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, 2013

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

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

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

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 28, 2013 $4,741,751,658

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 18, 2014 Common Stock, $0.01 par value per share 139,035,448 shares

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement relating to the 2014 Annual Meeting of Stockholders of Diamond Offshore Drilling, Inc., which will be filed within 120 days of December 31, 2013, are incorporated by reference in Part III of this report.

DIAMOND OFFSHORE DRILLING, INC.
FORM 10-K for the Year Ended December 31, 2013

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PART I

Item 1. Business.

General

Diamond Offshore Drilling, Inc. is a leader in offshore drilling, providing contract drilling services to the energy industry around the globe with a fleet of 45 offshore drilling rigs, including five rigs under construction. Our fleet consists of 33 semisubmersibles, two of which are under construction, seven jack-ups, one of which is held for sale, and five dynamically positioned drillships, three of which are under construction. The *Ocean BlackHawk*, the first of our four new ultra-deepwater drillships, was delivered in late January 2014 and, as of the date of this report, is en route to the U.S. Gulf of Mexico, or GOM, where it is expected to begin operating under contract in the second quarter of 2014. The deepwater floater *Ocean Onyx* was completed in late 2013 and is operating under contract in the GOM. *See* "— *Fleet Enhancements and Additions*" and "— *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. We were incorporated in Delaware in 1989.

Our Fleet

Our diverse fleet enables us to offer a broad range of services worldwide in both the floater market (ultra-deepwater, deepwater and mid-water) and the non-floater, or jack-up, market.

Floaters. A floater rig is a type of mobile offshore drilling unit that floats and does not rest on the seafloor. This asset class includes self-propelled drillships and semisubmersible rigs. Semisubmersible rigs consist 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 which 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 either an anchoring system or 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	13 (b)
Deepwater	5,000 to 7,500	7 (c)
Mid-Water	400 to 4,999	18

(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).
(b) Includes three drillships and one harsh environment semisubmersible rig under construction.
(c) Includes the *Ocean Apex,* currently under construction.

See "— *Fleet Enhancements and Additions"* for further discussion of our rigs under construction.

Jack-ups. Jack-up rigs are mobile, self-elevating drilling platforms equipped with legs that are lowered to the ocean floor. Our jack-ups are used for drilling in water depths from 20 feet to 350 feet. The water depth limit in which a particular rig is able to operate is principally determined by the length of the rig's legs. The rig hull includes the drilling equipment, jacking system, crew quarters, loading and unloading facilities, storage areas for bulk and liquid materials, heliport and other related equipment. A jack-up rig is towed to the drillsite with its hull riding in the sea, as a vessel, with its legs retracted. Once over a drillsite, the legs are lowered until they rest on the seabed and jacking continues with the legs penetrating the seabed until they are firm and stable, and resistance is sufficient to elevate the hull above the surface of the water. After completion of drilling operations, the hull is lowered until it rests in the water and then the legs are retracted for relocation to another drillsite. All of our jack-up rigs are equipped with a cantilever system that enables the rig to cantilever or extend its drilling package over the aft end of the rig.

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, and otherwise by enhancing the capabilities of our existing rigs at a lower cost and reduced construction period than newbuild construction would require. Since 2009, commencing with the acquisition of two newbuild, ultra-deepwater semisubmersible rigs, the *Ocean Courage* and *Ocean Valor*, we have committed over $5.0 billion towards upgrading our fleet. The *Ocean Onyx*, one of our two newest deepwater semisubmersible rigs, was completed in late 2013 and commenced drilling operations under a one-year contract in the GOM in early 2014. The *Ocean BlackHawk*, the first of four new ultra-deepwater drillships, is mobilizing to the GOM as of the date of this report and is expected to begin working under contract in the second quarter of 2014. We also have six other construction/enhancement projects underway.

The following is a summary of our ongoing rig construction/enhancement projects as of the date of this report:

Rig Name	Rig Type	Estimated Cost (In millions)	Expected Completion	Contract Status: Customer	Contract Status: Location
Ocean BlackHornet	Ultra-deepwater drillship	$ 635	Q2 2014	Anadarko	GOM
Ocean BlackRhino	Ultra-deepwater drillship	$ 645	Q3 2014	Actively marketing	South Korea (1)
Ocean BlackLion	Ultra-deepwater drillship	$ 655	Q1 2015	Actively marketing	South Korea (1)
Ocean GreatWhite	Ultra-deepwater semisubmersible	$ 755	Q1 2016	BP	Australia
Ocean Apex	Deepwater semisubmersible	$ 370	Q3 2014	ExxonMobil	Vietnam
Ocean Patriot	Mid-water semisubmersible **(2)**	$ 120	Q2 2014	Shell	North Sea/U.K.

(1) Rigs are under construction in South Korea. As of the date of this report, it has not yet been determined where these rigs will be located once shipyard work and commissioning are completed.
(2) Enhancements to the rig are underway which will enable it to work in the North Sea.

We will 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 — Cash Flow and Capital Expenditures” in Item 7 of this report.

See “— *Fleet Status”* for more detailed information about our drilling fleet.

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Fleet Status

The following table presents additional information regarding our floater fleet at January 27, 2014:

Rig Type and Name	Rated Water Depth (in feet)	Attributes	Year Built/ Redelivered(a)	Current Location(b)	Customer(c)
ULTRA-DEEPWATER:					
Semisubmersibles(8):					
Ocean GreatWhite	10,000	DP; 6R; 15K	Q1 2016	South Korea	Under construction/BP (d)
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	In transit/Cameroon	Murphy West Africa
Ocean Monarch	10,000	15K	2008	Indonesia	Actively marketing
Ocean Endeavor	10,000	15K	2007	In transit/Italy	Contract preparation/ExxonMobil
Ocean Rover	8,000	15K	2003	Malaysia	Murphy Exploration
Ocean Baroness	8,000	15K	2002	Brazil	Petrobras
Drillships(5):					
Ocean BlackLion	12,000	DP; 7R; 15K	Q1 2015	South Korea	Under construction
Ocean BlackRhino	12,000	DP; 7R; 15K	Q3 2014	South Korea	Under construction
Ocean BlackHornet	12,000	DP; 7R; 15K	Q2 2014	South Korea	Under construction/Anadarko (d)
Ocean BlackHawk	12,000	DP; 7R; 15K	2014	South Korea	Commissioning/Anadarko (d)
Ocean Clipper	7,875	DP; 15K	1997	Brazil	Petrobras
DEEPWATER:					
Semisubmersibles(7):					
Ocean Apex	6,000	15K	Q3 2014	Singapore	Under construction/ExxonMobil (d)
Ocean Onyx	6,000	15K	2013	GOM	Apache
Ocean Victory	5,500	15K	1997	GOM	Stone Energy
Ocean America	5,500	15K	1988	Australia	Chevron
Ocean Valiant	5,500	15K	1988	Canary Islands	Survey/Actively marketing
Ocean Star	5,500	15K	1997	Brazil	Queiroz Galvão Exploration
Ocean Alliance	5,250	DP; 15K	1988	Brazil	Petrobras
MID-WATER:					
Semisubmersibles(18):					
Ocean Winner	4,000		1976	Brazil	Petrobras
Ocean Worker	4,000		1982	Brazil	Petrobras
Ocean Quest	4,000	15K	1973	Labuan	Actively marketing
Ocean Yatzy	3,300	DP	1989	Brazil	Petrobras
Ocean Patriot	3,000	15K	1983	Singapore	Under construction/Shell
Ocean General	3,000		1976	Vietnam	Premier Vietnam
Ocean Yorktown	2,850		1976	Mexico	PEMEX
Ocean Concord	2,300		1975	Brazil	Petrobras
Ocean Lexington	2,200		1976	Trinidad and Tobago	BG International
Ocean Saratoga	2,200		1976	GOM	LLOG
Ocean Guardian	1,500	15K	1985	North Sea/U.K.	Shell
Ocean Princess	1,500	15K	1975	North Sea/U.K.	EnQuest
Ocean Vanguard	1,500	15K	1982	North Sea/Norway	Statoil
Ocean Nomad	1,200		1975	North Sea/U.K.	Dana Petroleum
Ocean Ambassador	1,100		1975	GOM	Contract preparation/PEMEX
Ocean Epoch	3,000		1977	Malaysia	Cold stacked
Ocean Whittington	1,650		1974	GOM	Cold stacked
Ocean New Era	1,500		1974	GOM	Cold stacked

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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 (or is expected to be) built and originally placed in service or year rig was (or is expected to be) 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.
(d) Rig is contracted for future work upon completion of commissioning.

The following table presents additional information regarding our jack-up fleet, all of which are independent-leg, cantilevered units, at January 27, 2014:

Rig Type and Name	Rated Water Depth(a) (in feet)	Year Built	Current Location(b)	Customer(c)
Jack-ups (7):				
Ocean Scepter [(d)]	350	2008	Mexico	PEMEX
Ocean Titan [(d)]	350	1974	Mexico	PEMEX
Ocean King	300	1973	GOM	Energy XXI
Ocean Nugget	300	1976	Mexico	PEMEX
Ocean Summit	300	1972	Mexico	PEMEX
Ocean Spur	300	1981	Ecuador	Saipem [(e)]
Ocean Spartan	300	1980	GOM	Cold stacked [(f)]

(a) Rated water depth reflects the operating water depth capability for each drilling unit.
(b) GOM means U.S. Gulf of Mexico.
(c) For ease of presentation in this table, customer names have been shortened or abbreviated.
(d) Rig has a 15,000 psi well control system.
(e) Rig is currently under a bareboat charter until the third quarter of 2014.
(f) Rig is marketed for sale.

Markets

The principal markets for our offshore contract drilling services are the following:

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

We actively market our rigs worldwide. From time to time our fleet operates in various other markets throughout the world. See Note 15 “Segments and Geographic Area Analysis” to our Consolidated Financial Statements in Item 8 of this report.

We believe our presence in multiple markets is valuable in many respects. For example, we believe that our experience with safety and other regulatory matters in the U.K. has been beneficial in Australia and other international areas in which we operate, while production experience we have gained through our Brazilian and North Sea operations has potential application worldwide. Additionally, we believe our performance for a customer in one market area enables us to better understand that customer’s needs and better serve that customer in different market areas or other geographic locations.

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 fixed dayrate regardless of whether or not such drilling results in a productive well. Drilling contracts may 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. See “Risk Factors — *Our business involves numerous operating hazards which 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,*” “Risk Factors — *The terms of our drilling contracts may limit our ability to attain profitability in a declining market or to benefit from increasing dayrates in an improving market,*” “Risk Factors — *Our drilling contracts may be terminated due to events beyond our control,*” “Risk Factors — *We may enter into drilling contracts that expose us to greater risks than we normally assume*” and “Risk Factors — *We have elected to self-insure for physical damage to rigs and equipment caused by named windstorms in the U.S. Gulf of Mexico*” 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 2013, 2012 and 2011, we performed services for 39, 35 and 52 different customers, respectively. During 2013, 2012 and 2011, one of our customers in Brazil, Petróleo Brasileiro S.A., or Petrobras (a Brazilian multinational energy company that is majority-owned by the Brazilian government), accounted for 34%, 33% and 35% of our annual total consolidated revenues, respectively. OGX Petróleo e Gás Ltda., or OGX (a privately owned Brazilian oil and natural gas company that filed for bankruptcy in October 2013), accounted for 2%, 12% and 14% of our annual total consolidated revenues for the years ended December 31, 2013, 2012 and 2011, respectively. No other customer accounted for 10% or more of our annual total consolidated revenues during 2013, 2012 or 2011. See “Risk Factors — *We rely heavily on a relatively small number of customers and the loss of a significant customer and/or a dispute that leads to the loss of a customer could have a material adverse impact on our financial results*” in Item 1A of this report, which is incorporated herein by reference.

Brazil is one of the most active floater markets in the world today. As of the date of this report, the greatest concentration of our operating assets is offshore Brazil, where we have ten rigs currently contracted. Our contract backlog attributable to our expected operations offshore Brazil is $953.0 million, $537.0 million and $62.0 million for the years 2014, 2015 and 2016, respectively. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Market Overview — *Contract Drilling Backlog*” in Item 7 of this report.

Competition

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. The industry may also experience additional consolidation in the future, which could create other large competitors. Some of our competitors may have greater financial or other resources than we do. We compete with offshore drilling contractors that together have approximately 600 mobile rigs available worldwide.

The offshore contract drilling industry is influenced by a number of factors, including global economies and demand for oil and natural gas, current and anticipated prices of oil and natural gas, expenditures by oil and gas companies for exploration and development of oil and natural gas and the availability of drilling rigs.

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, at a cost that may be substantial, from one region to another. It is characteristic of the offshore contract drilling industry to move rigs from areas of low utilization and dayrates to areas of greater activity and relatively higher dayrates. Significant new rig construction and upgrades of existing drilling units could also intensify price competition. See "Risk Factors — *Our industry is highly competitive and cyclical, with 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 — *Governmental laws and regulations, both domestic and international, may add to our costs or limit our drilling activity*" and "Risk Factors — *Compliance with or breach of environmental laws can be costly and could limit our operations*" 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 89%, 94% and 90% of our total consolidated revenues for the years ended December 31, 2013, 2012 and 2011, respectively. See "Risk Factors — *Significant portions of our operations are conducted outside the United States and involve additional risks not associated with domestic operations*," "Risk Factors — *We may enter into drilling contracts that expose us to greater risks than we normally assume*" and "Risk Factors — *Fluctuations in exchange rates and nonconvertibility of currencies could result in losses to us*" in Item 1A of this report, which are incorporated herein by reference.

Employees

As of December 31, 2013, we had approximately 5,500 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 to serve until the next annual meeting of our Board of Directors, or 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, 2014	Position
Lawrence R. Dickerson	61	Incumbent President, Chief Executive Officer and Director (1)
Marc Edwards	53	Incoming President, Chief Executive Officer and Director (1)
John M. Vecchio	63	Executive Vice President
Gary T. Krenek	55	Senior Vice President and Chief Financial Officer
William C. Long	47	Senior Vice President, General Counsel & Secretary
Beth G. Gordon	58	Controller – Chief Accounting Officer
Lyndol L. Dew	59	Senior Vice President – Worldwide Operations

(1) Effective March 3, 2014, Mr. Dickerson will retire as an officer and director and Mr. Edwards will become our President and Chief Executive Officer and a director.

Lawrence R. Dickerson has served as our President and a Director since March 1998 and as our Chief Executive Officer since May 2008. Mr. Dickerson served as our Chief Operating Officer from March 1998 to May 2008. Mr. Dickerson will retire from his positions as an officer and director effective upon the appointment of Mr. Edwards on March 3, 2014.

Marc Edwards will serve as our President and Chief Executive Officer and as a Director effective March 3, 2014. Mr. Edwards served as a member of the Executive Committee and as Senior Vice President of the Completion and Production Division at Halliburton Company, a diversified oilfield services company, from January 2010 to February 2014. Mr. Edwards previously served as Vice President for Production Enhancement of Halliburton Company from January 2008 through December 2009.

John M. Vecchio has served as Executive Vice President since August 2009. Mr. Vecchio previously served as our Senior Vice President — Technical Services from April 2002 to July 2009.

Gary T. Krenek has served as a Senior Vice President and our Chief Financial Officer since October 2006. Mr. Krenek previously served as our Vice President and Chief Financial Officer since March 1998.

William C. Long has served as a Senior Vice President and our General Counsel and Secretary since October 2006. Mr. Long previously served as our Vice President, General Counsel and Secretary since March 2001 and as our General Counsel and Secretary from March 1999 through February 2001.

Beth G. Gordon has served as our Controller and Chief Accounting Officer since April 2000.

Lyndol L. Dew has served as a Senior Vice President since September 2006. Previously, Mr. Dew served as our Vice President-International Operations from January 2006 to August 2006 and as our Vice President — North American Operations from January 2003 to December 2005.

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 information contained on our website, or on other websites linked to our website, is not part of this report.

Item 1A. Risk Factors.

Our business is subject to a variety of risks, including the risks described below. You should carefully consider these risks when evaluating us and our securities. The risks and uncertainties described below 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. If any of the following risks 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.

Our business depends on the level of activity in the oil and gas industry, which is significantly affected by volatile oil and gas prices.

Our business depends on the level of activity in offshore oil and gas exploration, development and production in markets worldwide. Worldwide demand for oil and gas, oil and gas prices, market expectations of potential changes in these prices and a variety of political and economic factors significantly affect this level of activity. However, higher or lower commodity demand and prices do not necessarily translate into increased or decreased drilling activity since our customers' project development time, reserve replacement needs, as well as expectations of future commodity demand and prices all combine to affect demand for our rigs. In addition, the level of offshore drilling activity may be adversely affected if operators reduce or defer new investment in offshore projects or reallocate their drilling budgets away from offshore drilling in favor of shale plays or other land-based energy markets, which could reduce demand for our rigs and newbuilds. Oil and gas prices have been, and are expected to continue to be, extremely volatile and are affected by numerous factors beyond our control, including:

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

- the worldwide economic environment or economic trends, such as recessions;
- the ability of the Organization of Petroleum Exporting Countries, commonly called OPEC, to set and maintain production levels and pricing;
- the level of production in non-OPEC countries;
- the worldwide political and military environment, including uncertainty or instability resulting from an escalation or additional outbreak of armed hostilities in the Middle East, other oil-producing regions or other geographic areas or further acts of terrorism in the United States or elsewhere;
- civil unrest;
- the cost of exploring for, producing and delivering oil and gas;
- the discovery rate of new oil and gas reserves;
- the rate of decline of existing and new oil and gas reserves;
- available pipeline and other oil and gas transportation and refining capacity;
- the ability of oil and gas companies to raise capital;
- weather conditions;
- 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;
- development and exploitation of alternative fuels or energy sources;
- competition for customers' drilling budgets from land-based energy markets around the world;
- laws and regulations relating to environmental or energy security matters, including those addressing the risks of global climate change;
- domestic and foreign tax policy; and
- advances in exploration and development technology.

Governmental laws and regulations, both domestic and international, may add to our costs or limit our drilling activity.

Our operations are affected from time to time in varying degrees by governmental laws and regulations. The offshore drilling industry is dependent on demand for services from the oil and gas exploration industry and, accordingly, is affected by changing tax and other laws relating to the energy business generally. We may be required to make significant capital expenditures for additional equipment 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 the aftermath of the 2010 Macondo well blowout and subsequent investigation into the causes of the event, new rules have been implemented for oil and gas operations in the U.S. Gulf of Mexico, or GOM, and in many of the international locations in which we operate, including new standards for well design, casing and cementing and well control procedures, as well as rules requiring operators to systematically identify risks and establish safeguards against those risks through a comprehensive safety and environmental management system, or SEMS. New regulations may continue to be announced, including rules regarding drilling systems and equipment, such as blowout preventer and well control systems and lifesaving systems, as well as rules regarding employee training, engaging personnel in safety management and requiring third party audits of SEMS programs. Such new regulations could require modifications or enhancements to existing systems and equipment, or require new equipment, and could increase our operating costs and cause downtime for our rigs if we are required to take any of them out of service between scheduled surveys or inspections, or if we are required to extend scheduled surveys or inspections, to meet any such new requirements. We are not able to predict the likelihood, nature or extent of additional rulemaking, nor are we able to predict the future impact of these events on our operations. Additional governmental regulations concerning licensing, taxation, equipment specifications, training requirements or other matters could increase the costs of our operations, and enhanced permitting requirements, as well as escalating costs borne by our customers, could reduce exploration activity in the GOM and therefore demand for our services.

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 materially and adversely affect our operations by limiting drilling opportunities.

As discussion of climate change issues increases, governments around the world are beginning to adopt laws and regulations to address the matter. 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.

Our business involves numerous operating hazards which 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, damage to producing or potentially productive oil and gas formations, and 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 perils peculiar to marine operations, 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, which could have a material adverse effect on our results of operations, financial condition and cash flows.

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 with our customers generally provide that we and our customers each assume liability for our respective personnel and property. Our contracts also generally provide that our customers assume most of the responsibility for and indemnify us against loss, damage or other liability resulting from, among other hazards and risks, pollution originating from the well and subsurface damage or loss, while we typically retain responsibility for and indemnify our customers against pollution originating from the rig. However, in certain drilling contracts we may not be fully indemnified by our customers for damage to their property and/or the property of their other contractors. In certain contracts we may assume liability for losses or damages (including punitive damages) resulting from pollution or contamination caused by negligent or willful acts of commission or omission by us, our suppliers and/or subcontractors, generally subject to negotiated caps on a per occurrence basis and/or on an aggregate basis for the term of the contract. In some cases, suppliers or subcontractors who provide equipment or services to us may seek to limit their liability resulting from pollution or contamination. 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.

Additionally, the enforceability of indemnification provisions in our contracts may be limited or prohibited by applicable law or 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 of 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, void or limited by public policy considerations, including when the cause of the underlying loss or damage is our gross negligence or willful misconduct, when punitive damages are attributable to us or when fines or penalties are imposed directly against us. 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. Current or future litigation in particular jurisdictions, whether or not we are a party, may impact the interpretation and enforceability of indemnification provisions in 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 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, pollution and environmental risks are generally not fully insurable when they are determined to be the result of criminal acts. Also, we do not typically purchase loss-of-hire insurance to cover lost revenues when a rig is unable to work. Moreover, insurance costs across the industry have increased following the Macondo incident and, in the future, certain insurance coverage is likely to become more costly and may become less available or not available at all. Accordingly, it is possible that our losses from the hazards we face could have a material adverse effect on our results of operations, financial condition and cash flows.

We believe that the policy limit under 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. However, if an accident or other event occurs that exceeds our coverage limits or is not an insurable event under our insurance policies, or is not fully covered by contractual indemnity, it could have a material adverse effect on our results of operations, financial condition and cash flows. 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.

Accordingly, the occurrence of any of the hazards we face could have a material adverse effect on our results of operations, financial condition and cash flows.

Compliance with or breach of environmental laws can be costly and could limit our operations.

In the United States and in many of the international locations in which we operate, laws and regulations controlling the discharge of materials into the environment, requiring removal and cleanup of materials that may harm the environment or otherwise relating to the protection of the environment apply to some of our operations. For example, we, as an operator of mobile offshore drilling units in navigable United States waters and some offshore areas, may be liable for damages and costs incurred in connection with oil spills related to those operations. 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. These laws and regulations may expose us to liability for the conduct of, or conditions caused by, others or for acts that were in compliance with all applicable laws at the time they were performed.

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 following the Macondo well blowout and other recent events that could substantially increase our exposure to liabilities which might arise in connection with our operations.

The application of these laws and regulations or the adoption of new laws and regulations could have a material adverse effect on our financial condition, results of operations and cash flows.

Our industry is highly competitive and cyclical, with intense price competition.

The offshore contract drilling industry is 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. 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.

Our industry has historically been cyclical. There have been periods of lower demand, excess rig supply and low dayrates, followed by periods of high demand, short rig supply and high dayrates. We cannot predict the timing or duration of such business cycles. Periods of lower demand or excess rig supply intensify the competition in the industry and often result in periods of low utilization. During these periods, our existing rigs and newbuilds 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, which could have a material adverse effect on our financial condition, results of operations and cash flows. Additionally, prolonged periods of low utilization and dayrates could also result in the recognition of 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.

Significant new rig construction and upgrades of existing drilling units could also intensify price competition. As of the date of this report, based on analyst reports, we believe that there are approximately 100 floaters on order and scheduled for delivery between 2014 and 2016, with approximately 32% of these rigs scheduled for delivery in 2014. The resulting increases in rig supply could be sufficient to depress rig utilization and intensify price competition from both existing competitors, as well as new entrants into the offshore drilling market. As of the date of this report, not all of the rigs currently under construction have been contracted for future work, which may further intensify price competition as scheduled delivery dates occur. The majority of the floaters on order are dynamically positioned drilling units, which further increases competition with our fleet in certain circumstances, depending on customer requirements. In Brazil, Petrobras, which accounted for approximately 34% of our consolidated revenues in 2013 and, as of February 5, 2014, accounted for approximately $1.0 billion and $0.5 billion of our contract drilling backlog in 2014 and in the aggregate for the years 2015 and 2016, respectively, and to which 10 of our floaters are currently contracted, has announced plans to construct locally 28 new ultra-deepwater drilling units to be delivered beginning in 2015. These new drilling units, if built, would increase rig supply and could intensify price competition in Brazil as well as other markets as they enter the market, would compete with, and could displace, both our deepwater and ultra-deepwater floaters coming off contract as well as our newbuilds coming to market and could materially adversely affect our utilization rates, particularly in Brazil.

We may not be able to renew or replace expiring contracts for our existing rigs or obtain contracts for our uncontracted newbuilds.

We have a number of customer contracts that will expire in 2014 and 2015. Additionally, certain of our newbuilds that we expect to come to market during 2014 are contracted on a short-term basis or are currently uncontracted. Although we will seek to secure contracts for these units before construction is completed, 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. Given the highly competitive and historically cyclical nature of our industry, we may be required to renew or replace expiring contracts or obtain new contracts at dayrates that are below, and potentially substantially below, existing dayrates, or we may be unable to secure contracts for these units. This could have a material adverse effect on our financial condition, results of operations and cash flows.

We can provide no assurance that our current backlog of contract drilling revenue will be ultimately realized.

As of the date of this report, our contract drilling backlog was approximately $6.8 billion for contracted future work extending, in some cases, until 2019. Generally, contract backlog only includes future revenues under firm commitments; however, from time to time, we may report anticipated commitments for which definitive agreements have not yet been, but are expected to be, executed. We can provide no assurance that we will be able to perform under these contracts due to events beyond our control or that we will be able to ultimately execute a definitive agreement in cases where one does not currently exist. In addition, we can provide no assurance that our customers will be able to or willing to fulfill their contractual commitments to us. Our inability to perform under our contractual obligations or to execute definitive agreements, or our customers' inability or unwillingness to fulfill their contractual commitments to us, may have a material adverse effect on our financial condition, results of operations and cash flows. See "— *Our industry is highly competitive and cyclical, with 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 rely heavily on a relatively small number of customers and the loss of a significant customer and/or a dispute that leads to the loss of a customer could have a material adverse impact on our financial results.

We provide offshore drilling services to a customer base that includes major and independent oil and gas companies and government-owned oil companies. In 2013, our five largest customers in the aggregate accounted for 54% of our consolidated revenues. We expect Petrobras, which accounted for approximately 34% of our consolidated revenues in 2013, to continue to be a significant customer in 2014. Our contract drilling backlog, as of the date of this report, includes $1.0 billion, or 36%, in 2014 and $0.5 billion in the aggregate for the years 2015 and 2016, which is attributable to contracts with Petrobras for operations offshore Brazil. Petrobras has announced plans to construct locally 28 new ultra-deepwater drilling units to be delivered beginning in 2015. These new drilling units, if built, would compete with, and could displace, our deepwater and ultra-deepwater floaters coming off contract and could materially adversely affect our utilization rates, particularly in Brazil. In addition, if Petrobras or another significant customer experiences liquidity constraints or other financial difficulties, it could materially adversely affect our utilization rates in Brazil or other markets and also displace demand for our other drilling rigs and newbuilds as the resulting excess supply enters the market. While it is normal for our customer base to change over time as work programs are completed, the loss of, or a significant reduction in the number of rigs contracted with, any major customer may have a material adverse effect on our financial condition, results of operations and cash flows. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Market Overview — *Contract Drilling Backlog*” in Item 7 of this report.

The terms of our drilling contracts may limit our ability to attain profitability in a declining market or to benefit from increasing dayrates in an improving market.

The duration of offshore drilling contracts is generally determined by customer requirements and, to a lesser extent, the respective management strategies of the offshore drilling contractors. In periods of decreasing demand for offshore rigs, drilling contractors generally prefer longer term contracts to preserve dayrates at existing levels and ensure utilization, while customers prefer shorter contracts that allow them to more quickly obtain the benefit of lower dayrates. Conversely, in periods of rising demand for offshore rigs, contractors typically prefer shorter contracts that allow them to more quickly profit from increasing dayrates, while customers with reasonably definite drilling programs typically prefer longer term contracts to maintain dayrate prices at a consistent level. We may be exposed to decreasing dayrates if any of our rigs are working under short-term contracts during a declining market. Likewise, if any of our rigs are committed under long-term contracts during an improving market, we may be unable to enjoy the benefit of rising dayrates for the duration of those contracts. Exposure to falling dayrates in a declining market or the inability to fully benefit from increasing dayrates in an improving market through shorter term contracts may limit our profitability.

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

Our contracts for our drilling units provide for the payment of a fixed dayrate per rig operating day, although some contracts do provide for a limited escalation in dayrate due to increased operating costs incurred by us. Many of our operating costs, such as labor costs, are unpredictable and fluctuate based on events beyond our control. In addition, equipment repair and maintenance expenses fluctuate 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. Our inability to recover these increased or unforeseen costs from our customers could materially and adversely affect our financial condition, results of operations and cash flows.

Our drilling contracts may be terminated due to events beyond our control.

Our customers may terminate some of our term drilling contracts if the drilling unit is destroyed or lost or if we have to suspend drilling operations for a specified period of time as a result of a breakdown of major equipment 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 by tendering contractually specified termination amounts. These termination payments may not fully compensate us for the loss of a contract. In some cases, because of depressed market conditions, restricted credit markets, economic downturns or other factors beyond our control, our customers may repudiate or otherwise fail to perform their obligations under our contracts with them. Any recovery we might obtain in these cases may not fully compensate us for the loss of the contract. In any case, the early termination of a contract may result in a rig being idle for an extended period of time, which could have a material adverse effect on our financial condition, results of operations and cash flows. If our customers cancel some of our contracts with them or if we elect to terminate in the event that a customer fails to perform, and we are unable to secure new contracts on a timely basis and on substantially similar terms, or if contracts are disputed or suspended for an extended period of time or if a number of our contracts are renegotiated, it could materially and adversely affect our financial condition, results of operations and cash flows.

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

We operate in various regions throughout the world which may expose us to political and other uncertainties, including risks of:

- war, riot, civil disturbances and acts of terrorism;
- piracy or assaults on property or personnel;
- 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 or import-export quotas;
- foreign and domestic monetary policies;
- the inability to repatriate income or capital;
- difficulties in collecting accounts receivable and longer collection periods;
- fluctuations in currency exchange rates;
- regulatory or financial requirements to comply with foreign bureaucratic actions;
- travel limitations or operational problems caused by public health threats;
- 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 subject to 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 worldwide anti-bribery laws. 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 units;
- 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.

Some foreign governments favor or effectively require the awarding of drilling contracts to local contractors, require use of a local agent or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. These practices may adversely affect our ability to compete in those regions. It is difficult to predict what governmental regulations may be enacted in the future that could adversely affect the international offshore drilling industry. The actions of foreign governments may materially and adversely affect our ability to compete.

In addition, the shipment of goods, including the movement of a drilling rig across international borders, subjects us to extensive trade laws and regulations. Our import activities are governed by unique customs laws and regulations that differ in each of the countries in which we operate and often impose record keeping and reporting obligations. The laws and regulations concerning import/export activity and record keeping and reporting requirements are complex and change frequently. These laws and regulations may be enacted, amended, enforced and/or interpreted in a manner that could materially and adversely impact our operations. Shipments can be delayed and denied export or entry for a variety of reasons, some of which may be outside of our control. Shipping delays or denials could cause unscheduled downtime for our rigs. 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 may enter into drilling contracts that expose us to greater risks than we normally assume.

From time to time, we may enter into drilling contracts with national oil companies, government-controlled entities or others that expose us to greater risks than we normally assume, such as exposure to greater environmental or other liability and more onerous termination provisions giving the customer a right to terminate without cause or upon little or no notice. Upon termination, these contracts may not result in a payment to us, or if a termination payment is required, it may not fully compensate us for the loss of a contract. In addition, the early termination of a contract may result in a rig being idle for an extended period of time, which could adversely affect our financial condition, results of operations and cash flows. While we believe that the financial terms of these contracts and our operating safeguards in place mitigate these risks, we can provide no assurance that the increased risk exposure will not have a material negative impact on our future operations or financial results.

Fluctuations in exchange rates and nonconvertibility of currencies could result in losses to us.

Due to our international operations, we have experienced currency exchange losses where revenues are received and expenses are paid in nonconvertible currencies or where we do not effectively hedge an exposure to a foreign currency. We may also incur losses as a result of an inability to collect revenues because of a shortage of convertible currency available to the country of operation, controls over currency exchange or controls over the repatriation of income or capital. We can provide no assurance that financial hedging arrangements will effectively hedge any foreign currency fluctuation losses that may arise.

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 different jurisdictions. We are subject to the tax laws, tax regulations and income tax treaties within and between the countries in which we operate as well as countries in which we may be resident. 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.

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 and our earnings and cash flows from operations could be materially adversely affected.

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 Offshore International Limited, or DOIL, a Cayman Islands subsidiary which we wholly own. It is our intention to indefinitely reinvest future earnings of DOIL and its foreign subsidiaries to finance foreign activities. We do not expect to provide for U.S. taxes on any future earnings generated by DOIL, except to the extent that these earnings are immediately subjected to U.S. federal income tax. Should a future distribution be made from any unremitted earnings of this subsidiary, we may be required to record additional U.S. income taxes that, if material, could have a material adverse effect on our financial condition, results of operations and cash flows.

Acts of terrorism and other political and military events could adversely affect the markets for our drilling services.

Terrorist attacks and the continued threat of terrorism in the U.S. and abroad, the continuation or escalation of existing armed hostilities or the outbreak of additional hostilities could lead to increased political, economic and financial market instability and a downturn in the economies of the U.S. and other countries. A lower level of economic activity could result in a decline in energy consumption or an increase in the volatility of energy prices, either of which could materially and adversely affect the market for our offshore drilling services, our dayrates or utilization and, accordingly, our financial condition, results of operations and cash flows. While we take steps that we believe are appropriate to secure our energy assets, there is no assurance that we can completely secure these assets, completely protect them against a terrorist attack or other political and military events or obtain adequate insurance coverage for such events at reasonable rates.

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

We are, from time to time, involved in various litigation matters. 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 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 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 factors.

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. To the extent that demand for drilling services and the size of the worldwide industry fleet increase (including due to the impact of newly constructed rigs), shortages of qualified personnel could arise, creating upward pressure on wages and difficulty in staffing and servicing our rigs, which could adversely affect our results of operations. As of the date of this report, we have three new ultra-deepwater drillships and one ultra-deepwater, semisubmersible rig, as well as the *Ocean Apex*, under construction. These rigs are not yet fully crewed, as of the date of this report, and will require additional skilled personnel to operate. Additional new capacity in the offshore drilling market could also cause further competition for qualified and experienced personnel as these entities seek to hire personnel with expertise in the offshore drilling industry. The heightened competition for skilled personnel could materially and adversely impact our financial condition, results of operations and cash flows by limiting our operations and further increasing our costs.

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

We have adopted a policy to consider paying special cash dividends, in amounts to be determined, on a quarterly basis. Any determination to declare a special cash dividend, as well as the amount of any special cash dividend which may be declared, will be based on our financial position, earnings, earnings outlook, capital spending plans and other factors that our Board of Directors considers relevant at that time. Moreover, our dividend policy may change from time to time. We cannot assure you that we will continue to declare any special cash dividends at all or in any particular amounts. If in the future we pay special cash dividends less frequently or in smaller amounts, or cease to pay any special cash dividends, it could have a negative effect on the market price of our common stock. 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.

Rig conversions, upgrades or new-builds may be subject to delays and cost overruns.

From time to time we add new capacity through conversions or upgrades to our existing rigs or through new construction, such as our three ultra-deepwater drillships and our harsh environment, ultra-deepwater semisubmersible rig under construction and construction of the *Ocean Apex*. Projects of this type are subject to risks of delay or cost overruns inherent in any large construction project resulting from numerous factors, including the following:

- shortages of equipment, materials or skilled labor;
- work stoppages;
- unscheduled delays in the delivery of ordered materials and equipment;
- unanticipated cost increases or change orders;
- weather interferences or storm damage;
- difficulties in obtaining necessary permits or in meeting permit conditions;
- design and engineering problems;
- disputes with shipyards or suppliers;
- availability of suppliers to recertify equipment for enhanced regulations;
- customer acceptance delays;
- shipyard failures or unavailability; and
- failure or delay of third party service providers, civil unrest and labor disputes.

Failure to complete a rig upgrade or new construction on time, or failure to complete a rig conversion or new construction in accordance with its design specifications may, in some circumstances, result in the delay, renegotiation or cancellation of a drilling contract, resulting in a loss of contract drilling backlog and revenue to us. If a drilling contract is terminated under these circumstances, we may not be able to secure a replacement contract with equally favorable terms.

We rely on third-party suppliers, manufacturers and service providers to secure 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 a drilling contract, thereby causing a loss of contract drilling backlog and/or revenue to us, as well as an increase in operating costs.

We have elected to self-insure for physical damage to rigs and equipment caused by named windstorms in the U.S. Gulf of Mexico.

Because the amount of insurance coverage available to us is limited, and the cost for such coverage is substantial, we have elected to self-insure for physical damage to rigs and equipment caused by named windstorms in the U.S. Gulf of Mexico. This results in a higher risk of losses, which could be material, that are not covered by third party insurance contracts. If one or more named windstorms in the U.S. Gulf of Mexico cause significant damage to our rigs or equipment, it could have a material adverse effect on our financial condition, results of operations and cash flows.

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

As of December 31, 2013, we had $2.5 billion in senior debt maturing at various times from September 2014 through 2043. We also had $750 million of availability under our revolving credit facility as of that date. We may 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. Our debt levels and the terms of our indebtedness could potentially limit our liquidity and flexibility in obtaining additional financing at rates which we consider reasonable, or at all. In addition, we may need to refinance our long-term debt on or before maturity, and our overall debt level and/or market conditions could lead the credit rating agencies to lower our corporate credit ratings. A downgrade in our corporate credit ratings could impact our ability to issue additional debt by raising the cost of issuing new 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.

We may incur asset impairments as a result of declining demand for certain types of offshore drilling rigs.

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 cold stacking a rig or excess spending over budget on a new-build, construction project or major rig upgrade), and we could incur impairment charges related to the carrying value of our drilling rigs. We utilize a probability-weighted cash flow analysis in testing an asset for potential impairment, which reflects 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. 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.

We can provide no assurance that our assumptions and estimates will ultimately be realized, nor can we provide any assurance that the current carrying value of our property and equipment, including rigs designated as held for sale, will ultimately be realized.

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.

The offshore drilling industry has become increasingly dependent upon digital technologies 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. We are dependent upon operational and financial computer systems to process the data necessary to conduct almost all aspects of our business. Any failure of our computer systems, or those of our customers, vendors or others with whom we do business, could materially disrupt our business operations and could result in the corruption of data or unauthorized release of confidential, proprietary or sensitive data concerning our company, business activities, employees or customers. 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. In addition, it has been reported that 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. Any cyber attack that affects our facilities could have a material adverse effect on our operations, business or reputation.

Unionization efforts and labor regulations in some of the countries in which we operate could materially increase our costs or limit our flexibility.

Some of our employees in non-U.S. markets are represented by labor unions and work under collective bargaining or similar agreements which are subject to periodic renegotiation. These negotiations could result in higher personnel expenses, other increased costs or increased operational restrictions. Efforts have been made from time to time to unionize other portions of our workforce. In addition, we may be subjected to strikes or work stoppages and other labor disruptions in certain countries. Additional unionization efforts, new collective bargaining agreements or work stoppages could materially increase our costs, reduce our revenues or limit our flexibility.

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 50.4% of our outstanding shares of common stock as of February 18, 2014 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, two officers of Loews serve on our Board of Directors. One of those, James S. Tisch, the Chairman of the Board of our company, is also the Chief Executive Officer and a director of Loews. 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. In addition to us, its principal subsidiaries are CNA Financial Corporation, a 90% owned subsidiary engaged in commercial property and casualty insurance; HighMount Exploration & Production LLC, a wholly owned subsidiary engaged in exploration, production and marketing of natural gas and natural gas liquids; Boardwalk Pipeline Partners, LP, a 53% owned subsidiary engaged in transportation and storage of natural gas and natural gas liquids and gathering and processing of natural gas; and Loews Hotels Holding Corporation, a wholly owned subsidiary engaged in the operation of a chain of hotels. It is possible that Loews may in some circumstances be in direct or indirect competition with us, including competition with respect to certain business strategies and transactions that we may propose to undertake. In addition, potential conflicts of interest exist or 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. We cannot assure you that these conflicts of interest will not materially adversely affect us.

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 Angola, Australia, Cameroon, Egypt, Indonesia, Louisiana, Malaysia, Norway, Singapore, Thailand, Trinidad and Tobago, the U.K.,and Vietnam 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
2013		
First Quarter	$76.48	$67.45
Second Quarter	72.84	64.42
Third Quarter	72.65	62.13
Fourth Quarter	64.63	55.39
2012		
First Quarter	$72.43	$55.61
Second Quarter	69.39	56.18
Third Quarter	69.24	58.85
Fourth Quarter	71.14	64.91

As of February 14, 2014 there were approximately 176 holders of record of our common stock. This number represents registered stockholders and does not include stockholders who hold their shares institutionally.

Dividend Policy

In 2013, we paid regular cash dividends of $0.125 and special cash dividends of $0.75 per share of our common stock on March 1, June 3, September 3 and December 2. In 2012, we paid regular cash dividends of $0.125 and special cash dividends of $0.75 per share of our common stock on March 1, June 1, September 4 and December 3.

On February 5, 2014, we declared a regular cash dividend and a special cash dividend of $0.125 and $0.75, respectively, per share of our common stock. Both the quarterly and special cash dividends are payable on March 3, 2014 to stockholders of record on February 19, 2014.

We have adopted a policy to consider paying special cash dividends, in amounts to be determined, on a quarterly basis. Any determination to declare a special cash dividend, as well as the amount of any special cash dividend that may be declared, will be based on our financial position, earnings, earnings outlook, capital spending plans and other factors that our Board of Directors considers relevant at that time.

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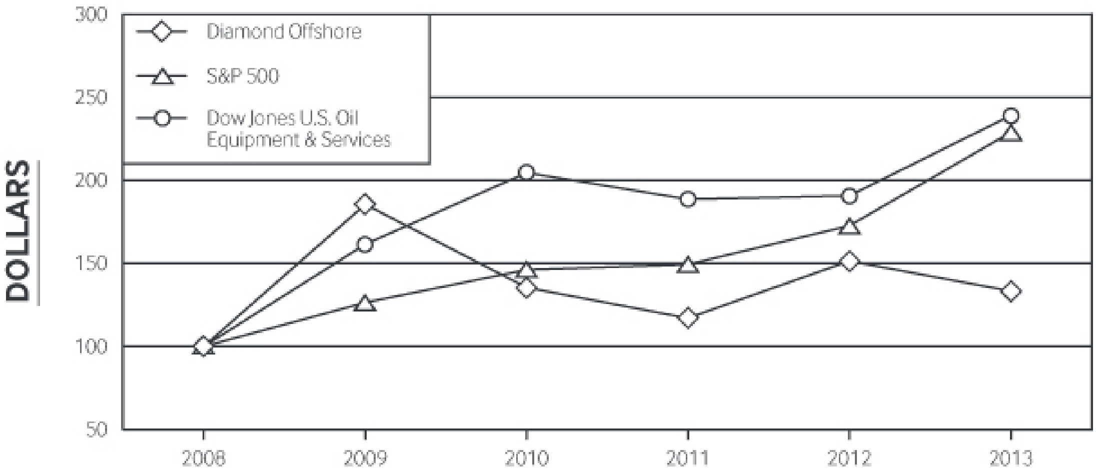
CUMULATIVE TOTAL STOCKHOLDER RETURN

The following graph shows the cumulative total stockholder return for our common stock, the Standard & Poor's 500 Index and the Dow Jones U.S. Oil Equipment & Services index over the five year period ended December 31, 2013.

Comparison of 2009 — 2013 Cumulative Total Return(1)



	Dec. 31, 2008	Dec. 31, 2009	Dec. 31, 2010	Dec. 31, 2011	Dec. 31, 2012	Dec. 31, 2013
Diamond Offshore	100	185	135	117	151	133
S&P 500	100	126	146	149	172	228
Dow Jones U.S. Oil Equipment & Services	100	161	204	188	190	238

(1) Total return assuming reinvestment of dividends. Assumes $100 invested on December 31, 2008 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**
2013	$0.125	$ 0.75	$0.125	$ 0.75	$0.125	$ 0.75	$0.125	$ 0.75
2012	$0.125	$ 0.75	$0.125	$ 0.75	$0.125	$ 0.75	$0.125	$ 0.75
2011	$0.125	$ 0.75	$0.125	$ 0.75	$0.125	$ 0.75	$0.125	$ 0.75
2010	$0.125	$1.875	$0.125	$1.375	$0.125	$ 0.75	$0.125	$ 0.75
2009	$0.125	$1.875	$0.125	$1.875	$0.125	$1.875	$0.125	$1.875

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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,				
	2013	2012	2011	2010	2009
	(In thousands, except per share and ratio data)				
Income Statement Data:					
Total revenues	$2,920,421	$2,986,508	$3,322,419	$3,322,974	$3,631,284
Operating income	801,606	962,378	1,255,414	1,425,374	1,903,213
Net income	548,686	720,477	962,542	955,457	1,376,219
Net income per share:					
Basic	3.95	5.18	6.92	6.87	9.90
Diluted	3.95	5.18	6.92	6.87	9.89
Balance Sheet Data:					
Drilling and other property and equipment, net	$5,467,227	$4,864,972	$4,667,469	$4,283,792	$4,432,052
Total assets	8,391,434	7,235,286	6,964,157	6,726,984	6,264,261
Long-term debt (excluding current maturities)(1)	2,244,189	1,496,066	1,495,823	1,495,593	1,495,375
Other Financial Data:					
Capital expenditures	$ 957,598	$ 702,041	$ 774,756	$ 434,262	$1,362,468
Cash dividends declared per share	3.50	3.50	3.50	5.25	8.00
Ratio of earnings to fixed charges(2)	7.79x	11.11x	14.40x	15.35x	37.29x

(1) See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Credit Agreement and Senior Notes" in Item 7 and 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.

(2) For all periods presented, the ratio of earnings to fixed charges has been computed on a total enterprise basis. Earnings represent pre-tax income 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.

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 are a leader in offshore drilling, providing contract drilling services to the energy industry around the globe with a fleet of 45 offshore drilling rigs, including five rigs under construction. Our fleet consists of 33 semisubmersibles, two of which are under construction, seven jack-ups, one of which is held for sale, and five dynamically positioned drillships, three of which are under construction. In late 2013 and in early 2014, we took delivery of the deepwater floater *Ocean Onyx* and the ultra-deepwater drillship *Ocean BlackHawk*, respectively. The *Ocean Onyx* is currently operating under a one-year contract in the U.S. Gulf of Mexico, or GOM, and we expect the *Ocean BlackHawk* to commence operating under contract in the second quarter of 2014, also in the GOM. The jack-up rig, *Ocean Spartan*, is being marketed for sale.

During 2014, we expect to take delivery of two sister ultra-deepwater drillships, the *Ocean BlackHornet* and *Ocean BlackRhino*, as well as the deepwater floater *Ocean Apex*. The remaining ultra-deepwater drillship *Ocean BlackLion* and the harsh environment, ultra-deepwater semisubmersible *Ocean GreatWhite* are expected to be delivered in 2015 and 2016, respectively. Of these rigs, the *Ocean BlackRhino* and *Ocean BlackLion* are not yet contracted.

Additionally, we expect to take the ultra-deepwater *Ocean Confidence* out of service late in the first quarter of 2014 for a service-life-extension project. The rig is expected to be unavailable until mid-January 2015, when the rig is projected to resume working under contract in West Africa.

Market Overview

Floater Markets

Ultra-Deepwater Floaters. The ultra-deepwater market has weakened, with an increasing number of units competing for fewer available jobs, resulting in a downward trend in recent contract dayrate fixtures and shorter-term contracts executed. The most active ultra-deepwater floater markets remain primarily within the offshore basins of West Africa, Brazil and the Gulf of Mexico. However, there has been limited tendering activity thus far in 2014 and the outlook is uncertain for the remainder of 2014. If this trend continues, ultra-deepwater floaters could experience lower utilization, or idle time, and realize lower margins. Many industry analysts predict that there will be an oversupply of floaters in the ultra-deepwater market by the end of 2014.

Deepwater Floaters. The market for deepwater floaters has also weakened and is characterized by intermittent demand, and multiple existing units face pockets of idle time throughout 2014 while newbuilds may have challenges securing work. Dayrate fixtures are also moderating in this market and are projected by industry analysts to continue softening in 2014. This market has also seen limited tendering activity in 2014 with an uncertain outlook for the balance of the year.

Mid-Water Floaters. Strength in the mid-water market also varies significantly by region. In both the United Kingdom, or U.K., and Norway sectors of the North Sea, the mid-water market is showing some signs of weakening, in the form of moderating or decreasing dayrates, in part due to an increase in the availability of sublet opportunities being offered for some term contracted units. Increasing operator interest in frontier markets across Southeast Asia and South America, including Colombia, Myanmar, Nicaragua, Peru and Trinidad and Tobago, indicates possible future strengthening in those regions, although opportunities in these areas are not expected to emerge quickly. In the GOM, demand for mid-water units is limited, while in Brazil, demand has moderated.

Impact of Newbuild Rigs and Other Challenges of the Offshore Drilling Industry

Since 2010, there have been a significant number of orders for newbuild ultra-deepwater and deepwater floaters by established drilling contractors as well as new entrants to the industry. As of the date of this report, there are approximately 100 newbuild floater rigs that have been announced, including an estimated 28 rigs potentially to be built on behalf of Petróleo Brasileiro S.A. Excluding these customer-ordered rigs, 31 of the 57 newbuilds scheduled for delivery in 2014 through 2015 are not yet contracted for future work, including two of our four rigs expected to be delivered in 2014 and 2015. The offshore drilling industry has been challenged by the addition of these newbuild rigs, which has increased competition and has resulted in downward pressure on dayrates. The influx of newbuilds into the market, combined with established rigs coming off contract in 2014 and 2015, is expected to continue to weaken the ultra-deepwater and deepwater floater markets.

The offshore drilling industry continues to be challenged by growing regulatory demands and more complex customer specifications, which could disadvantage some lower specification rigs. Additionally, customer focus on completing existing projects, possible reduction or deferral of new investment, reallocation of budgets away from offshore projects and particular customer requirements in certain markets could displace, or reduce, demand and result in the migration of some ultra-deepwater rigs to work in deepwater and, likewise, some deepwater rigs to compete against mid-water units. Various units across all segments could experience lower utilization or idle time, and lower specification rigs could be cold stacked or scrapped.

See "— Contract Drilling Backlog" for future commitments of our rigs during 2014 through 2019.

Contract Drilling Backlog

The following table reflects our contract drilling backlog as of February 5, 2014, October 23, 2013 (the date reported in our Quarterly Report on Form 10-Q for the quarter ended September 30, 2013), and February 1, 2013 (the date reported in our Annual Report on Form 10-K for the year ended December 31, 2012). 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 and adding one-half of any potential rig performance bonuses. 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 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.

	February 5, 2014	October 23, 2013	February 1, 2013
		(In thousands)	
Contract Drilling Backlog			
Floaters:			
Ultra-Deepwater(1)	$4,111,000	$4,306,000	$4,422,000
Deepwater(2)	794,000	862,000	1,229,000
Mid-Water (3)	1,744,000	1,997,000	2,649,000
Total Floaters	6,649,000	7,165,000	8,300,000
Jack-ups	180,000	188,000	272,000
Total	$6,829,000	$7,353,000	$8,572,000

(1) Contract drilling backlog as of February 5, 2014 for our ultra-deepwater floaters includes (i) $823.0 million attributable to our contracted operations offshore Brazil for the years 2014 and 2015, (ii) $1.8 billion in the aggregate attributable to future work for the *Ocean BlackHawk* and the *Ocean BlackHornet* for the years 2014 to 2019 and (iii) $641.0 million attributable to future work for the *Ocean GreatWhite*, which is under construction, for the years 2016 to 2019.

(2) Contract drilling backlog as of February 5, 2014 for our deepwater floaters includes (i) $308.0 million attributable to our contracted operations offshore Brazil for the years 2014 to 2016 and (ii) $36.0 million for the years 2014 to 2015 attributable to future work for the *Ocean Apex*, which is under construction.

(3) Contract drilling backlog as of February 5, 2014 for our mid-water floaters includes $421.0 million attributable to our contracted operations offshore Brazil for the years 2014 and 2015.

The following table reflects the amount of our contract drilling backlog by year as of February 5, 2014.

		For the Years Ending December 31,			
	Total	2014(1)	2015	2016	2017–2019
			(In thousands)		
Contract Drilling Backlog					
Floaters:					
Ultra-Deepwater**(2)**	$4,111,000	$ 971,000	$1,198,000	$499,000	$1,443,000
Deepwater**(3)**	794,000	516,000	216,000	62,000	—
Mid-Water**(4)**	1,744,000	999,000	471,000	159,000	115,000
Total Floaters	6,649,000	2,486,000	1,885,000	720,000	1,558,000
Jack-ups	180,000	110,000	48,000	22,000	—
Total	$6,829,000	$2,596,000	$1,933,000	$742,000	$1,558,000

(1) Represents a twelve-month period beginning January 1, 2014.

(2) Contract drilling backlog as of February 5, 2014 for our ultra-deepwater floaters includes (i) $499.0 million and $324.0 million for the years 2014 and 2015, respectively, attributable to our contracted operations offshore Brazil, (ii) $174.0 million, $361.0 million and $362.0 million for the years 2014, 2015 and 2016, respectively, and $909.0 million in the aggregate for the years 2017 to 2019, attributable to future work for the *Ocean BlackHawk* and *Ocean BlackHornet* and (iii) $107.0 million for the year 2016 and $534.0 million in the aggregate for the years 2017 to 2019 attributable to future work for the *Ocean GreatWhite*, which is under construction.

(3) Contract drilling backlog as of February 5, 2014 for our deepwater floaters includes (i) $112.0 million, $134.0 million and $62.0 million for the years 2014 to 2016, respectively, attributable to our contracted operations offshore Brazil and (ii) $29.0 million and $7.0 million for the years 2014 and 2015, respectively, attributable to future work for the *Ocean Apex*, which is under construction.

(4) Contract drilling backlog as of February 5, 2014 for our mid-water floaters includes $342.0 million and $79.0 million for the years 2014 and 2015, respectively, attributable to our contracted operations offshore Brazil.

The following table reflects the percentage of rig days committed by year as of February 5, 2014. 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). Total available days have been calculated based on the expected final commissioning dates for the *Ocean BlackHawk*, *Ocean BlackHornet*, *Ocean BlackRhino, Ocean BlackLion* and *Ocean GreatWhite*. All of these rigs are under construction, except for the *Ocean BlackHawk*, which was delivered in January 2014.

	For the Years Ending December 31,			
	2014(1)	2015	2016	2017–2019
Rig Days Committed(2)				
Floaters:				
Ultra-Deepwater	87%	62%	26%	19%
Deepwater	58%	21%	7%	—
Mid-Water	59%	26%	6%	1%
All Floaters	67%	37%	13%	7%
Jack-ups	53%	20%	9%	—

(1) Represents a twelve-month period beginning January 1, 2014.

(2) As of February 5, 2014, includes approximately 1,570, 270 and 215 currently known, scheduled shipyard days for rig commissioning, contract preparation, surveys and extended maintenance projects, as well as rig mobilization days, for the years 2014, 2015 and 2016, respectively.

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

Operating Income. Our operating income is primarily a function of contract drilling revenue earned less contract drilling expenses incurred or recognized. The two most significant variables affecting our contract drilling revenue are the dayrates earned and utilization rates achieved by our rigs, each of which is a function of rig supply and demand in the marketplace. These factors are not 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 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 (either lump-sum or dayrate), 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 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 new and seasoned employees can be significant. We expect our labor and training costs to increase in 2014 as a result of increased hiring and training activities as we continue the process of crewing our three remaining drillships under construction, the ultra-deepwater *Ocean GreatWhite* and the deepwater *Ocean Apex*. 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.

Regulatory Surveys and Planned Downtime. Our operating income is negatively impacted when we perform certain regulatory inspections, which we refer to as a 5-year survey, or special survey, that are due every five years for each of our rigs. 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 5-year survey will vary from year to year, as well as from quarter to quarter.

In addition, operating income may also be negatively impacted by intermediate surveys, which are performed at interim periods between 5-year surveys. Intermediate surveys are generally less extensive in duration and scope than a 5-year survey. Although an intermediate survey may require some downtime for the drilling rig, it normally does not require dry-docking or shipyard time, except for rigs located in the U.K. and Norwegian sectors of the North Sea.

During 2014, six of our rigs will require 5-year surveys and another three rigs will complete surveys that commenced in 2013. We expect these nine rigs to be out of service for approximately 380 days in the aggregate. We also expect to spend an additional approximately 670 days during 2014 for intermediate surveys, the mobilization of rigs, contract acceptance testing and extended maintenance projects, including contract preparation work for the *Ocean Endeavor* (approximately 162 days) and North Sea enhancements for the *Ocean Patriot* (approximately 165 days). The service-life-extension project for the *Ocean Confidence* is expected to commence late in the first quarter of 2014, and the rig will be out of service for the balance of the year (approximately 290 days). 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 "— Market Overview — *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. 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 insurance policy that expires on May 1, 2014, 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, we carry marine liability insurance covering certain legal liabilities, including coverage for certain personal injury claims, with no exclusions for 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, including for personal injury claims, 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 which might arise during the policy year.

Construction and Capital Upgrade Projects. We capitalize interest cost for the construction and upgrade of qualifying assets in accordance with accounting principles generally accepted in the U.S., or GAAP. The period of interest capitalization covers the duration of the activities required to make the asset ready for its intended use, and the capitalization period ends when the asset is substantially complete and ready for its intended use, which is expected to continue after delivery of the rigs from the shipyard and until the user acceptance phase of each project is completed. For the year ended December 31, 2013, we capitalized interest of $74.2 million on qualifying expenditures, primarily related to the construction of our four new drillships, the *Ocean GreatWhite*, the *Ocean Onyx* and the *Ocean Apex*. We will continue capitalizing interest on qualifying expenditures during 2014, which will no longer include expenditures related to the *Ocean Onyx*, which was completed in December 2013, and will include a limited interest capitalization period for the *Ocean BlackHawk,* which departed for the GOM in February 2014.

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. Maintenance and routine repairs are charged to income currently while replacements and betterments, which 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, 2013 and 2012, we capitalized $302.0 million and $220.3 million, respectively, in replacements and betterments of our drilling fleet, resulting from numerous projects ranging from $25,000 to $40 million per project.

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 cold stacking 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 (expressed as the actual percentage of time per year that the rig would be used);
- 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 costs associated with a rig returning to work;
- salvage value for each rig; and
- estimated proceeds that may be received on disposition of the rig.

Based on these assumptions and estimates, we develop a matrix using several different utilization/dayrate scenarios, to each of which we have assigned a probability of occurrence. The sum of our utilization scenarios (which include active, warm stacked and cold stacked) and probability of occurrence scenarios both equal 100% in the aggregate. We reevaluate our cold-stacked rigs annually, by updating the matrices for each rig and modifying our assumptions, giving consideration to the length of time the rig has been cold stacked, the current and expected market for the type of rig and expectations of future oil and gas prices.

Similarly, when a rig is reclassified to "Assets held for sale," we measure the asset at the lower of its carrying amount or fair value less cost to sell. In the absence of a letter of intent or contract for the rig's sale, we measure the fair value using an expected present value technique that utilizes a probability-weighted cash flow analysis, which includes assumptions for estimated proceeds that may be received on disposition of the rig. During 2012, we recognized an impairment loss of $62.4 million in connection with the transfer of three of our mid-water semisubmersible rigs to "Assets held for sale." These rigs were not sold during 2013 and remain cold stacked at December 31, 2013. As of December 31, 2013, the three mid-water semisubmersible rigs were transferred to "Drilling and Other Property and Equipment" in our Consolidated Balance Sheets in Item 8 of this report at their aggregate fair value of $3.9 million. See "— Results of Operations — Years Ended December 31, 2013, 2012 and 2011 — *Overview — 2013 Compared to 2012 — Impairment of Assets*" and Note 1 "General Information" to our Consolidated Financial Statements in Item 8 of this report.

Management's assumptions are an inherent part of our asset impairment evaluation and the use of different assumptions could produce results that differ from those reported.

Personal Injury Claims. Our deductibles for liability coverage for personal injury claims, which primarily result from Jones Act liability in the Gulf of Mexico, are currently $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 which 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 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 Diamond Offshore International Limited, or DOIL, a Cayman Islands subsidiary which we wholly own. It is our intention to indefinitely reinvest future earnings of DOIL and its foreign subsidiaries to finance foreign activities. Accordingly, we have not made a provision for U.S. income taxes on approximately $2.4 billion of undistributed foreign earnings and profits. Although we do not intend to repatriate the earnings of DOIL and have not provided U.S. income taxes for such earnings, except to the extent that such earnings were immediately subject to U.S. income taxes, these earnings could become subject to U.S. income tax if remitted, or if deemed remitted as a dividend; however, it is not practicable to estimate this potential liability.

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, 2013	2012	2011
REVENUE EARNING DAYS(1)			
Floaters:			
Ultra-Deepwater	2,392	2,475	2,387
Deepwater	1,530	1,605	1,718
Mid-Water	4,186	4,639	5,254
Jack-ups**(2)**	1,949	1,753	2,218
UTILIZATION(3)			
Floaters:			
Ultra-Deepwater	82%	85%	82%
Deepwater	84%	88%	94%
Mid-Water	64%	68%	72%
Jack-ups**(4)**	76%	53%	47%
AVERAGE DAILY REVENUE(5)			
Floaters:			
Ultra-Deepwater	$344,200	$354,900	$342,900
Deepwater	403,100	368,800	416,500
Mid-Water	275,700	263,600	269,600
Jack-ups	88,600	90,200	81,900

(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) Revenue earning days for the years ended December 31, 2012 and 2011 included approximately 87 days and 720 days, respectively, earned by certain of our jack-up rigs during the respective period prior to being sold in 2012.

(3) Utilization is calculated as the ratio of total revenue-earning days divided by the total calendar days in the period for all of the specified rigs in our fleet (including cold-stacked rigs).

(4) Utilization for our jack-up rigs would have been 87% and 59% for the years ended December 31, 2012 and 2011, respectively, excluding revenue earning days and total calendar days associated with rigs that we sold in 2012.

(5) Average daily revenue is defined as contract drilling revenue for all of the specified rigs in our fleet (excluding revenues for mobilization, demobilization and contract preparation) per revenue earning day.

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

Years Ended December 31, 2013, 2012 and 2011

	Year Ended December 31,		
	2013	2012	2011
		(In thousands)	
CONTRACT DRILLING REVENUE			
Floaters:			
Ultra-Deepwater	$ 854,515	$ 902,793	$ 841,565
Deepwater	617,080	597,694	733,037
Mid-Water	1,197,934	1,275,068	1,482,032
Total Floaters	2,669,529	2,775,555	3,056,634
Jack-ups	174,055	160,511	197,534
Other	—	—	145
Total Contract Drilling Revenue	$2,843,584	$2,936,066	$3,254,313
Revenues Related to Reimbursable Expenses	$ 76,837	$ 50,442	$ 68,106
CONTRACT DRILLING EXPENSE			
Floaters:			
Ultra-Deepwater	$ 538,765	$ 545,590	$ 492,816
Deepwater	267,820	253,176	227,733
Mid-Water	604,492	602,351	632,755
Total Floaters	1,411,077	1,401,117	1,353,304
Jack-ups	115,078	106,510	169,229
Other	46,370	29,597	25,969
Total Contract Drilling Expense	$1,572,525	$1,537,224	$1,548,502
Reimbursable Expenses	$ 74,967	$ 48,778	$ 66,052
OPERATING INCOME			
Floaters:			
Ultra-Deepwater	$ 315,750	$ 357,203	$ 348,749
Deepwater	349,260	344,518	505,304
Mid-Water	593,442	672,717	849,277
Total Floaters	1,258,452	1,374,438	1,703,330
Jack-ups	58,977	54,001	28,305
Other	(46,370)	(29,597)	(25,824)
Reimbursable expenses, net	1,870	1,664	2,054
Depreciation	(388,092)	(392,913)	(398,612)
Impairment of assets	—	(62,437)	—
General and administrative expense	(64,788)	(64,640)	(65,310)
Bad debt (expense) recovery	(22,513)	1,018	6,713
Gain on disposition of assets	4,070	80,844	4,758
Total Operating Income	$ 801,606	$ 962,378	$1,255,414
Other income (expense):			
Interest income	701	4,910	6,668
Interest expense	(24,843)	(46,216)	(73,137)
Foreign currency transaction gain (loss)	(4,915)	(1,999)	(8,588)
Other, net	1,691	(992)	(1,086)
Income before income tax expense	774,240	918,081	1,179,271
Income tax expense	(225,554)	(197,604)	(216,729)
NET INCOME	$ 548,686	$ 720,477	$ 962,542

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The following is a summary of the most significant transfers of our rigs during 2011, 2012 and 2013 between the geographic areas in which we operate:

Rig	Rig Type	Relocation Details	Date
Floaters:			
Ocean Monarch	Ultra-Deepwater	GOM to Vietnam	September 2011
Ocean Monarch	Ultra-Deepwater	Vietnam to Singapore (shipyard survey)	August 2012
Ocean Confidence	Ultra-Deepwater	Congo to Angola	January 2013
Ocean America	Deepwater	Australia to Singapore (shipyard survey)	July 2013
Ocean Valiant	Deepwater	Cameroon to Canary Islands (shipyard survey)	October 2013
Ocean America	Deepwater	Singapore to Australia	November 2013
Ocean Epoch	Mid-Water	Malaysia (a)	February 2011
Ocean Yorktown	Mid-Water	Brazil to GOM	August 2011
Ocean Yorktown	Mid-Water	GOM to Mexico	December 2011
Ocean Guardian	Mid-Water	Falkland Islands to U.K.	January 2012
Ocean Saratoga	Mid-Water	GOM to Guyana	January 2012
Ocean Saratoga	Mid-Water	Guyana to GOM	May 2012
Ocean Whittington	Mid-Water	Brazil to GOM (a)	May 2012
Ocean Apex	Mid-Water	Singapore shipyard (b)	September 2012
Ocean Ambassador	Mid-Water	Brazil to GOM	October 2012
Ocean Lexington	Mid-Water	Brazil to Trinidad	March 2013
Ocean Patriot	Mid-Water	Vietnam to Philippines	May 2013
Ocean Saratoga	Mid-Water	GOM to Nicaragua	August 2013
Ocean Quest	Mid-Water	Brazil to Malaysia	November 2013
Ocean Patriot	Mid-Water	Philippines to Singapore (shipyard upgrade)	November 2013
Ocean Saratoga	Mid-Water	Nicaragua to GOM	December 2013
Jack-ups:			
Ocean Scepter	Jack-up	Brazil to GOM	October 2011
Ocean Titan	Jack-up	GOM to Mexico	November 2011
Ocean Scepter	Jack-up	GOM to Mexico	December 2011
Ocean Columbia	Jack-up	Sold	March 2012
Ocean Heritage	Jack-up	Sold	April 2012
Ocean Drake	Jack-up	Sold	May 2012
Ocean Champion	Jack-up	Sold	May 2012
Ocean Crusader	Jack-up	Sold	May 2012
Ocean Sovereign	Jack-up	Sold	June 2012
Ocean Spur	Jack-up	Egypt to Ecuador; two year bareboat charter	August 2012
Ocean Spartan	Jack-up	GOM (a) (c)	December 2012
Ocean King	Jack-up	Montenegro to GOM	December 2012

(a) Rig is cold stacked.
(b) Rig formerly operated as the *Ocean Bounty* and was cold stacked in July 2009. Rig has been used in the construction of a deepwater floater, the *Ocean Apex*, in Singapore.
(c) Rig held for sale at December 31, 2013.

Overview

Customer Credit Issues

During 2013, based on our assessment of the financial condition of two of our customers, Niko Resources Ltd., or Niko, and OGX Petróleo e Gás Ltda., or OGX, and our expectations regarding the probability of collection of amounts due to us from them, we recorded $22.5 million in bad debt expense to fully reserve all outstanding receivables they owed us at June 30, 2013. In addition, during the second half of 2013, a total of four of our rigs were contracted to Niko and OGX, for an aggregate 337 revenue earning days during the period. We did not recognize revenue associated with these revenue earning days due to our assessment that collection of the amounts due was not reasonably assured, resulting in the “unrecognized revenue” referred to below.

In December 2013, we entered into a settlement agreement with Niko, which we refer to as the Settlement Agreement, whereby Niko will be released from certain obligations under the dayrate contracts for the *Ocean Monarch* and *Ocean Lexington*, subject to and effective upon the full payment of amounts owed to us under the Settlement Agreement and subject to its other conditions. In accordance with the terms of the Settlement Agreement, we received $25.0 million in cash during the fourth quarter of 2013, which we recognized as revenue against invoices due to us. Niko is further obligated to make future periodic payments to us pursuant to the Settlement Agreement totaling an aggregate of $55.0 million, payable at various times through September 2017. We plan to recognize these amounts in revenue as they are received due to the uncertainty regarding their timing and collection.

The following table sets forth the number of revenue earning days, the unrecognized revenue and the incremental effect on our historical results of operations for the comparative years ended December 31, 2013 and 2012 associated with the four rigs contracted to Niko or OGX during the second half of 2013 as discussed above:

		For the Year Ended December 31, 2013				
Rig Type	Revenue Recognized in 2012	Revenue Earning Days (a)	Potential Revenue (b)	Unrecognized Revenue (c)	Revenue Recognized	Variance in Revenue Recognized (d)
	(In millions, except number of days)					
Ultra-Deepwater Floater	$ 127.0	170	$ 125.4	$ (30.5) (e)	$ 94.9	$ (32.1)
Deepwater Floater	79.4	31	112.3	(9.3)	103.0	23.6
Mid-Water Floaters	217.8	136	157.5	(58.4)	99.1	(118.7)
	$ 424.2	337	$ 395.2	$ (98.2)	$ 297.0	$ (127.2)

(a) Represents revenue earning days, defined as a 24-hour period during which a rig earns a dayrate after commencement of operations, attributable to the *Ocean Monarch*, *Ocean Star*, *Ocean Lexington* and *Ocean Quest*, under their contracts to Niko or OGX during the period from July 1, 2013 through December 31, 2013.

(b) Represents the amount of revenue that would have been earned during 2013, were it not for these credit issues, by our four rigs under contract to Niko or OGX, including revenue associated with revenue earning days for these rigs during the period from July 1, 2013 to December 31, 2013.

(c) Represents contract drilling revenue earned by the four rigs under contract to Niko or OGX during the period from July 1, 2013 through December 31, 2013, which was not recognized in accordance with revenue recognition principles.

(d) Represents the change in contract drilling revenue recognized, comparing the years ended December 31, 2013 and 2012, attributable to the four rigs contracted to Niko or OGX during the second half of 2013.

(e) Net of a $25.0 million payment recognized as revenue for the *Ocean Monarch* pursuant to the Settlement Agreement with Niko.

2013 Compared to 2012

Operating Income. Operating income decreased $160.8 million, or 17%, in 2013, compared to 2012, primarily due to a $92.5 million, or 3%, reduction in contract drilling revenue, a $35.3 million increase in contract drilling expense and recognition of $22.5 million of bad debt expense in 2013, combined with the absence of an aggregate $76.5 million pre-tax gain on the sale of six of our jack-up rigs during 2012 . These negative contributors to operating income were partially offset by the absence of a $62.4 million impairment loss recognized in the fourth quarter of 2012.

Contract drilling revenue for our ultra-deepwater and mid-water fleets decreased a combined $125.4 million during 2013, compared to 2012, while revenue earned by our deepwater floaters and jack-up rigs increased an aggregate $32.9 million. Revenue earning days for our drilling fleet decreased an aggregate 415 days in 2013, compared to 2012, including 337 fewer revenue earning days for the *Ocean Monarch*, *Ocean Star*, *Ocean Lexington* and *Ocean Quest* in the second half of 2013, during which these rigs were contracted to Niko or OGX but no revenue was recognized, and 87 fewer days attributable to the jack-up rigs that we sold in 2012.

In general, the comparability of contract drilling expenses between years is impacted by significant events or changes in our rig fleet, including but not limited to the relocation of rigs between geographic locations and related changes in operating cost structures which differ between regions, the cost to mobilize such rigs, the number and extent of shipyard surveys and related repairs, the stacking of rigs and rising labor costs. Total contract drilling expense for our rig fleet during 2013 increased by $35.3 million, compared to 2012, reflecting higher labor and personnel-related costs ($38.1 million), primarily related to mid-2013 pay increases and costs associated with additional crews for the *Ocean Onyx* and *Ocean BlackHawk* and for our new rigs expected to be delivered in 2014, repair and maintenance costs ($23.7 million) and inspection costs ($10.1 million). The impact of these 2013 cost increases were partially offset by decreased costs associated with the mobilization of rigs ($21.9 million), freight ($11.5 million) and other rig operating costs ($3.3 million).

Impairment of Assets. In late 2012, our management adopted a plan to actively market for sale three of our mid-water semisubmersibles, the Ocean Epoch, the Ocean New Era and the Ocean Whittington, and the jack-up rig Ocean Spartan. As a result of this decision, we recognized an impairment loss of $62.4 million in the fourth quarter of 2012 to write down the aggregate net book value of these rigs to their estimated recoverable amounts.

Interest Expense. Interest expense decreased $21.4 million in 2013, compared to 2012, primarily due to a $36.6 million increase in interest capitalized on eligible construction projects during 2013 partially offset by incremental interest expense of $7.0 million for the senior unsecured notes that we issued in 2013 and an increase of $7.7 million in interest expense associated with uncertain tax positions, primarily in the Mexico tax jurisdiction.

Income Tax Expense Our effective tax rate for 2013 was 29.1%, compared to a 21.5% effective tax rate for 2012. The higher effective tax rate in 2013 was due to differences in the mix of our domestic and international pre-tax earnings and losses, as well as the mix of international tax jurisdictions in which we operate. Income tax expense for 2013 was also negatively impacted by a provision of $56.9 million related to an uncertain tax position in Egypt, partially offset by the recognition of the impact of The American Taxpayer Relief Act of 2012, which reduced 2013 income tax expense by $27.5 million.

As our rigs frequently operate in different tax jurisdictions as they move from contract to contract, our effective tax rate can fluctuate substantially and our historical effective tax rates may not be sustainable and could increase materially.

2012 Compared to 2011

Operating Income. Operating income decreased $293.0 million, or 23%, during 2012, compared to 2011, primarily due to a $318.2 million, or 10%, reduction in total contract drilling revenue and a $62.4 million impairment loss on certain assets held for sale, partially offset by an $11.3 million, or 1%, decrease in contract drilling expense and a $76.5 million pre-tax gain on the sale of six jack-up rigs in 2012. Both revenue earning days and average daily revenue earned by our deepwater and mid-water floaters declined during 2012, compared to 2011, and resulted in a $342.3 million reduction in revenue, while favorable market conditions at that time for our ultra-deepwater floaters resulted in a $61.2 million increase in contract drilling revenue. Revenue for our jack-up fleet decreased $37.0 million during 2012, compared to 2011, primarily due to the 2012 sale of three jack-up rigs that operated during 2011.

Aggregate contract drilling expense for our mid-water floater and jack-up fleets decreased $93.1 million during 2012 compared to the prior year, primarily due to the movement of certain of our rigs to other operating regions with lower cost structures, combined with lower repair and inspection costs, as well as the absence of operating costs in 2012 for the recently sold jack-up rigs. The overall decrease in contract drilling expense during 2012 was partially offset by a combined $78.2 million increase in contract drilling expense for our ultra-deepwater and deepwater floaters, primarily due to higher personnel related, inspection, and shorebase support costs in 2012.

Interest Expense. Interest expense decreased $26.9 million in 2012 compared to 2011, primarily due to $26.5 million in incremental interest costs capitalized during 2012 related to our continuing rig construction projects, which included a fourth drillship under construction and the *Ocean Apex*.

Income Tax Expense Our effective tax rate for 2012 was 21.5%, compared to an 18.4% effective tax rate for 2011. The higher effective tax rate in 2012 was primarily the result of differences in the mix of our domestic and international pre-tax earnings and losses, as well as the mix of international tax jurisdictions in which we operate and the impact of a tax law provision that expired at the end of 2011. This provision allowed us to defer recognition of certain foreign earnings for U.S. tax purposes during 2011, which deferral was unavailable in 2012. Our 2011 tax expense also included the reversal of $15 million of U.S. income tax expense, originally recognized in 2010, related to our intention at that time to repatriate certain foreign earnings, which changed in 2011 subsequent to our decision to build new drillships overseas.

Contract Drilling Revenue and Expense by Equipment Type

2013 Compared to 2012

Ultra-Deepwater Floaters. Revenue generated by our ultra-deepwater floaters decreased $48.3 million in 2013, compared to 2012, primarily due to lower average daily revenue earned ($25.5 million), 83 fewer revenue earning days ($29.8 million), and a $17.9 million decrease in amortized mobilization revenue, partially offset by $25.0 million in revenue recognized in connection with the Settlement Agreement with Niko. Average daily revenue decreased in 2013, compared to 2012, primarily due to a contract extension for the *Ocean Rover* during the second quarter of 2012 at a significantly lower dayrate than previously earned and lower revenue earned by the *Ocean Clipper* as a result of incremental revenue earning days at a reduced performance rate, equipment penalties assessed against revenue and the absence of additional revenue associated with the rig working outside its normal operating zone. Total revenue earning days for our ultra-deepwater floaters decreased during 2013, compared to 2012, primarily due to incremental unplanned downtime (225 additional days), partially offset by a reduction in downtime for shipyard projects and inspections (128 fewer days) and mobilization of rigs (21 fewer days). Mobilization revenue decreased primarily due to the absence in 2013 of $16.3 million in amortized mobilization revenue, which was recognized during 2012 in connection with the *Ocean Monarch*’s mobilization to Vietnam.

Contract drilling expense incurred by our ultra-deepwater floaters decreased $6.8 million during 2013, compared to 2012, primarily due to lower amortized mobilization costs ($21.8 million) and freight costs ($8.8 million), partially offset by higher costs associated with rig personnel ($18.8 million) and repairs and maintenance ($5.1 million).

Deepwater Floaters. Revenue generated by our deepwater floaters increased $19.4 million during 2013, compared to 2012, as a result of higher average daily revenue earned ($52.4 million), partially offset by 75 fewer revenue earning days ($27.7 million) and lower amortized mobilization revenue ($5.4 million). Average daily revenue earned by our deepwater floaters during 2013 increased primarily due to both the *Ocean Valiant* and *Ocean Victory* working at significantly higher dayrates than those earned in 2012. In contrast, total revenue earning days for our deepwater floaters declined in 2013 due to incremental unscheduled downtime for repairs (32 additional days), scheduled shipyard projects (26 additional days) and mobilization of the *Ocean America* (14 days). Contract drilling expense increased $14.6 million in 2013, compared to 2012, reflecting higher labor and other personnel-related costs ($8.4 million), shorebase support costs and overheads ($5.2 million), and repair and maintenance costs ($2.1 million), partially offset by lower costs associated with the mobilization of rigs ($4.0 million).

Mid-Water Floaters. Revenue generated by our mid-water floaters decreased $77.1 million during 2013, compared to 2012, primarily as a result of 453 fewer revenue earning days ($119.3 million) and a reduction in amortized mobilization and contract preparation fees ($8.3 million), partially offset by the effect of higher average daily revenue earned ($50.5 million). The decrease in revenue earning days during 2013 was primarily due to an increase in planned downtime for shipyard inspections and projects (322 additional days), additional non-operating days for the *Ocean Whittington* (102 additional days) and revenue generating days for the *Ocean Quest* and *Ocean Lexington* for which the associated revenue was not recognized (136 days), offset by fewer days for the mobilization of rigs (114 fewer days). Average daily revenue increased in 2013, compared to 2012, primarily due to new contracts or contract renewals for the *Ocean General*, *Ocean Patriot*, *Ocean Nomad* and *Ocean Vanguard* at higher dayrates than previously earned.

Contract drilling expense remained relatively consistent in 2013 compared to 2012, increasing only $2.1 million. During 2013, our mid-water floaters benefited from cost reductions associated with the cold stacking of the *Ocean Whittington* and return of the *Ocean Ambassador* to the GOM ($47.4 million), combined with the absence of costs associated with the 2012 demobilization of the *Ocean Guardian* from the Falkland Islands ($12.1 million) and repair and maintenance activities after arriving in the U.K. ($7.2 million). However, cost reductions were offset by higher contract drilling expenses for the remainder of our mid-water fleet, primarily for labor and other personnel-related costs ($8.7 million), repairs and maintenance ($18.8 million), inspections ($13.0 million) and mobilization of rigs ($21.6 million).

Jack-ups. Contract drilling revenue and expense for our jack-up rigs increased $13.5 million and $8.6 million, respectively, in 2013, compared to 2012. The *Ocean King*, which was warm stacked in Montenegro in 2010, returned to the GOM in early 2013 and commenced operations in the second quarter. During 2013, the *Ocean King* earned revenue and incurred incremental contract drilling expense of $26.2 million and $14.1 million, respectively, compared to 2012. The increase in both contract drilling revenue and expense for our jack-up fleet during 2013 was partially offset by the absence of $5.4 million in revenue and $8.4 million in costs attributable to our six jack-up rigs that we sold in 2012. Revenues in 2013 were further reduced as a result of 81 incremental days of scheduled downtime for repairs for the *Ocean Scepter* and *Ocean Nugget* ($9.5 million).

2012 Compared to 2011

Ultra-Deepwater Floaters. Revenue generated by our ultra-deepwater floaters increased $61.2 million during 2012, compared to 2011, primarily due to higher average daily revenue earned by our ultra-deepwater fleet ($29.9 million) and 88 incremental revenue earning days ($30.4 million). Average daily revenue earned increased primarily due to higher dayrates earned by the *Ocean Monarch* operating offshore Vietnam and Indonesia during 2012, compared to the average dayrate earned by the rig operating in the GOM during 2011. Total revenue earning days increased during 2012 primarily due to the inclusion of 155 incremental revenue earnings days for the *Ocean Monarch*, compared to 2011 when the rig incurred downtime associated with a force majeure assertion and subsequent mobilization of the rig to Vietnam. The increase in aggregate revenue earning days during 2012 was partially offset by downtime associated with scheduled surveys and shipyard projects, as well as unscheduled downtime for repairs for other rigs in our ultra-deepwater fleet.

Contract drilling expense in 2012 for our ultra-deepwater fleet included $26.3 million in incremental costs for the *Ocean Monarch*, which experienced a higher cost structure operating internationally for the full year, as well as costs associated with its 2012 shipyard survey, compared to 2011, when the rig was located in the GOM for a portion of the year. In addition, contract drilling expense for our other ultra-deepwater floaters increased compared to 2011, reflecting higher costs relating to personnel ($28.8 million), inspections ($3.9 million), freight, customs and duties ($3.3 million) and shorebase support ($5.5 million), as well as losses on foreign currency hedges ($3.8 million), partially offset by lower costs incurred for maintenance and repairs ($13.0 million) and amortized mobilization expense ($7.5 million).

Deepwater Floaters. Revenue generated by our deepwater floaters decreased $135.3 million in 2012, compared to 2011, as a result of lower average daily revenue earned ($76.5 million), 113 fewer revenue earning days ($47.2 million), and lower recognition of amortized mobilization revenue ($11.7 million). Average daily revenue earned was negatively impacted by the completion of the *Ocean Valiant*'s initial contract offshore Angola in December 2011, which was at a significantly higher dayrate than the rig earned during 2012. The decline in revenue earning days during 2012 was primarily attributable to 118 days of incremental downtime for shipyard projects and inspections compared to 2011. Contract drilling expense incurred by our deepwater floaters increased $25.4 million during 2012, compared to 2011, primarily due to the repair and inspection costs associated with 2012 surveys and shipyard projects for the *Ocean Star* and *Ocean Victory* and higher personnel related costs, partially offset by the absence of certain regional costs associated with the *Ocean Valiant*'s contract offshore Angola during 2011.

Mid-Water Floaters. Revenue generated by our mid-water floaters decreased $207.0 million during 2012, compared to 2011, primarily due to 615 fewer revenue earning days ($166.0 million). The reduction in revenue earning days in 2012, compared to 2011, reflected 322 incremental downtime days for the *Ocean Whittington*, which completed its contract in Brazil, as well as unplanned downtime for repairs and the warm stacking of rigs between contracts (163 additional days), planned downtime for mobilization of rigs and shipyard projects (51 additional days), and 91 additional cold-stacked days for the *Ocean Epoch*. Revenue for 2012, compared to the prior year, was further reduced by a decrease in average daily revenue earned ($27.9 million) and lower amortized mobilization revenue ($13.0 million).

Contract drilling expense for our mid-water floaters decreased $30.4 million during 2012, compared to 2011, and reflected lower costs for rig maintenance, repairs and inspections ($21.7 million), personnel related expenses ($12.8 million), freight, customs and duties ($5.7 million), revenue-based agency fees ($2.9 million), and shorebase support ($2.2 million). These decreases in contract drilling expense were partially offset by higher recognized mobilization costs ($10.0 million) and losses on foreign currency hedges ($7.2 million).

Jack-ups. Revenue and contract drilling expense for our jack-up rigs decreased $37.0 million and $62.7 million, respectively, in 2012, compared to 2011, primarily due to the sale of six jack-up rigs in 2012, which resulted in an incremental reduction of revenue and contract drilling expense of $37.8 million and $37.5 million, respectively, comparing the two years. The decrease in contract drilling expense in 2012, compared to 2011, also reflected a $22.0 million reduction in expense for the *Ocean Scepter*, primarily due to the absence of costs associated with return of the rig to the GOM in 2011, lower amortized mobilization expenses and the effect of a lower operating cost structure offshore Mexico than in Brazil.

Liquidity and Capital Resources

We have historically relied principally on our cash flows from operations and cash reserves to meet liquidity needs and fund our cash requirements. In addition, we currently have available a $750 million credit facility to meet our short-term and long-term liquidity needs. See "— Credit Agreement and Long-Term Debt — $750 Million Revolving Credit Agreement." At the date of this report, our contract drilling backlog was $6.8 billion, of which $2.6 billion is expected to be realized in 2014.

At December 31, 2013, 2012 and 2011, we had cash available for current operations as follows:

	December 31, 2013	December 31, 2012	December 31, 2011
	(In thousands)		
Cash and equivalents	$ 347,011	$ 335,432	$ 333,765
Marketable securities	1,750,053	1,150,158	902,414
Total cash available for current operations	$2,097,064	$1,485,590	$1,236,179

A substantial portion of our cash flows has been and is expected to continue to be invested in the enhancement of our drilling fleet. 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.

Certain of our international rigs are owned and operated, directly or indirectly, by DOIL, and, as a result of our intention to indefinitely reinvest the earnings of DOIL to finance our foreign activities, we do not expect such earnings to be available for distribution to our stockholders or to finance our domestic activities. See "— Market Overview — Critical Accounting Estimates — Income Taxes." We expect to utilize the operating cash flows generated by and cash reserves of DOIL 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.

However, in light of the significant cash requirements of our capital expansion program in 2014 and 2015, we may also make use of our credit facility to finance our capital expenditures and working capital requirements and/or to maintain a certain level of operating cash reserves. In addition, we will make periodic assessments of our capital spending programs based on industry conditions and make adjustments thereto if required. See "— Cash Flow and Capital Expenditures — Contractual Cash Obligations — Rig Construction" and "— Credit Agreement and Senior Notes — $750 Million Revolving Credit Agreement."

We pay dividends at the discretion of our Board of Directors, or Board, and, in recent years, we have a history of paying both regular quarterly and special cash dividends. 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. During the three-year period ended December 31, 2013, we paid regular cash dividends totaling $208.5 million and special cash dividends totaling $1.3 billion. Our Board has adopted a policy to consider paying special cash dividends, in amounts to be determined, on a quarterly basis. Our Board may, in subsequent quarters, consider paying additional special cash dividends, in amounts to be determined. Any determination to declare a special cash dividend, as well as the amount of any special cash dividend that may be declared, will be based on our financial position, earnings, earnings outlook, capital spending plans and other factors that our Board considers relevant at that time.

On February 5, 2014, we declared a regular cash dividend and a special cash dividend of $0.125 and $0.75, respectively, per share of our common stock. Both the quarterly and special cash dividends are payable on March 3, 2014 to stockholders of record on February 19, 2014.

During the three-year period ended December 31, 2013, our primary source of cash was an aggregate $3.8 billion generated from operating activities, $987.8 million net proceeds from the issuance of senior notes in 2013 and $131.9 million received from the sale of six drilling rigs in 2012. Cash usage during the same period was primarily for capital expenditures ($2.4 billion), payment of dividends ($1.5 billion) and the purchase of marketable securities, net of sales ($1.1 billion).

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 market conditions and other factors beyond our control.

Depending on market and other conditions, we may, from time to time, purchase shares of our common stock in the open market or otherwise. We did not repurchase any shares of our outstanding common stock during the years ended December 31, 2013, 2012 or 2011. In addition, Loews Corporation, or Loews, has stated that, depending on market and other conditions, it may, from time to time, purchase shares of our common stock in the open market or otherwise. Loews did not purchase any shares of our outstanding common stock during the years ended December 31, 2013, 2012 or 2011.

Cash Flow and Capital Expenditures

Our cash flow from operations and capital expenditures for each of the years in the three-year period ended December 31, 2013 were as follows:

	Year Ended December 31,		
	2013	2012	2011
		(In thousands)	
Cash flow from operations	$1,065,988	$1,311,269	$1,420,105
Capital expenditures:			
Drillship construction	$ 130,268	$ 248,346	$ 490,156
Construction of deepwater floaters	396,584	153,529	—
Construction of ultra-deepwater floater	195,578	—	—
Ocean Patriot enhancement programs	29,948	—	—
Rig equipment and replacement programs	205,220	300,166	284,600
Total capital expenditures	$ 957,598	$ 702,041	$ 774,756

Cash Flow. Cash flow from operations decreased approximately $245.3 million during 2013, compared to 2012, primarily due to a $165.3 million decrease in cash receipts from contract drilling services and higher cash payments related to contract drilling expenses of $83.2 million, partially offset by lower cash income taxes paid, net of refunds, of $3.3 million.

Cash flow from operations decreased approximately $108.8 million during 2012, compared to 2011, primarily due to a $297.4 million decrease in cash receipts from contract drilling services, partially offset by lower cash payments related to contract drilling expenses of $87.3 million and lower cash income taxes paid, net of refunds, of $102.0 million.

See "— Results of Operations —Years Ended December 31, 2013, 2012 and 2011."

Capital Expenditures.

As of the date of this report, we expect capital expenditures for 2014 to aggregate approximately $2.1 billion, of which we expect to spend approximately $1.5 billion and $82.0 million on our current rig construction projects and the *Ocean Patriot* North Sea enhancement project, respectively. Our 2014 capital spending estimate also includes approximately $184.0 million expected to be spent on a service-life-extension project for the *Ocean Confidence*. We expect to fund our 2014 capital spending from the operating cash flows generated by and cash reserves of DOIL and the operating cash flows available to and cash reserves of Diamond Offshore Drilling, Inc. See "— Contractual Cash Obligations — Rig Construction."

Contractual Cash Obligations — Rig Construction

In May 2013, we entered into an agreement with Hyundai Heavy Industries Co., Ltd., or Hyundai, for the construction of a 10,000 foot dynamically positioned, harsh environment semisubmersible drilling rig. The *Ocean GreatWhite* is under construction in South Korea at an estimated cost of $755 million, including capital spares, commissioning and shipyard supervision. The contracted price to Hyundai, totaling $628.5 million, is payable in two installments, of which the first installment was paid in 2013.

As of February 5, 2014, we are financially obligated under other agreements with several shipyards in connection with the construction of three ultra-deepwater drillships, the deepwater floater *Ocean Apex* and the *Ocean Patriot* North Sea enhancement project. The *Ocean Onyx* and the *Ocean BlackHawk*, the first of our four drillships, were delivered late in the fourth quarter of 2013 and in late January 2014, respectively. The final installments on these construction contracts were paid in January 2014. See Note 8 "Commitments and Contingencies" to our Consolidated Financial Statements included in Item 1 of Part I of this report for further discussion of these projects.

The following is a summary of our construction projects as of February 5, 2014, including estimated expenditures to be made during the remainder of 2014:

Project	Expected Delivery (1)	Total Project Cost (2)	Actual Inception-to-Date Project Expenditures(3)	Actual Inception-to-Date Capitalized Interest	2014(4)(5)
		(In millions)			
New Rig Construction:					
Drillships:					
Ocean BlackHawk	Q1 2014	$ 635	$ 620	$ 27	$ 15
Ocean BlackHornet	Q2 2014	635	204	26	430
Ocean BlackRhino	Q3 2014	645	189	26	456
Ocean BlackLion	Q1 2015	655	171	17	55
		2,570	1,184	96	956
Ultra-Deepwater Floater:					
Ocean GreatWhite	Q1 2016	755	190	7	23
Deepwater Floaters:					
Ocean Onyx	Q4 2013	366	350	18	16
Ocean Apex	Q3 2014	370	269	9	110
		$4,061	$ 1,993	$ 130	$1,105
Enhancement Project:					
Mid-Water Floater *Ocean Patriot*	Q2 2014	$ 120	$ 50	$ —	$ 70

(1) Represents expected delivery date of vessel from shipyard and does not include additional non-operating days for commissioning, contract preparation and mobilization to initial area of operation, which will occur prior to the rig being placed in service.
(2) Total project costs include contractual payments for shipyard construction, commissioning, capital spares and project management costs; amount does not include capitalized interest.

(3) Represents total project expenditures from inception of project to February 5, 2014, excluding project-to-date capitalized interest. Project-to-date expenditures include final construction milestone payments of $7.3 million paid to Keppel AmFELS, L.L.C. and an aggregate $396.1 million paid to Hyundai in January 2014 in connection with the deliveries of the *Ocean Onyx* and *Ocean BlackHawk*, respectively.

(4) Estimated expenditures for 2014, including construction milestone payments, are based on current expected delivery dates for the rigs under construction, and exclude expected capitalized interest costs.

(5) Construction milestone payments expected to be paid in the remainder of 2014 include:

- $54.1 million payable to Jurong Shipyard Pte Ltd. in connection with the construction of the *Ocean Apex;*
- $10.2 million payable to Keppel FELS Limited in connection with the *Ocean Patriot* enhancement project; and
- $393.5 million and $395.4 million payable to Hyundai in the second and third quarter of 2014 upon delivery of the *Ocean BlackHornet* and *Ocean BlackRhino*, respectively.

Credit Agreement and Senior Notes

$750 Million Revolving Credit Agreement. We have a syndicated 5-Year Revolving Credit Agreement, or Credit Agreement, with Wells Fargo Bank, National Association, as administrative agent and swingline lender. Effective December 9, 2013, we entered into an extension agreement and amendment to the Credit Agreement, which, among other things, provided for a one-year extension with all of the existing lenders. The Credit Agreement provides for a $750 million senior unsecured revolving credit facility, for general corporate purposes, maturing on September 28, 2018. The entire amount of the facility is available for revolving loans. Up to $250 million of the facility is available for the issuance of performance or other standby letters of credit and up to $75 million is available for swingline loans. As of December 31, 2013, there were no loans or letters of credit outstanding under the Credit Agreement.

Senior Notes.

Our senior notes are comprised as follows:

Debt Issue	Principal Amount (In millions)	Maturity Date	Stated Interest Rate	Semiannual Interest Payment Dates
5.15% Senior Notes due 2014	$ 250.0	September 1, 2014	5.15%	March 1 and September 1
4.875% Senior Notes due 2015	$ 250.0	July 1, 2015	4.875%	January 1 and July 1
5.875% Senior Notes due 2019	$ 500.0	May 1, 2019	5.875%	May 1 and November 1
3.45% Senior Notes due 2023	$ 250.0	November 1, 2023	3.45%	May 1 and November 1
5.70% Senior Notes due 2039	$ 500.0	October 15, 2039	5.70%	April 15 and October 15
4.875% Senior Notes due 2043	$ 750.0	November 1, 2043	4.875%	May 1 and November 1

Our 5.15% Senior Notes due 2014, in the aggregate principal amount of $250.0 million, will mature on September 1, 2014.

See Note 9 "Credit Agreement and Senior Notes" to our Consolidated Financial Statements in Item 8 of this report.

Credit Ratings. Our current credit rating is A3 for Moody's Investors Services and A for Standard & Poor's. Although our long-term ratings continue at investment grade levels, lower ratings could result in higher interest rates on future debt issuances.

Contractual Cash Obligations

The following table sets forth our contractual cash obligations at December 31, 2013.

Contractual Obligations (1) (2)	Payments Due By Period				
	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
			(In thousands)		
Long-term debt (principal and interest)	$4,622,939	$ 378,126	$ 468,314	$206,126	$3,570,373
Construction contracts	2,088,809	1,253,791	835,018	—	—
Operating leases	5,742	2,938	2,170	634	—
Total obligations	$6,717,490	$ 1,634,855	$1,305,502	$206,760	$3,570,373

(1) The above table excludes foreign currency forward exchange, or FOREX, contracts in the aggregate notional amount of $114.1 million outstanding at December 31, 2013. See further information regarding these contracts in "Quantitative and Qualitative Disclosures About Market Risk — *Foreign Exchange Risk*" in Item 7A of this report and Note 6 "Derivative Financial Instruments" to our Consolidated Financial Statements in Item 8 of this report.

(2) The above table excludes $76.3 million of unrecognized tax benefits related to uncertain tax positions as of December 31, 2013 and an additional $59.8 million and $12.8 million for potential penalties and interest, respectively, related to such uncertain tax positions. 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.

Except for the construction contracts discussed above and referred to in the preceding table, we had no other purchase obligations for major rig upgrades or any other significant obligations at December 31, 2013, 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, 2013 in the amount of $78.2 million under certain performance, bid, supersedeas, tax appeal and customs bonds and letters of credit. Agreements relating to approximately $67.4 million of performance, supersedeas and customs bonds can require collateral at any time. As of December 31, 2013, 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	2014	2015	Thereafter
		(In thousands)		
Other Commercial Commitments				
Customs bonds	$ 1,517	$ 1,517	$ —	$ —
Performance bonds	60,704	11,992	13,638	35,074
Other	16,027	16,027	—	—
Total obligations	$78,248	$29,536	$13,638	$35,074

Off-Balance Sheet Arrangements

At December 31, 2013 and 2012, we had no off-balance sheet debt or other 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. Currency environments in which we have significant business operations include Brazil, the U.K., Australia and Mexico. When possible, we attempt to minimize our currency exchange risk by seeking international contracts 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.

To the extent that we are not able to cover our local currency operating costs with customer payments in the local currency, we also utilize FOREX contracts to reduce our currency exchange risk. Our FOREX contracts may obligate us to exchange predetermined amounts of specified foreign currencies at specified foreign exchange rates on specific dates or to net settle the spread between the contracted foreign currency exchange rate and the spot rate on the contract settlement date, which, for most of our contracts, is the average spot rate for the contract period.

We record currency transaction gains and losses as "Foreign currency transaction gain (loss)" in our Consolidated Statements of Operations. Gains and losses arising from the settlement of our FOREX contracts that have been designated as cash flow hedges are reported as a component of "Contract drilling, excluding depreciation" expense 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 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;
- uses of and requirements for financial resources;
- interest rate and foreign exchange risk;
- contractual obligations;
- operations outside the United States;
- effects of the Macondo well blowout;
- business strategy;
- growth opportunities;
- competitive position;
- expected financial position;
- cash flows and contract backlog;
- regular or special dividends;
- financing plans;
- market outlook;
- tax planning;
- 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 rig upgrades, construction projects and other capital projects;
- delivery dates and drilling contracts related to rig conversion or upgrade projects, construction projects, other capital projects or rig acquisitions;
- plans and objectives of management;

- idling drilling rigs or reactivating stacked rigs;
- assets held for sale;
- asset impairment evaluations;
- performance of contracts;
- outcomes of legal proceedings;
- 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;
- worldwide 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 the Organization of Petroleum Exporting Countries, commonly called 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;
- our 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 in locations where our rigs are operating or where we have rigs under construction;
- casualty losses;
- operating hazards inherent in drilling for oil and gas offshore;
- the risk of physical damage to rigs and equipment caused by named windstorms in the U.S. Gulf of Mexico;
- industry fleet capacity, including, without limitation, construction of new drilling rig capacity in Brazil;
- 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;
- the ability of customers and suppliers to meet their obligations to us and our subsidiaries;
- the risk that a letter of intent may not result in a definitive agreement;
- foreign exchange and currency fluctuations and regulations, and the inability to repatriate income or capital;
- risks of war, military operations, other armed hostilities, terrorist acts and embargoes;
- changes in offshore drilling technology, which could require significant capital expenditures in order to maintain competitiveness;
- 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;
- 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;
- effects 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;
- the results of financing efforts;
- the risk that future regular or special dividends may not be declared;
- adequacy of our sources of liquidity;
- risks resulting from our indebtedness;
- public health threats;
- negative publicity;
- impairments of assets;
- the availability of qualified personnel to operate and service our drilling rigs; and
- various other matters, many of which are beyond our control.

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.

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, 2013 and 2012, assuming immediate adverse market movements of the magnitude described below. We believe that the various rates of adverse market movements represent a measure of exposure to loss under hypothetically assumed adverse conditions. The estimated market risk exposure represents the hypothetical loss to future earnings and does not represent the maximum possible loss or any expected actual loss, even under adverse conditions, because actual adverse fluctuations would likely differ. In addition, since our investment portfolio is subject to change based on our portfolio management strategy as well as in response to changes in the market, these estimates are not necessarily indicative of the actual results that may occur.

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

Interest Rate Risk

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

The sensitivity analysis estimates the change in the market value of our interest sensitive assets and liabilities that were held on December 31, 2013 and 2012, due to instantaneous parallel shifts in the yield curve of 100 basis points, with all other variables held constant.

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

Our long-term debt, as of December 31, 2013 and 2012, 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 $221.5 million and $131.4 million as of December 31, 2013 and 2012, respectively. A 100-basis point decrease would result in an increase in market value of $264.5 million and $151.1 million as of December 31, 2013 and 2012, respectively.

Foreign Exchange Risk

Foreign exchange rate risk arises from the possibility that changes in foreign currency exchange rates will impact the value of financial instruments. It is customary for us to enter into FOREX contracts in the normal course of business. These contracts generally require us to net settle the spread between the contracted foreign currency exchange rate and the spot rate on the contract settlement date, which for most of our contracts is the average spot rate for the contract period. As of December 31, 2013, we had FOREX contracts outstanding in the aggregate notional amount of $114.1 million, consisting of $15.3 million in Australian dollars, $72.4 million in Brazilian reais, $14.2 million in British pounds sterling, $5.9 million in Mexican pesos and $6.3 million in Norwegian kroner. These contracts generally settle monthly through September 2014. At December 31, 2013, we have presented the fair value of our outstanding FOREX contracts as a current asset of $1.6 million in “Prepaid expenses and other current assets” and a current liability of $(1.1) million in “Accrued liabilities” in our Consolidated Balance Sheets included in Item 8 of this report. We have presented the fair value of our outstanding FOREX contracts at December 31, 2012, as a current asset of $3.6 million in “Prepaid expenses and other current assets” and a current liability of $(29,137) in “Accrued liabilities” in our Consolidated Balance Sheets included in Item 8 of this report.

The following table presents our exposure to market risk by category (interest rates and foreign currency exchange rates):

	Fair Value Asset (Liability) December 31,		Market Risk December 31,	
	2013	2012	2013	2012
	(In thousands)			
Interest rate:				
Marketable securities	$1,750,100(a)	$1,150,200(a)	$ (2,200)(b)	$ (2,200)(b)
Foreign Exchange:				
Forward exchange contracts — receivable positions	1,600(c)	3,600(c)	(4,200)(d)	(21,600)(d)
Forward exchange contracts — liability positions	(1,100)(c)	(29)(c)	(16,000)(d)	(4,900)(d)

(a) The fair market value of our investment in marketable securities, excluding repurchase agreements, is based on the quoted closing market prices on December 31, 2013 and 2012.

(b) The calculation of estimated market risk exposure is based on assumed adverse changes in the underlying reference price or index of an increase in interest rates of 100 basis points at December 31, 2013 and 2012.

(c) The fair value of our foreign currency forward exchange contracts is based on both quoted market prices and valuations derived from pricing models on December 31, 2013 and 2012.

(d) The calculation of estimated foreign exchange risk assumes an instantaneous 20% decrease in the foreign currency exchange rates versus the U.S. dollar from their values at December 31, 2013 and 2012, with all other variables held constant.

Item 8. Financial Statements and Supplementary Data.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Diamond Offshore Drilling, Inc. and subsidiaries (the “Company”) as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, stockholders’ equity, and cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Diamond Offshore Drilling, Inc. and subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company’s internal control over financial reporting as of December 31, 2013, based on the criteria established in *Internal Control —Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2014, expressed an unqualified opinion on the Company’s internal control over financial reporting.

/s/ Deloitte & Touche LLP

Houston, Texas
February 24, 2014

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of Diamond Offshore Drilling, Inc. and subsidiaries (the “Company”) as of December 31, 2013, based on criteria established in *Internal Control — Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. 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 Item 9A of this Form 10-K under the heading “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 conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether 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.

A company’s internal control over financial reporting is a process designed by, or under the supervision of, the company’s principal executive and principal financial officers, or persons performing similar functions, and effected by the company’s board of directors, management, and other personnel 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the criteria established in *Internal Control — Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2013 of the Company and our report dated February 24, 2014 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Houston, Texas
February 24, 2014

DIAMOND OFFSHORE DRILLING, INC.
AND SUBSIDIARIES

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

	December 31, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 347,011	$ 335,432
Marketable securities	1,750,053	1,150,158
Accounts receivable, net of allowance for bad debts	469,355	499,660
Prepaid expenses and other current assets	143,997	136,099
Assets held for sale	7,694	11,594
Total current assets	2,718,110	2,132,943
Drilling and other property and equipment, net of accumulated depreciation	5,467,227	4,864,972
Other assets	206,097	237,371
Total assets	$8,391,434	$7,235,286
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 94,151	$ 96,631
Accrued liabilities	370,671	324,434
Taxes payable	30,806	64,481
Current portion of long-term debt	249,954	—
Total current liabilities	745,582	485,546
Long-term debt	2,244,189	1,496,066
Deferred tax liability	525,541	490,946
Other liabilities	238,864	186,334
Total liabilities	3,754,176	2,658,892
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; 143,952,248 shares issued and 139,035,448 shares outstanding at December 31, 2013; 143,948,370 shares issued and 139,031,570 shares outstanding at December 31, 2012)	1,440	1,439
Additional paid-in capital	1,988,720	1,983,957
Retained earnings	2,761,161	2,702,915
Accumulated other comprehensive gain (loss)	350	2,496
Treasury stock, at cost (4,916,800 shares of common stock at December 31, 2013 and 2012)	(114,413)	(114,413)
Total stockholders' equity	4,637,258	4,576,394
Total liabilities and stockholders' equity	$8,391,434	$7,235,286

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, 2013	2012	2011
Revenues:			
Contract drilling	$2,843,584	$2,936,066	$3,254,313
Revenues related to reimbursable expenses	76,837	50,442	68,106
Total revenues	2,920,421	2,986,508	3,322,419
Operating expenses:			
Contract drilling, excluding depreciation	1,572,525	1,537,224	1,548,502
Reimbursable expenses	74,967	48,778	66,052
Depreciation	388,092	392,913	398,612
General and administrative	64,788	64,640	65,310
Impairment of assets	—	62,437	—
Bad debt expense (recovery)	22,513	(1,018)	(6,713)
Gain on disposition of assets	(4,070)	(80,844)	(4,758)
Total operating expenses	2,118,815	2,024,130	2,067,005
Operating income	801,606	962,378	1,255,414
Other income (expense):			
Interest income	701	4,910	6,668
Interest expense	(24,843)	(46,216)	(73,137)
Foreign currency transaction loss	(4,915)	(1,999)	(8,588)
Other, net	1,691	(992)	(1,086)
Income before income tax expense	774,240	918,081	1,179,271
Income tax expense	(225,554)	(197,604)	(216,729)
Net income	$ 548,686	$ 720,477	$ 962,542
Earnings per share, Basic and Diluted	$ 3.95	$ 5.18	$ 6.92
Weighted-average shares outstanding:			
Shares of common stock	139,035	139,029	139,027
Dilutive potential shares of common stock	29	19	11
Total weighted-average shares outstanding	139,064	139,048	139,038
Cash dividends declared per share of common stock	$ 3.50	$ 3.50	$ 3.50

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

DIAMOND OFFSHORE DRILLING, INC.
AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In thousands)

	Year Ended December 31,		
	2013	2012	2011
Net income	$548,686	$720,477	$962,542
Other comprehensive gains (losses), net of tax:			
Derivative financial instruments:			
Unrealized holding (loss) gain	(6,833)	4,237	(625)
Reclassification adjustment for loss (gain) included in net income	4,840	2,733	(6,728)
Investments in marketable securities:			
Unrealized holding (loss) gain on investments	(6)	124	(46)
Reclassification adjustment for (gain) loss included in net income	(147)	44	(384)
Total other comprehensive (loss) gain	(2,146)	7,138	(7,783)
Comprehensive income	$546,540	$727,615	$954,759

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, 2011	143,943,624	$1,439	$1,972,550	$1,998,995	$ 3,141	4,916,800	$(114,413)	$3,861,712
Net income	—	—	—	962,542	—	—	—	962,542
Dividends to stockholders ($3.50 per share)	—	—	—	(486,595)	—	—	—	(486,595)
Anti-dilution adjustment paid to stock plan participants ($3.00 per share)	—	—	—	(2,632)	—	—	—	(2,632)
Stock options exercised	385	—	—	—	—	—	—	—
Stock-based compensation, net of tax	—	—	5,819	—	—	—	—	5,819
Net loss on derivative financial instruments	—	—	—	—	(7,353)	—	—	(7,353)
Net loss on investments	—	—	—	—	(430)	—	—	(430)
December 31, 2011	143,944,009	1,439	1,978,369	2,472,310	(4,642)	4,916,800	(114,413)	4,333,063
Net income	—	—	—	720,477	—	—	—	720,477
Dividends to stockholders ($3.50 per share)	—	—	—	(486,603)	—	—	—	(486,603)
Anti-dilution adjustment paid to stock plan participants ($3.00 per share)	—	—	—	(3,269)	—	—	—	(3,269)
Stock options exercised	4,361	—	148	—	—	—	—	148
Stock-based compensation, net of tax	—	—	5,440	—	—	—	—	5,440
Net gain on derivative financial instruments	—	—	—	—	6,970	—	—	6,970
Net gain on investments	—	—	—	—	168	—	—	168
December 31, 2012	143,948,370	1,439	1,983,957	2,702,915	2,496	4,916,800	(114,413)	4,576,394
Net income	—	—	—	548,686	—	—	—	548,686
Dividends to stockholders ($3.50 per share)	—	—	—	(486,620)	—	—	—	(486,620)
Anti-dilution adjustment paid to stock plan participants ($3.00 per share)	—	—	—	(3,820)	—	—	—	(3,820)
Stock options exercised	3,878	1	109	—	—	—	—	110
Stock-based compensation, net of tax	—	—	4,654	—	—	—	—	4,654
Net gain on derivative financial instruments	—	—	—	—	(1,993)	—	—	(1,993)
Net gain on investments	—	—	—	—	(153)	—	—	(153)
December 31, 2013	143,952,248	$1,440	$1,988,720	$2,761,161	$ 350	4,916,800	$(114,413)	$4,637,258

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, 2013	2012	2011
Operating activities:			
Net income	$ 548,686	$ 720,477	$ 962,542
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	388,092	392,913	398,612
Impairment of assets	—	62,437	—
Gain on disposition of assets	(4,070)	(80,844)	(4,758)
Bad debt expense (recovery)	22,513	(1,018)	(6,713)
Loss (gain) on foreign currency forward exchange contracts	6,501	4,302	(7,206)
Deferred tax provision	34,101	(51,472)	2,141
Accretion of discounts on marketable securities	(707)	4,622	1,586
Stock-based compensation expense	3,573	4,357	4,956
Deferred income, net	(54,274)	1,767	(32,219)
Deferred expenses, net	25,604	67,824	53,317
Long-term employee remuneration programs	8,966	7,611	3,944
Other assets, noncurrent	(4,922)	(2,794)	2,220
Other liabilities, noncurrent	(5,296)	3,614	6,921
(Payments of) proceeds from settlement of foreign currency forward exchange contracts designated as accounting hedges	(6,501)	(4,302)	7,206
Bank deposits denominated in nonconvertible currencies	(12,741)	—	—
Other	1,954	1,258	319
Changes in operating assets and liabilities:			
Accounts receivable	7,905	65,074	67,498
Prepaid expenses and other current assets	10,066	(8,960)	(6,406)
Accounts payable and accrued liabilities	46,752	10,354	(9,842)
Taxes payable	49,786	114,049	(24,013)
Net cash provided by operating activities	1,065,988	1,311,269	1,420,105
Investing activities:			
Capital expenditures (including rig construction)	(957,598)	(702,041)	(774,756)
Proceeds from disposition of assets, net of disposal costs	4,900	138,495	5,603
Proceeds from sale and maturities of marketable securities	4,650,085	2,725,118	5,362,138
Purchases of marketable securities	(5,249,462)	(2,977,290)	(5,653,665)
Net cash used in investing activities	(1,552,075)	(815,718)	(1,060,680)
Financing activities:			
Issuance of senior notes	997,805	—	—
Debt issuance costs and arrangement fees	(9,973)	(3,838)	—
Payment of dividends	(490,331)	(490,245)	(490,057)
Other	165	199	4
Net cash used in financing activities	497,666	(493,884)	(490,053)
Net change in cash and cash equivalents	11,579	1,667	(130,628)
Cash and cash equivalents, beginning of year	335,432	333,765	464,393
Cash and cash equivalents, end of year	$ 347,011	$ 335,432	$ 333,765

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. is a leader in offshore drilling, providing contract drilling services to the energy industry around the globe with a fleet of 45 offshore drilling rigs, including five rigs under construction. Our fleet consists of 33 semisubmersibles, two of which are under construction, seven jack-ups, one of which is held for sale, and five dynamically positioned drillships, three of which are under construction. At December 31, 2013, one of our jack-up rigs, the *Ocean Spartan*, was reported as “Asset held for sale” in our Consolidated Balance Sheets. 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 18, 2014, Loews Corporation, or Loews, owned 50.4% 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 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.

Reclassifications

Certain amounts applicable to the prior periods have been reclassified to conform to the classifications currently followed. Such reclassifications did not affect earnings.

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. We had bank deposits denominated in Egyptian pounds totaling $14.3 million at December 31, 2013. However, the local currency is not readily convertible into U.S. dollars or other currencies at this time. While we believe that a portion of these amounts will be used to fund local operations and obligations in Egyptian pounds in the short term, we reclassified $12.7 million to “Other assets” in our Consolidated Balance Sheets at December 31, 2013.

The effect of exchange rate changes on cash balances held in foreign currencies was not material for the years ended December 31, 2013, 2012 and 2011.

Marketable Securities

We classify our investments in marketable securities as available for sale and they are stated at fair value in our Consolidated Balance Sheets. Accordingly, any unrealized gains and losses, net of taxes, are reported in our Consolidated Balance Sheets in “Accumulated other comprehensive gain (loss)” until realized. The cost of debt securities is adjusted for amortization of premiums and accretion of discounts to maturity and such adjustments are included in our Consolidated Statements of Operations in “Interest income.” The sale and purchase of securities are recorded on the date of the trade. The cost of debt securities sold is based on the specific identification method. Realized gains or losses, as well as any declines in value that are judged to be other than temporary, are reported in our Consolidated Statements of Operations in “Other income (expense) — Other, net.”

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 2.

DIAMOND OFFSHORE DRILLING, INC.
AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Derivative Financial Instruments

Our derivative financial instruments consist primarily of foreign currency forward exchange, or FOREX, contracts which we may designate as cash flow hedges. In accordance with GAAP, each derivative contract is stated in the balance sheet at its fair value with gains and losses reflected in the income statement except that, to the extent the derivative qualifies for and is designated as an accounting hedge, the gains and losses are reflected in income in the same period as offsetting gains and losses on the qualifying hedged positions. Designated hedges are expected to be highly effective, and therefore, adjustments to record the carrying value of the effective portion of our derivative financial instruments to their fair value are recorded as a component of "Accumulated other comprehensive gain (loss)," or AOCGL, in our Consolidated Balance Sheets. The effective portion of the cash flow hedge will remain in AOCGL until it is reclassified into earnings in the period or periods during which the hedged transaction affects earnings or it is determined that the hedged transaction will not occur. We report such realized gains and losses as a component of "Contract drilling, excluding depreciation" expense in our Consolidated Statements of Operations to offset the impact of foreign currency fluctuations in our expenditures in local foreign currencies in the countries in which we operate.

Adjustments to record the carrying value of the ineffective portion of our derivative financial instruments to fair value and realized gains or losses upon settlement of derivative contracts not designated as cash flow hedges are reported as "Foreign currency transaction gain (loss)" in our Consolidated Statements of Operations. See Notes 6 and 7.

Assets Held For Sale

In 2012, our management adopted a plan to actively market for sale three mid-water semisubmersibles, the *Ocean Epoch*, the *Ocean New Era* and the *Ocean Whittington*, and one jack-up rig, the *Ocean Spartan*. This decision was based on management's review of our drilling fleet at the end of 2012 and their assessment that three of these rigs had no short-term outlook for work due to their age and capabilities. These rigs were put on the market for sale at the end of 2012.

In connection with the reclassification of these rigs to "Assets held for sale," we measured the fair value of each rig in the disposal group using a probability-weighted cash flow analysis that utilized significant unobservable inputs, representing a Level 3 fair value measurement, which included assumptions for estimated proceeds that may be received upon disposition of the rig and estimated costs to sell. For our three mid-water semisubmersibles in the disposal group, we determined, at that time, that, due to the expected resale market for rigs of this type and age, the highest and best use of these rigs would be for sale as scrap. Based on our analyses, we determined that the carrying values of the mid-water semisubmersible rigs in the disposal group were impaired, as the carrying value for each exceeded its aggregate fair value, and recognized an impairment loss in the fourth quarter of 2012. We determined that the carrying value of the *Ocean Spartan* was not impaired.

These rigs were not sold during 2013. The three mid-water semisubmersible rigs have been transferred to "Drilling and Other Property and Equipment" at their aggregate fair value of $3.9 million. Only the *Ocean Spartan* was reported as "Assets Held for Sale" at December 31, 2013. We reported "Assets held for sale" aggregating $7.7 million and $11.6 million in our Consolidated Balance Sheets at December 31, 2013 and 2012, respectively. See "*Impairment of Long-Lived Assets"* and Note 7.

Drilling and Other Property and Equipment

We carry our drilling and other property and equipment at cost. Maintenance and routine repairs are charged to income currently while replacements and betterments, which 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, 2013 and 2012, we capitalized $302.0 million and $220.3 million, respectively, in replacements and betterments of our drilling fleet, resulting from numerous projects ranging from $25,000 to $40 million per project.

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 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 qualifying construction and upgrade projects. During the three years ended December 31, 2013, we capitalized interest on qualifying expenditures, primarily related to our rig construction projects. See Note 8.

A reconciliation of our total interest cost to “Interest expense” as reported in our Consolidated Statements of Operations is as follows:

	For the Year Ended December 31,		
	2013	2012	2011
		(In thousands)	
Total interest cost including amortization of debt issuance costs	$ 99,080	$ 83,890	$ 84,349
Capitalized interest	(74,237)	(37,674)	(11,212)
Total interest expense as reported	$ 24,843	$ 46,216	$ 73,137

Asset Retirement Obligations

At December 31, 2013 and 2012, we had no asset retirement obligations.

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 cold stacking 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 (expressed as the actual percentage of time per year that the rig would be used);
- 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 costs associated with a rig returning to work;
- salvage value for each rig; and
- estimated proceeds that may be received on disposition of the rig.

Based on these assumptions and estimates, we develop a matrix using several different utilization/dayrate scenarios, to each of which we have assigned a probability of occurrence. The sum of our utilization scenarios (which include active, warm stacked and cold stacked) and probability of occurrence scenarios both equal 100% in the aggregate. We reevaluate our cold-stacked rigs annually, by updating the matrices for each rig and modifying our assumptions, giving consideration to the length of time the rig has been cold stacked, the current and expected market for the type of rig and expectations of future oil and gas prices.

At December 31, 2012, our four cold-stacked rigs were reported as “Assets held for sale” and had an aggregate net book value of $11.6 million. In connection with the presentation of these rigs as held for sale at the end of 2012, we recognized an impairment loss of $62.4 million. These four rigs remained cold stacked at December 31, 2013. We did not record any impairment with respect to our cold-stacked rigs at December 31, 2013. See “*Assets Held for Sale.”*

DIAMOND OFFSHORE DRILLING, INC.
AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Management's assumptions are an inherent part of our asset impairment evaluation and the use of different assumptions could produce results that differ from those reported.

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. For non-current financial instruments we use quoted market prices, when available, and discounted cash flows to estimate fair value. See Note 7.

Debt Issuance Costs

Debt issuance costs are included in our Consolidated Balance Sheets in "Other assets" and are amortized over the respective terms of the related debt.

Income Taxes

We account for income taxes in accordance with accounting standards that require the recognition of the amount of taxes payable or refundable for the current year and an asset and liability approach in recognizing the amount of deferred tax liabilities and assets for the future tax consequences of events that have been currently recognized in our financial statements or tax returns. In each of our tax jurisdictions we recognize a current tax liability or asset for the estimated taxes payable or refundable on tax returns for the current year and a deferred tax asset or liability for the estimated future tax effects attributable to temporary differences and carryforwards. Deferred tax assets are reduced by a valuation allowance, if necessary, which is determined by the amount of any tax benefits that, based on available evidence, are not expected to be realized under a "more likely than not" approach. We make judgments regarding future events and related estimates especially as they pertain to the forecasting of our effective tax rate, the potential realization of deferred tax assets such as 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 and recognize penalties associated with uncertain tax positions in our tax expense. See Note 13.

Treasury Stock

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 2013, 2012 or 2011.

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, 2013, 2012 and 2011 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. Foreign currency transaction gains and losses are reported as "Foreign currency transaction gain (loss)" in our Consolidated Statements of Operations and include, when applicable, unrealized gains and losses to record the carrying value of our FOREX contracts not designated as accounting hedges, as well as realized gains and losses from the settlement of such contracts. For the years ended December 31, 2013, 2012 and 2011, we recognized aggregate net foreign currency gains (losses) of $(4.9) million, $(2.0) million and $(8.6) million, respectively. See Note 6.

Revenue Recognition

We recognize revenue from dayrate drilling contracts as services are performed. In connection with such drilling contracts, we may receive fees (either lump-sum or dayrate) 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 2 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.

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 (either lump-sum or dayrate). 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 (either lump-sum or dayrate). 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.

2. Supplemental Financial Information

Consolidated Balance Sheet Information

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

	December 31,	
	2013	2012
	(In thousands)	
Trade receivables	$473,013	$478,930
Value added tax receivables	19,407	13,884
Amounts held in escrow	3,066	11,555
Interest receivable	7	6
Related party receivables	587	527
Other	615	216
	496,695	505,118
Allowance for bad debts	(27,340)	(5,458)
Total	$469,355	$499,660

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An analysis of the changes in our provision for bad debts for each of the three years ended December 31, 2013, 2012 and 2011 is as follows (see Note 7):

	For the Year Ended December 31,		
	2013	2012	2011
	(In thousands)		
Allowance for bad debts, beginning of year	$ 5,458	$ 6,867	$ 31,908
Bad debt expense:			
Provision for bad debts	22,513	—	5,688
Recovery of bad debts	—	(1,018)	(12,401)
Total bad debt expense (recovery)	22,513	(1,018)	(6,713)
Write off of uncollectible accounts against reserve	(509)	(391)	(18,380)
Other(1)	(122)	—	52
Allowance for bad debts, end of year	$27,340	$ 5,458	$ 6,867

(1) Includes revaluation adjustments for non-U.S. dollar denominated receivables, which have been recorded as “Foreign currency transaction gain (loss)” in our Consolidated Statements of Operations.

Prepaid expenses and other current assets consist of the following:

	December 31,	
	2013	2012
	(In thousands)	
Rig spare parts and supplies	$ 52,439	$ 57,558
Deferred mobilization costs	20,274	38,074
Prepaid insurance	12,503	12,549
Deferred tax assets	10,221	8,619
Prepaid taxes	42,058	5,950
FOREX contracts	1,562	3,627
Other	4,940	9,722
Total	$143,997	$136,099

Accrued liabilities consist of the following:

	December 31,	
	2013	2012
	(In thousands)	
Rig operating expenses	$ 87,307	$ 70,078
Payroll and benefits	121,387	88,612
Deferred revenue	26,975	71,699
Accrued capital project/upgrade costs	86,274	56,595
Interest payable	28,324	21,219
Personal injury and other claims	9,687	10,312
FOREX contracts	1,143	29
Other	9,574	5,890
Total	$370,671	$324,434

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, 2013	2012	2011
		(In thousands)	
Accrued but unpaid capital expenditures at period end	$86,274	$56,595	$ 37,325
Income tax benefits related to exercise of stock options	1,081	1,083	863
Cash interest payments**(1)(2)**	82,938	83,125	82,938
Cash income taxes paid, net of refunds:			
U.S. federal	62,000	71,000	94,843
Foreign	78,041	72,249	150,465
State	190	243	210

(1) Interest payments, net of amounts capitalized, were $16.5 million, $46.2 million and $71.9 million for the years ended December 31, 2013, 2012 and 2011, respectively.

(2) Interest paid on Internal Revenue Service assessments was $0.2 million during the year ended December 31, 2012.

3. Stock-Based Compensation

Our Second Amended and Restated 2000 Stock Option Plan, as amended, or Stock Plan, provides for the issuance of either incentive stock options or non-qualified stock options to our employees, consultants and non-employee directors. Our Stock Plan also authorizes the award of stock appreciation rights, or SARs, in tandem with stock options or separately. The maximum aggregate number of shares of our common stock for which stock options or SARs may be granted is 1,500,000 shares. The exercise price per share may not be less than the fair market value of the common stock on the date of grant. Generally, stock options and SARs vest ratably over a four year period and expire in ten years.

Total compensation cost recognized for Stock Plan transactions, consisting solely of awards of SARs, for the years ended December 31, 2013, 2012 and 2011 was $3.9 million, $4.7 million and $5.0 million, respectively. Tax benefits recognized for the years ended December 31, 2013, 2012 and 2011 related thereto were $1.3 million, $1.6 million and $1.7 million, respectively.

The fair value of SARs granted under the Stock Plan during each of the years ended December 31, 2013, 2012 and 2011 was estimated using the Black Scholes pricing model.

The following are the weighted average assumptions used in estimating the fair value of our SARs:

	Year Ended December 31, 2013	2012	2011
Expected life of SARs (in years)	7	6	5
Expected volatility	18.24%	33.45%	30.37%
Dividend yield	.75%	.78%	.76%
Risk free interest rate	1.61%	.89%	1.54%

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.

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A summary of activity under the Stock Plan as of December 31, 2013 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, 2013	1,229,480	$ 80.32		
Granted	233,625	$ 66.95		
Exercised	(15,091)	$ 59.58		
Forfeited	(24,283)	$ 67.51		
Expired	(31,072)	$ 94.01		
Awards outstanding at December 31, 2013	1,392,659	$ 78.22	7.0	$ 460
Awards exercisable at December 31, 2013	973,918	$ 83.32	6.0	$ 438

The weighted-average grant date fair values per share of awards granted during the years ended December 31, 2013, 2012 and 2011 were $13.74, $19.01 and $18.17, respectively. The total intrinsic value of awards exercised during the years ended December 31, 2013, 2012 and 2011 was $162,000, $147,000 and $28,000, respectively. The total fair value of awards vested during the years ended December 31, 2013, 2012 and 2011 was $4.1 million, $5.2 million and $5.4 million, respectively. As of December 31, 2013 there was $5.1 million of total unrecognized compensation cost related to nonvested stock awards granted under the Stock Plan which we expect to recognize over a weighted average period of 2.4 years.

4. Earnings Per Share

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

	Year Ended December 31, 2013	2012	2011
	(In thousands, except per share data)		
Net income — basic and diluted (numerator):	$548,686	$720,477	$962,542
Weighted-average shares — basic (denominator):	139,035	139,029	139,027
Effect of dilutive potential shares			
Stock options and stock appreciation rights	29	19	11
Weighted-average shares including conversions — diluted (denominator):	139,064	139,048	139,038
Earnings per share:			
Basic	$ 3.95	$ 5.18	$ 6.92
Diluted	$ 3.95	$ 5.18	$ 6.92

The following table sets forth the share effects of stock options and the number of SARs excluded from our computations of diluted earnings per share, or EPS, as the inclusion of such potentially dilutive shares would have been antidilutive for the periods presented:

	Year Ended December 31, 2013	2012	2011
	(In thousands)		
Employee and director:			
Stock options	18	18	19
SARs	956	853	847

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5. Marketable Securities

We report our investments in marketable securities as current assets in our Consolidated Balance Sheets in “Marketable securities,” representing the investment of cash available for current operations. See Note 7.

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

	December 31, 2013		
	Amortized Cost	Unrealized Gain (Loss)	Market Value
		(In thousands)	
U.S. Treasury Bills and Notes (due within one year)	$1,749,879	$ (22)	$1,749,857
Mortgage-backed securities	188	8	196
Total	$1,750,067	$ (14)	$1,750,053

	December 31, 2012		
	Amortized Cost	Unrealized Gain (Loss)	Market Value
		(In thousands)	
U.S. Treasury Bills and Notes (due within one year)	$1,149,707	$ 150	$1,149,857
Mortgage-backed securities	276	25	301
Total	$1,149,983	$ 175	$1,150,158

Proceeds from maturities and sales of marketable securities and gross realized gains and losses are summarized as follows:

	Year Ended December 31,		
	2013	2012	2011
		(In thousands)	
Proceeds from maturities	$4,650,000	$2,575,000	$5,350,000
Proceeds from sales	85	150,118	12,138
Gross realized gains	—	—	784
Gross realized losses	(1)	(6)	(5)

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 for employee compensation, foreign income tax payments and purchases from foreign suppliers. We may utilize FOREX contracts to manage our foreign exchange risk. Our FOREX contracts generally require us to net settle the spread between the contracted foreign currency exchange rate and the spot rate on the contract settlement date, which, for most of our contracts, is the average spot rate for the contract period.

We enter into FOREX contracts when we believe market conditions are favorable to purchase contracts for future settlement with the expectation that such contracts, when settled, will reduce our exposure to foreign currency gains and losses on future foreign currency expenditures. The amount and duration of such contracts is based on our monthly forecast of expenditures in the significant currencies in which we do business and for which there is a financial market (*i.e.*, Australian dollars, Brazilian reais, British pounds sterling, Mexican pesos and Norwegian kroner). These forward contracts are derivatives as defined by GAAP.

During the years ended December 31, 2013, 2012 and 2011, we settled FOREX contracts with aggregate notional values of approximately $307.4 million, $305.6 million and $318.9 million, respectively, of which the entire aggregate amounts were designated as an accounting hedge. During the years ended December 31, 2013, 2012 and 2011, we did not enter into or settle any FOREX contracts that were not designated as accounting hedges.

The following table presents the amounts recognized in our Consolidated Statements of Operations related to our FOREX contracts designated as hedging instruments for the years ended December 31, 2013, 2012 and 2011.

Location of (Loss) Gain Recognized in Income	Amount of (Loss) Gain Recognized in Income For the Years Ended December 31, 2013	2012	2011
	(In thousands)		
Contract drilling expense	$ (6,501)	$ (4,302)	$ 7,206

As of December 31, 2013, we had FOREX contracts outstanding in the aggregate notional amount of $114.1 million, consisting of $15.3 million in Australian dollars, $72.4 million in Brazilian reais, $14.2 million in British pounds sterling, $5.9 million in Mexican pesos and $6.3 million in Norwegian kroner. These contracts generally settle monthly through September 2014. As of December 31, 2013, all outstanding derivative contracts had been designated as cash flow hedges.

We have International Swap Dealers Association, or ISDA, contracts, which are standardized master legal arrangements that establish key terms and conditions, which govern certain derivative transactions. Historically, our FOREX contracts have been with two counterparties and have been governed under such ISDA agreements. There are no requirements to post collateral under these contracts; however, they do contain credit-risk related contingent provisions including credit support provisions and the net settlement of amounts owed in the event of early terminations. Additionally, should our credit rating fall below a specified rating immediately following the merger of Diamond Offshore Drilling, Inc. with another entity, the counterparty may require all outstanding derivatives under the ISDA contract to be settled immediately at current market value. Our ISDA arrangements also include master netting agreements to further manage counterparty credit risk associated with our FOREX contracts. We have elected not to offset the fair value amounts recorded for our derivative contracts under these agreements in our Consolidated Balance Sheets as of December 31, 2013 and 2012; however, there would have been no significant differences in our Consolidated Balance Sheets if the estimated fair values were presented on a net basis for these periods.

The following table presents the fair values of our FOREX contracts at December 31, 2013 and 2012.

Balance Sheet Location	Fair Value December 31, 2013	Fair Value December 31, 2012	Balance Sheet Location	Fair Value December 31, 2013	Fair Value December 31, 2012
	(In thousands)			(In thousands)	
Prepaid expenses and other current assets	$ 1,562	$ 3,627	Accrued liabilities	$ (1,143)	$ (29)

Treasury Lock Agreements

In connection with the offering of our senior unsecured notes in 2013, we entered into two treasury lock agreements in October 2013 for notional amounts totaling $500 million and designated such contracts as cash flow hedges of interest rate risk. The agreements were settled in November 2013 upon the completion of the offering of the senior notes for a net gain of $26,728, before tax. The gain has been recorded as a component of AOCGL and is being amortized to interest expense over the terms of the respective unsecured senior notes. See Note 9.

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The following table presents the amounts recognized in our Consolidated Balance Sheets and Consolidated Statements of Operations related to our derivative contracts designated as cash flow hedges for the years ended December 31, 2013, 2012 and 2011.

	For the years ended December 31, 2013	2012	2011
	(In thousands)		
FOREX contracts:			
Amount of (loss) gain recognized in AOCGL on derivative (effective portion)	$ (10,542)	$ 6,519	$ (962)
Location of (loss) gain reclassified from AOCGL into income (effective portion)	Contract drilling, excluding depreciation	Contract drilling, excluding depreciation	Contract drilling, excluding depreciation
Amount of (loss) gain reclassified from AOCGL into income (effective portion)	$ (7,449)	$ (4,205)	$ 10,351
Location of loss recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	Foreign currency transaction gain (loss)	Foreign currency transaction gain (loss)	Foreign currency transaction gain (loss)
Amount of loss recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	$ (104)	$ (17)	$ (85)
Treasury lock agreements:			
Amount of gain recognized in AOCGL on derivative (effective portion)	$ 27	$ —	$ —
Location of gain reclassified from AOCGL into income (effective portion)	Interest expense	Interest expense	Interest expense
Amount of gain reclassified from AOCGL into income (effective portion)	$ 1	$ —	$ —

As of December 31, 2013, the estimated amount of net unrealized gains associated with our FOREX contracts and treasury lock agreements that will be reclassified to earnings during the next twelve months was $0.5 million and $8,000, respectively. The net unrealized gains associated with our FOREX contracts will be reclassified to contract drilling expense to the extent fully effective. During the years ended December 30, 2013, 2012 and 2011 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 which 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.

Most of our investments in debt securities are U.S. government securities with minimal credit risk. However, we are exposed to market risk due to price volatility associated with interest rate fluctuations.

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. During 2013 and 2012, our largest customer in Brazil, Petróleo Brasileiro S.A. (a Brazilian multinational energy company that is majority-owned by the Brazilian government), accounted for $154.5 million and $116.4 million, or 35% and 24%, respectively, of our total consolidated gross trade accounts receivable balance. Our second largest customer in Brazil, OGX Petróleo e Gás Ltda. (a privately owned Brazilian oil and natural gas company that filed for bankruptcy in October 2013), or OGX, accounted for $80.3 million or 17% of our total consolidated gross trade accounts receivable balance at December 31, 2012. Our accounts receivable balance from OGX was fully reserved at December 31, 2013.

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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.

During 2013, based on our assessment of the financial condition of two of our customers, Niko Resources Ltd., or Niko, and OGX, and our expectations regarding the probability of collection of amounts due to us from them, we recorded $22.5 million in bad debt expense to fully reserve all outstanding receivables they owed us at June 30, 2013. With the exception of the settlement discussed below, we did not recognize revenue associated with these customers during the second half of 2013. See Note 2.

In December 2013, we entered into a settlement agreement with Niko, which we refer to as the Settlement Agreement, whereby Niko will be released from certain obligations under the dayrate contracts for the *Ocean Monarch* and *Ocean Lexington*, subject to and effective upon the full payment of amounts owed to us under the Settlement Agreement and subject to its other conditions. In accordance with the terms of the Settlement Agreement, we received $25.0 million in cash during the fourth quarter of 2013, which we recognized as revenue against invoices due us. Niko is further obligated to make future periodic payments to us pursuant to the Settlement Agreement totaling an aggregate of $55.0 million, payable at various times through September 2017. We plan to recognize these amounts in revenue as they are received due to the uncertainty regarding their timing and collection.

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, 2013 consisted of cash held in money market funds of $281.3 million, time deposits of $30.0 million and investments in U.S. Treasury securities of $1,749.9 million. Our Level 1 assets at December 31, 2012 consisted of cash held in money market funds of $264.9 million, time deposits of $20.0 million and investments in U.S. Treasury securities of $1,149.9 million.
Level 2	Quoted market prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model-derived valuations in which all significant inputs and significant value drivers are observable in active markets. Level 2 assets and liabilities include residential mortgage-backed securities and over-the-counter FOREX contracts. Our residential mortgage-backed securities were valued using a model-derived valuation technique based on the quoted closing market prices received from a financial institution. Our FOREX contracts are valued based on quoted market prices, which are derived from observable inputs including current spot and forward rates, less the contract rate multiplied by the notional amount. 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.
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, 2013 and 2012 consisted of nonrecurring measurements of certain rigs held for sale for which we recorded an impairment loss in 2012. The value of these rigs was determined using a present value technique which utilized unobservable inputs such as assumptions for estimated proceeds that may be received on disposition of each rig and estimated costs to sell. See Note 1.

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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, 2013 and 2012.

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 did not record any impairment charges related to assets measured at fair value on a nonrecurring basis during the year ended December 31, 2013.

	December 31, 2013				
	Fair Value Measurements Using			Assets at Fair Value	Total Losses for Year Ended
	Level 1	Level 2	Level 3		
			(In thousands)		
Recurring fair value measurements:					
Assets:					
Short-term investments	$2,061,154	$ —	$ —	$2,061,154	$ —
FOREX contracts	—	1,562	—	1,562	—
Mortgage-backed securities	—	197	—	197	—
Total assets	$2,061,154	$ 1,759	$ —	$2,062,913	$ —
Liabilities:					
FOREX contracts	$ —	$(1,143)	$ —	$ (1,143)	$ —
Nonrecurring fair value measurements:					
Assets:					
Impaired assets	$ —	$ —	$3,900	$ 3,900	$ —

	December 31, 2012				
	Fair Value Measurements Using			Assets at Fair Value	Total Losses for Year Ended
	Level 1	Level 2	Level 3		
			(In thousands)		
Recurring fair value measurements:					
Assets:					
Short-term investments	$1,434,751	$ —	$ —	$1,434,751	$ —
FOREX contracts	—	3,627	—	3,627	—
Mortgage-backed securities	—	301	—	301	—
Total assets	$1,434,751	$3,928	$ —	$1,438,679	$ —
Liabilities:					
FOREX contracts	$ —	$ (29)	$ —	$ (29)	$ —
Nonrecurring fair value measurements:					
Assets:					
Assets held for sale	$ —	$ —	$3,900	$ 3,900	$ (62,437)

We have presented the loss related to assets held for sale in "Impairment of assets" in our Consolidated Statements of Operations for the year ended December 31, 2012.

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.

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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, 2013 and 2012. 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 (see Note 9) of our senior notes are shown below.

	December 31, 2013		December 31, 2012	
	Fair Value	Carrying Value	Fair Value	Carrying Value
	(In millions)			
5.15% Senior Notes due 2014	$ 257.4	$ 250.0	$ 269.0	$ 249.9
4.875% Senior Notes due 2015	265.7	249.9	275.5	249.8
5.875% Senior Notes due 2019	578.1	499.6	617.1	499.5
3.45% Senior Notes due 2023	241.4	249.0	—	—
5.70% Senior Notes due 2039	543.1	496.9	641.4	496.9
4.875% Senior Notes due 2043	736.1	748.8	—	—

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,	
	2013	2012
	(In thousands)	
Drilling rigs and equipment	$ 7,412,066	$ 7,107,279
Construction work-in-progress	1,668,211	990,964
Land and buildings	65,627	64,296
Office equipment and other	65,799	60,239
Cost	9,211,703	8,222,778
Less accumulated depreciation	(3,744,476)	(3,357,806)
Drilling and other property and equipment, net	$ 5,467,227	$ 4,864,972

Construction work-in-progress, including capitalized interest, at December 31, 2013 and 2012 is summarized as follows:

	December 31,	
	2013	2012
	(In thousands)	
Ultra-deepwater drillships	$ 868,908	$741,059
Ultra-deepwater semisubmersible:		
Ocean GreatWhite	195,578	—
Deepwater semisubmersibles:		
Ocean Onyx	339,129	167,403
Ocean Apex	264,596	82,502
Total construction work-in-progress	$1,668,211	$990,964

During 2013, we entered into a shipyard contract for the construction of the *Ocean GreatWhite*, an ultra-deepwater, harsh environment semisubmersible. See Note 11.

9. Credit Agreement and Senior Notes

Credit Agreement

We have a syndicated 5-Year Revolving Credit Agreement, or Credit Agreement, with Wells Fargo Bank, National Association, as administrative agent and swingline lender. Effective December 9, 2013, we entered into an extension agreement and amendment to the Credit Agreement, which, among other things, provided for a one-year extension with all of the existing lenders. The Credit Agreement provides for a $750 million senior unsecured revolving credit facility for general corporate purposes, maturing on September 28, 2018. The entire amount of the facility is available for revolving loans. Up to $250 million of the facility is available for the issuance of performance or other standby letters of credit and up to $75 million is available 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. The ABR is the greatest 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 margin for ABR loans varies from 0% to 0.25%. The applicable interest margin for Eurodollar loans varies between 0.75% and 1.25%.

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 our Credit Agreement, we also pay, based on our current credit ratings, and as applicable, other customary fees including, but not limited to, a commitment fee on the unused commitments under the Credit Agreement, varying between 0.06% and 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, varying between 0.375% and 0.625% per annum for performance letters of credit, and between 0.75% and 1.25% per annum for all other letters of credit. Changes in credit ratings could lower or raise the fees that we pay under the Credit Agreement.

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.

Based on our current credit ratings at December 31, 2013, the applicable margin on ABR loans and Eurodollar loans would have been 0.00% and 0.875%, respectively. As of December 31, 2013, there were no amounts outstanding under the Credit Agreement.

Senior Notes

At December 31, 2013, our senior notes were comprised of the following debt issues:

Debt Issue	Principal Amount (In millions)	Maturity Date	Interest Rate		Semiannual Interest Payment Dates
			Coupon	Effective	
5.15% Senior Notes due 2014	$ 250.0	September 1, 2014	5.15%	5.18%	March 1 and September 1
4.875% Senior Notes due 2015	$ 250.0	July 1, 2015	4.875%	4.90%	January 1 and July 1
5.875% Senior Notes due 2019	$ 500.0	May 1, 2019	5.875%	5.89%	May 1 and November 1
3.45% Senior Notes due 2023	$ 250.0	November 1, 2023	3.45%	3.50%	May 1 and November 1
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

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At December 31, 2013 and 2012, the carrying value of our senior notes was as follows:

	December 31, 2013	December 31, 2012
	(In thousands)	
5.15% Senior Notes due 2014	$ 249,954	$ 249,882
4.875% Senior Notes due 2015	249,898	249,837
5.875% Senior Notes due 2019	499,551	499,480
3.45% Senior Notes due 2023	248,988	—
5.70% Senior Notes due 2039	496,919	496,867
4.875% Senior Notes due 2043	748,833	—
Total senior notes, net of unamortized discount	$2,494,143	$1,496,066
Less: Current portion of long-term debt	249,954	—
Total Long-term debt	$2,244,189	$1,496,066

As of December 31, 2013, the aggregate annual maturity of our senior notes was as follows:

	Aggregate Principal Amount (In thousands)
Years Ending December 31,	
2014	$ 250,000
2015	250,000
2016	—
2017	—
2018	—
Thereafter	2,000,000
Total maturities of senior notes	2,500,000
Less: unamortized discounts	(5,857)
Total maturities of senior notes, net of unamortized discount	$ 2,494,143

2013 Debt Issues. On November 5, 2013, we completed the issuance of $1.0 billion aggregate principal amount of senior notes consisting of $250.0 million aggregate principal amount of 3.45% senior unsecured notes due 2023, or 2023 Notes, and $750.0 million aggregate principal amount of 4.875% senior unsecured notes due 2043, or 2043 Notes, and, collectively, the New Notes, for general corporate purposes, including redemption, repurchase or retirement of our 5.15% senior notes due September 1, 2014, or 2014 Notes, and our 4.875% senior notes due July 1, 2015, or 2015 Notes. The transaction resulted in net proceeds to us of $987.8 million after deducting underwriting discounts, commissions and estimated expenses.

The 2023 Notes bear interest at 3.45% per year and mature on November 1, 2023. The 2043 Notes bear interest at 4.875% per year and mature on November 1, 2043. Interest on the New Notes is payable semiannually in arrears on May 1 and November 1 of each year, beginning May 1, 2014. The New Notes 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 the New 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.

Other Debt. Our 2014 Notes, 2015 Notes, 5.875% Senior Notes due 2019 and 5.70% Senior Notes due 2039 are all unsecured and unsubordinated obligations of Diamond Offshore Drilling, Inc. and rank equal in right of payment to 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.

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Our 2014 Notes, in the aggregate principal amount of $250.0 million, will mature on September 1, 2014. Accordingly, the aggregate $249.9 million accreted value of our 2014 Notes has been presented as “Current portion of long-term debt” in our Consolidated Balance Sheets at December 31, 2013.

10. Other Comprehensive Income (Loss)

The following table sets forth the components of “Other comprehensive income (loss)” and the related income tax effects thereon for the three years ended December 31, 2013 and the cumulative balances in AOCGL by component at December 31, 2013, 2012 and 2011.

	Unrealized Gain (Loss) on		
	Derivative Financial Instruments	Marketable Securities	Total AOCGL
	(In thousands)		
Balance at January 1, 2011	$ 2,733	$ 408	$ 3,141
Unrealized gain (loss) before reclassifications, after tax of $337 and $15	(625)	(46)	(671)
Reclassification adjustments for items included in Net Income, after tax of $3,623 and $205	(6,728)	(384)	(7,112)
Total other comprehensive income (loss)	(7,353)	(430)	(7,783)
Balance at December 31, 2011	(4,620)	(22)	(4,642)
Unrealized gain (loss) before reclassifications, after tax of $(2,282) and $(28)	4,237	124	4,361
Reclassification adjustments for items included in Net Income, after tax of $(1,472) and $(1)	2,733	44	2,777
Total other comprehensive income (loss)	6,970	168	7,138
Balance at December 31, 2012	2,350	146	2,496
Unrealized gain (loss) before reclassifications, after tax of $3,682 and $18	(6,833)	(6)	(6,839)
Reclassification adjustments for items included in Net Income, after tax of $(2,608) and $18	4,840	(147)	4,693
Total other comprehensive income (loss)	(1,993)	(153)	(2,146)
Balance at December 31, 2013	$ 357	$ (7)	$ 350

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, 2013	2012	2011	Consolidated Statements of Operations Line Items
		(In thousands)		
Derivative financial instruments:				
Unrealized (gain) loss on FOREX contracts	$(7,449)	$(4,205)	$10,351	Contract drilling, excluding depreciation
Unrealized loss (gain) on Treasury Lock Agreements	1	—	—	Interest expense
	2,608	1,472	(3,623)	Income tax expense
	$(4,840)	$(2,733)	$ 6,728	Net of tax
Marketable securities:				
Unrealized (gain) loss on marketable securities	$ 165	$ (45)	$ 589	Other, net
	(18)	1	(205)	Income tax expense
	$ 147	$ (44)	$ 384	Net of tax

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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.

Litigation. We are one of several unrelated defendants in lawsuits filed in 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 offshore 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 and we expect to receive complete defense and indemnity with respect to a majority of the lawsuits from Murphy Exploration & Production Company pursuant to the terms of our 1992 asset purchase agreement with them. We also believe that we are not liable for the damages asserted in the remaining lawsuits pursuant to the terms of our 1989 asset purchase agreement with Diamond M Corporation, and we filed a declaratory judgment action in Texas state court against NuStar Energy LP, or NuStar, the successor to Diamond M Corporation, seeking a judicial determination that we did not assume liability for these claims. We obtained summary judgment on our claims in the declaratory judgment action, but NuStar appealed the trial court's decision, and the appellate court has remanded the case to trial. We are unable to estimate our potential exposure, if any, to these lawsuits at this time but do not believe that ultimate liability, if any, resulting from this litigation will have a material effect on our consolidated financial condition, results of operations and cash flows.

Various other claims have been filed against us in the ordinary course of business. 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 condition, results of operations and cash flows.

We intend to defend these matters vigorously; however, we cannot predict with certainty the outcome or effect of any litigation matters specifically described above or any other pending litigation or claims. There can be no assurance as to the ultimate outcome of these lawsuits.

NPI Arrangement. We received payments measured by a percentage net profits interest (of primarily 27%) under an overriding royalty interest in certain developmental oil-and-gas producing properties, or NPI, which we believe is a real property interest. Our drilling program related to the NPI was completed in 2011, and the balance of the amounts due to us under the NPI was received in 2013. However, the customer who conveyed the NPI to us filed a voluntary petition for reorganization under Chapter 11 of the Bankruptcy Code in August of 2012. Certain parties (including the debtor) in the bankruptcy proceedings have questioned whether our NPI, and certain amounts we received under it since the filing of the bankruptcy, should be included in the debtor's estate under the bankruptcy proceeding. We filed a declaratory judgment action in the bankruptcy court seeking a declaration that our NPI, and payments that we received from it since the filing of the bankruptcy, are not part of the bankruptcy estate. Once discovery is concluded in the bankruptcy court, the federal district court will hold a trial to determine the nature of our NPI. We will vigorously defend our rights and pursue our interests in this matter.

Personal Injury Claims. Our deductibles for marine liability insurance coverage, including personal injury claims, which primarily result from Jones Act liability in the Gulf of Mexico, are currently $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 which 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, 2013, our estimated liability for personal injury claims was $35.5 million, of which $9.5 million and $26.0 million were recorded in "Accrued liabilities" and "Other liabilities," respectively, in our Consolidated Balance Sheets. At December 31, 2012, our estimated liability for personal injury claims was $36.1 million, of which $9.9 million and $26.2 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.

Ultra-Deepwater Floater Construction. In May 2013, we entered into an agreement with Hyundai Heavy Industries Co., Ltd., or Hyundai, for the construction of a 10,000 foot dynamically positioned, harsh environment semisubmersible drilling rig. The *Ocean GreatWhite* is under construction in South Korea at an estimated cost of $755 million, including commissioning, capital spares and project management costs. The contracted price to Hyundai, totaling $628.5 million, is payable in two installments, of which the first installment of $188.6 million was paid in 2013. The final installment of $439.9 million is due upon delivery of the rig, which is expected to occur in the first quarter of 2016.

Drillship Construction. We are financially obligated under four separate turnkey construction contracts with Hyundai for the construction of four ultra-deepwater drillships. We expect the aggregate cost of the construction of our drillships, including commissioning, capital spares and project management costs, to be approximately $2.6 billion. The contracted price of each drillship is payable to Hyundai in two installments, with final payment due on delivery of each drillship. We have paid the first installment for each of the four drillships, aggregating $647.6 million. The *Ocean Black Hawk*, the first of our four drillships to be completed, was delivered in late January 2014, and we paid the final installment due to Hyundai of $396.1 million upon delivery of the drillship. The *Ocean BlackHornet* is expected to be delivered in the second quarter of 2014 at which time the second installment of approximately $394 million will be payable to Hyundai. The *Ocean BlackRhino* and *Ocean BlackLion* are expected to be delivered in the third quarter of 2014 and first quarter of 2015, respectively, at which times approximately $395 million will be payable to Hyundai for each rig.

Ocean Onyx Construction. We were obligated under a vessel modification agreement with Keppel AmFELS, L.L.C., or Keppel, for the construction of the *Ocean Onyx,* a moored semisubmersible deepwater rig, which was delivered late in the fourth quarter of 2013. We estimate the aggregate cost for the construction of the *Ocean Onyx* to be approximately $366.0 million, including commissioning, capital spares and project management costs. The contracted price due to Keppel was payable in 11 installments based on the occurrence of certain events as detailed in the vessel modification agreement. As of December 31, 2013, we had paid the first ten installments, of which we paid $73.0 million and $65.7 million in 2013 and 2012, respectively. We paid the final installment payable to Keppel under the construction agreement of $7.3 million in January 2014.

Ocean Apex Construction. We are obligated under a vessel modification agreement with Jurong Shipyard Pte Ltd, or Jurong, for the construction of the *Ocean Apex*, a moored semisubmersible deepwater rig, which is expected to be delivered in the third quarter of 2014 at an aggregate cost of approximately $370.0 million, including commissioning, capital spares and project management costs. The contracted price due to Jurong is payable in 12 installments based on the occurrence of certain events as detailed in the vessel modification agreement. We have paid the first seven installments, of which we paid $54.1 million and $27.0 million in 2013 and 2012, respectively. The remaining $54.1 million in aggregate milestone payments is payable to Jurong during 2014 as construction milestones are met.

Ocean Patriot Enhancements. In February 2013, we entered into a vessel modification agreement with Keppel FELS Limited, or Keppel Singapore, for enhancements to the *Ocean Patriot* that will enable the rig to work in the North Sea. We estimate the cost of the enhancement project to be approximately $120.0 million, including shipyard costs, owner-furnished equipment and labor, commissioning and capital spares. Construction work commenced in Singapore in the fourth quarter of 2013 and is expected to be completed in the second quarter of 2014. The contracted price due Keppel Singapore is approximately $29.0 million, payable in seven installments based on the occurrence of certain events as detailed in the vessel modification agreement. We paid the first four installments due to Keppel Singapore aggregating $18.8 million in 2013. The remaining $10.2 million in aggregate milestone payments are payable to Keppel Singapore during 2014 as construction milestones are met.

At December 31, 2013 and 2012, we had no other 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, equipment and vehicles under operating leases, which expire at various times through the year 2018. Total rent expense amounted to $13.5 million, $10.8 million and $9.3 million for the years ended December 31, 2013, 2012 and 2011, respectively. Future minimum rental payments under leases are approximately $2.9 million and $1.6 million for the years 2014 and 2015, respectively, and $1.2 million in the aggregate for the years 2016 to 2018. There are no minimum future rental payments under operating leases after 2018.

Letters of Credit and Other. We were contingently liable as of December 31, 2013 in the amount of $78.2 million under certain performance, bid, supersedeas, tax appeal and custom bonds and letters of credit. Agreements relating to approximately $67.4 million of performance, security, supersedeas and customs bonds can require collateral at any time. As of December 31, 2013, 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. 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, $0.8 million and $1.1 million by Loews for these support functions during the years ended December 31, 2013, 2012 and 2011, 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. and Era Group Inc. The Executive Chairman of the Board of Directors of SEACOR Holdings Inc. and the Non-Executive Chairman of the Board of Directors of Era Group Inc. is also a member of our Board of Directors. We paid $0.1 million in each of the three years ended December 31, 2013 for the hire of such vessels and such services.

During the years ended December 31, 2013, 2012 and 2011, we made payments of $1.6 million, $1.0 million and $1.2 million, respectively, to Ernst & Young LLP for tax and other consulting services. The wife of our President and Chief Executive Officer is an audit partner at this firm.

13. Income Taxes

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 international rigs are owned and operated indirectly, by Diamond Offshore International Limited, or DOIL, a foreign subsidiary which we wholly own. It is our intention to indefinitely reinvest future earnings of DOIL and its foreign subsidiaries to finance foreign activities. Accordingly, we have not made a provision for U.S. income taxes on approximately $2.4 billion of undistributed foreign earnings and profits. Although we do not intend to repatriate the earnings of DOIL, and have not provided U.S. income taxes for such earnings, except to the extent that such earnings were immediately subject to U.S. income taxes, these earnings could become subject to U.S. income tax if remitted, or if deemed remitted as a dividend; however, it is not practical to estimate this potential liability.

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

	Year Ended December 31, 2013	2012	2011
	(In thousands)		
Federal — current	$ 40,045	$173,061	$109,684
State — current	69	267	264
Foreign — current	151,339	75,748	104,640
Total current	191,453	249,076	214,588
Federal — deferred	46,767	(51,852)	(1,023)
Foreign — deferred	(12,666)	380	3,164
Total deferred	34,101	(51,472)	2,141
Total	$225,554	$197,604	$216,729

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, 2013	2012	2011
	(In thousands)		
Income before income tax expense:			
U.S.	$ 537,635	$ 512,733	$ 486,393
Foreign	236,605	405,348	692,878
Worldwide	$ 774,240	$ 918,081	$1,179,271
Expected income tax expense at federal statutory rate	$ 270,984	$ 321,328	$ 412,745
Foreign earnings of foreign subsidiaries (not taxed at the statutory federal income tax rate) net of related foreign taxes	(102,359)	(166,251)	(189,051)
Foreign earnings of foreign subsidiaries for which U.S. federal income taxes have been provided	805	28,252	(14,681)
Foreign taxes of domestic and foreign subsidiaries for which U.S. federal income taxes have also been provided	45,428	35,722	65,521
Foreign tax credits	(46,524)	(45,824)	(67,232)
Interest capitalized by foreign subsidiaries	(18,391)	(11,764)	(3,924)
Reduction of deferred tax liability related to a goodwill deduction resulting from a prior period stock acquisition	—	—	(2,950)
Impact of American Taxpayer Relief Act of 2012	(27,509)	—	—
Uncertain tax positions	66,085	6,325	(7,733)
Amortization of deferred charges associated with intercompany rig sales to other tax jurisdictions	30,894	31,276	29,556
Net expense (benefit) in connection with resolutions of tax issues and adjustments relating to prior years	4,804	(2,152)	(6,085)
Other	1,337	692	563
Income tax expense	$ 225,554	$ 197,604	$ 216,729

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

	December 31, 2013	December 31, 2012
	(In thousands)	
Deferred tax assets:		
Net operating loss carryforwards, or NOLs	$ 12,038	$ 24,067
Worker's compensation and other current accruals	17,269	16,929
Disputed receivables reserved	3,516	956
Deferred compensation	14,020	9,051
Foreign contribution taxes	5,749	6,780
Mobilization	1,673	4,736
Nonqualified stock options and SARs	9,584	8,698
Deferred deductions	8,577	—
Interest -Uncertain Tax Positions	1,008	206
Other	1,714	1,434
Total deferred tax assets(1)	75,148	72,857
Valuation allowance for NOLs	(7,321)	(22,876)
Net deferred tax assets	67,827	49,981
Deferred tax liabilities:		
Depreciation	(578,742)	(526,606)
Unbilled revenue	(4,371)	(5,649)
Undistributed earnings of foreign subsidiaries	(24)	(24)
Other	(9)	(29)
Total deferred tax liabilities	(583,146)	(532,308)
Net deferred tax liability	$(515,319)	$(482,327)

(1) $10.2 million and $8.6 million reflected in "Prepaid expenses and other current assets" in our Consolidated Balance Sheets at December 31, 2013 and 2012, respectively. See Note 2.

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, 2013	2012	2011
		(In thousands)	
Valuation allowance as of January 1	$ 22,876	$26,353	$32,102
Establishment of valuation allowances:			
Foreign tax credits	—	—	(186)
Net operating losses	25	946	1,844
Releases of valuation allowances in various jurisdictions	(15,580)	(4,423)	(7,407)
Valuation allowance as of December 31	$ 7,321	$22,876	$26,353

Net Operating Loss Carryforwards — As of December 31, 2013, we had recorded a deferred tax asset of $12.0 million for the benefit of NOL carryforwards related to our international operations. Approximately $11.2 million of this deferred tax asset relates to NOL carryforwards that have an indefinite life. The remaining $0.8 million relates to NOL carryforwards of our Mexican entities. Unless utilized, the tax benefits of these Mexican NOL carryforwards will expire between 2021 and 2023 as follows:

Year Expiring	Tax Benefit of NOL Carryforwards (In millions)
2021	$ 0.2
2022	0.2
2023	0.4
Total	$ 0.8

As of December 31, 2013, a valuation allowance of $7.3 million has been recorded for our NOLs as only $4.7 million of the deferred tax asset is more likely than not to be realized.

Unrecognized Tax Benefits. Our income tax returns are subject to review and examination in the various jurisdictions in which we operate and we are currently contesting various tax assessments. We accrue for income tax contingencies, or uncertain tax positions, that we believe are 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, and is as follows:

	For the Year Ended December 31,		
	2013	2012	2011
		(In thousands)	
Balance, beginning of period	$ (67,150)	$ (62,936)	$ (75,311)
Additions for current year tax positions	(1,724)	(3,837)	(913)
Additions for prior year tax positions	(31,264)	(5,136)	—
Reductions for prior year tax positions	7,280	4,759	4,770
Reductions related to statute of limitation expirations	1,937	—	8,518
Balance, end of period	$ (90,921)	$ (67,150)	$ (62,936)

At December 31, 2013, $6.3 million and $82.6 million of the net liability for uncertain tax positions were reflected in “Other assets” and “Other liabilities,” respectively. At December 31, 2012, $7.0 million and $55.4 million of the net liability for uncertain tax positions were reflected in “Other assets” and “Other liabilities,” respectively. Of the net unrecognized tax benefits at December 31, 2013, 2012 and 2011, all $76.3 million, $48.4 million and $41.2 million, respectively, would affect the effective tax rates if recognized.

The following table presents the amount of accrued interest and penalties at December 31, 2013 and 2012 related to uncertain tax positions:

	December 31,	
	2013	2012
	(In thousands)	
Uncertain tax positions net, excluding interest and penalties	$ (76,303)	$ (48,353)
Accrued interest on uncertain tax positions	(12,786)	(7,029)
Accrued penalties on uncertain tax positions	(59,797)	(21,662)
Uncertain tax positions net, including interest and penalties	$ (148,886)	$ (77,044)

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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 and penalties recognized during the three years ended December 31, 2013 related to uncertain tax positions are as follows:

	For the Year Ended December 31,		
	2013	2012	2011
		(In thousands)	
Net increase (decrease) in interest expense related to unrecognized tax positions	$ 5,758	$(1,902)	$ 245
Net increase (decrease) in penalties related to unrecognized tax positions	38,136	(787)	(3,039)

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.

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 years 2003 to 2012. We are currently under audit in several of these jurisdictions. 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 and cash flows.

U.S. Tax Jurisdiction. In May 2013, we were notified by the Department of the Treasury that the Internal Revenue Service audit of our 2010 corporate tax return was completed without adjustment.

Brazil Tax Jurisdiction. In March 2013, the Brazilian tax authorities began an audit of our income tax returns for the years 2009 and 2010. In addition, we are continuing to defend tax assessments by the Brazilian tax authorities for the years 2000, 2004, 2005 and 2007.

In February 2012, the tax authorities concluded their audit of our income tax return for the 2007 tax year for which we received an assessment of R$35.1 million (approximately equal to USD $15 million at December 31, 2013) for income tax, including interest and penalties. We contested the assessment and a court in Brazil ruled to cancel the assessment. However, the Brazilian tax authorities have appealed the ruling, and we are awaiting the outcome of the appeal. We have not accrued any tax expense related to this assessment.

In December 2009, we received an assessment of approximately $26.0 million for the years 2004 and 2005, including interest and penalty. We contested the tax assessment in January 2010 and are awaiting the outcome of the appeal. As required by GAAP, only the portion of the tax benefit that has a greater than 50% likelihood of being realized upon settlement is to be recognized. Consequently, we have accrued approximately $9.9 million of expense attributable to the portion of the tax assessment we determined to be an uncertain tax position, of which approximately $3.4 million is interest related and approximately $2.8 million is penalty related.

In addition, the tax auditors have issued an assessment for tax year 2000 of approximately $1.5 million, including interest and penalty. We have appealed the tax assessment and are awaiting the outcome of the appeal.

During 2011, unrecognized tax benefits were reduced by approximately $6.8 million due to the lapse in the applicable statute of limitations for the 2006 tax year, of which $1.1 million was interest and $2.0 million was penalty.

Mexico Tax Jurisdiction. The tax authorities in Mexico previously audited our income tax returns for the years 2004 and 2006 and had issued assessments for tax years 2004 and 2006 of approximately $22.9 million and $24.4 million, respectively, including interest and penalties, which we had appealed. In 2013 the Mexican tax authorities initiated a tax amnesty program whereby income tax assessments, including penalties and interest, could be partially or completely waived. Under the tax amnesty, we were able to settle our tax liabilities for the years 2004 and 2006 for a net cash cost of $3.7 million. As a result of increases in uncertain tax positions for later years, we recorded an additional $13.2 million of expense, including $5.0 million of interest and $2.7 million of penalties.

DIAMOND OFFSHORE DRILLING, INC.
AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Due to the expiration of the statute of limitations in Mexico for the 2007 tax year at the end of June 2013, during the second quarter of 2013, we reversed our $4.3 million accrual for this uncertain tax position, of which $1.5 million was interest and $0.6 million was penalty.

In addition, in August 2012, the Mexican tax authorities dismissed a claim against one of our Mexican subsidiaries and the 2004 tax year for that subsidiary is now closed. Consequently, during the third quarter of 2012, we reversed our $4.4 million accrual for this uncertain tax position, which included $0.2 million of penalty and $2.6 million of interest.

On June 13, 2013 we received official notification that the Mexican tax authorities will be auditing the 2008 income tax return of one of our Mexican subsidiaries.

Egypt Tax Jurisdiction*.* During 2013 we were under audit by the Egyptian tax authorities for the tax years 2006 through 2010. In December 2013, we received notification that the Egyptian government had concluded the income tax audit for the period 2006 to 2008 and a $1.2 billion increase to taxable income was proposed. We disagree with the tax audit findings and intend to vigorously pursue all legal remedies available to defend ourselves against any ensuing tax assessment. Due to the inherent uncertainties associated with the Egyptian income tax law, we have accrued approximately $56.9 million of expense for uncertain tax positions in Egypt, of which approximately $31.4 million is penalty related. We recently completed operating in Egypt and no longer have drilling operations there.

American Taxpayer Relief Act of 2012. The American Taxpayer Relief Act of 2012, or the Act, was signed into law on January 2, 2013. The Act extends through 2013 several expired or expiring temporary business provisions, commonly referred to as “extenders,” which are retroactively extended to the beginning of 2012. As required by GAAP, the effects of new legislation are recognized when signed into law. Consequently, we reduced our 2013 tax expense by $27.5 million as a result of recognizing the 2012 effect of the extenders.

14. Employee Benefit Plans

Defined Contribution Plans

We maintain defined contribution retirement plans for our U.S., United Kingdom, or 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 Internal Revenue Code of 1986, as amended, or 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 each year ended December 31, 2013, 2012 and 2011, we made a 4% profit-share contribution of participants’ defined compensation and matched up to 6% of each employee’s compensation contributed to the 401k Plan. Participants are fully vested in the employer match immediately upon enrollment in the 401k Plan and subject to a three-year cliff vesting period for the profit sharing contribution. For the years ended December 31, 2013, 2012 and 2011, our provision for contributions was $29.6 million, $25.9 million and $21.5 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. For the years ended December 31, 2013, 2012 and 2011, our contribution for employees working in the U.K. sector of the North Sea was up to a maximum of 10%, 10% and 5.25%, respectively, of the employee’s defined compensation. For the years ended December 31, 2013, 2012 and 2011, our contribution for U.K. nationals working in the Norwegian sector of the North Sea was up to a maximum of 15%, 15% and 9.0%, respectively, of the employee’s defined compensation. Our provision for contributions was $3.5 million, $2.7 million and $1.2 million for the years ended December 31, 2013, 2012 and 2011, respectively.

The defined contribution retirement plan for our TCN employees, or International Savings Plan, is similar to the 401k Plan. During each year ended December 31, 2013, 2012 and 2011, we contributed 4% of participants’ defined compensation and matched up to 6% of each employee’s compensation contributed to the International Savings Plan. Our provision for contributions was $3.1 million, $2.8 million and $2.9 million for the years ended December 31, 2013, 2012 and 2011, respectively.

DIAMOND OFFSHORE DRILLING, INC.
AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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 the years ended December 31, 2013, 2012 and 2011 was approximately $261,000, $256,000 and $245,000, respectively.

15. 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,		
	2013	2012	2011
		(In thousands)	
Floaters:			
Ultra-Deepwater	$ 854,515	$ 902,793	$ 841,565
Deepwater	617,080	597,694	733,037
Mid-Water	1,197,934	1,275,068	1,482,032
Total Floaters	2,669,529	2,775,555	3,056,634
Jack-ups	174,055	160,511	197,534
Other	—	—	145
Total contract drilling revenues	2,843,584	2,936,066	3,254,313
Revenues related to reimbursable expenses	76,837	50,442	68,106
Total revenues	$2,920,421	$2,986,508	$3,322,419

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, 2013, our actively-marketed drilling rigs were en route to or located offshore 12 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,		
	2013	2012	2011
		(In thousands)	
United States	$ 330,471	$ 173,961	$ 323,381
International:			
South America	1,219,287	1,427,927	1,736,798
Europe/Africa/Mediterranean	731,888	662,995	749,128
Australia/Asia	438,814	524,957	451,364
Mexico	199,961	196,668	61,748
	2,589,950	2,812,547	2,999,038
Total revenues	$2,920,421	$2,986,508	$3,322,419

DIAMOND OFFSHORE DRILLING, INC.
AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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, 2013, 2012 and 2011, individual countries that comprised 5% or more of our total contract drilling revenues from unaffiliated customers are listed below.

	Year Ended December 31,		
	2013	2012	2011
Brazil	38.3%	46.1%	49.4%
United Kingdom	7.9%	6.9%	4.6%
Australia	3.2%	6.7%	6.7%
Mexico	6.9%	6.6%	1.9%
Angola	3.8%	2.7%	9.6%
Indonesia	4.4%	2.4%	5.0%

The following table presents our long-lived tangible assets by geographic location as of December 31, 2013, 2012 and 2011. 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,		
	2013	2012	2011
	(In thousands)		
Drilling and other property and equipment, net:			
United States**(1)**	$ 611,731	$ 444,984	$ 283,049
International:			
Australia/Asia/Middle East**(2)**	2,078,348	1,474,999	1,212,461
South America	1,690,976	1,827,247	1,979,303
Europe/Africa/Mediterranean	793,097	799,194	852,300
Mexico	293,075	318,548	340,356
	4,855,496	4,419,988	4,384,420
Total	$5,467,227	$4,864,972	$4,667,469

(1) Long-lived tangible assets in the United States region as of December 31, 2013, 2012 and 2011 include $339.1 million, $167.4 million and $14.6 million, respectively, in construction work-in-progress for the Ocean Onyx under construction in Brownsville, Texas.

(2) Long-lived tangible assets in the Australia/Asia/Middle East region include $1,064.5 million, $741.1 million and $490.2 million in construction work-in-progress for our four drillships and the Ocean GreatWhite under construction in South Korea as of December 31, 2013, 2012 and 2011, respectively, and $264.6 million and $82.5 million for the Ocean Apex under construction in Singapore as of December 31, 2013 and 2012, respectively.

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The following table presents the countries in which material concentrations of our long-lived tangible assets were located as of December 31, 2013, 2012 and 2011:

	December 31,		
	2013	2012	2011
Brazil	30.2%	37.3%	41.9%
South Korea	19.5%	15.2%	10.5%
United States	11.2%	9.1%	6.1%
Singapore	8.2%	1.8%	—
Angola	6.3%	—	8.0%
Mexico	5.4%	6.5%	7.3%
Indonesia	5.2%	6.8%	3.4%
Egypt	4.0%	4.7%	5.5%
Vietnam	0.6%	1.4%	6.6%
Republic of Congo	—	7.4%	—

As of December 31, 2013, 2012 and 2011, 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, 2013, 2012 and 2011 that contributed more than 10% of our total revenues are as follows:

	Year Ended December 31,		
Customer	2013	2012	2011
Petróleo Brasileiro S.A.	33.6%	33.3%	35.0%
OGX Petróleo e Gás Ltda.	2.4%	12.5%	14.1%

16. Unaudited Quarterly Financial Data

Unaudited summarized financial data by quarter for the years ended December 31, 2013 and 2012 is shown below.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share data)			
2013				
Revenues	$729,741	$758,018	$706,165	$726,497
Operating income	213,726	262,859	137,352	187,669
Income before income tax expense	206,179	256,301	131,565	180,195
Net income	175,989	185,334	94,748	92,615
Net income per share, basic and diluted	$ 1.27	$ 1.33	$ 0.68	$ 0.67
2012				
Revenues	$768,642	$738,188	$729,141	$750,537
Operating income**(a)**	265,410	257,184	244,822	194,962
Income before income tax expense	251,435	246,758	234,847	185,041
Net income	185,169	201,461	178,186	155,661
Net income per share, basic and diluted	$ 1.33	$ 1.45	$ 1.28	$ 1.12

(a) Results for the fourth quarter of 2012 include a $62.4 million impairment charge related to rigs transferred to “Assets held for sale” in our Consolidated Balance Sheets at December 31, 2012. See Note 1.

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 which are designed to ensure that 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, 2013. Based on their participation in that evaluation, our CEO and CFO concluded that our disclosure controls and procedures were effective as of December 31, 2013.

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 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.

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2013. 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 (1992)*. Based on this assessment our management believes that, as of December 31, 2013, 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.

Changes in Internal Control Over Financial Reporting

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 2013 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

Reference is made to the information responsive to Items 10, 11, 12, 13 and 14 of this Part III contained in our definitive proxy statement for our 2014 Annual Meeting of Stockholders, which is incorporated herein by reference.

Item 10. Directors, Executive Officers and Corporate Governance.

Item 11. Executive Compensation.

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

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

Item 14. Principal Accountant Fees and Services.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

(a) Index to Financial Statements, Financial Statement Schedules and Exhibits

(1) Financial Statements

See the Exhibit Index for a list of those exhibits filed herewith, which Exhibit Index also includes and identifies management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by Item 601 of Regulation S-K.

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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 24, 2014.

DIAMOND OFFSHORE DRILLING, INC.

By: /s/ GARY T. KRENEK
Gary T. Krenek
Senior Vice President and Chief Financial Officer

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/ LAWRENCE R. DICKERSON* Lawrence R. Dickerson	President, Chief Executive Officer and Director (Principal Executive Officer)	February 24, 2014
/s/ GARY T. KRENEK* Gary T. Krenek	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 24, 2014
/s/ BETH G. GORDON* Beth G. Gordon	Controller (Principal Accounting Officer)	February 24, 2014
/s/ JAMES S. TISCH* James S. Tisch	Chairman of the Board	February 24, 2014
/s/ JOHN R. BOLTON* John R. Bolton	Director	February 24, 2014
/s/ CHARLES L. FABRIKANT* Charles L. Fabrikant	Director	February 24, 2014
/s/ PAUL G. GAFFNEY II* Paul G. Gaffney II	Director	February 24, 2014
/s/ EDWARD GREBOW* Edward Grebow	Director	February 24, 2014
/s/ HERBERT C. HOFMANN* Herbert C. Hofmann	Director	February 24, 2014
/s/ CLIFFORD M. SOBEL* Clifford M. Sobel	Director	February 24, 2014
/s/ ANDREW H. TISCH* Andrew H. Tisch	Director	February 24, 2014
/s/ RAYMOND S. TROUBH* Raymond S. Troubh	Director	February 24, 2014

*By: /s/ WILLIAM C. LONG
William C. Long
Attorney-in-fact

EXHIBIT INDEX

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 (formerly 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	Fourth Supplemental Indenture, dated as of August 27, 2004, between Diamond Offshore Drilling, Inc. and The Bank of New York Mellon (formerly known as The Bank of New York) (as successor to JPMorgan Chase Bank), as Trustee (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K filed September 1, 2004) (SEC File No. 1-13926).
4.3	Fifth Supplemental Indenture, dated as of June 14, 2005, between Diamond Offshore Drilling, Inc. and The Bank of New York Mellon (formerly known as The Bank of New York) (as successor to JPMorgan Chase Bank, National Association), as Trustee (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K filed June 16, 2005) (SEC File No. 1-13926).
4.4	Sixth Supplemental Indenture, dated as of May 4, 2009, between Diamond Offshore Drilling, Inc. and The Bank of New York Mellon, as Trustee (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K filed May 4, 2009).
4.5	Seventh Supplemental Indenture, dated as of October 8, 2009, between Diamond Offshore Drilling, Inc. and 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).
4.6	Eighth Supplemental Indenture, dated as of November 5, 2013, between Diamond Offshore Drilling, Inc. and 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).
10.1	Registration Rights Agreement (the “Registration Rights Agreement”) dated October 16, 1995 between Loews 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 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 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+	Second Amended and Restated Diamond Offshore Drilling, Inc. 2000 Stock Option Plan, as amended (incorporated by reference to Exhibit 10.6 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2007) (SEC File No. 1-13926).
10.7+	Form of Stock Option Certificate for grants to executive officers, other employees and consultants pursuant to the Second Amended and Restated Diamond Offshore Drilling, Inc. 2000 Stock Option 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 Second Amended and Restated Diamond Offshore Drilling, Inc. 2000 Stock Option 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).

Exhibit No.	Description
10.9+	The Diamond Offshore Drilling, Inc. Incentive Compensation Plan for Executive Officers (Amended and Restated as of March 20, 2012) (incorporated by reference to Exhibit A attached to our definitive proxy statement on Schedule 14A filed March 29, 2012).
10.10+	Form of Award Certificate for stock appreciation right grants to the Company's executive officers, other employees and consultants pursuant to the Second Amended and Restated Diamond Offshore Drilling, Inc. 2000 Stock Option 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 Second Amended and Restated Diamond Offshore Drilling, Inc. 2000 Stock Option 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+	Employment Agreement between Diamond Offshore Management Company and Lawrence R. Dickerson dated as of December 15, 2006 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed December 21, 2006) (SEC File No. 1-13926).
10.13+	Employment Agreement between Diamond Offshore Management Company and Gary T. Krenek dated as of December 15, 2006 (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed December 21, 2006) (SEC File No. 1-13926).
10.14+	Employment Agreement between Diamond Offshore Management Company and John M. Vecchio dated as of December 15, 2006 (incorporated by reference to Exhibit 10.15 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2006) (SEC File No. 1-13926).
10.15+	Employment Agreement between Diamond Offshore Management Company and William C. Long dated as of December 15, 2006 (incorporated by reference to Exhibit 10.16 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2006) (SEC File No. 1-13926).
10.16+	Employment Agreement between Diamond Offshore Management Company and Lyndol L. Dew dated as of December 15, 2006 (incorporated by reference to Exhibit 10.17 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2006) (SEC File No. 1-13926).
10.17+	Employment Agreement between Diamond Offshore Management Company and Beth G. Gordon dated as of January 3, 2007 (incorporated by reference to Exhibit 10.19 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2006) (SEC File No. 1-13926).
10.18+	Amendment to Employment Agreement, dated June 16, 2008, between Diamond Offshore Management Company and Lawrence R. Dickerson (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008) (SEC File No. 1-13926).
10.19	5-Year Revolving Credit Agreement, dated as of September 28, 2012, among Diamond Offshore Drilling, Inc., Wells Fargo Bank, National Association, as administrative agent and swingline lender, the issuing banks named therein and the lenders named therein (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed October 1, 2012).
10.20*	Extension Agreement and Amendment No. 1 to Credit Agreement, dated as of December 9, 2013, among Diamond Offshore Drilling, Inc., Wells Fargo Bank, National Association, as an issuing bank, as swingline lender and as administrative agent for the lenders, and the lenders named therein.
10.21+	Retirement Agreement and General Release between Diamond Offshore Management Company and Lawrence R. Dickerson dated September 23, 2013 (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2013).
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*	Powers of Attorney.
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.

Exhibit No.	Description
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.

EXTENSION AGREEMENT AND AMENDMENT NO. 1 TO CREDIT AGREEMENT

This EXTENSION AGREEMENT AND AMENDMENT NO. 1 TO CREDIT AGREEMENT (this "Amendment"), dated effective as of December 9, 2013 (the "Effective Time"), is by and among Diamond Offshore Drilling, Inc., a Delaware corporation (the "Borrower"), the Lenders party hereto, and Wells Fargo Bank, National Association, as an issuing bank, as swing line lender, and as administrative agent for the Lenders (in such capacity, the "Administrative Agent").

WHEREAS, the Borrower, the lenders from time to time party thereto (the "Lenders"), and the Administrative Agent are parties to the Credit Agreement dated as of September 28, 2012 (as it may be amended, supplemented or modified from to time to time, the "Credit Agreement", the capitalized terms of which are used herein as therein defined unless otherwise defined herein);

WHEREAS, the Borrower has requested, and the Administrative Agent and the Required Lenders have agreed, to make certain amendments to the Credit Agreement, each as provided for herein. Furthermore, certain of the Lenders have severally agreed to extend their respective Commitments on the terms and conditions set forth herein.

NOW, THEREFORE, in consideration of the premises and the mutual covenants, representations and warranties contained herein, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto hereby agree as follows:

Section 1. Amendments.

(a) Section 1.01 of the Credit Agreement is hereby amended by adding the following new defined terms in their appropriate alphabetical order:

"Declining Lender" has the meaning set forth in Section 2.22(b).

"Extending Lender" has the meaning set forth in Section 2.22(b).

"Extension Effective Date" has the meaning set forth in Section 2.22(c).

"First Amendment" means that certain Extension Agreement and Amendment No. 1 to Credit Agreement dated as of December 9, 2013 among the Borrower, the Lenders party thereto, and the Administrative Agent.

"First Amendment Effective Date" means December 9, 2013.

"Replacement Lender" has the meaning set forth in Section 2.19(b).

(b) Section 1.01 of the Credit Agreement is hereby amended by restating the following definitions in their entirety as follows:

"Commitment" means, with respect to each Lender, the commitment of such Lender to make Revolving Loans and to acquire participations in Letters of Credit and Swingline Loans hereunder, expressed as an amount representing the maximum aggregate amount of such Lender's Credit Exposure hereunder, as such commitment may be (a) increased from time to time pursuant to Section 2.02, (b) reduced or terminated from time to time pursuant to Section 2.08 or Section 2.19, (c) increased and/or extended from time to time pursuant to Section 2.22 and (d) reduced or increased from time to time pursuant to assignments by or to such Lender pursuant to Section 9.04. The amount of each Lender's Commitment as of the First Amendment Effective Date is set forth on Schedule 2.01.

"Lenders" means the Persons listed on Schedule 2.01 and any other Person that shall have become a party hereto pursuant to Section 2.02, Section 2.22 or pursuant to an Assignment and Assumption, other than any such Person that ceases to be a party hereto pursuant to an Assignment and Assumption. Unless the context otherwise requires, the term "Lenders" includes the Swingline Lender.

"Maturity Date" means the fifth anniversary of the Effective Date, as such date may be extended by the relevant Lenders pursuant to Section 2.22.

(c) Section 2.02(b) of the Credit Agreement is hereby amended by adding the following new sentence at the end of such Section 2.02(b):

If the Maturity Date has been extended for any Lender(s) pursuant to Section 2.22, the Notice of Commitment Increase shall also specify the Maturity Date applicable to the additional Commitment of each CI Lender and Increasing Lender, as the case may be, which Maturity Date shall be (x) in the case of a CI Lender, a date on which Commitments of at least one existing Lender currently expire and (y) in the case of an Increasing Lender, the Maturity Date applicable to such Increasing Lender's Commitments in effect prior to such Commitment Increase.

(d) Section 2.19(b) of the Credit Agreement is hereby amended by adding the following clause (vi) in numerical order and changing the existing clause (vi) to be clause (vii):

(vi) any Lender is a Declining Lender (including, for the avoidance of doubt, any Lender that does not extend the Maturity Date of any of its Commitments pursuant to the First Amendment, effective as of the First Amendment Effective Date),

(e) Section 2.19(b) of the Credit Agreement is hereby amended by inserting "*(such assignee being referred to as a "Replacement Lender")*" immediately following "*(which assignee may be another Lender, if a Lender accepts such assignment)*".

(f) Section 2.19(b) of the Credit Agreement is hereby amended by deleting the word "and" following the semicolon in clause (E), changing the period at the end of clause (F) to a semicolon followed by the word "and", and adding the following as a new clause (G):

(G) in the case of any assignment of a Declining Lender's Commitments, the relevant Replacement Lender, after giving effect to such assignment, elects to extend its Commitment pursuant to Section 2.22 to a date which shall be the latest Maturity Date for any Commitments then in effect under this Agreement (after giving effect to the latest Extension Effective Date).

(g) *Section 2.19(b)* of the Credit Agreement is hereby amended by adding the following new sentence at the end of such Section 2.19(b):

If the Maturity Date has been extended for any Lender(s) pursuant to Section 2.22, the assignment pursuant to this Section 2.19(b) shall specify the Maturity Date applicable to the Commitment of such Replacement Lender pursuant to this Section 2.19(b), which Maturity Date shall be the same as that for the Commitment of the Lender being replaced, unless such Lender is being replaced pursuant to Section 2.19(b)(vi), in which case such Maturity Date shall be the latest Maturity Date for any Commitments then in effect under this Agreement (after giving effect to the latest Extension Effective Date).

(h) The Credit Agreement is hereby amended by adding the following as a new Section 2.22:

Section2.22 Extension of Maturity Date.

(a) Request for Extension. No earlier than 90 days prior and no later than 30 days prior to each anniversary of the Effective Date, upon notice to the Administrative Agent (which shall promptly, but in any event within three (3) Business Days after receipt of such notice, notify each Lender thereof), the Borrower may request an extension of the Maturity Date for an additional one-year period; provided that no more than two (2) of such one-year extensions shall be permitted hereunder (including the extension effectuated pursuant to the First Amendment). At the time of sending such notice, the Borrower (in consultation with the Administrative Agent) shall specify the time period within which each Lender is requested to respond (which shall in no event be less than ten (10) Business Days from the date of delivery of such notice to the Lenders).

(b) Lender Elections to Extend; Payments to Declining Lenders. Each Lender that agrees in its sole discretion to extend its Commitment (an "Extending Lender") shall notify the Administrative Agent within such specified time period of its agreement to extend its Commitment, which notice shall be irrevocable. The Commitment of any Lender that declines or fails to respond to the Borrower's request for an extension of the Maturity Date within such specified time period (a "Declining Lender") shall be terminated on the Maturity Date then in effect for such Lender (without regard to any extension by other Lenders) and on such date the aggregate Commitments of all Lenders shall be reduced by the total Commitments of all Declining Lenders expiring on such Maturity Date (without giving effect to the applicable extension request) except to the extent one or more lenders (including other Lenders) shall have agreed to assume such Commitments hereunder in accordance with Section 2.19(b). The Administrative Agent shall notify the Borrower and each Lender of the Lenders' responses to each request made hereunder no later than three (3) Business Days after the expiration of the time period within which each Lender is requested to respond as set forth above. Subject to Section 2.22(c) below, the Borrower shall pay in full the unpaid principal amount of all Loans owing to each Declining Lender, together with all accrued and unpaid interest thereon and all fees accrued and unpaid under this Agreement that are due to such Declining Lender and all other amounts due to such Declining Lender under this Agreement, including any breakage fees or costs that are payable to such Declining Lender pursuant to Section 2.16, on such Maturity Date (without giving effect to the applicable extension request) or, in the case of the earlier replacement of such Declining Lender pursuant to Section 2.19(b), the requirements of Section 2.19(b) shall be satisfied with respect to such Declining Lender.

(c) Effective Date and Allocations. If the Maturity Date is extended in accordance with this Section 2.22, the Administrative Agent and the Borrower shall determine the effective date of such extension, which in no instance shall be earlier than the anniversary of the Effective Date immediately following the Borrower's most recent extension request pursuant to clause (a) above

or later than the Maturity Date applicable prior to giving effect to such extension (the "Extension Effective Date"), and upon such effectiveness (i) the Administrative Agent shall record in the register any Replacement Lender's information as provided pursuant to an Administrative Questionnaire that shall be executed and delivered by such Replacement Lender to the Administrative Agent on or before such Extension Effective Date, (ii) the Administrative Agent shall amend and restate Schedule 2.01 hereof (without any further action required of the Lenders) to set forth all Lenders (including any Replacement Lenders) that will be Lenders hereunder after giving effect to such extension and the Administrative Agent shall distribute to each Lender (including each Replacement Lender) a copy of such amended and restated Schedule 2.01, (iii) each Replacement Lender that complies with the provisions of this Section 2.22 shall be a "Lender" for all purposes under this Agreement, (iv) all calculations and payments of interest on the Loans shall take into account the actual Commitments of each Lender and the principal amount outstanding of each Loan made by such Lender during the relevant period of time, and (v) each Lender's share of the LC Exposure on such date shall automatically be deemed to equal such Lender's Applicable Percentage of the LC Exposure (such Applicable Percentage for such Lender to be determined as of such Extension Effective Date in accordance with its Commitment on such date as a percentage of the Aggregate Commitment on such date) without further action by any party.

(d) Representations and Warranties; No Default. Each extension shall be deemed to constitute a representation and warranty by the Borrower on the applicable Extension Effective Date that, at the time of and immediately after giving effect to such extension, (i) the representations and warranties of the Borrower set forth in this Agreement are true and correct in all material respects (except that such materiality qualifier shall not be applicable to the extent that any representations and warranties already are qualified or modified by materiality in the text thereof) on and as of such Extension Effective Date, except to the extent any such representations and warranties are expressly limited to an earlier date, in which case, on and as of such Extension Effective Date, such representations and warranties shall continue to be true and correct in all material respects (except that such materiality qualifier shall not be applicable to the extent that any representations and warranties already are qualified or modified by materiality in the text thereof) as of such specified earlier date, and (ii) no Event of Default shall have occurred and be continuing.

(e) Extension; Conditions to Effectiveness. If, but only if, Extending Lenders and Replacement Lenders have agreed to provide Commitments in an aggregate amount greater than 50% of the aggregate amount of the Commitments outstanding immediately prior to the Extension Effective Date, the Maturity Date of such Extending Lenders and Replacement Lenders shall be extended by one year; provided that the Commitment of each Extending Lender and each Replacement Lender shall be on the same terms and conditions as the Commitment of each other Extending Lender and Replacement Lender. In addition, as a condition precedent to such extension, the Administrative Agent shall have received (i) a certificate of a Responsible Officer of the Borrower dated as of the applicable Extension Effective Date (A) certifying and attaching the resolutions adopted by the Borrower approving such extension, and (B) certifying that the conditions of this Section 2.22 with respect to such extension have been satisfied, and (ii) such other documents reasonably requested by the Administrative Agent in connection therewith.

(i) Section 9.02(a)(iv) of the Credit Agreement is hereby amended by replacing the reference to "*Section 2.18(b)*" with "*Section 2.18(c)*".

(j) Schedule 2.01 to the Credit Agreement is hereby replaced in its entirety with Schedule 2.01 attached hereto.

Section 2. Consent to Extension of Maturity Date. Upon the effectiveness of this Amendment pursuant to Section 3 below, the Maturity Date of the Commitments of the Lenders who have severally agreed to extend their respective Commitments (each, an "Initial Extending Lender" and collectively, the "Initial Extending Lenders") is hereby extended to the sixth (6th) anniversary of the Effective Date as set forth on Schedule 2.01 to the Credit Agreement, as amended by this Amendment. The Maturity Date with respect to the Commitments of each other Lender, if any, shall remain unchanged (*i.e.*, shall remain the fifth (5th) anniversary of the Effective Date), as set forth on Schedule 2.01 to the Credit Agreement, as amended by this Amendment. The extension of the Maturity Date at the Effective Time as set forth in this Section 2 shall be deemed to constitute the first exercise of the Borrower's right to request an extension pursuant to Section 2.22 of the Credit Agreement, as amended by this Amendment. The requirements of Section 2.22 of the Credit Agreement, as amended by this Amendment, with respect to notices and timing are hereby waived by all parties hereto with respect to the extension described in this Section 2.

Section 3. Conditions Precedent. This Amendment shall become effective as of the Effective Time upon the satisfaction of the following conditions precedent:

(a) Documentation. The Administrative Agent shall have received the following, each dated on or before the Effective Time, duly executed by all the parties thereto, each in form and substance reasonably satisfactory to the Administrative Agent:

(1) counterparts of this Amendment duly executed by the Borrower, the Required Lenders and the Administrative Agent;

(2) a certificate from a Responsible Officer of the Borrower dated as of the Effective Time hereof stating that, both before and after giving effect to this Amendment and the extension of the Commitments pursuant to this Amendment (i) all representations and warranties of the Borrower set forth in the Credit Agreement are true and correct in all material respects (except that such materiality qualifier shall not be applicable to the extent that any representations and warranties already are qualified or modified by materiality in the text thereof) on and as of the Effective Time, except to the extent any such representations and warranties are expressly limited to an earlier date, in which case, on and as of the Effective Time, such representations and warranties shall continue to be true and correct in all material respects (except that such materiality qualifier shall not be applicable to the extent that any representations and warranties already are qualified or modified by materiality in the text thereof) as of such specified earlier date, and (ii) no Event of Default shall have occurred and be continuing;

(3) a secretary's certificate of the Borrower dated the Effective Time and certifying (i) that that there have been no changes to the organizational documents of the Borrower since the Effective Date or attaching such amendments, (ii) that attached thereto is a true and complete copy of resolutions duly adopted by the Board of Directors of the Borrower authorizing the execution and delivery of this Amendment and the Loan Documents executed in connection herewith, if any, the performance of the Credit Agreement as amended hereby and the other Loan Documents and the extension of the Commitments pursuant hereto, and that such resolutions have not been modified, rescinded or amended and are in full force and effect, and (iii) as to the incumbency and specimen signature of each officer of the Borrower executing this Amendment, any Loan Document delivered in connection herewith, if any, or any other document delivered in connection herewith on behalf of the Borrower;

(4) such documents and certificates as the Administrative Agent or its counsel may reasonably request relating to the organization, existence and good standing of the Borrower;

(5) a legal opinion of Duane Morris LLP, counsel for the Borrower, in form and substance reasonably acceptable to the Administrative Agent; and

(6) such other documents and governmental certificates as the Lender Parties may reasonably request.

(b) Extended Commitments. The aggregate Commitments being extended on the Effective Time pursuant to this Amendment must be (giving effect to the agreements of the Initial Extending Lenders hereunder) at least $375,000,000.

(c) Payment of Fees and Expenses. On the Effective Time, the Borrower shall have paid the fees required to be paid to the Administrative Agent on the Effective Time, including, without limitation, an extension fee for the account of each Initial Extending Lender equal to 4.0 basis points on the amount of such Initial Extending Lender's Commitment being extended pursuant hereto and all other costs and expenses which are payable pursuant to Section 9.03 of the Credit Agreement.

Section 4. Representations and Warranties. The Borrower represents and warrants to the Administrative Agent that the representations and warranties set forth in Article III of the Credit Agreement are true and correct on the Effective Time as if made on and as of the Effective Time, except to the extent any such representations and warranties are expressly limited to an earlier date, in which case they are true and correct as of such earlier date, and as if each reference in said Article III to "this Agreement" or "the Loan Documents" included reference to this Amendment.

Section 5. Miscellaneous. THIS AMENDMENT SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAW OF THE STATE OF NEW YORK. Except as herein provided, the Credit Agreement shall remain unchanged and in full force and effect. Upon the effectiveness of this Amendment, each reference in the Credit Agreement to "this Agreement," "hereunder" or words of like import shall mean and be a reference to the Credit Agreement, as affected and amended by this Amendment. This Amendment may be executed in any number of counterparts, all of which taken together shall constitute one and the same amendatory instrument and any of the parties hereto may execute this Amendment by signing any such counterpart. Transmission by facsimile or electronic transmission (*e.g.*, PDF) of an executed counterpart of this Amendment shall be deemed to constitute due and sufficient delivery of such counterpart.

[Signature Pages Follow]

IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be duly executed and delivered by their respective duly authorized officers as of the Effective Time.

BORROWER :

DIAMOND OFFSHORE DRILLING, INC.

By: /s/ Scott Kornblau
Scott Kornblau
Treasurer

LENDER PARTIES:

WELLS FARGO BANK, NATIONAL ASSOCIATION,
as Administrative Agent, Swingline Lender, an Issuing Bank, a Lender and an Initial Extending Lender

By: /s/ T. Alan Smith
Name: T. Alan Smith
Title: Managing Director

JPMORGAN CHASE BANK, N.A.,
as an Issuing Bank, a Lender and an Initial Extending Lender

By: /s/ Robert Traband
Name: Robert Traband
Title: Managing Director

HSBC BANK USA, NATIONAL ASSOCIATION,
as an Issuing Bank, a Lender and an Initial Extending Lender

By: /s/ Steven Smith
Name: Steven Smith
Title: Director #20290

BANK OF CHINA, NEW YORK BRANCH,
as an Issuing Bank, a Lender and an Initial Extending Lender

By: /s/ Haifeng Xu
Name: Haifeng Xu
Title: Executive Vice President

CITIBANK, N.A.,
as a Lender and an Initial Extending Lender

By: /s/ Jim Reilly
Name: Jim Reilly
Title: Managing Director

SUNTRUST BANK,
as a Lender and an Initial Extending Lender

By: /s/ Shannon Juhan
Name: Shannon Juhan
Title: Vice President

PNC BANK, NATIONAL ASSOCIATION,
as a Lender and an Initial Extending Lender

By: /s/ John Berry
Name: John Berry
Title: Vice President

GOLDMAN SACHS BANK USA,
as a Lender and an Initial Extending Lender

By: /s/ Mark Walton
Name: Mark Walton
Title: Authorized Signatory

THE BANK OF NEW YORK MELLON,
as a Lender and an Initial Extending Lender

By: /s/ Hussam S. Alsahlani
Name: Hussam S. Alsahlani
Title: Vice President

ROYAL BANK OF CANADA,
as a Lender and an Initial Extending Lender

By: /s/ Jay T. Sartain
Name: Jay T. Sartain
Title: Authorized Signatory

SCHEDULE 2.01

LENDER	NON-EXTENDED COMMITMENT	EXTENDED COMMITMENT	AGGREGATE COMMITMENT
Wells Fargo Bank, National Association	$ 0	$95,000,000.00	$95,000,000.00
JPMorgan Chase Bank, N.A.	$ 0	$95,000,000.00	$95,000,000.00
HSBC Bank USA, National Association	$ 0	$95,000,000.00	$95,000,000.00
Bank of China, New York Branch	$ 0	$95,000,000.00	$95,000,000.00
Citibank, N.A.	$ 0	$95,000,000.00	$95,000,000.00
SunTrust Bank	$ 0	$95,000,000.00	$95,000,000.00
PNC Bank, National Association	$ 0	$60,000,000.00	$60,000,000.00
Goldman Sachs Bank USA	$ 0	$40,000,000.00	$40,000,000.00
The Bank of New York Mellon	$ 0	$40,000,000.00	$40,000,000.00
Royal Bank of Canada	$ 0	$40,000,000.00	$40,000,000.00
Total	**$ 0**	**$ 750,000,000**	**$ 750,000,000**

Exhibit 12.1

DIAMOND OFFSHORE DRILLING, INC.
Statement re Computation of Ratios
(In Thousands of Dollars)

Ratio of Earnings to Fixed Charges:

	Year Ended December 31,				
	2013	2012	2011	2010	2009
Computation of Earnings:					
Pretax income (loss) from continuing operations	$774,240	$918,081	$1,179,271	$1,336,016	$1,868,431
Less Interest capitalized during the period and actual preferred dividend requirements of majority-owned subsidiaries and 50%-owned persons included in fixed charges but not deducted from pretax income from above	(74,237)	(37,674)	(11,212)	—	—
Add: Previously capitalized interest amortized during the period	3,400	3,400	3,400	3,400	3,400
Total earnings (losses), before fixed charge addition	703,403	883,807	1,171,459	1,339,416	1,871,831
Computation of Fixed Charges:					
Interest, including interest capitalized	103,547	87,449	87,425	93,334	51,585
Total fixed charges	103,547	87,449	87,425	93,334	51,585
Total Earnings (Losses) and Fixed Charges	**$806,950**	**$971,256**	**$1,258,884**	**$1,432,750**	**$1,923,416**
Ratio of Earnings (Losses) to Fixed Charges(1)	**7.79**	**11.11**	**14.40**	**15.35**	**37.29**

(1) For purposes of this ratio, 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.

Exhibit 21.1

SUBSIDIARIES

Subsidiary	*Jurisdiction of Organization*
Diamond Offshore Finance Company	Delaware
Diamond Offshore Company	Delaware
Diamond Offshore Services Company	Delaware
Diamond Offshore International Limited	Cayman Islands
Diamond Offshore International, L.L.C.	Delaware
Diamond Offshore (Bermuda) Limited	Bermuda
Diamond Offshore Drilling (Bermuda) Limited	Bermuda
Diamond Offshore (Brazil) L.L.C.	Delaware
Diamond Offshore Drilling (Overseas) L.L.C.	Delaware
Diamond Offshore Drilling Company N.V.	Netherlands Antilles
Diamond Offshore Netherlands B.V.	The Netherlands
Diamond Offshore Drilling Limited	Cayman Islands
Diamond Hungary Leasing L.L.C.	Hungary
Diamond Offshore Enterprises Limited	England
Diamond Offshore Holding, L.L.C.	Delaware
Z North Sea	Delaware

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-22745 on Form S-8, Registration Statement No. 333-23547 on Form S-4, Registration Statement No. 333-42930 on Form S-8, Registration Statement No. 333-117512 on Form S-8 and Registration Statement No. 333-180004 on Form S-3 of our reports dated February 24, 2014, relating to the consolidated financial statements of Diamond Offshore Drilling, Inc. ("the Company") and the effectiveness of the Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of the Company for the year ended December 31, 2013.

/s/ Deloitte & Touche LLP
Houston, Texas
February 24, 2014

EXHIBIT 24.1

POWER OF ATTORNEY

James S. Tisch hereby designates and appoints William C. Long and Gary T. Krenek and each of them (with full power to each of them to act alone) as his attorney-in-fact, with full power of substitution and re-substitution (the "Attorneys-in-Fact"), for him and in his name, place and stead, in any and all capacities, to execute the Annual Report on Form 10-K (the "Annual Report") to be filed by Diamond Offshore Drilling, Inc. with the Securities and Exchange Commission and any amendment(s) to the Annual Report, which amendment(s) may make such changes in the Annual Report as either Attorney-in-Fact deems appropriate, and to file the Annual Report and each such amendment to the Annual Report together with all exhibits thereto and any and all documents in connection therewith.

Signature	Title	Date
/s/ James S. Tisch James S. Tisch	Chairman of the Board	February 14, 2014

POWER OF ATTORNEY

Lawrence R. Dickerson hereby designates and appoints William C. Long and Gary T. Krenek and each of them (with full power to each of them to act alone) as his attorney-in-fact, with full power of substitution and re-substitution (the “Attorneys-in-Fact”), for him and in his name, place and stead, in any and all capacities, to execute the Annual Report on Form 10-K (the “Annual Report”) to be filed by Diamond Offshore Drilling, Inc. with the Securities and Exchange Commission and any amendment(s) to the Annual Report, which amendment(s) may make such changes in the Annual Report as either Attorney-in-Fact deems appropriate, and to file the Annual Report and each such amendment to the Annual Report together with all exhibits thereto and any and all documents in connection therewith.

Signature	Title	Date
/s/ Lawrence R. Dickerson Lawrence R. Dickerson	Director, President and Chief Executive Officer	February 14, 2014

POWER OF ATTORNEY

Gary T. Krenek hereby designates and appoints William C. Long as his attorney-in-fact, with full power of substitution and re-substitution (the “Attorney-in-Fact”), for him and in his name, place and stead, in any and all capacities, to execute the Annual Report on Form 10-K (the “Annual Report”) to be filed by Diamond Offshore Drilling, Inc. with the Securities and Exchange Commission and any amendment(s) to the Annual Report, which amendment(s) may make such changes in the Annual Report as the Attorney-in-Fact deems appropriate, and to file the Annual Report and each such amendment to the Annual Report together with all exhibits thereto and any and all documents in connection therewith.

Signature	Title	Date
/s/ Gary T. Krenek Gary T. Krenek	Senior Vice President and Chief Financial Officer	February 14, 2014

POWER OF ATTORNEY

Beth G. Gordon hereby designates and appoints William C. Long and Gary T. Krenek and each of them (with full power to each of them to act alone) as her attorney-in-fact, with full power of substitution and re-substitution (the "Attorneys-in-Fact"), for her and in her name, place and stead, in any and all capacities, to execute the Annual Report on Form 10-K (the "Annual Report") to be filed by Diamond Offshore Drilling, Inc. with the Securities and Exchange Commission and any amendment(s) to the Annual Report, which amendment(s) may make such changes in the Annual Report as either Attorney-in-Fact deems appropriate, and to file the Annual Report and each such amendment to the Annual Report together with all exhibits thereto and any and all documents in connection therewith.

Signature	Title	Date
/s/ Beth G. Gordon Beth G. Gordon	Controller	February 14, 2014

POWER OF ATTORNEY

John R. Bolton hereby designates and appoints William C. Long and Gary T. Krenek and each of them (with full power to each of them to act alone) as his attorney-in-fact, with full power of substitution and re-substitution (the “Attorneys-in-Fact”), for him and in his name, place and stead, in any and all capacities, to execute the Annual Report on Form 10-K (the “Annual Report”) to be filed by Diamond Offshore Drilling, Inc. with the Securities and Exchange Commission and any amendment(s) to the Annual Report, which amendment(s) may make such changes in the Annual Report as either Attorney-in-Fact deems appropriate, and to file the Annual Report and each such amendment to the Annual Report together with all exhibits thereto and any and all documents in connection therewith.

Signature	Title	Date
/s/ John R. Bolton John R. Bolton	Director	February 14, 2014

POWER OF ATTORNEY

Charles L. Fabrikant hereby designates and appoints William C. Long and Gary T. Krenek and each of them (with full power to each of them to act alone) as his attorney-in-fact, with full power of substitution and re-substitution (the “Attorneys-in-Fact”), for him and in his name, place and stead, in any and all capacities, to execute the Annual Report on Form 10-K (the “Annual Report”) to be filed by Diamond Offshore Drilling, Inc. with the Securities and Exchange Commission and any amendment(s) to the Annual Report, which amendment(s) may make such changes in the Annual Report as either Attorney-in-Fact deems appropriate, and to file the Annual Report and each such amendment to the Annual Report together with all exhibits thereto and any and all documents in connection therewith.

Signature	Title	Date
/s/ Charles L. Fabrikant Charles L. Fabrikant	Director	February 14, 2014

POWER OF ATTORNEY

Paul G. Gaffney II hereby designates and appoints William C. Long and Gary T. Krenek and each of them (with full power to each of them to act alone) as his attorney-in-fact, with full power of substitution and re-substitution (the "Attorneys-in-Fact"), for him and in his name, place and stead, in any and all capacities, to execute the Annual Report on Form 10-K (the "Annual Report") to be filed by Diamond Offshore Drilling, Inc. with the Securities and Exchange Commission and any amendment(s) to the Annual Report, which amendment(s) may make such changes in the Annual Report as either Attorney-in-Fact deems appropriate, and to file the Annual Report and each such amendment to the Annual Report together with all exhibits thereto and any and all documents in connection therewith.

Signature	Title	Date
/s/ Paul G. Gaffney II Paul G. Gaffney II	Director	February 14, 2014

POWER OF ATTORNEY

Edward Grebow hereby designates and appoints William C. Long and Gary T. Krenek and each of them (with full power to each of them to act alone) as his attorney-in-fact, with full power of substitution and re-substitution (the “Attorneys-in-Fact”), for him and in his name, place and stead, in any and all capacities, to execute the Annual Report on Form 10-K (the “Annual Report”) to be filed by Diamond Offshore Drilling, Inc. with the Securities and Exchange Commission and any amendment(s) to the Annual Report, which amendment(s) may make such changes in the Annual Report as either Attorney-in-Fact deems appropriate, and to file the Annual Report and each such amendment to the Annual Report together with all exhibits thereto and any and all documents in connection therewith.

Signature	Title	Date
/s/ Edward Grebow Edward Grebow	Director	February 14, 2014

POWER OF ATTORNEY

Herbert C. Hofmann hereby designates and appoints William C. Long and Gary T. Krenek and each of them (with full power to each of them to act alone) as his attorney-in-fact, with full power of substitution and re-substitution (the "Attorneys-in-Fact"), for him and in his name, place and stead, in any and all capacities, to execute the Annual Report on Form 10-K (the "Annual Report") to be filed by Diamond Offshore Drilling, Inc. with the Securities and Exchange Commission and any amendment(s) to the Annual Report, which amendment(s) may make such changes in the Annual Report as either Attorney-in-Fact deems appropriate, and to file the Annual Report and each such amendment to the Annual Report together with all exhibits thereto and any and all documents in connection therewith.

Signature	Title	Date
/s/ Herbert C. Hofmann Herbert C. Hofmann	Director	February 14, 2014

POWER OF ATTORNEY

Clifford M. Sobel hereby designates and appoints William C. Long and Gary T. Krenek and each of them (with full power to each of them to act alone) as his attorney-in-fact, with full power of substitution and re-substitution (the "Attorneys-in-Fact"), for him and in his name, place and stead, in any and all capacities, to execute the Annual Report on Form 10-K (the "Annual Report") to be filed by Diamond Offshore Drilling, Inc. with the Securities and Exchange Commission and any amendment(s) to the Annual Report, which amendment(s) may make such changes in the Annual Report as either Attorney-in-Fact deems appropriate, and to file the Annual Report and each such amendment to the Annual Report together with all exhibits thereto and any and all documents in connection therewith.

Signature	Title	Date
/s/ Clifford M. Sobel Clifford M. Sobel	Director	February 14, 2014

POWER OF ATTORNEY

Andrew H. Tisch hereby designates and appoints William C. Long and Gary T. Krenek and each of them (with full power to each of them to act alone) as his attorney-in-fact, with full power of substitution and re-substitution (the “Attorneys-in-Fact”), for him and in his name, place and stead, in any and all capacities, to execute the Annual Report on Form 10-K (the “Annual Report”) to be filed by Diamond Offshore Drilling, Inc. with the Securities and Exchange Commission and any amendment(s) to the Annual Report, which amendment(s) may make such changes in the Annual Report as either Attorney-in-Fact deems appropriate, and to file the Annual Report and each such amendment to the Annual Report together with all exhibits thereto and any and all documents in connection therewith.

Signature	Title	Date
/s/ Andrew H. Tisch Andrew H. Tisch	Director	February 14, 2014

POWER OF ATTORNEY

Raymond S. Troubh hereby designates and appoints William C. Long and Gary T. Krenek and each of them (with full power to each of them to act alone) as his attorney-in-fact, with full power of substitution and re-substitution (the “Attorneys-in-Fact”), for him and in his name, place and stead, in any and all capacities, to execute the Annual Report on Form 10-K (the “Annual Report”) to be filed by Diamond Offshore Drilling, Inc. with the Securities and Exchange Commission and any amendment(s) to the Annual Report, which amendment(s) may make such changes in the Annual Report as either Attorney-in-Fact deems appropriate, and to file the Annual Report and each such amendment to the Annual Report together with all exhibits thereto and any and all documents in connection therewith.

Signature	Title	Date
/s/ Raymond S. Troubh Raymond S. Troubh	Director	February 14, 2014

Exhibit 31.1

I, Lawrence R. Dickerson, certify that:

1. I have reviewed this Annual Report on Form 10-K for the fiscal year ended December 31, 2013 of Diamond Offshore Drilling, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2014

/s/ Lawrence R. Dickerson
Lawrence R. Dickerson
Chief Executive Officer

Exhibit 31.2

I, Gary T. Krenek, certify that:

1. I have reviewed this Annual Report on Form 10-K for the fiscal year ended December 31, 2013 of Diamond Offshore Drilling, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2014

/s/ Gary T. Krenek
Gary T. Krenek
Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED BY SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

Each of the undersigned hereby certifies, pursuant to 18 U.S.C. § 1350, in his capacity as an officer of Diamond Offshore Drilling, Inc. (the “Company”), that, to his knowledge:

(1) the Company’s Annual Report on Form 10-K for the fiscal year ended December 31, 2013, as filed with the U.S. Securities and Exchange Commission on the date hereof (the “Report”), fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 24, 2014

/s/ Lawrence R. Dickerson
Lawrence R. Dickerson,
Chief Executive Officer of the Company

/s/ Gary T. Krenek
Gary T. Krenek,
Chief Financial Officer of the Company