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, 2017

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from _________ to_________

Commission file number 1-13926

DIAMOND OFFSHORE DRILLING, INC.
(Exact name of registrant as specified in its charter)

Delaware	**76-0321760**
(State or other jurisdiction of incorporation or organization)	*(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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post 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 ☐ (Do not check if a smaller reporting company)	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 7(a)(2)(B) of the Securities Act. ☐

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 as of the last business day of the registrant's most recently completed second fiscal quarter.

As of June 30, 2017 $694,258,330

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 9, 2018 Common Stock, $0.01 par value per share 137,227,782 shares

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement relating to the 2018 Annual Meeting of Stockholders of Diamond Offshore Drilling, Inc., which will be filed within 120 days of December 31, 2017, are incorporated by reference in Part III of this report.

DIAMOND OFFSHORE DRILLING, INC.

FORM 10-K for the Year Ended December 31, 2017

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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 seven ultra-deepwater, four deepwater and two mid-water semisubmersible rigs. The semisubmersible *Ocean Victory* was sold in January 2018 and the jack-up *Ocean Scepter* is currently being marketed for sale. Both rigs have been excluded from our current fleet total. *See* "— Our Fleet — *Fleet Enhancements and Additions*" and "— Our Fleet — *Fleet Status*."

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.

Our floater fleet (semisubmersibles and drillships) can be further categorized based on the nominal water depth for each class of rig as follows:

Category	Rated Water Depth (a) (in feet)	Number of Units in Our Fleet
Ultra-Deepwater	7,501 to 12,000	11
Deepwater	5,000 to 7,500	4
Mid-Water	400 to 4,999	2

(a) Rated water depth for semisubmersibles and drillships reflects the maximum water depth in which a floating rig has been designed to operate. 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).

Fleet Status

The following table presents additional information regarding our floater fleet at January 29, 2018:

Rig Type and Name	Rated Water Depth (in feet)	Attributes	Year Built/ Redelivered [a]	Current Location [b]	Customer [c]
ULTRA-DEEPWATER:					
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 (7):					
Ocean GreatWhite	10,000	DP; 6R; 15K	2016	Malaysia	BP
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/Cooper Energy
Ocean Endeavor	10,000	15K	2007	Italy	Cold Stacked
Ocean Rover	8,000	15K	2003	Malaysia	Cold Stacked
DEEPWATER:					
Semisubmersibles (4):					
Ocean Apex	6,000	15K	2014	Australia	Woodside Energy
Ocean Onyx	6,000	15K	2013	Malaysia	Cold Stacked
Ocean America	5,500	15K	1988	Malaysia	Cold Stacked
Ocean Valiant	5,500	15K	1988	North Sea/U.K.	Maersk
MID-WATER:					
Semisubmersibles (2):					
Ocean Patriot	3,000	15K	1983	North Sea/U.K.	Shipyard/Shell
Ocean Guardian	1,500	15K	1985	North Sea/U.K.	Warm Stacked/Decipher Prod Ltd

Attributes

DP	=	Dynamically Positioned/Self-Propelled	7R	=	2 Seven ram blow out preventers
6R	=	Six ram blow out preventer	15K	=	15,000 psi well control system

(a) 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.

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

(c) For ease of presentation in this table, customer names have been shortened or abbreviated.

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*.

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 — Sources and Uses of Cash — *Capital Expenditures*” in Item 7 of this report.

Pressure Control by the Hour®. In 2016, we launched an initiative to increase the operational efficiency of our rigs by reducing subsea non-productive time, or downtime incurred by a contracted rig due to the performance of routine maintenance on or failure of subsea equipment, primarily the blowout preventer, or BOP. As part of this initiative, we entered into a ten-year collaborative arrangement with a subsidiary of GE Oil & Gas, or GE, to monitor the BOP equipment and proactively manage the maintenance, certification and reliability of such equipment. In connection with the services agreement with GE, we sold the BOP equipment to a GE affiliate and have leased back such equipment under four 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." At the end of 2016, all of our drillships were participants in the PCbtH program. Since the fourth quarter of 2016 through the fourth quarter of 2017, the operational efficiency of our drillships has increased from 95.1% to 99.7%.

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 and Vietnam;
- Europe, principally offshore the United Kingdom, or U.K., and Norway;
- East and West Africa;
- the Mediterranean; and
- the Middle East.

We actively market our rigs worldwide. From time to time our fleet operates in various other markets throughout the world. See Note 17 "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. Many 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 at competitive market rates and mutually agreeable terms 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 — Market Overview — *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 2017, 2016 and 2015, we performed services for 14, 18 and 19 different customers, respectively. During 2017, 2016 and 2015, our most significant customers were as follows:

Customer	Percentage of Annual Consolidated Revenues 2017	2016	2015
Anadarko	24.9%	22.4%	12.4%
Petróleo Brasileiro S.A.	18.9%	17.9%	24.1%
Hess Corporation	16.0%	7.7%	0.3%
BP	15.8%	9.0%	0.1%
ExxonMobil	—	5.8%	12.4%

No other customer accounted for 10% or more of our annual total consolidated revenues during 2017, 2016 or 2015. See "Risk Factors — *Our industry is highly competitive, with oversupply 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, 2018, our contract backlog was $2.4 billion attributable to 13 customers. All four of our drillships are currently contracted to work in the GOM. As of January 1, 2018, contract backlog attributable to our expected operations in the GOM was $653.0 million, $554.0 million and $86.0 million for the years 2018, 2019 and 2020, respectively, all of which was attributable to two customers. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Market Overview — *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 800 mobile drilling rigs in service worldwide, including approximately 260 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 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*" in Item 1A of this report, which are incorporated herein by reference.

Operations Outside the United States

Our operations outside the U.S. accounted for approximately 58%, 66% and 79% of our total consolidated revenues for the years ended December 31, 2017, 2016 and 2015, respectively. See "Risk Factors — *Significant portions of our operations are conducted outside the United States and involve additional risks not associated with United States domestic operations*" and "Risk Factors — *We may be required to accrue additional tax liability on certain of our foreign earnings*" in Item 1A of this report, which are incorporated herein by reference.

Employees

As of December 31, 2017, we had approximately 2,400 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, 2018	Position
Marc Edwards	57	President and Chief Executive Officer and Director
David L. Roland	56	Senior Vice President, General Counsel and Secretary
Thomas Roth	62	Senior Vice President — Worldwide Operations
Ronald Woll	50	Senior Vice President and Chief Commercial Officer
Scott Kornblau	46	Vice President, Acting Chief Financial Officer and Treasurer
Beth G. Gordon	62	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.

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.

Ronald Woll has served as our Senior Vice President and Chief Commercial Officer since June 2014. Mr. Woll previously served as Senior Vice President — Supply Chain at Halliburton Company from January 2011 through June 2014.

Scott Kornblau has served as our Vice President, Acting Chief Financial Officer and Treasurer since December 2017. Mr. Kornblau previously served as our 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, any amendments to those reports, proxy statements and other information with the United States Securities and Exchange Commission, or SEC. You may read and copy the information we file with the SEC at the public reference facilities maintained by the SEC at 100 F Street, N.E., Washington, DC 20549. Please call the SEC at 1-800-SEC-0330 for further information on the operation of the public reference room. Our SEC filings are also 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 has declined significantly as a result of the decline in oil prices, and demand has continued to be depressed in 2017.

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 in 2015, 2016 and 2017, compared to previous years. Any prolonged 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;
- 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 United States 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;
- 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 purporting to address global climate change;
- domestic and foreign tax policy; and
- advances in exploration and development technology.

An increase 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, although, historically, higher commodity prices have generally resulted in increases in offshore drilling projects. 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. 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 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 in the past 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 may also be 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.

Generally, our customers may terminate our drilling contracts under certain circumstances, such as the destruction or loss of a drilling rig, if we suspend 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 and intense price competition*" and "Management's Discussion and Analysis of Financial Condition and Results of Operations — Market Overview — *Contract Drilling Backlog*" in Item 7 of 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 2018 and 2020. 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, and likely substantially 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 customers, during the most recent market downturn, have expressed a preference for ready or "hot" 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 excess spending over 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 27 drilling rigs and recorded impairment losses aggregating $1.7 billion, including $99.3 million recognized in 2017. 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 — Market Overview — *Critical Accounting Estimates — Property, Plant and Equipment*" in Item 7 of this report and Note 2 "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, including rigs designated as held for sale, will ultimately be realized.

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 2017, two of our customers in the GOM and our three largest customers in the aggregate accounted for 41% and 60%, 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 14 in 2017. 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 — Market Overview — *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. Although we intend to defend these matters vigorously, 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 we are generally reimbursed by the customer 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 floater 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. Many of our operating costs, such as labor costs, are unpredictable and may fluctuate based on 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.

Changes in tax laws, 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. 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 and suddenly 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 law, 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 intercompany 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.

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 United States 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 United States 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, 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. 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 and 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.

Governments around the world are also increasingly considering and adopting laws and regulations to address climate change issues. Lawmakers and regulators in the United States 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. 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.

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

Our operations outside the United States accounted for approximately 58%, 66% and 79% of our total consolidated revenues for 2017, 2016 and 2015, 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.

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.

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 assurances 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.

We may be required to accrue additional tax liability on certain of our foreign earnings.

Certain of our international rigs are owned and operated, directly or indirectly, by Diamond Foreign Asset Company, or DFAC, a Cayman Islands subsidiary that we own. It is our intention to continue to indefinitely reinvest the earnings of DFAC and its foreign subsidiaries to finance our foreign activities. We do not expect to provide for U.S. taxes on any earnings generated by DFAC and its foreign subsidiaries, except to the extent that these earnings are immediately subjected to U. S. federal income tax (such as under the Tax Cuts and Jobs Act of 2017). Should a future distribution be made from any unremitted earnings of this subsidiary, we may be required to record additional U.S. income taxes and/or withholding taxes in certain jurisdictions; however, it is not practical to estimate this potential liability.

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.

Although we have paid cash dividends in the past, we did not pay any dividends in 2017 and we may not pay dividends in the future, and we can give no assurance as to the amount or timing of the payment of any future dividends.

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 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. See "Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities — Dividend Policy" in Item 5 of this report and "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources" in Item 7 of this report.

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.

We must make substantial capital and operating expenditures to 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 desired 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; 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. We can provide no assurance that we will have access to adequate or economical sources of capital to fund our capital expenditures.

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, 2017, we had outstanding approximately $2.0 billion of senior notes, maturing at various times from 2023 through 2043. As of February 9, 2018, we had no borrowings outstanding under our revolving credit facility and $1.5 billion available under our credit facility to meet our short-term liquidity requirements. We may incur additional indebtedness in the future and borrow from time to time under our revolving credit facility to fund working capital or other needs, subject to compliance with its covenants.

Our ability to meet our debt service obligations is dependent upon our future performance, which is subject to general economic conditions, industry cycles and financial, business and other factors affecting our operations, many of which are beyond our control. 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;

- our customers may react adversely to our significant debt level and seek alternative service providers; and
- our failure to comply with the restrictive covenants in our debt instruments that, among other things, require us to maintain a specified ratio of our consolidated indebtedness to total capitalization and limit the ability of our subsidiaries to incur debt, could result in an event of default that, if not cured or waived, could have a material adverse effect on our business.

In addition, our $1.5 billion revolving credit facility matures on October 22, 2020, except for $40 million of commitments that mature on March 17, 2019 and $60 million of commitments that mature on October 22, 2019. Our ability to renew or replace our revolving credit facility is dependent on numerous factors, including our financial condition and prospects at the time and the then current state of the bank and capital markets in the U.S. Our liquidity may be adversely affected if we are unable to replace our revolving credit facility upon acceptable terms when it matures.

In July 2017, Moody's Investor Services downgraded our corporate credit rating to Ba3 with a negative outlook from Ba2 with a stable outlook. In October 2017, S&P Global Ratings, or S&P, downgraded our corporate credit rating to B+ from BB-; our outlook by S&P 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 facility bears 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 facility may also increase. Although we may employ hedging strategies such that a portion of the aggregate principal amount outstanding under our credit facility would effectively carry a fixed rate of interest, any hedging arrangement put in place may not offer complete protection from this risk.

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

Our business has become increasingly dependent upon information technologies, systems and networks to conduct day-to-day operations, and we are placing greater reliance on 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 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. It has also 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. 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.

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 9, 2018, 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, a 90%-owned subsidiary engaged in commercial property and casualty insurance; Boardwalk Pipeline Partners, LP, a 51%-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, a 99% 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 11 “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.

Price Range of Common Stock

Our common stock is listed on the New York Stock Exchange, or NYSE, under the symbol "DO." The following table sets forth, for the calendar quarters indicated, the high and low closing prices of our common stock as reported by the NYSE.

	Common Stock	
	High	Low
2017		
First Quarter	$19.49	$14.70
Second Quarter	16.31	10.26
Third Quarter	14.85	10.22
Fourth Quarter	18.94	14.31
2016		
First Quarter	$24.09	$15.55
Second Quarter	26.04	20.28
Third Quarter	26.11	14.80
Fourth Quarter	21.08	15.42

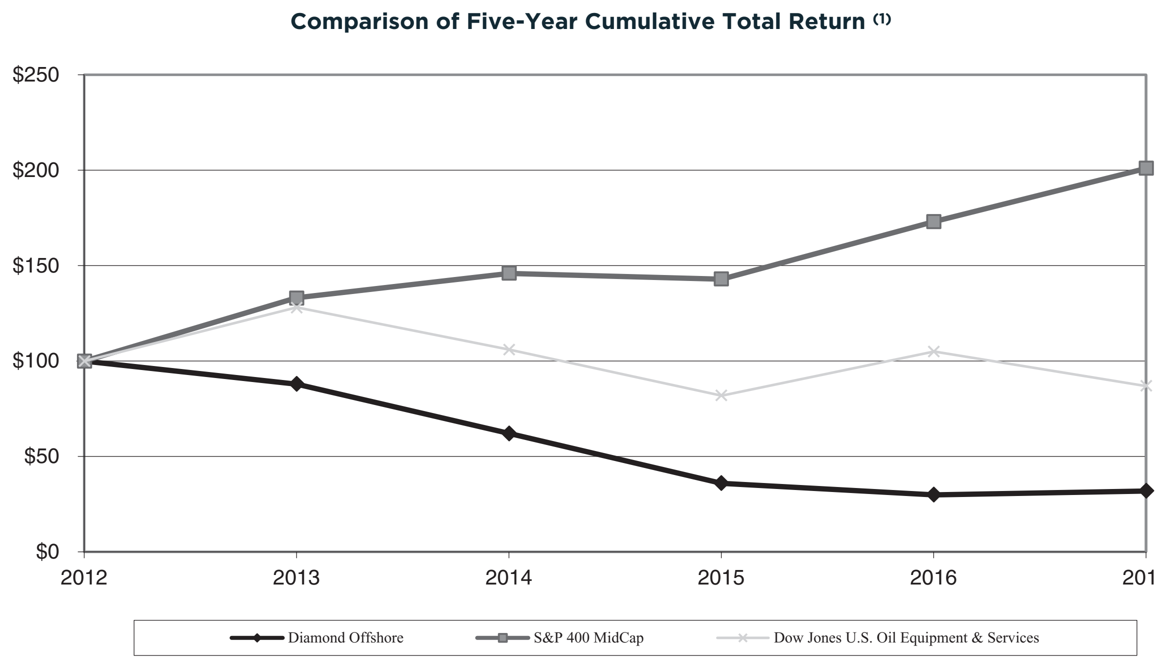
As of February 9, 2018, there were approximately 149 holders of record of our common stock. This number represents registered stockholders and does not include stockholders who hold their shares through an institution.

Dividend Policy

We pay dividends at the discretion of our Board of Directors. 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 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. See "Risk Factors — *Although we have paid cash dividends in the past, we did not pay any dividends in 2017 and we may not pay dividends in the future, and we can give no assurance as to the amount or timing of the payment of any future dividends*" in Item 1A of this report, which is incorporated herein by reference. We discontinued our regular cash dividend in 2016.

CUMULATIVE TOTAL STOCKHOLDER RETURN

The following graph shows the cumulative total stockholder return for our common stock, the Standard & Poor's 400 MidCap Index and the Dow Jones U.S. Oil Equipment & Services index over the five year period ended December 31, 2017.



	Dec. 31, 2012	Dec. 31, 2013	Dec. 31, 2014	Dec. 31, 2015	Dec. 31, 2016	Dec. 31, 2017
Diamond Offshore	100	88	62	36	30	32
S&P 400 MidCap Index	100	133	146	143	173	201
Dow Jones U.S. Oil Equipment & Services	100	128	106	82	105	87

(1) Total return assuming reinvestment of dividends. Assumes $100 invested on December 31, 2012 in our common stock and the two published indices.

Our dividend history for the periods reported above is as follows:

	Q1		Q2		Q3		Q4	
Year	**Regular**	**Special**	**Regular**	**Special**	**Regular**	**Special**	**Regular**	**Special**
2017	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
2016	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
2015	$0.125	$ —	$0.125	$ —	$0.125	$ —	$0.125	$ —
2014	$0.125	$0.75	$0.125	$0.75	$0.125	$0.75	$0.125	$0.75
2013	$0.125	$0.75	$0.125	$0.75	$0.125	$0.75	$0.125	$0.75

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,				
	2017	2016	2015	2014	2013
	(In thousands, except per share and ratio data)				
Income Statement Data:					
Total revenues	$1,485,746	$1,600,342	$2,419,393	$2,814,671	$2,920,421
Operating income (loss)	123,879 (1)	(356,884) (1)	(294,074) (1)	572,562 (1)	801,606
Net income (loss)	18,346	(372,503)	(274,285)	387,011	548,686
Net income (loss) per share:					
Basic	0.13	(2.72)	(2.00)	2.82	3.95
Diluted	0.13	(2.72)	(2.00)	2.81	3.95
Balance Sheet Data:					
Drilling and other property and equipment, net	$5,261,641 (1)	$5,726,935 (1)	$6,378,814 (1)	$6,945,953 (1)	$5,467,227
Total assets	6,250,570	6,371,877	7,149,894 (2)	8,005,398 (2)	8,374,437 (2)
Long-term debt (excluding current maturities) (3)	1,972,225	1,980,884	1,979,778 (2)	1,978,635 (2)	2,227,192 (2)
Other Financial Data:					
Capital expenditures, excluding accruals	$ 139,581	$ 652,673	$ 830,655	$2,032,764 (4)	$ 957,598
Cash dividends declared per share	—	—	0.50	3.50	3.50
Ratio of earnings to fixed charges (5)	0.91x	(3.21)x (6)	(2.45)x (6)	4.64x	7.79x

(1) During 2017, 2016, 2015 and 2014 we recorded impairment losses aggregating $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 — *Years Ended December 31, 2017, 2016, and 2015 — Overview — 2017 Compared to 2016 — Impairment of Assets" and* "Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations — *Years Ended December 31, 2017, 2016 and 2015 — Overview — 2016 Compared to 2015 — Impairment of Assets*" in Item 7 and Note 2 "Asset Impairments" to our Consolidated Financial Statements in Item 8 of this report for a discussion of these impairments.

(2) Historical data for the three annual periods ending on or before December 31, 2015 has been restated to reflect the effect thereon of the adoption on January 1, 2016 of an accounting standard which 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. See Note 1 "General Information — Debt Issuance Costs" to our Consolidated Financial Statements in Item 8 of this report.

(3) See Note 9 "Credit Agreement 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.

(4) During 2014, we took delivery of three ultra-deepwater drillships and two deepwater semisubmersible rigs. The aggregate net book value of these newly constructed rigs was $2.7 billion at December 31, 2014, of which $1.3 billion was reported in construction work-in-progress at December 31, 2013.

(5) For all periods presented, the ratio of earnings to fixed charges has been computed on a total enterprise basis. Earnings represent pre-tax income (loss) from continuing operations plus fixed charges. Fixed charges include (i) interest, whether expensed or capitalized, (ii) amortization of debt issuance costs, whether expensed or capitalized, and (iii) a portion of rent expense, which we believe represents the interest factor attributable to rent.

(6) The deficiency in our earnings available for fixed charges for the years ended December 31, 2016 and 2015 was $479.8 million and $388.9 million, respectively.

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

The following discussion should be read in conjunction with 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 seven ultra-deepwater, four deepwater and two mid-water semisubmersible rigs. The semisubmersible *Ocean Victory* was sold in January 2018 and the jack-up *Ocean Scepter* is currently being marketed for sale. We have excluded both rigs from our current fleet total.

Market Overview

Oil prices have partially rebounded from the historical 12-year low of less than $30 per barrel in January 2016 to the upper $60s-per-barrel range at the end of January 2018. The increase in commodity price is in part due to the late December 2017 shutdown of a major North Sea pipeline which led to production shutdowns at several offshore fields, and, production cuts by certain members of the Organization of Petroleum Exporting Countries, or OPEC, and others that went into effect in 2017 to reduce the oversupply of oil and raise and potentially stabilize oil prices. However, the increase in oil prices has not yet resulted in a measurable increase in demand for offshore contract drilling services or higher dayrates as capital spending for offshore exploration and development remains at a relatively low level at the start of 2018. As a consequence, the offshore contract drilling industry remains weak.

Industry analysts have reported that in 2017, for the third consecutive year, the global supply of floater rigs decreased with 30 floaters being scrapped during the year, for a total of over 80 floaters retired since 2015. Despite these events, the oversupply of drilling rigs in the floater markets continues to persist as drilling rigs across all water depth categories continue to be cold stacked as they come off contract with no immediate future work. Industry reports indicate that there remain approximately 40 newbuild floaters on order with scheduled deliveries between 2018 and 2021. Industry analysts predict that the 2018 delivery dates may be deferred.

Given the oversupply of rigs, competition for the limited number of offshore drilling jobs remains intense. In some cases, dayrates have been negotiated at break-even or below-cost levels in order to enable the drilling contractor to recover a portion of operating costs for rigs that would otherwise be uncontracted or cold stacked. In addition, customers have indicated a preference for "hot" rigs rather than reactivated cold-stacked rigs. This preference incentivizes the drilling contractor to contract rigs at lower rates for the sole purpose of maintaining the rigs in an active state and allowing for at least partial cost recovery.

Our results of operations and cash flows for the three years ended December 31, 2017 have been materially impacted by continuing depressed market conditions in the offshore drilling industry. We currently expect that these adverse market conditions will continue for the near term, which could result in more of our rigs being without contracts, contracted at lower rates than the rigs are currently earning and/or cold stacked or scrapped. These events, if they were to occur, could further materially and adversely affect our financial condition, results of operations and cash flows. When we cold stack or elect to scrap a rig, we evaluate the rig for impairment. During 2017, 2016 and 2015, we recognized aggregate impairment losses of $99.3 million (three rigs), $678.1 million (eight rigs and related spares) and $860.4 million (17 rigs). See "— Results of Operations — *Overview — 2017 Compared to 2016 — Impairment of Assets*," "— Results of Operations — *Overview — 2016 Compared to 2015 — Impairment of Assets*," "Risk Factors — *We may incur additional asset impairments and/or rig retirements as a result of reduced demand for certain offshore drilling rigs*" in Item 1A of this report and Note 2 "Asset Impairments" to our Consolidated Financial Statements in Item 8 of this report.

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. As of January 29, 2018, five rigs in our fleet were cold stacked.

See "— Contract Drilling Backlog" for future commitments of our rigs during 2018 through 2020.

Contract Drilling Backlog

The following table reflects our contract drilling backlog as of January 1, 2018 (based on contract information known at that time), October 1, 2017 (the date reported in our Quarterly Report on Form 10-Q for the quarter ended September 30, 2017), and January 1, 2017 (the date reported in our Annual Report on Form 10-K for the year ended December 31, 2016). 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.

	January 1, 2018	October 1, 2017	January 1, 2017
		(In thousands)	
Contract Drilling Backlog			
Ultra-Deepwater Floaters	$2,222,000	$2,413,000	$3,215,000
Deepwater Floaters	90,000	86,000	197,000
Other Rigs [(1)]	105,000	118,000	152,000
Total	$2,417,000	$2,617,000	$3,564,000

(1) Includes contract drilling backlog for our mid-water floaters and, and for periods prior to 2018, our jack-up rig.

The following table reflects the amount of our contract drilling backlog by year as of January 1, 2018.

	For the Years Ending December 31,			
	Total	2018	2019	2020
		(In thousands)		
Contract Drilling Backlog				
Ultra-Deepwater Floaters	$2,222,000	$1,062,000	$ 927,000	$233,000
Deepwater Floaters	90,000	45,000	45,000	—
Other Rigs [(1)]	105,000	42,000	45,000	18,000
Total	$2,417,000	$1,149,000	$1,017,000	$251,000

(1) Includes contract drilling backlog for our mid-water floaters.

The following table reflects the percentage of rig days committed by year as of January 1, 2018. 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 multiplied by the number of days in a particular year).

	For the Years Ending December 31,		
	2018	2019	2020
Rig Days Committed [(1)]			
Ultra-Deepwater Floaters	71%	59%	17%
Deepwater Floaters	29%	24%	—
Other Rigs [(2)]	37%	33%	12%

(1) As of January 1, 2018, includes approximately 95 currently known, scheduled shipyard days for contract preparation, surveys and extended maintenance projects, as well as mobilization days, for the year 2018.

(2) Includes rig days committed for our mid-water floaters.

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.

Revenue is also 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 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 earn these fees 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. Absent a contract, mobilization costs are recognized currently.

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 the operator 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 2018, we expect to spend approximately 20 and 75 days for special surveys and upgrades for the *Ocean Patriot* and *Ocean Valiant,* respectively. Additionally, we expect to spend approximately 35 days for a special survey for the *Ocean Valor* in 2018, during the paid contracted standby period. 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. 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, 2017, 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, under our current insurance policy, which renewed effective May 1, 2017, 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 is $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.

2017 Reduction Plan. The contract drilling industry has experienced a severe downturn that began in mid-2014 with a dramatic decline in oil prices, resulting in a lack of demand for the services we provide, primarily in the area of deepwater drilling. This lack of demand, combined with a significant oversupply of drilling rigs, has caused our management to again review our organizational and operational structure, in an effort to further reduce our operating profile. In late 2017, we undertook a reorganization of our operational structure, including the identification of redundant positions and, among other things, negotiated the termination of our agency relationship in Brazil. For the year ended December 31, 2017, we recognized $14.1 million in "Restructuring and separation costs" in our Consolidated Statements of Operations primarily associated with the severance of certain executives and other employees and termination of our agency agreement in Brazil, the majority of which was unpaid at December 31, 2017. As we continue to position our organization to compete effectively in what we continue to expect to be a protracted downturn, we expect to continue our assessment of our organizational structure during 2018. For the first quarter of 2018, we expect to incur approximately $3 million in severance costs for additional redundant employees. If market conditions do not significantly improve in the near term and the market downturn remains protracted, additional actions may be required to further reduce our cost profile.

Impact of Changes in Tax Laws or Their Interpretation. We operate through our various subsidiaries in a number of countries 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.

On December 22, 2017, the President of the United States signed into law the Tax Cuts and Jobs Act, commonly referred to as the Tax Reform Act. The Tax Reform Act amended the Internal Revenue Code in several areas that had a direct and immediate effect on our results of operations and statement of financial position as of and for the year ended December 31, 2017, including, among other items, a one-time mandatory deemed repatriation of accumulated earnings of our foreign subsidiaries as of December 31, 2017 and a reduction in the U.S corporate income tax rate from 35% to 21% beginning in January 2018. We have used our best judgment to estimate the impact of the Tax Reform Act on our reported results. Due to the timing of the enactment of the Tax Reform Act, there 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. We will continue to monitor developments in this area and adjust our estimates throughout the year in 2018, as and if necessary, as additional guidance and clarification becomes available. See "*— Critical Accounting Estimates — Income Taxes,*" "Results of Operations — *Overview — 2017 Compared to 2016 —* Income Tax Benefit" and Note 15 "Income Taxes" to our Consolidated Financial Statements in Item 8 of this report.

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. Historically, the amount of capital additions requiring significant judgments, assumptions or estimates has not been significant. During the years ended December 31, 2017 and 2016, we capitalized $69.4 million and $177.6 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 2017, in response to continued depressed market conditions for the offshore contract drilling industry and our expectations that a market recovery is not likely to occur in the near term, we evaluated ten of our drilling rigs with indications that their carrying values may not be recoverable. As a result of these evaluations, we determined that the carrying values of one ultra-deepwater semisubmersible, one deepwater semisubmersible and one jack-up rig were impaired and recorded impairment losses of $71.3 million and $28.0 million during the second and fourth quarters of 2017, respectively.

During 2016, we evaluated 15 of our drilling rigs with indications that their carrying amounts may not be recoverable and recorded an aggregate impairment loss of $678.1 million, related to eight rigs including an $8.1 million impairment of rig spares and supplies. During 2015, we evaluated 25 of our drilling rigs with indications that their carrying amounts may not be recoverable and recorded an aggregate impairment loss of $860.4 million related to 17 drilling rigs. See "— Results of Operations — *Overview — 2017 Compared to 2016 — Impairment of Assets*" and "— Results of Operations — *Overview — 2016 Compared to 2015 — Impairment of Assets*" and Note 2 "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, 2017, 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 deductible for personal injury claims arising due to named windstorms in the U.S. Gulf of Mexico is $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 do not establish deferred tax liabilities for certain of our foreign earnings that we intend to indefinitely reinvest to finance foreign activities. However, if these earnings become subject to U.S. federal tax, any required provision could have a material adverse impact on our financial results. 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.

Certain of our international rigs are owned and operated, directly or indirectly, by DFAC. As of December 31, 2017, all unremitted earnings of DFAC have been deemed repatriated as a result of the Tax Reform Act, and U.S. taxes have been provided for them. We intend to indefinitely reinvest earnings of DFAC and its foreign subsidiaries to finance our foreign activities.

The Tax Reform Act requires a U.S. shareholder of a foreign corporation to include in income its global intangible low-taxed income, or GILTI. Due to the fact that the GILTI computation is dependent on contingent or future events that cannot reasonably be known, we have made the accounting policy decision, as permitted by U.S. GAAP, to account for U.S. tax on GILTI, should it be applicable, as a period cost in the period in which the tax would be incurred, as opposed to recognizing deferred taxes on the basis differences that are expected to affect the amount of GILTI.

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 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

Although we perform contract drilling services with different types of drilling rigs and in many geographic locations, there is a 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. We believe that the combination of our drilling rigs into one reportable segment is the appropriate aggregation in accordance with applicable accounting standards on segment reporting. However, for purposes of this discussion and analysis of our results of operations, we provide greater detail with respect to the types of rigs in our fleet to enhance the reader's understanding of our financial condition, changes in financial condition and results of operations.

Key performance indicators by equipment type are listed below.

	Year Ended December 31,		
	2017	2016	2015
REVENUE-EARNING DAYS (1)			
Floaters:			
Ultra-Deepwater	2,546	2,074	2,690
Deepwater	874	844	1,339
Mid-Water	445	727	1,433
Jack-ups	282	149	909
UTILIZATION (2)			
Floaters:			
Ultra-Deepwater	59%	51%	64%
Deepwater	41%	34%	52%
Mid-Water	27%	30%	36%
Jack-ups	61%	8%	42%
AVERAGE DAILY REVENUE (3)			
Floaters:			
Ultra-Deepwater	$428,200	$477,000	$497,700
Deepwater	231,600	304,600	409,800
Mid-Water	309,500	342,000	270,500
Jack-ups	74,900	202,700	93,400

(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 cold-stacked rigs, but excluding rigs under construction). As of December 31, 2017, our cold-stacked rigs included three ultra-deepwater semisubmersibles and two deepwater semisubmersibles. As of December 31, 2016, our cold-stacked rigs included four ultra-deepwater semisubmersibles, three deepwater semisubmersibles, and three mid-water semisubmersibles. As of December 31, 2015, our cold-stacked rigs consisted of one ultra-deepwater, two deepwater and four mid-water semisubmersible rigs and five jack-up rigs, which were being marketed for sale at that time.

(3) Average daily revenue is defined as total contract drilling revenue for all of the specified rigs in our fleet per revenue-earning day.

Comparative data relating to our revenues and operating expenses by equipment type are listed below.

	Year Ended December 31,		
	2017	2016	2015
		(In thousands)	
CONTRACT DRILLING REVENUE			
Floaters:			
Ultra-Deepwater	$1,090,139	$ 989,158	$1,339,059
Deepwater	202,329	256,997	548,667
Mid-Water	137,607	248,846	387,549
Total Floaters	1,430,075	1,495,001	2,275,275
Jack-ups	21,144	30,213	84,909
Total Contract Drilling Revenue	$1,451,219	$1,525,214	$2,360,184
REVENUES RELATED TO REIMBURSABLE EXPENSES	$ 34,527	$ 75,128	$ 59,209
CONTRACT DRILLING EXPENSE			
Floaters:			
Ultra-Deepwater	$ 561,505	$ 494,510	$ 620,122
Deepwater	115,350	148,992	277,779
Mid-Water	69,050	84,194	230,606
Total Floaters	745,905	727,696	1,128,507
Jack-ups	25,428	17,854	65,699
Other	30,631	26,623	33,658
Total Contract Drilling Expense	$ 801,964	$ 772,173	$1,227,864
REIMBURSABLE EXPENSES	$ 33,744	$ 58,058	$ 58,050
OPERATING INCOME (LOSS)			
Floaters:			
Ultra-Deepwater	$ 528,634	$ 494,648	$ 718,937
Deepwater	86,979	108,005	270,888
Mid-Water	68,557	164,652	156,943
Total Floaters	684,170	767,305	1,146,768
Jack-ups	(4,284)	12,359	19,210
Other	(30,631)	(26,623)	(33,658)
Reimbursable expenses, net	783	17,070	1,159
Depreciation	(348,695)	(381,760)	(493,162)
General and administrative expense	(74,505)	(63,560)	(66,462)
Bad debt recovery	—	265	—
Impairment of assets	(99,313)	(678,145)	(860,441)
Restructuring and separation costs	(14,146)	—	(9,778)
Gain (loss) on disposition of assets	10,500	(3,795)	2,290
Total Operating Income (Loss)	$ 123,879	$ (356,884)	$ (294,074)
Other income (expense):			
Interest income	2,473	768	3,322
Interest expense	(113,528)	(89,934)	(93,934)
Loss on extinguishment of senior notes	(35,366)	—	—
Foreign currency transaction (loss) gain	(1,128)	(11,522)	2,465
Other, net	2,230	(10,727)	873
(Loss) income before income tax benefit	(21,440)	(468,299)	(381,348)
Income tax benefit	39,786	95,796	107,063
NET INCOME (LOSS)	$ 18,346	$ (372,503)	$ (274,285)

Overview

2017 Compared to 2016

Operating Income (Loss). Operating results for 2017 increased $480.8 million compared to 2016, primarily due to a lower aggregate impairment loss recognized in 2017 ($578.8 million), combined with reduced depreciation expense ($33.1 million). Depreciation expense decreased compared to 2016, primarily due to a lower depreciable asset base, as a result of asset impairments in 2016 and 2017. These favorable variances were partially offset by a $99.8 million net reduction in rig operating results for our floater and jack-up rigs, $14.1 million in restructuring and severance costs recognized in 2017 and the absence of $14.6 million in net reimbursable revenue earned by the *Ocean Endeavor* in 2016.

Contract drilling revenue decreased $74.0 million during 2017 compared to 2016, primarily as a result of a lower average daily revenue earned by all rig types, partially offset by the favorable impact of an aggregate 353 incremental revenue-earning days. Total contract drilling expense for 2017 increased $29.8 million 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).

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 newly-issued debt and subsequent debt redemption of existing debt in August 2017 ($4.0 million), which was partially offset by reduced interest expense associated with lower borrowings under our revolving credit agreement ($2.8 million). See "— Liquidity and Capital Resources — Senior Notes."

Impairment of Assets. During 2017, we determined that the carrying values of one ultra-deepwater semisubmersible, one deepwater semisubmersible, and one jack-up rig were impaired. As a result, we recorded impairment losses of $71.3 million and $28.0 million during the second and fourth quarters of 2017, respectively. The deepwater semisubmersible rig was sold for scrap in January 2018, and the jack-up rig is being marketed for sale. During the second quarter of 2016, we recognized an aggregate impairment charge of $678.1 million with respect to the carrying values of two mid-water, three deepwater, and three ultra-deepwater semisubmersible rigs, including related rig spares and supplies. See "— Critical Accounting Estimates — *Property, Plant and Equipment*" and Note 1 "General Information — *Assets Held for Sale*" and Note 2 "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. 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. See "Important Factors that May Impact Our Operating Results, Financial Condition or Cash Flows — *2017 Reduction Plan.*"

Gain on Disposition of Assets. During 2017, we sold one ultra-deepwater floater, one deepwater floater, three mid-water 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 one deepwater rig, three midwater rigs and four jack-ups for a net pre-tax loss of $4.0 million.

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 "— Liquidity and Capital Resources — Senior Notes."

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 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, including but not limited to, tax audits or assessments and filed or amended tax returns.

In addition, as a result of the Tax Reform Act that was signed into law on December 22, 2017, we recorded incremental income tax expense of $1.1 million, 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. 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 "Important Factors that May Impact Our Operating Results, Financial Condition or Cash Flows — *Impact of Changes in Tax Laws or Their Interpretation*" and Note 15 "Income Taxes" to our Consolidated Financial Statements in Item 8 of this report.

2016 Compared to 2015

Operating Income (Loss). Operating results for 2016 decreased $62.8 million compared to 2015, primarily due to lower utilization of our rig fleet, which reduced both contract drilling revenue and expense. Our operating results for 2016 reflected an aggregate impairment charge of $678.1 million compared to impairment charges aggregating $860.4 million in 2015. As a result of the impairment charges in 2015 and 2016 and resulting lower depreciable asset base, depreciation expense decreased $111.4 million in 2016 compared to 2015.

Contract drilling revenue decreased $835.0 million, during 2016, compared to 2015, due to depressed market conditions in all floater markets and for our jack-up rig. Operating results for 2016 reflected an aggregate of 2,577 fewer revenue-earning days compared to 2015, and lower average daily revenue earned by our ultra-deepwater and deepwater floater fleets. Average daily revenue increased for our mid-water and jack-up fleets primarily due to the favorable settlement of a contractual dispute and receipt of loss-of-hire insurance proceeds, each in 2016.

Total contract drilling expense for 2016 decreased $455.7 million compared to 2015, reflecting our lower cost structure due to additional rigs idled, cold stacked or retired during 2015 and 2016, as well as the favorable impact of our cost control initiatives. The reduction in contract drilling expense during 2016 included lower costs associated with labor and personnel ($222.9 million), repairs and maintenance ($63.1 million), mobilization ($71.3 million), shorebase and operational support ($48.1 million), freight ($17.4 million), revenue-based agency fees ($16.1 million), inspections ($8.9 million), and other rig operating expenses ($7.9 million), including rig stacking costs and late start penalties recognized in 2015.

Impairment of Assets. During 2016, we recognized an aggregate impairment charge of $678.1 million related to the carrying values of eight rigs, including related rig spares and supplies. In 2015, we recorded an aggregate impairment loss of $860.4 million related to 17 of our rigs, consisting of two ultra-deepwater, one deepwater and nine mid-water floaters and five jack-up rigs. See "— Critical Accounting Estimates — *Property, Plant and Equipment*" and Note 2 "Asset Impairments" to our Consolidated Financial Statements in Item 8 of this report.

Restructuring and Separation Costs. During the first quarter of 2015, our management approved and initiated a reduction in workforce at our onshore bases and corporate facilities, which resulted in the recognition of $9.8 million in restructuring and other employee separation related costs in 2015.

Income Tax Expense. Our effective tax rate for 2016 was 20.5% compared to a 28.1% effective tax rate for 2015. The variance in the tax rate was due to differences in the mix of our domestic and international pre-tax earnings and losses, including asset impairments taken during both 2016 and 2015 in various jurisdictions, with differing tax consequences. The 2016 period was also favorably impacted by a $43.0 million adjustment, primarily related to our Egyptian tax liability for uncertain tax positions related to the devaluation of the Egyptian Pound.

Contract Drilling Revenue and Expense by Equipment Type

2017 Compared to 2016

Ultra-Deepwater Floaters. Revenue generated by our ultra-deepwater floaters increased $101.0 million during 2017 compared to 2016, primarily as a result of 472 incremental revenue-earning days ($225.2 million), partially offset by lower average daily revenue earned ($124.2 million). Revenue-earning days increased primarily due to incremental revenue-earning days for the *Ocean GreatWhite* (351 days), which went on contract during the first quarter of 2017, and the *Ocean BlackRhino,* which was warm-stacked for much of 2016 (275 days) before commencing its current contract, and fewer days associated with downtime for repairs (89 days). The increase in 2017 revenue-earning days was partially offset by incremental downtime for the *Ocean Monarch*, which was in the shipyard for a survey and contract modifications during the first half of 2017 (168 days), and the absence of revenue-earning days for two cold-stacked rigs that had worked in 2016 (78 days). Average daily revenue decreased during 2017, primarily due to the absence of $40.0 million in demobilization revenue recognized in 2016 for the *Ocean Endeavor* and the effect of lower dayrates earned under new contracts for both the *Ocean Monarch* and *Ocean BlackRhino* during 2017, compared to 2016.

Contract drilling expense for our ultra-deepwater floaters increased $67.0 million during 2017, compared to 2016, primarily due to incremental contract drilling expense for the *Ocean GreatWhite* ($37.0 million), incremental costs associated with the PCbtH program on our drillships ($27.8 million), higher costs for rig mobilization ($14.0 million) and labor and personnel ($5.9 million), combined with a net increase in other rig operating costs ($2.5 million). These increased costs for our ultra-deepwater floaters were partially offset by a reduction in repair and maintenance expenses ($5.6 million) and costs associated with international shorebases and overhead costs ($14.5 million).

Deepwater Floaters. Revenue generated by our deepwater floaters decreased $54.7 million in 2017, compared to 2016, primarily due to a reduction in average daily revenue earned ($63.8 million), partially offset by the effect of 30 incremental revenue-earning days ($9.2 million). Average daily revenue decreased during 2017, primarily as a result of a lower dayrate being earned by the *Ocean Valiant* under its current contract in the North Sea that commenced in the fourth quarter of 2016. Revenue-earning days increased primarily due to 218 incremental days for our active deepwater floaters, partially offset by 188 fewer days for the *Ocean Victory*, which had been under contract during 2016.

Contract drilling expense for our deepwater floaters decreased $33.6 million during 2017, compared to 2016, primarily due to a net reduction in costs associated with labor and personnel ($14.2 million), maintenance and repairs ($11.2 million), equipment rental ($2.6 million), freight ($1.4 million) and other rig operating and overhead costs ($4.2 million) attributable to various factors, including the cold stacking of rigs and implementation of cost control initiatives for our working rigs and shorebase operations in 2016.

Mid-Water Floaters. Revenue and contract drilling expense during 2017 for our mid-water floaters decreased $111.2 million and $15.1 million, respectively, compared to 2016. The decrease in revenue during 2017 resulted from 282 fewer revenue-earning days ($96.5 million), combined with a lower average daily revenue earned ($14.4 million). The decrease in revenue-earning days primarily related to the completion of the final contract for the *Ocean Ambassador* in March 2016 (78 days) and fewer days for both the *Ocean Guardian*, which was warm stacked between contracts for much of 2017 (166 days), and the *Ocean Patriot* (38 days), which commenced a shipyard project and survey in late 2017. The decrease in contract drilling expense was primarily due to reduced costs related to the *Ocean Ambassador* ($8.1 million), and a reduction in labor and personnel ($5.6 million) and other costs ($1.5 million) for the remainder of our mid-water rigs. Only two rigs remain in our mid-water fleet, both of which operated under contract for portions of 2017 and 2016, while the remainder of our mid-water fleet was cold stacked and has now been sold.

Jack-ups. Contract drilling revenue attributable to our current and previously-owned jack-up rigs decreased $9.1 million during 2017, compared to 2016. The *Ocean Scepter*, which had been idle since completion of its previous contract in 2016, returned to Mexico for a new contract in early 2017 and operated until November 2017 at a lower dayrate than previously earned ($4.1 million). The rig was relocated to the Gulf of Mexico in late 2017 and is currently being marketed for sale. The decrease in contract drilling revenue also reflected the absence of $4.9 million in loss-of-hire insurance proceeds recognized in 2016.

Contract drilling expense for our jack-up rigs increased $7.6 million during 2017, compared to 2016, primarily due to higher costs incurred by the *Ocean Scepter* for labor and personnel ($6.4 million) and repairs ($1.7 million), partially offset by reduced costs associated with sold rigs ($0.5 million).

2016 Compared to 2015

Ultra-Deepwater Floaters. Revenue generated by our ultra-deepwater floaters during 2016 decreased $349.9 million compared to 2015, primarily as a result of 616 fewer revenue-earning days ($306.8 million), combined with lower average daily revenue earned ($43.1 million). Revenue-earning days for 2016 decreased primarily due to fewer revenue-earning days for cold-stacked rigs that had operated during 2015 (716 days) and the *Ocean Clipper*, which was sold in late 2015 (245 days), and unplanned downtime for repairs (22 days). The aggregate decrease in revenue-earning days was partially offset by incremental revenue-earning days for our drillships (185 days), and the *Ocean Monarch*, which was warm stacked for the first half of 2015 (182 days). Average daily revenue decreased in 2016 primarily due to lower amortized mobilization and contract preparation revenue compared to 2015.

Contract drilling expense for our entire ultra-deepwater floater fleet decreased $125.6 million during 2016, compared to 2015 and was net of incremental contract drilling expense of $74.9 million attributable to our four drillships and the *Ocean GreatWhite,* which was placed in service in late 2016. Contract drilling expense for our other ultra-deepwater floaters decreased $200.5 million during 2016, compared to 2015, reflecting lower expense for labor and personnel ($92.7 million), maintenance and inspections ($38.5 million), mobilization ($26.8 million), shorebase and operational support ($16.2 million), freight ($9.8 million), revenue-based agency fees ($8.2 million), and other rig operating and overhead costs ($8.3 million). These reductions in contract drilling expense were primarily due to lower costs for our cold-stacked rigs and the *Ocean Clipper*, as well as other cost reduction initiatives.

Deepwater Floaters. Revenue generated by our deepwater floaters decreased $291.7 million in 2016, compared to 2015, primarily due to 495 fewer revenue-earning days ($202.9 million), combined with a lower average daily revenue earned ($88.7 million). The net reduction in revenue-earning days in 2016 reflected 782 fewer days for cold-stacked rigs that had operated in 2015, partially offset by incremental revenue-earning days for other deepwater rigs with contracts that commenced in mid-2015 and in 2016. Average daily revenue decreased primarily as a result of lower amortized mobilization and contract preparation fees ($21.9 million), combined with lower dayrates earned by the *Ocean Valiant* and *Ocean Apex* during 2016 compared to 2015.

Contract drilling expense incurred by our deepwater floaters decreased $128.8 million during 2016, compared to 2015, primarily due to lower costs associated with cold-stacked rigs and cost control initiative in our onshore bases and corporate facilities. Compared to 2015, contract drilling expense in 2016 for our deepwater floaters reflected reductions in costs for labor and personnel ($51.3 million), mobilization of rigs ($29.5 million), repairs, maintenance and inspections ($18.7 million), shorebase and operational support ($15.1 million), revenue-based agency fees ($4.4 million), freight ($4.1 million) and other operating costs ($5.7 million).

Mid-Water Floaters. Revenue generated by our mid-water floaters during 2016 decreased $138.7 million compared to 2015, primarily due to 706 fewer revenue-earning days ($191.0 million), partially offset by higher average daily revenue earned ($52.0 million), which included a $36.0 million settlement received in connection with a contractual dispute with a former customer. Revenue-earning days decreased in 2016, primarily due to fewer mid-water floaters operating under contracts during 2016 (three rigs) compared to 2015 (nine rigs).

Contract drilling expense for our mid-water floaters decreased $146.4 million in 2016, compared to 2015, reflecting a reduction in costs attributable to rigs that have been retired ($109.0 million). Other cost reductions in 2016, compared to 2015, include lower costs for labor and personnel ($19.1 million), maintenance, repairs and inspections ($9.9 million), shorebase and operational support ($6.1 million) and other ($2.3 million), primarily due to lower activity and cost control initiatives.

Jack-ups. Contract drilling revenue and expense for our jack-up fleet decreased $54.7 million and $47.8 million, respectively, during 2016 compared to 2015. Revenue-earning days decreased by 760 days due to the cold stacking of three rigs that operated under contract during 2015 and an early contract termination for the *Ocean Scepter* in 2016.

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 $1.5 billion syndicated revolving credit agreement, or Credit Agreement. See "— Credit Agreement."

Based on our cash available for current operations and contractual backlog of $2.4 billion, as of January 1, 2018, of which $1.2 billion is expected to be realized in 2018, we believe future capital spending and debt service requirements will be funded from our cash and cash equivalents, future operating cash flows and borrowings under our Credit Agreement, as needed. See "— Sources and Uses of Cash — *Capital Expenditures*" and "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.

To the extent available, we expect to utilize the operating cash flows generated by and cash reserves of DFAC and the operating cash flows available to and cash reserves of Diamond Offshore Drilling, Inc. to meet each entity's respective working capital requirements and capital commitments. At December 31, 2017, 2016 and 2015, we had cash available for current operations as follows:

	December 31,		
	2017	2016	2015
		(In thousands)	
Cash and cash equivalents	$376,037	$156,233	$119,028
Marketable securities	—	35	11,518
Total cash available for current operations	$376,037	$156,268	$130,546

A substantial portion of our cash flows has historically been invested in the enhancement of our drilling fleet, including $1.6 billion since 2015 for the construction of two newbuild rigs and other capital enhancement projects. We determine the amount of cash required to meet our capital commitments by evaluating our rig construction obligations, the need to upgrade rigs to meet specific customer requirements and our ongoing rig equipment enhancement/ replacement programs. We also make periodic assessments of our capital spending programs based on current and expected industry conditions and make adjustments thereto if required. See "— Sources and Uses of Cash — Capital Expenditures."

We pay dividends at the discretion of our Board of Directors, or Board, and 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 and other factors that our Board considers relevant at that time. Our dividend policy may change from time to time, and there can be no assurance that we will declare any cash dividends at all or in any particular amounts. See "Risk Factors — *Although we have paid cash dividends in the past, we did not pay any dividends in 2017 and we may not pay dividends in the future and we can give no assurance as to the amount or timing of the payment of any future dividends*" in Item 1A of this report, which is incorporated herein by reference. We did not pay any dividends in 2017 or 2016. We paid regular cash dividends in the aggregate amount of $68.6 million during 2015.

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 of our outstanding common stock during 2017, 2016 or 2015.

During 2016, we entered into four sale-and-leaseback transactions for certain well control equipment on our drillships and received proceeds of $210.0 million. See "— Contractual Cash Obligations — *Pressure Control by the Hour®*."

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

Our cash flow from operations and capital expenditures for each of the years in the three-year period ended December 31, 2017 was as follows:

	Year Ended December 31,		
	2017	2016	2015
		(In thousands)	
Cash flow from operations	$493,808	$646,554	$736,427
Capital expenditures:			
Drillship construction	$ —	$ 55,426	$454,093
Construction of ultra-deepwater floater	—	503,172	55,805
Rig equipment and replacement program	139,581	94,075	320,757
Total capital expenditures	$139,581	$652,673	$830,655

Cash Flow from Operations. Cash flow from operations decreased approximately $152.7 million during 2017, compared to 2016, primarily due to lower cash receipts from contract drilling services ($245.0 million) and higher income taxes paid, net of refunds ($26.3 million), partially offset by a $118.6 million net decrease in cash payments for contract drilling and general and administrative expenses, including personnel-related, repairs and maintenance, shorebase, overheads and other rig operating costs. The decline in both cash receipts and cash payments related to the performance of contract drilling services reflects continued depressed market conditions in the offshore drilling industry, as well as the positive results of our focus on controlling costs.

Cash flow from operations decreased approximately $89.9 million during 2016, compared to 2015, primarily due to lower cash receipts from contract drilling services ($704.9 million), partially offset by a $584.8 million net decrease in cash payments for contract drilling and general and administrative expenses, including personnel-related, maintenance, mobilization, shorebase and operational support and other rig operating costs and lower income taxes paid, net of refunds ($30.2 million). The decline in both cash receipts from and cash payments related to contract drilling services reflects an aggregate decline in our contract drilling operations, as well as a lower cost structure and implementation of our cost control initiatives.

See "— Results of Operations — Years Ended December 31, 2017, 2016 and 2015."

Capital Expenditures. As of the date of this report, we expect total capital expenditures for 2018 to aggregate approximately $220.0 million for our ongoing capital maintenance and replacement programs. We expect to fund our 2018 capital spending from our operating cash flows and our cash reserves.

Credit Agreement

Our Credit Agreement provides for a $1.5 billion senior unsecured revolving credit facility for general corporate purposes maturing on October 22, 2020, except for $40 million of commitments that mature on March 17, 2019 and $60 million of commitments that mature on October 22, 2019. As of December 31, 2017, we had no borrowings outstanding under the Credit Agreement, and we were in compliance with all covenant requirements. As of February 9, 2018, we had no borrowings outstanding and $1.5 billion available under our Credit Agreement to provide short-term liquidity for our payment obligations.

Senior Notes

As of December 31, 2017, 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.

During 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 deducting underwriting discounts, commissions and expenses. The 2025 Notes bear interest at 7.875% per year and mature on August 15, 2025. Interest on the 2025 Notes is payable semiannually in arrears on February 15 and August 15 of each year, beginning February 15, 2018. We used the net proceeds from the 2025 Notes, together with cash on hand, to fund the redemption of our 5.875% senior notes due 2019 at a redemption price of $543.0 million. See Note 9 “Credit Agreement and Senior Notes” to our Consolidated Financial Statements in Item 8 of this report.

During 2015, we repaid maturing senior notes of $250.0 million.

Credit Ratings

In July 2017, Moody’s Investor Services downgraded our corporate credit rating to Ba3 with a negative outlook from Ba2 with a stable outlook. In October 2017, S&P Global Ratings, or S&P, downgraded our corporate credit rating to B+ from BB-; our outlook by S&P remains negative. These credit ratings are below investment grade. Market conditions and other factors, many of which are outside of our control, could cause our credit ratings to be lowered further. Any further downgrade in our credit ratings could adversely impact our cost of issuing additional debt and the amount of additional debt that we could issue, and could further restrict our access to capital markets and our ability to raise funds by issuing additional debt. 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, 2017.

	Payments Due By Period				
Contractual Obligations (1)	Total	Less than 1 year	1–3 years	4–5 years	After 5 years
	(In thousands)				
Long-term debt (principal and interest)	$3,944,375	$113,063	$226,125	$226,125	$3,379,063
PCbtH program	550,000	65,000	130,000	130,000	225,000
Property leases	2,587	1,733	762	92	—
Total obligations	$4,496,962	$179,796	$356,887	$356,217	$3,604,063

(1) The above table excludes $105.0 million of total net unrecognized tax benefits related to uncertain tax positions as of December 31, 2017. 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.

Tax Reform Act. At December 31, 2017, we had no current income tax liability with respect to the deemed repatriation of earnings or other provisions of the Tax Reform Act. See “Important Factors that May Impact Our Operating Results, Financial Condition or Cash Flows — *Impact of Changes in Tax Laws or Their Interpretation*” and Note 15 “Income Taxes” to our Consolidated Financial Statements in Item 8 of this report.

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 12 "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, 2017, 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, 2017 in the amount of $20.4 million under certain performance, tax, supersedeas, bid and customs bonds and letters of credit. Agreements relating to approximately $14.8 million of supersedeas, tax and customs bonds can require collateral at any time. As of December 31, 2017, 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.

		For the Years Ending December 31,	
	Total	2018	2019
	(In thousands)		
Other Commercial Commitments			
Performance bond	$ 1,000	$ —	$1,000
Supersedeas bond	9,189	9,189	—
Tax bond	5,408	5,408	—
Bid bond	3,200	3,200	—
Other	1,649	1,649	—
Total obligations	$20,446	$19,446	$1,000

Off-Balance Sheet Arrangements

At December 31, 2017 and 2016, we had no off-balance sheet debt or other off-balance sheet arrangements.

Other

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. 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 dayrates and term for the *Ocean GreatWhite;*
- idling drilling rigs or reactivating stacked rigs;
- outcomes of 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;
- plans and objectives of management;
- scrapping retired rigs;
- assets held for sale;
- 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*" 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, 2017 and 2016, 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. Historically, our investments in marketable securities were primarily 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. Our exposure to such risk was minimal in 2017 and 2016 as we had no investments in marketable securities at December 31, 2017 and the fair value of such securities was immaterial as of December 31, 2016.

Our long-term debt, as of December 31, 2017 and 2016, 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 $145.1 million and $125.3 million as of December 31, 2017 and 2016, respectively. A 100-basis point decrease would result in an increase in market value of $168.9 million and $147.3 million as of December 31, 2017 and 2016, respectively.

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

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, 2017 and 2016, the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows, for each of the three years in the period ended December 31, 2017, 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, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with the 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, 2017, 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, 2018, 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, 2018

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, 2017, 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, 2017, 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, 2017, of the Company and our report dated February 13, 2018, 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, 2018

DIAMOND OFFSHORE DRILLING, INC.
AND SUBSIDIARIES

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

	December 31, 2017	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 376,037	$ 156,233
Accounts receivable, net of allowance for bad debts	256,730	247,028
Prepaid expenses and other current assets	157,625	102,146
Assets held for sale	96,261	400
Total current assets	886,653	505,807
Drilling and other property and equipment, net of accumulated depreciation	5,261,641	5,726,935
Other assets	102,276	139,135
Total assets	$6,250,570	$6,371,877
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 38,755	$ 30,242
Accrued liabilities	154,655	182,159
Taxes payable	29,878	23,898
Short-term borrowings	—	104,200
Total current liabilities	223,288	340,499
Long-term debt	1,972,225	1,980,884
Deferred tax liability	167,299	197,011
Other liabilities	113,497	103,349
Total liabilities	2,476,309	2,621,743
Commitments and contingencies (Note 11)	—	—
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; 144,085,292 shares issued and 137,227,782 shares outstanding at December 31, 2017; 143,997,757 shares issued and 137,169,663 shares outstanding at December 31, 2016)	1,441	1,440
Additional paid-in capital	2,011,397	2,004,514
Retained earnings	1,964,497	1,946,765
Accumulated other comprehensive gain (loss)	(5)	1
Treasury stock, at cost (6,857,510 and 6,828,094 shares of common stock at December 31, 2017 and 2016, respectively)	(203,069)	(202,586)
Total stockholders' equity	3,774,261	3,750,134
Total liabilities and stockholders' equity	$6,250,570	$6,371,877

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,		
	2017	2016	2015
Revenues:			
Contract drilling	$1,451,219	$1,525,214	$2,360,184
Revenues related to reimbursable expenses	34,527	75,128	59,209
Total revenues	1,485,746	1,600,342	2,419,393
Operating expenses:			
Contract drilling, excluding depreciation	801,964	772,173	1,227,864
Reimbursable expenses	33,744	58,058	58,050
Depreciation	348,695	381,760	493,162
General and administrative	74,505	63,560	66,462
Impairment of assets	99,313	678,145	860,441
Bad debt recovery	—	(265)	—
Restructuring and separation costs	14,146	—	9,778
(Gain) loss on disposition of assets	(10,500)	3,795	(2,290)
Total operating expenses	1,361,867	1,957,226	2,713,467
Operating income (loss)	123,879	(356,884)	(294,074)
Other income (expense):			
Interest income	2,473	768	3,322
Interest expense, net of amounts capitalized	(113,528)	(89,934)	(93,934)
Foreign currency transaction (loss) gain	(1,128)	(11,522)	2,465
Loss on extinguishment of senior notes	(35,366)	—	—
Other, net	2,230	(10,727)	873
Loss before income tax benefit	(21,440)	(468,299)	(381,348)
Income tax benefit	39,786	95,796	107,063
Net income (loss)	$ 18,346	$ (372,503)	$ (274,285)
Earnings (loss) per share:			
Basic	$ 0.13	$ (2.72)	$ (2.00)
Diluted	$ 0.13	$ (2.72)	$ (2.00)
Weighted-average shares outstanding:			
Shares of common stock	137,213	137,168	137,157
Dilutive potential shares of common stock	52	—	—
Total weighted-average shares outstanding	137,265	137,168	137,157

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,		
	2017	2016	2015
Net income (loss)	$18,346	$(372,503)	$(274,285)
Other comprehensive (losses) gains, net of tax:			
Derivative financial instruments:			
Unrealized holding loss	—	—	(1,574)
Reclassification adjustment for (gain) loss included in net income (loss)	(6)	(5)	5,084
Investments in marketable securities:			
Unrealized holding loss on investments	—	(6,559)	(4,940)
Reclassification adjustment for loss included in net income (loss)	—	11,600	—
Total other comprehensive (loss) gain	(6)	5,036	(1,430)
Comprehensive income (loss)	$18,340	$(367,467)	$(275,715)

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, 2015	143,960,260	1,440	1,993,898	2,661,999	(3,605)	6,812,361	(202,169)	4,451,563
Net loss	—	—	—	(274,285)	—	—	—	(274,285)
Dividends to stockholders ($0.50 per share)	—	—	—	(68,578)	—	—	—	(68,578)
Stock-based compensation, net of tax	18,617	—	5,736	—	—	7,810	(236)	5,500
Net gain on derivative financial instruments	—	—	—	—	3,510	—	—	3,510
Net loss on investments	—	—	—	—	(4,940)	—	—	(4,940)
December 31, 2015	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 policy	—	—	634	(634)	—	—	—	—
Adjusted balance at December 31, 2016	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

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,		
	2017	2016	2015
Operating activities:			
Net income (loss)	$ 18,346	$(372,503)	$(274,285)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation	348,695	381,760	493,162
Loss on impairment of assets	99,313	678,145	860,441
Loss on extinguishment of senior notes	35,366	—	—
Restructuring and separation costs	14,146	—	—
(Gain) loss on disposition of assets	(10,500)	3,795	(2,290)
Loss on sale of marketable securities, net	—	12,146	—
Loss on foreign currency forward exchange contracts	—	—	8,364
Deferred tax provision	(72,127)	(106,263)	(242,034)
Stock-based compensation expense	6,250	4,880	4,856
Deferred income, net	8,676	(29,108)	(45,383)
Deferred expenses, net	46,337	(20,155)	(26,405)
Other assets, noncurrent	(326)	(4,914)	2,483
Other liabilities, noncurrent	(963)	(31)	(3,890)
Payments of settlement of foreign currency forward exchange contracts designated as accounting hedges	—	—	(8,364)
Other	7,708	5,691	858
Changes in operating assets and liabilities:			
Accounts receivable	(11,049)	159,098	58,872
Prepaid expenses and other current assets	(1,291)	6,187	19,195
Accounts payable and accrued liabilities	19,803	(71,085)	(180,872)
Taxes payable	(14,576)	(1,089)	71,719
Net cash provided by operating activities	493,808	646,554	736,427
Investing activities:			
Capital expenditures (including rig construction)	(139,581)	(652,673)	(830,655)
Proceeds from disposition of assets, net of disposal costs	15,196	221,722	13,049
Proceeds from sale and maturities of marketable securities	35	4,614	51
Net cash used in investing activities	(124,350)	(426,337)	(817,555)
Financing activities:			
Repayment of long-term debt	(500,000)	—	(250,000)
Payment of debt extinguishment costs	(34,395)	—	—
Proceeds from issuance of senior notes	496,360	—	—
(Repayment of) proceeds from short-term borrowings, net	(104,200)	(182,389)	286,589
Debt issuance costs and arrangement fees	(7,263)	(215)	(624)
Payment of dividends and anti-dilution payments	(156)	(408)	(69,432)
Net cash used in financing activities	(149,654)	(183,012)	(33,467)
Net change in cash and cash equivalents	219,804	37,205	(114,595)
Cash and cash equivalents, beginning of year	156,233	119,028	233,623
Cash and cash equivalents, end of year	$ 376,037	$ 156,233	$ 119,028

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 seven ultra-deepwater, four deepwater and two mid-water semisubmersible rigs. Two rigs, the semisubmersible *Ocean Victory* and jack-up *Ocean Scepter,* are reported as "Assets held for sale" in our Consolidated Balance Sheets at December 31, 2017 and have been excluded from our current fleet. The *Ocean Victory* was sold in January 2018. 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 9, 2018, 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.

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, 2017, 2016 and 2015.

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 3.

Assets Held For Sale

We reported the $96.3 million and $0.4 million carrying values of certain of our rigs being marketed for sale as "Assets held for sale" in our Consolidated Balance Sheets at December 31, 2017 and 2016, respectively. The *Ocean Victory*, which was reported as "Assets held for sale" at December 31, 2017 with a carrying value of $1.2 million, was sold in January 2018. We also reported the *Ocean Scepter*, a jack-up rig, as held for sale at December 31, 2017, based upon management's decision to sell the rig after receipt of an unsolicited bid for the rig in November 2017. The sale of the rig has not yet been negotiated; however, management is actively marketing the rig for sale and expects to complete a sale during 2018. The *Ocean Spur*, which was reported as "Assets held for sale" at December 31, 2016, was sold in 2017.

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, 2017 and 2016, we capitalized $69.4 million and $177.6 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 or upgrades, as well as other qualifying projects. During the three years ended December 31, 2017, we capitalized interest on qualifying expenditures, primarily related to our rig construction 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:

	For the Year Ended December 31,		
	2017	2016	2015
		(In thousands)	
Total interest cost including amortization of debt issuance costs	$113,618	$110,748	$110,242
Capitalized interest	(90)	(20,814)	(16,308)
Total interest expense as reported	$113,528	$ 89,934	$ 93,934

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 2.

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 7.

Debt Issuance Costs

Deferred costs associated with our senior notes are presented in our Consolidated Balance Sheets at December 31, 2017 and 2016 as a reduction in the related long-term debt and are amortized over the respective terms of the related debt. See Note 9.

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 15.

Treasury Stock

In connection with the vesting of restricted stock units held by certain individuals, we acquired 29,416 and 7,923 shares of our common stock during 2017 and 2016, respectively (valued at $0.5 million in 2017 and $0.2 million in 2016), in satisfaction of tax withholding obligations that were incurred on the vesting date. See Note 4.

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 2017, 2016 or 2015.

Comprehensive Income (Loss)

Comprehensive income (loss) 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 income (loss) for the three years ended December 31, 2017, 2016 and 2015 includes net income (loss) and unrealized holding gains and losses on marketable securities and financial derivatives designated as cash flow accounting hedges. See Note 10.

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 and may also include, when applicable, unrealized gains and losses to record the carrying value of foreign currency forward exchange, or FOREX, contracts not designated as accounting hedges and realized gains and losses from the settlement of such contracts. 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.

Revenue Recognition

We recognize revenue from dayrate drilling contracts as services are performed. In connection with such drilling contracts, we may receive fees (on either a lump-sum or dayrate basis) for the mobilization of equipment. We earn these fees as services are performed over the initial term of the related drilling contracts. We defer mobilization fees received, as well as direct and incremental mobilization costs incurred, and amortize each, on a straight-line basis, over the term of the related drilling contracts (which is the period we estimate to be benefited from the mobilization activity). Straight-line amortization of mobilization revenues and related costs over the term of the related drilling contracts (which generally range from two to 60 months) is consistent with the timing of net cash flows generated from the actual drilling services performed. Absent a contract, mobilization costs are recognized currently. Upon completion of a drilling contract, we recognize in earnings any demobilization fees received and costs incurred.

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 lump-sum or dayrate basis). These fees are generally earned as services are performed over the initial term of the related drilling contracts. We defer contract preparation fees received, as well as direct and incremental costs associated with the contract preparation activities and amortize each, on a straight-line basis, over the term of the related drilling contracts (which we estimate to be benefited from the contract preparation activity).

From time to time, we may receive fees from our customers for capital improvements to our rigs (on either a lump-sum or dayrate basis). We defer such fees received in "Accrued liabilities" and "Other liabilities" in our Consolidated Balance Sheets and recognize these fees into income on a straight-line basis over the period of the related drilling contract. We capitalize the costs of such capital improvements and depreciate them over the estimated useful life of the improvement.

We record reimbursements received for the purchase of supplies, equipment, personnel services and other services provided at the request of our customers in accordance with a contract or agreement, for the gross amount billed to the customer, as "Revenues related to reimbursable expenses" in our Consolidated Statements of Operations.

Recent Accounting Pronouncements

In October 2016, the Financial Accounting Standards Board, or FASB, issued Accounting Standards Update, or ASU, No. 2016-16, *Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory,* or ASU 2016-16. ASU 2016-16 amends the guidance in Topic 740 with respect to the accounting for the income tax consequences of intra-entity transfers of assets other than inventory. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017. We have evaluated our historical intra-group transactions for possible impact under the provisions of ASU 2016-16. The guidance in ASU 2016-16 will be applied effective January 1, 2018 using the modified retrospective approach whereby we will record the cumulative effect of applying the new standard as an adjustment to opening retained earnings with an offset to a deferred income tax liability. We expect to reduce opening retained earnings by approximately $18 million upon adoption of the standard on January 1, 2018.

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 amendments in ASU 2016-15 are effective for interim and annual periods beginning after December 15, 2017. ASU 2016-15 should be applied using a retrospective transition method, unless it is impracticable to do so for some of the issues. In such case, the amendments for those issues would be applied prospectively as of the earliest date practicable. We do not expect ASU 2016-15 to have a significant impact on the presentation of cash receipts and cash payments within our consolidated statements of cash flows.

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)*, or ASU 2016-02, which requires an entity to separate the lease components from the non-lease components in a contract. The lease components are to be accounted for under ASU 2016-02, which, under the guidance, may require recognition of lease assets and lease liabilities by lessees for most leases and derecognition of the leased asset and recognition of a net investment in the lease by the lessor. ASU 2016-02 also provides for additional disclosure requirements for both lessees and lessors. Non-lease components would be accounted for under ASU 2014-09. We have determined that under the new standard, our drilling contracts contain a lease component and therefore we will be required to separately recognize revenues associated with the lease and services components. Additionally, for transactions in which we are considered lessees, we will recognize a lease liability and right of use asset based on our portfolio of leases as of the time of adoption. The guidance of ASU 2016-02 is effective for annual reporting periods beginning after December 15, 2018, including interim periods within that reporting period. Early adoption of ASU 2016-02 is permitted. We expect to adopt ASU 2016-02 on January 1, 2019 using the modified retrospective approach. We are currently reviewing the requirements of the accounting standard with regard to arrangements under which we are either the lessor or lessee, to determine the impact of ASU 2016-02, including any newly issued guidance, on our financial position, results of operations, cash flows and disclosures contained in the notes to our consolidated financial statements.

In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers (Topic 606),* or ASU 2014-09, which is effective for annual reporting periods beginning after December 15, 2017. The new standard supersedes the industry-specific standards that currently exist under GAAP and provides a framework to address revenue recognition issues comprehensively for all contracts with customers regardless of industry-specific or transaction-specific fact patterns. Under the new guidance, companies recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. ASU 2014-09 provides a five-step analysis of transactions to determine when and how revenue is recognized and requires enhanced disclosures about revenue. When applying the new standard, we plan to account for the integrated services provided within our drilling contracts as a single performance obligation composed of a series of distinct time increments, which will be satisfied over time. We will determine the total transaction price for each individual contract by estimating both fixed and variable consideration expected to be earned over the term of the contract. Consideration that does not relate to a distinct good or service, such as mobilization, demobilization, and contract preparation revenue, will be allocated across the single performance obligation and recognized ratably over the term of the contract. All other components of consideration within a contract, including the dayrate revenue, will continue to be recognized in the period when the services are performed. We expect our revenue recognition under ASU 2014-09 to differ from our current revenue recognition pattern only as it relates to demobilization revenue. Such revenue, which is recognized upon completion of a contract under current GAAP, will be estimated at contract inception and recognized over the term of the contract under the new guidance. We plan to adopt ASU 2014-09 effective January 1, 2018 using the modified retrospective approach whereby we will record the cumulative effect of applying the new standard to all outstanding contracts as of January 1, 2018 as an adjustment to opening retained earnings. We do not expect this adjustment to be significant as it will primarily consist of the impact of the timing difference related to recognition of demobilization revenue for affected contracts. Not all contracts include a demobilization provision.

2. Asset Impairments

2017 Impairments. During 2017, in response to continued depressed market conditions for the offshore contract drilling industry, our expectations that a market recovery is not likely to occur in the near term, as well as decisions by our management to market certain rigs for sale, we evaluated ten of our drilling rigs with indications that their carrying values may not be recoverable. Based on our analyses, we determined that the carrying values of three rigs were impaired, including one rig that had previously been impaired in a prior year and two rigs that were classified as held for sale at December 31, 2017. We collectively refer to these three rigs as the “2017 Impaired Rigs.” The 2017 Impaired Rigs consist of one ultra-deepwater semisubmersible, one deepwater semisubmersible and one jack-up rig.

We estimated the fair value of two of the 2017 Impaired Rigs using an income approach in which the fair value was estimated based on a calculation of the rig’s discounted future net cash flows over its remaining economic life, which utilized significant unobservable inputs, including, but not limited to, assumptions related to estimated dayrate revenue, rig utilization, estimated reactivation and regulatory survey costs, as well as estimated proceeds that may be received on ultimate disposition of the rig. The fair value of the other 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, as well as our evaluation of other market data points; however, the rig has not been sold. 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 the second and fourth quarters of 2017, we recorded impairment losses of $71.3 million and $28.0 million, respectively, or an aggregate impairment loss 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." The 2016 Impaired Rigs consisted of three ultra-deepwater, three deepwater and two mid-water semisubmersible 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 the second quarter of 2016, we recorded an impairment loss of $670.0 million related to our 2016 Impaired Rigs.

2015 Impairments. During 2015, we evaluated 25 of our drilling rigs with indications that their carrying amounts may not be recoverable. Using an undiscounted, projected probability-weighted cash flow analysis, we determined that the carrying value of 17 of these rigs, consisting of two ultra-deepwater, one deepwater and nine mid-water floaters and five jack-up rigs, were impaired. We collectively refer to these 17 rigs as the "2015 Impaired Rigs."

We estimated the fair value of 16 of the 2015 Impaired Rigs utilizing a market approach, as described above. We estimated the fair value of the one remaining 2015 Impaired Rig using an income approach, as discussed above. Our fair value estimates are 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 the first, third and fourth quarters of 2015, we recognized impairment losses of $358.5 million, $2.6 million and $499.4 million, respectively, for an aggregate impairment loss of $860.4 million for the year ended December 31, 2015.

See Notes 1 and 8.

3. Supplemental Financial Information

Consolidated Balance Sheet Information

Accounts receivable, net of allowance for bad debts, consists of the following:

	December 31,	
	2017	2016
	(In thousands)	
Trade receivables	$247,453	$236,040
Value added tax receivables	14,067	14,639
Related party receivables	205	149
Other	464	1,659
	262,189	252,487
Allowance for bad debts	(5,459)	(5,459)
Total	$256,730	$247,028

An analysis of the changes in our provision for bad debts for each of the three years ended December 31, 2017, 2016 and 2015 is as follows:

	For the Year Ended December 31,		
	2017	2016	2015
		(In thousands)	
Allowance for bad debts, beginning of year	$5,459	$5,724	$5,724
Bad debt recovery	—	(265)	—
Allowance for bad debts, end of year	$5,459	$5,459	$5,724

See Note 7 for a discussion of our provision for bad debts and write off of uncollectible accounts against the reserve.

Prepaid expenses and other current assets consist of the following:

	December 31, 2017	December 31, 2016
	(In thousands)	
Rig spare parts and supplies	$ 28,383	$ 25,343
Deferred mobilization costs	51,297	61,488
Prepaid BOP Lease	3,873	3,873
Prepaid insurance	3,091	3,771
Prepaid taxes	67,212	2,894
Other	3,769	4,777
Total	$157,625	$102,146

During 2016, we recognized an $8.1 million impairment loss related to our rig spare parts and supplies.

Accrued liabilities consist of the following:

	December 31, 2017	December 31, 2016
	(In thousands)	
Rig operating expenses	$ 48,894	$ 33,732
Payroll and benefits	46,560	45,619
Deferred revenue	11,371	9,522
Accrued capital project/upgrade costs	3,698	60,308
Interest payable	28,234	18,365
Personal injury and other claims	5,699	6,424
Other	10,199	8,189
Total	$154,655	$182,159

"Accrued liabilities" at December 31, 2017, includes $13.6 million in accrued costs related to our 2017 Reduction Plan of which $11.5 million and $2.1 million were reported as "Rig operating expenses" and "Payroll and benefits," respectively. See Note 14.

Consolidated Statement of Cash Flows Information

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

	December 31,		
	2017	2016	2015
		(In thousands)	
Accrued but unpaid capital expenditures at period end	$ 3,698	$ 60,308	$ 84,146
Common stock withheld for payroll tax obligations (1)	483	181	236
Cash interest payments (2)	97,096	105,987	110,412
Cash income taxes paid (refunded), net:			
U.S. federal	—	(31,151)	(21,751)
Foreign	43,999	48,931	69,697
State	94	1	58

(1) Represents the cost of 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 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, 2017 and 2016.

(2) Interest payments, net of amounts capitalized, were $97.0 million, $86.1 million and $94.7 million for the years ended December 31, 2017, 2016 and 2015, respectively.

4. 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 and to permit the payment of performance-based compensation as defined by the Internal Revenue Code of 1986, as amended, or the Code. 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. ASU 2016-09 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. The update also clarifies the statement of cash flows presentation for certain components of share-based awards and 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:

	Retained Earnings	Additional Paid-in Capital
	(In thousands)	
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, 2017, 2016 and 2015 was $8.7 million, $7.0 million and $5.7 million, respectively. Tax benefits recognized for the years ended December 31, 2017, 2016 and 2015 related thereto were $2.6 million, $2.4 million and $1.9 million, respectively. As of December 31, 2017 there was $11.2 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. SARs awarded under the Equity Plan generally vest ratably over a four-year period 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, 2017, 2016 and 2015 was estimated using the Black Scholes pricing model with the following weighted average assumptions:

	Year Ended December 31,		
	2017	2016	2015
Expected life of SARs (in years)	7	7	6
Expected volatility	31.70%	45.79%	55.12%
Dividend yield	—	.60%(1)	1.70%
Risk free interest rate	2.09%	1.46%	1.66%

(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, 2017 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, 2017	1,449,706	$67.43		
Granted	66,000	$14.95		
Exercised	—			
Forfeited	5,240	$41.88		
Expired	248,352	$90.95		
Awards outstanding at December 31, 2017	1,262,114	$60.16	4.3	$272
Awards exercisable at December 31, 2017	1,230,382	$60.63	4.2	$272

The weighted-average grant date fair values per share of awards granted during the years ended December 31, 2017, 2016 and 2015 were $5.61, $9.32 and $14.44, respectively. The total intrinsic value of awards exercised during the years ended December 31, 2017, 2016 and 2015 was $0, $0 and $0, respectively. The total fair value of awards vested during the years ended December 31, 2017, 2016 and 2015 was $1.2 million, $2.2 million and $3.6 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 2017, 2016 and 2015, we granted an aggregate of 276,085, 183,076 and 153,493 time-vesting RSUs, respectively. One-half of each annual grant will vest two years from the date of grant and the remaining 50% of which 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. The fair value of non-participating RSUs granted in 2015 was discounted at a three-year risk-free interest rate of 1.48%, in consideration of the non-participative rights of the awards. The fair values of non-participating RSUs granted in 2017 and 2016 were not discounted as the fair values would have reflected the 2016 suspension of regular dividend payments.

A summary of activity for time-vesting RSUs under the Equity Plan as of December 31, 2017 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, 2017	319,560	$23.13
Granted	276,085	$16.37
Vested	68,659	$25.08
Forfeited	55,697	$20.76
Nonvested awards at December 31, 2017	471,289	$19.15

The total fair value of time-vesting RSUs vested during the year ended December 31, 2017 was $1.1 million. No time-vesting RSUs vested during the years ended December 31, 2016 or 2015.

Performance-Vesting Awards

Restricted Stock Units. In 2017, 2016 and 2015, we granted an aggregate of 370,616, 248,188 and 169,312 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 in 2015, other than to our CEO, was estimated based on the fair market value of our common stock on the date of grant. The fair value of non-participating, performance-vesting RSUs granted in 2015 was discounted at a three-year risk-free interest rate of 1.48% in consideration of the non-participative rights of the awards. The fair value of performance-vesting RSUs granted to our CEO in 2015 was not discounted as such awards are participating securities. The fair values of performance-vesting RSUs granted in 2017 and 2016 were not discounted as the fair values would have reflected the 2016 suspension of regular dividend payments.

A summary of activity for performance-vesting RSUs under the Equity Plan as of December 31, 2017 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, 2017	431,706	$24.55
Granted	370,616	$16.61
Vested	18,876	$46.64
Forfeited	55,590	$19.95
Nonvested awards at December 31, 2017	727,856	$20.28

The total grant date fair value of the performance-vesting RSUs that vested during the years ended December 31, 2017, 2016 and 2015 was $0.3 million, $0.4 million and $0.6 million, respectively.

5. Earnings (Loss) Per Share

A reconciliation of the numerators and the denominators of the basic and diluted per-share computations follows:

	Year Ended December 31,		
	2017	2016	2015
	(In thousands, except per share data)		
Net income (loss) — basic and diluted (numerator):	$ 18,346	$(372,503)	$(274,285)
Weighted-average shares — basic (denominator):	137,213	137,168	137,157
Dilutive effect of stock-based awards	52	—	—
Weighted-average shares including conversions — diluted (denominator):	137,265	137,168	137,157
Earnings (loss) per share:			
Basic	$ 0.13	$ (2.72)	$ (2.00)
Diluted	$ 0.13	$ (2.72)	$ (2.00)

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.

	Year Ended December 31,		
	2017	2016	2015
	(In thousands)		
Employee and director:			
Stock options	—	7	26
SARs	1,315	1,505	1,553
RSUs	757	704	278

6. Derivative Financial Instruments

Foreign Currency Forward Exchange Contracts

Our international operations expose us to foreign exchange risk associated with our costs payable in foreign currencies. To manage this risk, in prior years we entered into FOREX contracts for future delivery of Australian dollars, Brazilian reais, British pounds sterling, Mexican pesos and Norwegian kroner. These forward contracts were derivatives as defined by GAAP.

During the year ended December 31, 2015, we settled FOREX contracts with aggregate a notional value of approximately $91.6 million of which the entire aggregate amount was designated as an accounting hedge. During the year ended December 31, 2015 we did not enter into or settle any FOREX contracts that were not designated as accounting hedges. We did not enter into any FOREX contracts during 2017 or 2016 and there were no FOREX contracts outstanding at December 31, 2017 or 2016.

During the year ended December 31, 2015, we recognized an aggregate loss of $8.4 million related to our FOREX contracts designated as hedging instruments, which was reported in Contract drilling expense in our Consolidated Statements of Operations.

The following table presents the amounts recognized in our Consolidated Balance Sheets and Consolidated Statements of Operations related to our derivative financial instruments designated as cash flow hedges for the year ended December 31, 2015.

	For the Year Ended December 31, 2015 (In thousands)
FOREX contracts:	
Amount of loss recognized in AOCGL on derivative (effective portion)	$ (2,420)
Location of loss reclassified from AOCGL into income (effective portion)	Contract drilling, excluding depreciation
Amount of loss reclassified from AOCGL into income (effective portion)	$ (7,829)
Location of loss recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	Foreign currency transaction gain (loss)
Amount of loss recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	$ (1)

During the year ended December 31, 2015, we did not reclassify any amounts from AOCGL due to the probability of an underlying forecasted transaction not occurring.

7. 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 a geographic area, we do not believe that we have any significant concentrations of credit risk at December 31, 2017.

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 and, historically, losses on our trade receivables have been infrequent occurrences.

In December 2013, we entered into a settlement with Niko with respect to certain obligations under dayrate contracts for the *Ocean Monarch* and *Ocean Lexington*, whereby we would receive an aggregate of $80.0 million. From December

2013 until Niko's default on the agreement, we received $49.0 million from Niko. Commencing in 2015, we filed a lawsuit against Niko in a U.S. court and a Canadian court, both of which granted judgments against Niko. On October 18, 2016, we executed a final settlement agreement with Niko, or which we refer to as the 2016 Agreement. Under the 2016 Agreement, Niko paid us a cash settlement amount of $3.0 million, agreed to make future payments to us equal to 20% of amounts to be retained by Niko pursuant to a waterfall distribution under their credit facility and assigned to us Niko's interest in potential contingent payments related to the sale of five Indonesian production sharing contracts. We plan to recognize revenue from these amounts as funds are received due to the uncertainty regarding their timing and collection. As of December 31, 2017, the amount outstanding to us under the agreement was $28.0 million.

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, 2017 consisted of cash held in money market funds of $337.1 million and time deposits of $20.9 million. Our Level 1 assets at December 31, 2016 consisted of cash held in money market funds of $125.7 million and time deposits of $20.6 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. Our Level 2 assets at December 31, 2016 consisted solely of residential mortgage-backed securities, which were valued using a model-derived valuation technique based on the quoted closing market prices received from a financial institution. The inputs used in our valuation are obtained from a Bloomberg curve analysis which uses par coupon swap rates to calculate implied forward rates so that projected floating rate cash flows can be calculated. The valuation techniques underlying the models are widely accepted in the financial services industry and do not involve significant judgment. We had no Level 2 assets or liabilities as of December 31, 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 and 2016 consisted of nonrecurring measurements of certain of our drilling rigs and associated spare parts and supplies for which we recorded an impairment loss during the second and fourth quarters of 2017 and the second quarter of 2016. See Notes 1, 2 and 3.

Market conditions could cause an instrument to be reclassified among Levels 1, 2 and 3. Our policy regarding fair value measurements of financial instruments transferred into and out of levels is to reflect the transfers as having occurred at the beginning of the reporting period. There were no transfers between fair value levels during the years ended December 31, 2017 and 2016.

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 and related spare parts and supplies, which were measured at fair value on a nonrecurring basis in 2017 and 2016, respectively, and have presented the aggregate loss in “Impairment of assets” in our Consolidated Statements of Operations for the years ended December 31, 2017 and 2016.

Assets and liabilities measured at fair value are summarized below.

	December 31, 2017				
	Fair Value Measurements Using			Assets at Fair Value	Total Losses for Year Ended (1)
	Level 1	Level 2	Level 3		
	(In thousands)				
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 impairment losses of $71.3 million and $28.0 million recognized during the second and fourth quarters of 2017, respectively, related to our 2017 Impaired Rigs. See Note 2.

(2) Represents the total book value as of December 31, 2017 of one ultra-deepwater rig and one deepwater semisubmersible rig, which were written down to their estimated fair value during the second quarter of 2017, and one jack-up rig, which was written down to fair value during the fourth quarter of 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 2.

	December 31, 2016				
	Fair Value Measurements Using			Assets at Fair Value	Total Losses for Year Ended (1)
	Level 1	Level 2	Level 3		
	(In thousands)				
Recurring fair value measurements:					
Assets:					
Short-term investments	$146,360	$—	$ —	$146,360	
Mortgage-backed securities	—	35	—	35	
Total assets	$146,360	$35	$ —	$146,395	
Nonrecurring fair value measurements:					
Assets:					
Impaired assets (2)	$ —	$—	$69,153	$ 69,153	$678,145

(1) Represents impairment losses of $8.1 million and $670.0 million recognized during the year ended December 31, 2016 related to our rig spare parts and supplies and 2016 Impaired Rigs, respectively. See Notes 2 and 3.

(2) Represents the total book value as of December 31, 2016 for 11 drilling rigs ($45.5 million) and for rig spare parts and supplies ($23.6 million), which were previously written down to their estimated fair value. Of the total fair value, $23.6 million, $0.4 million and $45.1 million were reported as "Prepaid expenses and other current assets," "Assets held for sale" and "Drilling and other property and equipment, net of accumulated depreciation," respectively, in our Consolidated Balance Sheets at December 31, 2016. See Notes 1, 2 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.

- *Short-term borrowings* — The carrying amounts approximate fair value because of the short maturity of these 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, 2017 and 2016. 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 9) are shown below.

	December 31, 2017		December 31, 2016	
	Fair Value	Carrying Value	Fair Value	Carrying Value
	(In millions)			
5.875% Senior Notes due 2019	$ —	$ —	$518.6	$499.8
3.45% Senior Notes due 2023	223.1	249.4	215.0	249.3
7.875% Senior Notes due 2025	523.1	496.5	—	—
5.70% Senior Notes due 2039	405.0	497.2	392.5	497.1
4.875% Senior Notes due 2043	547.5	748.9	532.7	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.

8. Drilling and Other Property and Equipment

Cost and accumulated depreciation of drilling and other property and equipment are summarized as follows:

	December 31,	
	2017	2016
	(In thousands)	
Drilling rigs and equipment	$ 7,971,406	$ 8,950,385
Land and buildings	63,309	64,449
Office equipment and other	82,691	73,108
Cost	8,177,406	9,087,942
Less accumulated depreciation	(2,855,765)	(3,361,007)
Drilling and other property and equipment, net	$ 5,261,641	$ 5,726,935

During the years ended December 31, 2017 and 2016, we recognized impairment losses of $99.3 million and $670.0 million, respectively. See Note 2.

9. Credit Agreement and Senior Notes

Credit Agreement

We have a syndicated revolving credit agreement with Wells Fargo Bank, National Association, as administrative agent and swingline lender, that provides for a $1.5 billion senior unsecured revolving credit facility for general corporate purposes, which we refer to as the Credit Agreement. Our Credit Agreement matures on October 22, 2020, except for $40 million of commitments that mature on March 17, 2019 and $60 million of commitments that mature on October 22, 2019. In addition, we also have the option to increase the revolving commitments under the Credit Agreement by up to an additional $500 million from time to time, upon receipt of additional commitments from new or existing lenders, and to request one additional one-year extension of the maturity date. The entire amount of the facility is available, subject to its terms, for revolving loans. Up to $250 million of the facility may be used for the issuance of performance or other standby letters of credit and up to $100 million may be used for swingline loans.

Revolving loans under the Credit Agreement 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 Credit Agreement, plus the applicable interest margin for an ABR loan or a Eurodollar loan. Based on our current credit ratings, the applicable interest rate for ABR loans under the Credit Agreement is 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%. The applicable interest rate for Eurodollar loans under the Credit Agreement is currently 1.25% over British Bankers' Association LIBOR.

Swingline loans 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 Agreement, 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 the Credit Agreement of 0.20% per annum 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, currently 0.625% per annum for performance letters of credit and

1.25% per annum for all other letters of credit. Favorable changes in our current credit ratings could lower the fees that we pay under the Credit Agreement; however, current interest rates and fees will apply should there be any further downgrade in our credit ratings.

The Credit Agreement contains customary covenants, including, but not limited to, maintenance of a ratio of consolidated indebtedness to total capitalization, as defined in the Credit Agreement, 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. As of December 31, 2017, we were in compliance with all covenant requirements.

At December 31, 2017, we had no borrowings outstanding under the Credit Agreement. At February 9, 2018, we had no borrowings outstanding under the Credit Agreement and an additional $1.5 billion available. At December 31, 2016, we had $104.2 million in borrowings outstanding under the Credit Agreement that bore interest at a weighted average interest rate of 1.9%.

Senior Notes

At December 31, 2017, our senior notes were comprised of the following debt issues:

Debt Issue	Principal Amount (In millions)	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, 2017 and 2016, the carrying value of our senior notes, net of unamortized discount and debt issuance costs, was as follows:

	December 31, 2017	December 31, 2016
	(In thousands)	
5.875% Senior Notes due 2019	$ —	$ 498,679
3.45% Senior Notes due 2023	248,162	247,879
7.875% Senior Notes due 2025	489,420	—
5.70% Senior Notes due 2039	492,971	492,812
4.875% Senior Notes due 2043	741,672	741,514
Total senior notes, net	$1,972,225	$1,980,884

As of December 31, 2017, the aggregate annual maturity of our senior notes, excluding net unamortized discounts and debt issuance costs of $8.1 million and $19.7 million, respectively, was as follows:

	Aggregate Principal Amount (In thousands)
Year Ending December 31,	
2018	$ —
2019	—
2020	—
2021	—
2022	—
Thereafter	2,000,000
Total maturities of senior notes	$2,000,000

Senior Notes Due 2019. 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 deducting underwriting discounts, commissions and estimated expenses. The 2025 Notes bear interest at 7.875% per year and mature on August 15, 2025. Interest on the 2025 Notes is payable semiannually in arrears on February 15 and August 15 of each year, beginning February 15, 2018. We used the net proceeds from the 2025 Notes, together with cash on hand, to fund the redemption of our 2019 Notes.

The 2025 Notes are unsecured obligations of Diamond Offshore Drilling, Inc., 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. The 2025 Notes 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 the governing indenture.

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 Diamond Offshore Drilling, Inc., 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 Diamond Offshore Drilling, Inc. 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.

10. 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, 2017 and the cumulative balances in AOCGL by component at December 31, 2017, 2016 and 2015.

	Unrealized Gain (Loss) on		
	Derivative Financial Instruments	Marketable Securities	Total AOCGL
	(In thousands)		
Balance at January 1, 2015	(3,504)	(101)	(3,605)
Change in other comprehensive loss before reclassifications, after tax of $846 and $(1)	(1,574)	(4,940)	(6,514)
Reclassification adjustments for items included in Net Loss, after tax of $(2,737) and $0	5,084	—	5,084
Total other comprehensive income (loss)	3,510	(4,940)	(1,430)
Balance at December 31, 2015	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)

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

Major Components of AOCGL	Year Ended December 31, 2017	2016	2015	Consolidated Statements of Operations Line Items
		(In thousands)		
Derivative financial instruments:				
Unrealized loss on FOREX contracts	$—	$ —	$ 7,829	Contract drilling, excluding depreciation
Unrealized gain on Treasury Lock Agreements	(8)	(8)	(8)	Interest expense
	2	3	(2,737)	Income tax expense (benefit)
	$ (6)	$ (5)	$ 5,084	Net of tax
Marketable securities:				
Unrealized loss on marketable securities	$—	$11,600	$ —	Other, net
	—	—	—	Income tax expense
	$—	$11,600	$ —	Net of tax

11. 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 alleges 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*) and is seeking unspecified monetary damages. The Transocean patents, which expired in May 2016, do not apply to drilling activities outside the United States or to activities that occurred after the expiration of the patents. We are unable to estimate our potential exposure, if any, to the Transocean lawsuit 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.

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, 2017, 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 deductible for personal injury claims arising due to named windstorms in the U.S. Gulf of Mexico is $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, 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. At December 31, 2016 our estimated liability for personal injury claims was $32.9 million, of which $6.1 million and $26.8 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, 2017, 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, non-rig equipment and vehicles under operating leases, which expire at various times through the year 2022. Total rent expense amounted to $3.9 million, $5.5 million and $7.8 million for the years ended December 31, 2017, 2016 and 2015, respectively. Future minimum rental payments under leases are approximately $1.7 million and $0.5 million for 2018 and 2019, respectively, and an aggregate of $0.3 million for the years 2020 through 2022.

In addition, we lease certain blowout preventer equipment, or BOP, and related well control equipment under ten-year operating leases. See Note 12.

Letters of Credit and Other. We were contingently liable as of December 31, 2017 in the amount of $20.4 million under certain performance, supersedeas, tax, bid and customs bonds and letters of credit. Agreements relating to approximately $14.8 million of supersedeas, tax and customs bonds can require collateral at any time. As of December 31, 2017, 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.

12. 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 $550.0 million in the aggregate over the remaining term of the agreements. During the years ended December 31, 2017 and 2016, we recognized $61.7 million and $34.0 million, respectively, in aggregate expense related to the Well Control Equipment leases and contractual services agreements.

13. 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 $1.0 million, $1.0 million and $1.3 million by Loews for these support functions during the years ended December 31, 2017, 2016 and 2015, 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 $47,000, $0.7 million and $6.0 million for the hire of such vessels and such services during the years ended December 31, 2017, 2016 and 2015, 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.

14. Restructuring and Separation Costs

In late 2017, in response to expectations that a recovery of the offshore drilling market will not occur in the near term, combined with changes to the size and composition of our drilling fleet since 2015, we reviewed our 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. As of December 31, 2017, appropriate communications had been made to substantially all impacted personnel, and we incurred $14.1 million in restructuring and employee separation related costs during 2017. Accrued costs associated with the 2017 Reduction Plan were $13.6 million as of December 31, 2017, of which $11.5 million is related to the termination of our Brazilian agency agreement, which is expected to be paid in the first quarter of 2018, and $2.1 million is related to severance payments to two former executives, payable over a two year period.

During 2015, in response to depressed conditions in the offshore drilling market at that time, we reviewed our cost and organization structure, and, as a result, our management approved and initiated a reduction in workforce at our onshore bases and corporate facilities, also referred to as the 2015 Reduction Plan. During 2015, we paid $9.8 million in restructuring and employee separation related costs to impacted personnel.

15. Income Taxes

On December 22, 2017, the President of the United States signed into law the Tax Cuts and Jobs Act, commonly referred to as the Tax Reform Act. The Tax Reform Act amended the Internal Revenue Code in several areas that had a direct and immediate effect on our results of operations and statement of financial position as of and for the year ended December 31, 2017, including, among other items, a one-time mandatory deemed repatriation of accumulated earnings of our foreign subsidiaries as of December 31, 2017 and a reduction in the U.S corporate income tax rate from 35% to 21% beginning in January 2018. As a result of these changes, we recorded a provisional net tax expense of $1.1 million during the fourth quarter of 2017, consisting of (i) a $75.4 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 provisional liability for uncertain tax positions related to such attributes and (ii) a $74.3 million credit resulting from the remeasurement of our net U.S. deferred tax liabilities at the lower corporate income tax rate.

Also on December 22, 2017, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 118, which allows companies to report the income tax effects of the Tax Reform Act as a provisional amount based on a reasonable estimate, which would be subject to adjustment during a reasonable measurement period, not to exceed twelve months, until the accounting and analysis under ASC 740 is complete. Due to the timing of the enactment of the Tax Reform Act, there 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. We will continue to monitor developments in this area and adjust our estimates throughout the year in 2018, as and if necessary, as additional guidance and clarification becomes available. Our provisional estimate of the tax effect of the Tax Reform Act is a net charge of $1.1 million as discussed above. We are still in the process of evaluating our estimate as it relates to the tax effect of (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%, and (iii) the ability to more likely than not realize the benefit of deferred tax assets, including net operating losses and foreign tax credits. Any adjustments to these provisional amounts will be reported as a component of "Tax expense (benefit)" in the reporting period in which such adjustments are determined, which will be no later than the fourth quarter of 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 Diamond Foreign Asset Company, or DFAC. We currently intend to indefinitely reinvest the earnings of DFAC and its foreign subsidiaries to finance foreign activities. Except to the extent of the U.S. tax provided under the Tax Reform Act or other required U.S. tax provision, we have not provided tax on the outside basis difference of this subsidiary nor provided for any withholding or other tax that may be applicable should a future distribution be made from any unremitted earnings of this subsidiary. It is not practical to estimate this potential liability.

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

	Year Ended December 31,		
	2017	2016	2015
		(In thousands)	
Federal — current	$ 6,994	$ 230	$ 63,223
State — current	95	(60)	93
Foreign — current	25,252	10,297	71,655
Total current	32,341	10,467	134,971
Federal — deferred	(85,066)	(108,274)	(245,045)
Foreign — deferred	12,939	2,011	3,011
Total deferred	(72,127)	(106,263)	(242,034)
Total	$(39,786)	$ (95,796)	$(107,063)

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:

	Year Ended December 31,		
	2017	2016	2015
		(In thousands)	
Income before income tax expense:			
U.S.	$(241,178)	$(146,037)	$ (11,158)
Foreign	219,738	(322,262)	(370,190)
	$ (21,440)	$(468,299)	$(381,348)
Expected income tax benefit at federal statutory rate	$ (7,504)	$(163,905)	$(133,472)
Effect of tax rate changes	(74,294)	—	—
Mandatory repatriation of earnings pursuant to Tax Reform and Jobs Act	94,194	—	—
Effect of foreign operations	(42,102)	48,573	(4,906)
Amortization of deferred charges associated with intercompany rig sales to other tax jurisdictions	—	—	38,466
Valuation allowance	(41,492)	62,400	—
Uncertain tax positions, settlements and adjustments relating to prior years	31,726	(34,666)	(1,114)
Other	(314)	(8,198)	(6,037)
Income tax benefit	$ (39,786)	$ (95,796)	$(107,063)

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

	December 31, 2017	December 31, 2016
	(In thousands)	
Deferred tax assets:		
Net operating loss carryforwards, or NOLs	$ 133,298	$ 159,653
Foreign tax credits	27,623	95,145
Worker's compensation and other current accruals	10,330	14,824
Bareboat charter deductions	—	23,353
UK depreciation deduction	52,800	21,222
Anticipatory deductions and credits	13,111	—
Deferred compensation	3,711	4,689
Foreign contribution taxes	3,806	3,857
Stock compensation awards	6,872	11,679
Deferred deductions	94	8,185
Other	3,748	2,526
Total deferred tax assets	255,393	345,133
Valuation allowance	(169,224)	(210,716)
Net deferred tax assets	86,169	134,417
Deferred tax liabilities:		
Property, plant and equipment	(236,038)	(284,480)
Mobilization	(17,192)	(46,274)
Other	(238)	(674)
Total deferred tax liabilities	(253,468)	(331,428)
Net deferred tax liability	$(167,299)	$(197,011)

We record a valuation allowance to derecognize a portion of our deferred tax assets, which we do not expect to be ultimately realized. A summary of changes in the valuation allowance is as follows:

	For the Year Ended December 31, 2017	2016	2015
		(In thousands)	
Valuation allowance as of January 1	$210,716	$146,647	$ 48,036
Establishment of valuation allowances:			
Net operating losses	20,805	10,318	82,155
Foreign tax credits	2,877	62,400	—
Other deferred tax assets	14,213	4,823	27,928
Releases of valuation allowances in various jurisdictions	(79,387)	(13,472)	(11,472)
Valuation allowance as of December 31	$169,224	$210,716	$146,647

Net Operating Loss Carryforwards — As of December 31, 2017, we had recorded a deferred tax asset of $133.3 million for the benefit of NOL carryforwards, $18.1 million related to our U.S. losses and $115.2 million related to our international operations. Approximately $73.5 million of this deferred tax asset relates to NOL carryforwards that have an indefinite life. The remaining $59.8 million relates to NOL carryforwards in several of our foreign subsidiaries, as well as in the United States. Unless utilized, the NOL carryforwards will expire between 2021 and 2037 as follows:

Year Expiring	Tax Benefit of NOL Carryforwards (In millions)
2021	$ 5.1
2022	0.2
2023	0.1
2025	28.7
2027	7.6
2036	17.9
2037	0.2
Total	$59.8

As of December 31, 2017, a valuation allowance for $110.9 million has been recorded for our NOLs for which the deferred tax assets are not likely to be realized.

Foreign Tax Credits. As of December 31, 2017, we had recorded a deferred tax asset of $27.6 million for the benefit of foreign tax credits in the U.S. Unless utilized, our excess foreign tax credits of $27.6 million in the U.S. will expire in 2019 and in the years 2024 to 2027 as follows:

Year Expiring	Foreign Tax Credits (In millions)
2019	$ 0.8
2024	3.1
2025	3.5
2026	20.0
2027	0.2
Total	$27.6

As of December 31, 2017, a valuation allowance of $26.7 million has been recorded for our foreign tax credits for which the deferred tax assets are not likely to be realized.

Valuation Allowances — Other Deferred Tax Assets. As of December 31, 2017, we recorded valuation allowances for other deferred tax assets of $31.6 million.

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 more likely than not exposures. A reconciliation of the beginning and ending amount of unrecognized tax benefits, gross of tax carryforwards and excluding interest and penalties, is as follows:

	For the Year Ended December 31,		
	2017	2016	2015
		(In thousands)	
Balance, beginning of period	$(34,970)	$(53,952)	$(57,116)
Additions for current year tax positions	(51,260)	(4,233)	(7,013)
Additions for prior year tax positions	(2,938)	(1,020)	(82)
Reductions for prior year tax positions	623	19,661	2,673
Reductions related to statute of limitation expirations	6,681	4,574	7,586
Balance, end of period	$(81,864)	$(34,970)	$(53,952)

The $51.3 million addition to 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, 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. At December 31, 2016, $2.1 million, $3.1 million and $35.0 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, 2017, 2016 and 2015, all $101.9 million, $36.0 million and $49.4 million, respectively, would affect the effective tax rates if recognized.

At December 31, 2017, the amount of accrued interest and penalties related to uncertain tax positions were $3.1 million and $15.1 million, respectively. At December 31, 2016, the amount of accrued interest and penalties related to uncertain tax positions were $2.7 million and $16.8 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 three years ended December 31, 2017 related to uncertain tax positions was $0.5 million, $(0.1) million and $(4.8) million, respectively. Penalties recognized during the three years ended December 31, 2017 related to uncertain tax positions were $(1.7) million, $(23.2) million and $2.3 million, respectively.

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 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. Taxing authorities in the various foreign locations in which we operate could apply one of the alternative transfer pricing methodologies which could result in an increase to our income tax liabilities with respect to tax returns that remain subject to examination.

We expect the statute of limitations for the 2012 tax year to expire in 2018 for one of our subsidiaries operating in Mexico. We anticipate that the related unrecognized tax benefit will decrease by $1.5 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 2016. We are currently under audit in the United States, Australia, Brazil, Egypt, Mexico, Nicaragua, Norway, Qatar and the United Kingdom. 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.

16. 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 2017, 2016 and 2015, we matched 5%, 6% and 6%, respectively, of each employee's compensation contributed to the 401k Plan. We ceased making discretionary profit sharing contributions to the 401k Plan on May 1, 2015. Prior to that date, we made discretionary profit sharing contributions equal to 4% of a participant's defined compensation. 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, 2017, 2016 and 2015, our provision for contributions was $8.9 million, $12.9 million and $23.8 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 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 and in 2015, our contribution was 10% of the employee's defined compensation. Our provision for contributions was $1.4 million, $2.0 million and $3.4 million for the years ended December 31, 2017, 2016 and 2015, respectively.

The defined contribution retirement plan for our TCN employees, or International Savings Plan, is similar to the 401k Plan. During 2017, 2016 and 2015, we matched 5%, 6% and 6%, respectively, of each employee's compensation contributed to the International Savings Plan. During the four months ended April 30, 2015, we made discretionary profit sharing contributions to the International Savings Plan equal to 4% of a participant's defined compensation. We ceased making profit sharing contributions on May 1, 2015. Our provision for contributions was $0.4 million, $0.8 million and $2.2 million for 2017, 2016 and 2015, 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 our 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 2017, 2016 and 2015 was approximately $136,000, $146,000 and $153,000, respectively.

17. 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.

Revenues from contract drilling services by equipment-type are listed below:

	Year Ended December 31,		
	2017	2016	2015
		(In thousands)	
Floaters:			
Ultra-Deepwater	$1,090,139	$ 989,158	$1,339,059
Deepwater	202,329	256,997	548,667
Mid-Water	137,607	248,846	387,549
Total Floaters	1,430,075	1,495,001	2,275,275
Jack-ups	21,144	30,213	84,909
Total contract drilling revenues	1,451,219	1,525,214	2,360,184
Revenues related to reimbursable expenses	34,527	75,128	59,209
Total revenues	$1,485,746	$1,600,342	$2,419,393

Geographic Areas

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, 2017, our actively-marketed drilling rigs were located offshore four 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.

	Year Ended December 31,		
	2017	2016	2015
		(In thousands)	
United States	$ 630,595	$ 548,024	$ 513,605
International:			
South America	348,479	434,956	812,271
Australia/Asia	307,925	234,182	415,033
Europe	177,603	344,964	532,824
Mexico	21,144	38,216	145,660
	855,151	1,052,318	1,905,788
Total revenues	$1,485,746	$1,600,342	$2,419,393

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, 2017, 2016 and 2015, individual countries that comprised 5% or more of our total contract drilling revenues from unaffiliated customers are listed below.

	Year Ended December 31,		
	2017	2016	2015
Brazil	18.9%	18.0%	23.1%
United Kingdom	12.0%	15.3%	11.4%
Malaysia	11.2%	1.7%	6.8%
Australia	9.5%	12.8%	7.0%
Trinidad & Tobago	4.6%	9.2%	9.8%
Mexico	1.4%	2.4%	6.0%
Romania	—	4.0%	9.7%

The following table presents our long-lived tangible assets by geographic location as of December 31, 2017, 2016 and 2015. 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.

	December 31,		
	2017 (1)	2016 (1)	2015 (1)
		(In thousands)	
Drilling and other property and equipment, net:			
United States	$2,300,956	$2,753,511	$3,292,474
International:			
Australia/Asia/Middle East	1,714,246	1,429,563	1,224,089
South America	923,398	1,030,069	1,051,283
Europe/Africa	320,473	380,462	664,520
Mexico	2,568	133,330	146,448
	2,960,685	2,973,424	3,086,340
Total	$5,261,641	$5,726,935	$6,378,814

(1) During 2017, 2016 and 2015, we recorded aggregate impairment losses of $99.3 million, $678.1 million and $860.4 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, 2017, 2016 and 2015:

	December 31,		
	2017	2016	2015
United States	43.7%	48.1%	51.6%
Malaysia	20.6%	13.6%	10.4%
Brazil	17.5%	16.8%	15.3%
Australia	12.0%	11.4%	4.5%

As of December 31, 2017, 2016 and 2015, 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, 2017, 2016 and 2015 that contributed more than 10% of our total revenues are as follows:

	Year Ended December 31,		
Customer	2017	2016	2015
Anadarko	24.9%	22.4%	12.4%
Petróleo Brasileiro S.A.	18.9%	17.9%	24.1%
Hess Corporation	16.0%	7.7%	0.3%
BP	15.8%	9.0%	0.1%
ExxonMobil	—	5.8%	12.4%

18. Unaudited Quarterly Financial Data

Unaudited summarized financial data by quarter for the years ended December 31, 2017 and 2016 is shown below.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share data)			
2017				
Revenues	$374,226	$ 399,289	$366,023	$346,208
Operating income (loss) [(1)]	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)
2016				
Revenues	$470,543	$ 388,747	$349,178	$391,874
Operating income (loss) [(2)]	111,569	(626,669)	54,071	104,145
Income (loss) before income tax expense	83,196	(666,115)	34,746	79,874
Net income (loss)	87,425	(589,937)	13,927	116,082
Net income (loss) per share, basic and diluted	$ 0.64	$ (4.30)	$ 0.10	$ 0.85

(1) During the second and fourth quarters of 2017, we recognized an aggregate impairment loss 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 2.

(2) During the second quarter of 2016, we recognized an aggregate impairment loss of $678.1 million to write down certain of our drilling rigs and related spare parts with indicators of impairment to their estimated recoverable amounts. See Notes 1 and 2.

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, 2017. Based on their participation in that evaluation, our CEO and CFO concluded that our disclosure controls and procedures were effective as of December 31, 2017.

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 if 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, 2017. 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, 2017, 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 2017 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 2018 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2017, or our 2018 Proxy Statement, and is incorporated herein by reference. Information about our executive officers is reported under the caption "Executive Officers of the Registrant" in 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 2018 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 2018 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 experts is contained in our 2018 Proxy Statement under the caption "Board Committees – Audit Committee" 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 2018 Proxy Statement under the captions "Compensation Committee — Compensation Committee Interlocks and Insider Participation," "Director Compensation," "Compensation Discussion and Analysis" 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 can be found under the caption "Stock-Based Compensation" under Item 4 of this Report and is contained in our 2018 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 on each beneficial owner of more than 5% of our common stock is contained under the captions "Security Ownership of Certain Beneficial Owners" and "Security ownership of Management and Directors" in our 2018 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 2018 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 2018 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).

Exhibit No.	Description
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).
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+	The Diamond Offshore Drilling, Inc. Incentive Compensation Plan for Executive Officers (as Amended and Restated as of March 28, 2014) (incorporated by reference to Exhibit A attached to our definitive proxy statement on Schedule 14A filed April 1, 2014).
10.10+	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).
10.11+	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).
10.12+	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).
10.13+	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).
10.14+	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).
10.15	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).

Exhibit No.	Description
10.16	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).
10.17	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).
10.18	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).
10.19	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).
10.20	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).
10.21+	Severance Agreement, dated May 2, 2016, between Diamond Offshore Drilling, Inc. and Kelly Youngblood (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2016).
10.22+	Diamond Offshore Executive Retention Plan (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed January 31, 2017).
10.23+	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).
12.1*	Statement re Computation of Ratios.
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, 2018.

DIAMOND OFFSHORE DRILLING, INC.

By: /s/ SCOTT KORNBLAU

Scott Kornblau

Acting 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, 2018
/s/ SCOTT KORNBLAU Scott Kornblau	Vice President, Acting Chief Financial Officer and Treasurer (Principal Financial Officer)	February 13, 2018
/s/ BETH G. GORDON Beth G. Gordon	Vice President and Controller (Principal Accounting Officer)	February 13, 2018
/s/ JAMES S. TISCH James S. Tisch	Chairman of the Board	February 13, 2018
/s/ JOHN R. BOLTON John R. Bolton	Director	February 13, 2018
/s/ CHARLES L. FABRIKANT Charles L. Fabrikant	Director	February 13, 2018
/s/ PAUL G. GAFFNEY II Paul G. Gaffney II	Director	February 13, 2018

Signature	Title	Date
/s/ EDWARD GREBOW Edward Grebow	Director	February 13, 2018
/s/ HERBERT C. HOFMANN Herbert C. Hofmann	Director	February 13, 2018
/s/ KENNETH I. SIEGEL Kenneth I. Siegel	Director	February 13, 2018
/s/ CLIFFORD M. SOBEL Clifford M. Sobel	Director	February 13, 2018
/s/ ANDREW H. TISCH Andrew H. Tisch	Director	February 13, 2018
/s/ RAYMOND S. TROUBH Raymond S. Troubh	Director	February 13, 2018