 2016 related to uncertain tax positions was $0.1 million, $0.5 million and $(0.1) million, respectively. Penalties recognized during the years ended December 31, 2018, 2017 and 2016 related to uncertain tax positions were $0.6 million $(1.7) million and $(23.2) million, respectively.

We expect the statute of limitations for the 2012 through 2017 tax years to expire in 2019 for various of our subsidiaries operating in Egypt, Ireland, Malaysia, Mexico and the U.K. We anticipate that the related unrecognized tax benefit will decrease by $3.9 million at that time.

Tax Returns and Examinations. We file income tax returns in the U.S. federal jurisdiction, various state jurisdictions and various foreign jurisdictions. Tax years that remain subject to examination by these jurisdictions include the year 2000 and the years 2006 to 2017. We are currently under audit in the United States, Australia, Brazil, Egypt, Equatorial Guinea, Mexico, Nicaragua, Qatar and the United Kingdom, or U.K. We do not anticipate that any adjustments resulting from the tax audit of any of these years will have a material impact on our consolidated results of operations, financial condition or cash flows.

17. Employee Benefit Plans

Defined Contribution Plans

We maintain defined contribution retirement plans for our U.S., U.K., and third-country national, or TCN, employees. The plan for our U.S. employees, or the 401k Plan, is designed to qualify under Section 401(k) of the Code. Under the 401k Plan, each participant may elect to defer taxation on a portion of his or her eligible earnings, as defined by the 401k Plan, by directing his or her employer to withhold a percentage of such earnings. A participating employee may also elect to make after-tax contributions to the 401k Plan. During 2018, 2017 and 2016, we matched 5%, 5% and 6%, respectively, of each employee’s compensation contributed to the 401k Plan. Participants are fully vested in the employer match immediately upon enrollment in the 401k Plan and subject to a three-year cliff vesting period for any profit sharing contribution. For the years ended December 31, 2018, 2017 and 2016, our provision for contributions was $8.0 million, $8.9 million and $12.9 million, respectively.

The defined contribution retirement plan for our U.K. employees provides that we make annual contributions in an amount equal to the employee’s contributions generally up to a maximum percentage of the employee’s defined compensation per year. Our contribution during 2018, 2017 and from July 1, 2016 to December 31, 2016 for employees working in the U.K. sector of the North Sea was 6% of the employee’s defined compensation. During the first six months of 2016, our contribution was 10% of the employee’s defined compensation. Our provision for contributions was $1.5 million, $1.4 million and $2.0 million for the years ended December 31, 2018, 2017 and 2016, respectively.

The defined contribution retirement plan for our TCN employees, or International Savings Plan, is similar to the 401k Plan. During 2018, 2017 and 2016, we matched 5%, 5% and 6%, respectively, of each employee’s compensation contributed to the International Savings Plan. Our provision for contributions was $0.4 million, $0.4 million and $0.8 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Deferred Compensation and Supplemental Executive Retirement Plan

Our Amended and Restated Diamond Offshore Management Company Supplemental Executive Retirement Plan, or Supplemental Plan, provides benefits to a select group of our management or other highly compensated employees to compensate such employees for any portion of the applicable percentage of the base salary contribution and/or matching contribution under the 401k Plan that could not be contributed to that plan because of limitations within the Code. Our provision for contributions to the Supplemental Plan for 2018, 2017 and 2016 was approximately $0.1 million in each respective year.

18. Segments and Geographic Area Analysis

Although we provide contract drilling services with different types of offshore drilling rigs and also provide such services in many geographic locations, we have aggregated these operations into one reportable segment based on the similarity of economic characteristics due to the nature of the revenue-earning process as it relates to the offshore drilling industry over the operating lives of our drilling rigs.

Our drilling rigs are highly mobile and may be moved to other markets throughout the world in response to market conditions or customer needs. At December 31, 2018, our active drilling rigs were located offshore three countries in addition to the United States. Revenues by geographic area are presented by attributing revenues to the individual country or areas where the services were performed.

The following tables provide information about disaggregated revenue by equipment-type and primary geographical market (in thousands):

	Year Ended December 31, 2018				
	Floater Rigs	Jack-up Rigs [1]	Total Contract Drilling Revenues	Revenues Related to Reimbursable Expenses	Total
United States	$ 628,574	$8,413	$ 636,987	$ 7,436	$ 644,423
Australia/Asia	167,398	—	167,398	7,811	175,209
South America	170,839	—	170,839	(26)	170,813
Europe	84,749	—	84,749	8,021	92,770
Total	$1,051,560	$8,413	$1,059,973	$23,242	$1,083,215

(1) Loss-of-hire insurance proceeds related to early contract terminations for two jack-up rigs.

	Year Ended December 31, 2017				
	Floater Rigs	Jack-up Rigs	Total Contract Drilling Revenues	Revenues Related to Reimbursable Expenses	Total
United States	$ 619,655	$ —	$ 619,655	$10,940	$ 630,595
Australia/Asia	290,552	—	290,552	17,373	307,925
South America	348,721	—	348,721	(242)	348,479
Europe	171,147	—	171,147	6,456	177,603
Mexico	—	21,144	21,144	—	21,144
Total	$1,430,075	$21,144	$1,451,219	$34,527	$1,485,746

	Year Ended December 31, 2016				
	Floater Rigs	Jack-up Rigs	Total Contract Drilling Revenues	Revenues Related to Reimbursable Expenses	Total
United States	$ 482,638	$ 4,882	$ 487,520	$ 9,832	$ 497,352
Australia/Asia	234,182	—	234,182	14,795	248,977
South America	434,956	—	434,956	720	435,676
Europe	330,340	—	330,340	49,781	380,121
Mexico	12,885	25,331	38,216	—	38,216
Total	$1,495,001	$30,213	$1,525,214	$75,128	$1,600,342

An individual international country may, from time to time, comprise a material percentage of our total contract drilling revenues from unaffiliated customers. For the years ended December 31, 2018, 2017 and 2016, individual countries that comprised 5% or more of our total contract drilling revenues from unaffiliated customers are listed below.

	Year Ended December 31,		
	2018	2017	2016
Brazil	15.8%	18.9%	18.0%
Malaysia	10.5%	11.2%	1.7%
United Kingdom	8.5%	12.0%	15.3%
Australia	5.6%	9.5%	12.8%
Trinidad & Tobago	—	4.6%	9.2%

The following table presents our long-lived tangible assets by geographic location as of December 31, 2018, 2017 and 2016. A substantial portion of our assets is comprised of rigs that are mobile, and therefore asset locations at the end of the period are not necessarily indicative of the geographic distribution of the earnings generated by such assets during the periods and may vary from period to period due to the relocation of rigs. In circumstances where our drilling rigs were in transit at the end of a calendar year, they have been presented in the tables below within the geographic area in which they were expected to operate (in thousands).

	December 31,		
	2018[1]	2017[1]	2016(1)
Drilling and other property and equipment, net:			
United States	$2,245,989	$2,300,956	$2,753,511
International:			
Europe/Africa	1,084,540	320,473	380,462
Australia/Asia/Middle East	927,919	1,714,246	1,429,563
South America	923,355	923,398	1,030,069
Mexico	2,419	2,568	133,330
	2,938,233	2,960,685	2,973,424
Total	$5,184,222	$5,261,641	$5,726,935

(1) During 2018, 2017 and 2016, we recorded aggregate impairment losses of $27.2 million, $99.3 million and $678.1 million, respectively, to write down certain of our drilling rigs and related equipment with indicators of impairment to their estimated recoverable amounts.

The following table presents the countries in which material concentrations of our long-lived tangible assets were located as of December 31, 2018, 2017 and 2016:

	December 31,		
	2018	2017	2016
United States	43.3%	43.7%	48.1%
United Kingdom	20.9%	2.5%	2.9%
Brazil	17.8%	17.5%	16.8%
Singapore	7.1%	—	—
Malaysia	6.1%	20.6%	13.6%
Australia	4.7%	12.0%	11.4%

As of December 31, 2018, 2017 and 2016, no other countries had more than a 5% concentration of our long-lived tangible assets.

Major Customers

Our customer base includes major and independent oil and gas companies and government-owned oil companies. Revenues from our major customers for the years ended December 31, 2018, 2017 and 2016 that contributed more than 10% of our total revenues are as follows:

	Year Ended December 31,		
Customer	**2018**	**2017**	**2016**
Anadarko	33.8%	24.9%	22.4%
Hess Corporation	25.0%	16.0%	7.7%
Petróleo Brasileiro S.A.	15.8%	18.9%	17.9%
BP	10.5%	15.8%	9.0%

19. Unaudited Quarterly Financial Data

Unaudited summarized financial data by quarter for the years ended December 31, 2018 and 2017 is shown below (in thousands).

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2018				
Revenues	$295,510	$268,861	$286,322	$232,522
Operating income (loss) (1)	512	(52,375)	(23,043)	(37,277)
(Loss) income before income tax expense	(25,142)	(79,286)	(55,894)	(66,303)
Net income (loss)	19,321	(69,274)	(51,112)	(79,207)
Net income (loss) per share, basic and diluted	$ 0.14	$ (0.50)	$ (0.37)	$ (0.58)
2017				
Revenues	$374,226	$399,289	$366,023	$346,208
Operating income (loss) (2)	50,859	20,824	58,581	(6,385)
Income (loss) before income tax expense	24,462	(7,020)	(3,801)	(35,081)
Net income (loss)	23,539	15,949	10,799	(31,941)
Net income (loss) per share, basic and diluted	$ 0.17	$ 0.12	$ 0.08	$ (0.23)

(1) During the second quarter of 2018, we recognized an impairment loss of $27.2 million to write down the carrying value of the *Ocean Scepter* to its estimated recoverable amount. See Notes 1 and 3.

(2) During the second and fourth quarters of 2017, we recognized aggregate impairment losses of $71.2 million and $28.0 million, respectively, to write down certain of our drilling rigs with indicators of impairment to their estimated recoverable amounts. See Notes 1 and 3.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

Not applicable.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that are designed to ensure information required to be disclosed by us in reports that we file or submit under the federal securities laws, including this report, is recorded, processed, summarized and reported on a timely basis. These disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed by us under the federal securities laws is accumulated and communicated to our management on a timely basis to allow decisions regarding required disclosure.

Our Chief Executive Officer, or CEO, and Chief Financial Officer, or CFO, participated in an evaluation by our management of the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of December 31, 2018. Based on their participation in that evaluation, our CEO and CFO concluded that our disclosure controls and procedures were effective as of December 31, 2018.

Internal Control Over Financial Reporting

Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for Diamond Offshore Drilling, Inc. Our internal control system was designed to provide reasonable assurance to our management and Board of Directors regarding the preparation and fair presentation of published financial statements.

There are inherent limitations to the effectiveness of any control system, however well designed, including the possibility of human error or mistakes, faulty judgments in decision-making and the possible circumvention or overriding of controls. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Management must make judgments with respect to the relative cost and expected benefits of any specific control measure. The design of a control system also is based in part upon assumptions and judgments made by management about the likelihood of future events, and there can be no assurance that a control will be effective under all potential future conditions. As a result, even an effective system of internal controls can provide no more than reasonable assurance with respect to the fair presentation of financial statements and the processes under which they were prepared. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2018. In making this assessment, our management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control – Integrated Framework (2013)*. Based on this assessment our management believes that, as of December 31, 2018, our internal control over financial reporting was effective.

Deloitte & Touche LLP, the registered public accounting firm that audited our financial statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of our internal control over financial reporting. The attestation report of Deloitte & Touche LLP is included at the beginning of Item 8 of this Form 10-K.

There were no changes in our internal control over financial reporting identified in connection with the foregoing evaluation that occurred during our fourth fiscal quarter of 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information.

Not applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Information about our directors and persons nominated to become directors is contained under the caption "Election of Directors" in our Proxy Statement for our 2019 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2018, or our 2019 Proxy Statement, and is incorporated herein by reference. Information about our executive officers is reported under the caption "Executive Officers of the Registrant" in Item 1 of Part I of this Report.

Information about beneficial ownership reporting compliance is contained under the caption "Section 16(a) Beneficial Ownership Reporting Compliance" in our 2019 Proxy Statement and is incorporated herein by reference.

We have a Code of Business Conduct and Ethics that applies to all of our directors, officers and employees, including our principal executive officer, principal financial officer and principal accounting officer. Our code can be found in the Corporate Governance section of our website at www.diamondoffshore.com and is available in print to any stockholder who requests a copy by writing to our Corporate Secretary at Diamond Offshore, Attention: Corporate Secretary, 15415 Katy Freeway, Suite 100, Houston, Texas 77094. We intend to post any changes to or waivers of our code for our directors or executive officers, including our principal executive officer, principal financial officer and principal accounting officer, on our website within the time period required by the SEC and the NYSE.

Information about the procedures by which security holders may recommend nominees to our Board of Directors can be found in our 2019 Proxy Statement under the captions "Board Diversity and Director Nominating Process" and "Communications with Diamond Offshore and Others" and is incorporated herein by reference.

Information about the composition of the Audit Committee and our Audit Committee financial expert is contained in our 2019 Proxy Statement under the caption "Board Committees" and is incorporated herein by reference.

Item 11. Executive Compensation.

Information about Compensation Committee interlocks, director and executive officer compensation and the Compensation Committee report is contained in our 2019 Proxy Statement under the captions "Compensation Discussion and Analysis," "Executive Compensation," "Equity Plan," "Director Compensation," "Board Committees – Compensation Committee – Compensation Committee Interlocks and Insider Participation" and "Compensation Committee Report" and is incorporated herein by reference.

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

Information about securities authorized for issuance under equity compensation plans is contained in our 2019 Proxy Statement under the caption "Equity Plan" and is incorporated herein by reference.

Information about the number of shares of our common stock beneficially owned by each director and named executive officer, by all directors and executive officers as a group and by each beneficial owner of more than 5% of our common stock is contained under the captions "Stock Ownership of Principal Stockholders" and "Stock Ownership of Management and Directors" in our 2019 Proxy Statement and is incorporated herein by reference.

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

Information about certain relationships and related transactions and director independence is contained under the captions “Director Independence” and “Transactions with Related Persons” in our 2019 Proxy Statement and is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services.

Information about our Audit Committee’s pre-approval policy and procedures for audit and other services and information about our principal accountant fees and services is contained in our 2019 Proxy Statement under the caption “Ratification of Appointment of Independent Auditor – Audit Fees” and “ – Auditor Engagement and Pre-Approval Policy” and is incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

(a) Index to Financial Statements and Financial Statement Schedules

(b) Exhibits

Exhibit No.	Description
3.1	Amended and Restated Certificate of Incorporation of Diamond Offshore Drilling, Inc. (incorporated by reference to Exhibit 3.1 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003) (SEC File No. 1-13926).
3.2	Amended and Restated By-laws (as amended through October 4, 2013) of Diamond Offshore Drilling, Inc. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed October 8, 2013).
4.1	Indenture, dated as of February 4, 1997, between Diamond Offshore Drilling, Inc. and The Bank of New York Mellon Trust Company, N.A. (successor to The Bank of New York Mellon which was previously known as The Bank of New York) (as successor to The Chase Manhattan Bank), as Trustee (incorporated by reference to Exhibit 4.1 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2001) (SEC File No. 1-13926).
4.2	Seventh Supplemental Indenture, dated as of October 8, 2009, between Diamond Offshore Drilling, Inc. and The Bank of New York Mellon Trust Company, N.A. (successor to The Bank of New York Mellon), as Trustee (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K filed October 8, 2009) (SEC File No. 1-13926).
4.3	Eighth Supplemental Indenture, dated as of November 5, 2013, between Diamond Offshore Drilling, Inc. and The Bank of New York Mellon Trust Company, N.A. (successor to The Bank of New York Mellon), as Trustee (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K filed November 5, 2013).
4.4	Ninth Supplemental Indenture, dated as of August 15, 2017, between Diamond Offshore Drilling, Inc. and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K filed August 16, 2017).
10.1	Registration Rights Agreement (the "Registration Rights Agreement") dated October 16, 1995 between Loews Corporation and Diamond Offshore Drilling, Inc. (incorporated by reference to Exhibit 10.1 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2001) (SEC File No. 1-13926).
10.2	Amendment to the Registration Rights Agreement, dated September 16, 1997, between Loews Corporation and Diamond Offshore Drilling, Inc. (incorporated by reference to Exhibit 10.2 to our Annual Report on Form 10-K for the fiscal year ended December 31, 1997) (SEC File No. 1-13926).

Exhibit No.	Description
10.3	Services Agreement, dated October 16, 1995, between Loews Corporation and Diamond Offshore Drilling, Inc. (incorporated by reference to Exhibit 10.3 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2001) (SEC File No. 1-13926).
10.4+	Amended and Restated Diamond Offshore Management Company Supplemental Executive Retirement Plan effective as of January 1, 2007 (incorporated by reference to Exhibit 10.4 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2006) (SEC File No. 1-13926).
10.5+	Diamond Offshore Management Bonus Program, as amended and restated, and dated as of December 31, 1997 (incorporated by reference to Exhibit 10.6 to our Annual Report on Form 10-K for the fiscal year ended December 31, 1997) (SEC File No. 1-13926).
10.6+	Diamond Offshore Drilling, Inc. Equity Incentive Compensation Plan (incorporated by reference to Exhibit B attached to our definitive proxy statement on Schedule 14A filed April 1, 2014).
10.7+	Form of Stock Option Certificate for grants to executive officers, other employees and consultants pursuant to the Equity Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed October 1, 2004) (SEC File No. 1-13926).
10.8+	Form of Stock Option Certificate for grants to non-employee directors pursuant to the Equity Incentive Compensation Plan (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed October 1, 2004) (SEC File No. 1-13926).
10.9+	Form of Award Certificate for stock appreciation right grants to the Company’s executive officers, other employees and consultants pursuant to the Equity Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed April 28, 2006) (SEC File No. 1-13926).
10.10+	Form of Award Certificate for stock appreciation right grants to non-employee directors pursuant to the Equity Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2007) (SEC File No. 1-13926).
10.11+	Form of Award Certificate for grants of Performance Restricted Stock Units under the Equity Incentive Compensation Plan (incorporated by reference to Exhibit 10.5 to our Quarterly Report Form 10-Q for the quarterly period ended March 31, 2014).
10.12+	Specimen Agreement for grants of restricted stock units to officers under the Equity Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed March 30, 2015).
10.13+	Specimen Agreement for grants of restricted stock units to the Chief Executive Officer under the Equity Incentive Compensation Plan (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed March 30, 2015).
10.14+	Specimen agreement for grants of restricted stock units to executive officers under the Equity Incentive Compensation Plan (incorporated by reference to Exhibit 10.4 to our Current Report on Form 8-K filed March 14, 2018).
10.15+	Specimen agreement for grants of restricted stock units to the Chief Executive Officer under the Equity Incentive Compensation Plan (incorporated by reference to Exhibit 10.5 to our Current Report on Form 8-K filed March 14, 2018).
10.16+	The Diamond Offshore Drilling, Inc. Incentive Compensation Plan (Amended and Restated as of January 1, 2018, as amended June 28, 2018) (incorporated by reference to Exhibit 10.1 to our Quarterly Report Form 10-Q for the quarterly period ended June 30, 2018).
10.17+	Specimen agreement for cash incentive awards to executive officers under the Incentive Compensation Plan (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed March 14, 2018).

Exhibit No.	Description
10.18+	Specimen agreement for performance cash incentive awards to the Chief Executive Officer under the Incentive Compensation Plan (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K filed March 14, 2018).
10.19	5-Year Revolving Credit Agreement, dated as of September 28, 2012, among Diamond Offshore Drilling, Inc., Wells Fargo Bank, National Association, as administrative agent and swingline lender, the issuing banks named therein and the lenders named therein (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed October 1, 2012) (SEC File No. 1-13926).
10.20	Extension Agreement and Amendment No. 1 to Credit Agreement, dated as of December 9, 2013, among Diamond Offshore Drilling, Inc., Wells Fargo Bank, National Association, as an issuing bank, as swingline lender and as administrative agent for the lenders, and the lenders named therein (incorporated by reference to Exhibit 10.20 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2013).
10.21	Commitment Increase and Amendment No. 2 to Credit Agreement, dated as of March 17, 2014, among Diamond Offshore Drilling, Inc., Wells Fargo Bank, National Association, as an issuing bank, as swingline lender and as administrative agent for the lenders, and the lenders named therein (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2014).
10.22	Commitment Increase and Extension Agreement and Amendment No. 3 to Credit Agreement, dated as of October 22, 2014, among Diamond Offshore Drilling, Inc., Wells Fargo Bank, National Association, as administrative agent and swingline lender, the issuing banks named therein and the lenders named therein (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed October 24, 2014).
10.23	Extension Agreement and Amendment No. 4 to Credit Agreement, dated as of October 22, 2015, among Diamond Offshore Drilling, Inc., Wells Fargo Bank, National Association, as administrative agent and swingline lender, the issuing banks named therein and the lenders named therein (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2015).
10.24	Agreement and Amendment No. 5 to Credit Agreement, dated as of August 18, 2016, among Diamond Offshore Drilling, Inc., Wells Fargo Bank, National Association, as administrative agent and swingline lender, the issuing banks named therein and the lenders named therein (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2016).
10.25	Amendment No. 6 and Consent to Credit Agreement and Successor Agency Agreement, dated as of October 2, 2018, among Diamond Offshore Drilling, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, Wilmington Trust, National Association, as successor administrative agent, the lenders party thereto and the other parties thereto (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed October 4, 2018).
10.26	5-Year Revolving Credit Agreement, dated as of October 2, 2018, among Diamond Offshore Drilling, Inc., as the U.S. borrower, Diamond Foreign Asset Company, as the foreign borrower, Wells Fargo Bank, National Association, as administrative agent and swingline lender, the issuing banks named therein and the lenders named therein (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed October 4, 2018).
10.27+	Diamond Offshore Executive Retention Plan (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed January 31, 2017).
10.28+	Form of Retention Agreement under Diamond Offshore Executive Retention Plan (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed January 31, 2017).

Exhibit No.	Description
10.29+	Executive Retention Agreement, dated June 29, 2018, between Diamond Offshore Drilling, Inc. and Ronald Woll (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed July 2, 2018).
21.1*	List of Subsidiaries of Diamond Offshore Drilling, Inc.
23.1*	Consent of Deloitte & Touche LLP.
24.1*	Power of Attorney (set forth on the signature page hereof).
31.1*	Rule 13a-14(a) Certification of the Chief Executive Officer.
31.2*	Rule 13a-14(a) Certification of the Chief Financial Officer.
32.1*	Section 1350 Certification of the Chief Executive Officer and Chief Financial Officer.
101.INS**	XBRL Instance Document.
101.SCH**	XBRL Taxonomy Extension Schema Document.
101.CAL**	XBRL Taxonomy Calculation Linkbase Document.
101.LAB**	XBRL Taxonomy Label Linkbase Document.
101.PRE**	XBRL Presentation Linkbase Document.
101.DEF**	XBRL Taxonomy Extension Definition.

* Filed or furnished herewith.

** The documents formatted in XBRL (Extensible Business Reporting Language) and attached as Exhibit 101 to this report are deemed not filed or part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act, are deemed not filed for purposes of section 18 of the Exchange Act, and otherwise, not subject to liability under these sections.

\+ Management contracts or compensatory plans or arrangements.

Item 16. Form 10-K Summary.

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on February 13, 2019.

DIAMOND OFFSHORE DRILLING, INC.

By: /s/ SCOTT KORNBLAU
Scott Kornblau
Chief Financial Officer

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints Scott Kornblau and David L. Roland and each of them, as his or her true and lawful attorneys-in-fact and agents, with full power of substitution and re-substitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all documents relating to this Annual Report on Form 10-K, including any and all amendments and supplements thereto, and to file the same with all exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully as to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or their or his or her substitute or substitutes may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ MARC EDWARDS Marc Edwards	President, Chief Executive Officer and Director (Principal Executive Officer)	February 13, 2019
/s/ SCOTT KORNBLAU Scott Kornblau	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 13, 2019
/s/ BETH G. GORDON Beth G. Gordon	Vice President and Controller (Principal Accounting Officer)	February 13, 2019
/s/ JAMES S. TISCH James S. Tisch	Chairman of the Board	February 13, 2019
/s/ CHARLES L. FABRIKANT Charles L. Fabrikant	Director	February 13, 2019
/s/ PAUL G. GAFFNEY II Paul G. Gaffney II	Director	February 13, 2019
/s/ EDWARD GREBOW Edward Grebow	Director	February 13, 2019
/s/ KENNETH I. SIEGEL Kenneth I. Siegel	Director	February 13, 2019

Signature	Title	Date
/s/ CLIFFORD M. SOBEL Clifford M. Sobel	Director	February 13, 2019
/s/ ANDREW H. TISCH Andrew H. Tisch	Director	February 13, 2019

CORPORATE INFORMATION

Corporate Headquarters
15415 Katy Freeway
Houston, TX 77094
281.492.5300
www.diamondoffshore.com

Investor Relations
Samir Ali
Vice President, Investor Relations and Corporate Development
15415 Katy Freeway
Houston, TX 77094
281.647.4035

Notice of Annual Meeting
The Annual Meeting of Stockholders will be held on Wednesday, May 15, 2019, at 8:30 am (EDT) at the offices of:
Loews Corporation
667 Madison Avenue
New York, NY 10065

Transfer Agent & Registrar
Computershare
PO Box 505000
Louisville, KY 40233-5000
877.812.4207
www.computershare.com/investor

Stock Exchange Listing
New York Stock Exchange
Trading Symbol "DO"

Independent Auditors
Deloitte & Touche LLP

Design: Savage Brands, Houston TX

DIAMOND
OFFSHORE

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