ATWOOD OCEANICS INC
Form 10-K
November 15, 2016

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D. C. 20549
Form 10-K
ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended September 30, 2016
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 1-13167
ATWOOD OCEANICS, INC.
(Exact name of registrant as specified in its charter)

Texas	74-1611874
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
15011 Katy Freeway, Suite 800 Houston, Texas	77094
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (281) 749-7800
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock $1.00 par value	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 ý
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 ý
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 filings requirements for the past 90 days. Yes ý No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the 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 ý.
Indicate by check mark whether the registrant is a large accelerated filer, 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.

Large accelerated filer ý	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 Act). Yes ¨ No ý

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which our Common Stock, $1.00 par value, was last sold, or the average bid and asked price of such Common Stock, as of March 31, 2016 was $0.6 billion.

The number of shares outstanding of our Common Stock, $1.00 par value, as of November 9, 2016: 64,805,914.

DOCUMENTS INCORPORATED BY REFERENCE

Proxy Statement for 2017 Annual Meeting of Shareholders - Referenced in Part III of this report.

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FORWARD-LOOKING STATEMENTS

Statements included in this Form 10-K regarding future financial performance, capital sources and results of operations and other statements, other than statements of historical fact, that address activities, events or developments that we expect, believe or anticipate will or may occur in the future are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, and Section 21E of the Securities Exchange Act of 1934. Such statements are those concerning strategic plans, expectations and objectives for future operations and performance. When used in this report, the words "believes," "expects," "anticipates," "plans," "intends," "estimates," "projects," "could," "s "may," or similar expressions are intended to be among the statements that identify forward-looking statements.

Such statements are subject to numerous risks, uncertainties and assumptions that are beyond our ability to control, including, but not limited to:

- prices of oil and natural gas and industry expectations about future prices;
- market conditions and level of activity in the drilling industry and the global economy in general;
- the level of capital expenditures by our clients;
- the termination, renegotiation, or repudiation of contracts or payment delays by our clients;
- the operational risks involved in drilling for oil and gas;
- the highly competitive and volatile nature of our business;
- our ability to enter into, and the terms of, future drilling contracts, including contracts for our newbuild units, for rigs currently idled and for rigs whose contracts are expiring;
- our ability to service our indebtedness and make payments on our rigs under construction;
- our ability to access debt and equity capital markets, and the terms and prices that are available if we issue debt or equity securities;
- the impact of governmental or industry regulation, both in the United States and internationally;
- the risks of and disruptions to international operations, including political instability and the impact of terrorist acts, acts of piracy, embargoes, war or other military operations;
- our ability to obtain and retain qualified personnel to operate our vessels;
- unplanned downtime and repairs on our rigs;
- timely access to spare parts, equipment and personnel to maintain and service our fleet;
- client requirements for drilling capacity and client drilling plans;
- the adequacy of sources of liquidity for us and for our clients;
- changes in tax laws, treaties and regulations;
- the risks involved in the construction, upgrade, and repair of our drilling units; and
- such other risks discussed in Item 1A. "Risk Factors" of this Form 10-K and in our other reports filed with the Securities and Exchange Commission, or SEC.

Forward-looking statements are made based upon management's current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements. Undue reliance should not be placed on these forward-looking statements, which are applicable only on the date hereof. We undertake no obligation to revise or update these forward-looking statements to reflect events or circumstances that arise after the date hereof or to reflect the occurrence of unanticipated events.

PART I

ITEM 1. BUSINESS

Atwood Oceanics, Inc. (which together with its subsidiaries is identified as the “Company,” “we,” “us” or “our,” except where stated or the context requires otherwise) is a global offshore drilling contractor engaged in the drilling and completion of exploratory and developmental oil and gas wells. We currently own a diversified fleet of 10 mobile offshore drilling units located in the U.S. Gulf of Mexico, the Mediterranean Sea, offshore West Africa, offshore Southeast Asia and offshore Australia. We also are constructing 2 ultra-deepwater drillships currently scheduled for delivery in fiscal years 2017 and 2018. We were founded in 1968 and are headquartered in Houston, Texas with support offices in Australia, Malaysia, Thailand, Singapore, Luxembourg, Mauritius, the Cayman Islands, the United Arab Emirates and the United Kingdom.

We report our offshore contract drilling operation as a single reportable segment: Offshore Contract Drilling Services. The mobile offshore drilling units and related equipment comprising our offshore rig fleet operate in a single, global market for contract drilling services and are often redeployed globally due to changing demands of our clients, which consist largely of major integrated oil and natural gas companies and independent oil and natural gas companies. The offshore drilling markets where we currently operate, including the U.S. Gulf of Mexico, the Mediterranean Sea, offshore West Africa, offshore Southeast Asia and offshore Australia, are rich in hydrocarbon deposits and thus offer the potential for drilling activity over the long-term.

OFFSHORE DRILLING EQUIPMENT

Each type of drilling rig is uniquely designed for different purposes and applications, for operations in different water depths, bottom conditions, environments and geographical areas, and for different drilling and operating requirements. We classify rigs with the ability to operate in 5,000 feet of water or greater as deepwater rigs and rigs with the ability to operate in 7,500 feet of water or greater as ultra-deepwater rigs. The following descriptions of the various types of drilling rigs we own or are constructing illustrate the diversified range of applications of our rig fleet.

Ultra-Deepwater Drillships

Drillships are self-propelled vessels, shaped like conventional ships and are the most mobile of the major rig types. Our high-specification drillships, including the two currently under construction at the Daewoo Shipbuilding & Marine Engineering Co. Ltd. ("DSME") yard in South Korea, are dynamically-positioned, which allows them to maintain position without anchors through the use of their onboard propulsion and station-keeping systems. Drillships typically have greater load capacity than semisubmersible rigs, which enables them to carry more supplies on board, often making them better suited for drilling in remote locations where resupply is more difficult. Drillships are designed to operate in greater water depths than bottom support drilling rigs. Drillships are a subset of floating rigs or floaters.

Semisubmersible Rigs

Semisubmersible rigs can be either dynamically-positioned, which renders them self-propelled similar to drillships, or moored. They typically have two hulls, the lower of which is capable of being flooded. Drilling equipment is mounted on the main hull. After the drilling unit is towed to location, the ballast tanks in the lower hull are flooded, lowering the entire drilling unit to its operating draft, and the drilling unit is then either anchored in place (conventionally moored drilling unit) or maintains position through the use of onboard propulsion and station-keeping systems (dynamically-positioned drilling unit). On completion of operations, the lower hull is deballasted, raising the entire drilling unit to its towing draft. Similar to drillships, this type of drilling unit is designed to operate in greater water depths than bottom supported drilling rigs. Semisubmersibles also operate in more severe sea conditions than other types of drilling units. Semisubmersible rigs are also a subset of floating rigs or floaters.

Jackup Drilling Rigs

Jackup drilling rigs consist of a single hull supported by at least three legs positioned on the sea floor. It is typically towed to the well site and once on location, its legs are lowered to the sea floor and the unit is raised out of the water by jacking the hull up the legs. Jackup drilling units typically operate in water depths no greater than 500 feet.

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The following table presents our rig fleet as of November 9, 2016, all of which are wholly owned:

Rig Name	Rig Type	Construction Completed/Last Upgraded (Calendar Year)	Water Depth Rating (feet)
Atwood Achiever	Drillship	construction completed 2014	12,000
Atwood Advantage	Drillship	construction completed 2013	12,000
Atwood Condor	Semisubmersible	construction completed 2012	10,000
Atwood Osprey	Semisubmersible	construction completed 2011	8,200
Atwood Eagle (1)	Semisubmersible	upgraded 2002	5,000
Atwood Mako (1)	Jackup	construction completed 2012	400
Atwood Manta (1)	Jackup	construction completed 2012	400
Atwood Orca (1)	Jackup	construction completed 2013	400
Atwood Beacon (1)	Jackup	construction completed 2003	400
Atwood Aurora (1)	Jackup	construction completed 2009	350

(1) Currently idled and actively marketed.

In addition to the above drilling units, we are in the process of constructing two additional drillships. The following table presents our current newbuild projects as of November 9, 2016:

Rig Name	Rig Type	Scheduled Delivery Date	Estimated Cost (in millions)	Water Depth Rating (feet)
Atwood Admiral	Drillship	September 30, 2017	$635	12,000
Atwood Archer	Drillship	June 30, 2018	635	12,000

The Atwood Admiral and Atwood Archer are DP-3 dynamically-positioned, dual derrick, ultra-deepwater drillships rated to operate in water depths up to 12,000 feet and are currently under construction at the DSME shipyard in South Korea. These drillships will have enhanced technical capabilities, including two seven-ram BOPs, three 100-ton knuckle boom cranes, a 165-ton active heave “tree-running” knuckle boom crane and 200 person accommodations. As of September 30, 2016, we had approximately $399.8 million of firm commitments related to the construction of these two drillships.

Maintaining high equipment utilization and revenue efficiency through the industry cycles is a significant factor in generating cash flow to satisfy current and future obligations and has been one of our primary initiatives. We had a 100% available utilization rate in fiscal year 2016 for our in-service rigs, while our available utilization rate for in-service rigs averaged approximately 99% during the past five fiscal years. See "Item 6: Selected Financial Data" for further discussion on in-service rigs and the calculation of available utilization rates.

The following table presents information regarding the contract status of our drilling units as of November 9, 2016:

Rig Name	Percentage of Fiscal 2016 Contract Drilling Revenues*	Location at November 9, 2016	Client	Contract Status at November 9, 2016
ULTRA-DEEPWATER DRILLSHIPS AND SEMISUBMERSIBLES:				
Atwood Advantage	18%	Israel	Noble Energy Inc. ("Noble")	The rig is currently working under a drilling program with Noble which extends to August 2017.
Atwood Achiever	18%	Mauritania	Kosmos Energy Ltd. ("Kosmos")	The rig is currently working under a drilling program with Kosmos which extends to November 2018.
Atwood Admiral	-	South Korea	-	The rig is under construction in South Korea with scheduled delivery in September 2017.
Atwood Archer	-	South Korea	-	The rig is under construction in South Korea with scheduled delivery in June 2018.
Atwood Condor	21%	U.S. Gulf of Mexico	Shell Offshore Inc. ("Shell")/Noble	The rig is currently working under a drilling program with Shell which extends to mid-November 2016, followed by a drilling program with Noble to January 2017.
Atwood Osprey	16%	Australia	Woodside Energy Ltd. ("Woodside")	The rig is currently working under a drilling program with Woodside which may extend to January 2017, followed by a drilling program with ConocoPhillips which extends to March 2017.
DEEPWATER SEMISUBMERSIBLES:				
Atwood Eagle	7%	Singapore	-	Idled in March 2016 and being actively marketed.
JACKUPS:				
Atwood Mako	-	Philippines	-	Idled in October 2015 and being actively marketed.
Atwood Manta	-	Philippines	-	Idled in October 2015 and being actively marketed.
Atwood Orca	3%	Singapore	-	Idled in October 2016 and being actively marketed.
Atwood Aurora	7%	Ghana	-	Idled in September 2016 and being actively marketed.
Atwood Beacon	4%	Malta	-	Idled in October 2016 and being actively marketed.

* Atwood Falcon, which was sold in April 2016, accounted for 6% of fiscal year 2016 Contract Drilling Revenue.

INDUSTRY TRENDS

Our industry is subject to intense price competition and volatility in day rates and utilization. Due to the cyclical nature of the oil and gas industry, periods of higher rig demand and higher day rates are often followed by periods of lower rig demand and lower day rates. Offshore drilling contractors can build new drilling rigs, mobilize rigs from one region of the world to another, “idle” or scrap rigs (taking them out-of-service) or reactivate idled rigs in order to adjust the supply of existing rigs in various markets to meet demand. The market for drilling services is typically driven by global hydrocarbon demand and changes in actual or anticipated oil and gas prices. Generally, sustained high energy prices result in higher cash flow generation by exploration and production ("E&P") companies which can fund increased spending by these companies on offshore drilling services. Conversely,

low energy prices reduce cash flow generation by E&P companies which reduces funds available to spend on offshore drilling services. As a result of the lower than previously expected oil and gas prices in the current market, the industry is experiencing a trend of declining rig utilization and lower day rates across all offshore rig classes.
Offshore drilling market fundamentals have significantly deteriorated since the second half of calendar year 2014. Activity, measured by the number of working offshore rigs, has declined considerably for both floating and jackup rigs. At the same time, the supply of both floating and jackup rigs has increased as newbuilds have been delivered from shipyards in Singapore, South Korea and China. The resulting rig supply and demand imbalance has severely reduced rig utilization and day rates. International oil prices have declined significantly from mid-year 2014 levels due to a number of factors, including growth in U.S. unconventional oil production, increased OPEC and Russia oil supplies, modest global oil demand growth and a strengthening U.S. dollar. A prolonged lower oil price environment will restrain a rebound in exploration and development drilling investment providing significant uncertainty as to if or when offshore drilling rig demand and/or pricing fundamentals will return to pre-downturn levels. See "Management's Discussion and Analysis of Financial Condition and Results of Operations-Market Outlook" of this Form 10-K.
E&P companies generally prefer newer, higher specification drilling rigs to perform contract drilling services either as a response to increased technical challenges or for the safety, reliability and efficiency typical of the newer, more capable rigs. This trend is commonly referred to as the bifurcation of the drilling fleet. Bifurcation is occurring in the floater drilling rig class and is evidenced by higher specification drilling rigs operating at generally higher overall utilization levels than the lower specification or standard drilling rigs. However, due to the significant oversupply of offshore drilling rigs relative to demand, the bifurcation effect for both floater and jackup rig markets has been muted since the industry entered the current downturn. All classes of offshore rigs are experiencing reduced utilization and lower day rates, leading to a significant number of rigs being either warm-stacked, cold-stacked or scrapped.

DRILLING CONTRACTS

Our drilling contracts are obtained either through direct negotiation with clients or by submitting proposals in competition with other contractors. Our contracts vary in their terms and rates depending on the nature of the operations to be performed, the duration of the work, the amount and type of equipment and services provided, the geographic areas involved, market conditions and other variables.
The initial terms of our drilling contracts range from the length of time necessary to drill one well to several years. Drilling contracts may contain renewal provisions, which in time of weak market conditions are usually at the option of the client, and in strong market conditions may be upon mutual agreement.
Generally, contracts for drilling services specify a basic rate of compensation computed on a day rate basis. Contracts generally provide for a reduced day rate payable when operations are interrupted by equipment failure and subsequent repairs, field moves, adverse weather conditions or other factors beyond our control. Some contracts also provide for revision of the specified day rates in the event of material changes in the cost of certain items. Any period during which a rig is not earning a full operating day rate because of the above conditions or because the rig is idle and not on contract will have an adverse effect on operating profits.
For mobilization or demobilization of rig moves outside of in-field relocations, we may obtain from our clients either a lump sum or a day rate as mobilization compensation for services performed and expenses incurred during the period in transit. In a weaker market environment, such as we are currently experiencing, we may not fully recover our relocation costs or receive any mobilization compensation from our clients. We can give no assurance that we will receive full or partial recovery of any future rig relocation costs, including mobilization costs out of the shipyard for our two drillships currently in the DSME shipyard.
Operation of our drilling equipment is subject to the offshore drilling requirements of petroleum exploration companies and agencies of local or foreign governments. These requirements are, in turn, subject to changes in government policies, global demand and prices for petroleum and petroleum products, proved reserves and production in relation to such demand and the extent by which such demand can be met from onshore sources. An over-supply of drilling rigs in any market area can adversely affect our ability to employ our drilling rigs in these market areas.
The current trend of some E&P companies seeking to terminate, renegotiate or repudiate existing drilling contracts that began in 2014 has continued throughout 2016 as rig demand and market day rates decline further. Some of our contracts are cancellable at the option of the client upon payment of a termination fee which may not fully compensate

us for the loss of the contract and may result in a rig being idle for an extended period of time. In addition, some of our clients could experience liquidity or solvency issues or could otherwise be unable or unwilling to perform under a contract, which could ultimately lead a client to enter bankruptcy or otherwise encourage a client to seek to terminate, renegotiate, or repudiate a contract or delay payment. Further deterioration in cash flow generation by E&P companies may accelerate these trends. If our clients seek to terminate, repudiate, or renegotiate our significant contracts and we are unable to negotiate favorable terms or secure new contracts on substantially similar terms, or at all, our revenues and operating profit could be materially reduced.

Contracts also customarily provide for either automatic termination or termination at the option of the client in the event of total loss of the drilling rig, if a rig is not timely delivered to the client, if a rig does not pass acceptance testing within the period specified in the contract, if drilling operations are suspended for extended periods of time, including excessive rig downtime for repairs, or other specified conditions, including force majeure or failure to meet minimum performance criteria. Early termination of a contract may result in a rig being idle for an extended period of time.

The majority of our contracts are denominated in U.S. dollars, but occasionally all or a portion of a contract is payable in local currency. To the extent there is a local currency component in a contract, we attempt to match revenue in the local currency to the operating costs paid in the local currency such as local labor, shore base expenses, and local taxes, if any, in order to minimize foreign currency fluctuation impact. Failure to obtain currency protection on a contract may be detrimental to our cash flows and results of operations.

Contract Backlog

Our contract backlog at September 30, 2016 was approximately $0.8 billion, representing an approximate 50% decrease compared to our contract backlog of $1.6 billion at September 30, 2015. As of November 9, 2016, our four rigs currently under contract had approximately 25% and 17% of our available rig days contracted for fiscal years 2017 and 2018, respectively. As noted in the contract status above, only one of our current contracts extends beyond fiscal year 2017. However, two of our rigs are contracted in fiscal year 2018 and one rig for a portion of fiscal year 2019. For a discussion of the challenges faced in the current market for offshore drilling services as a result of recent declines in the price of oil please read "Management’s Discussion and Analysis of Financial Condition and Results of Operations—Market Outlook” in Item 7 of this Form 10-K. Also see Item 1A. “Risk Factors—Our current backlog of contract drilling revenue may not be fully realized, and the periods during which revenues are earned may vary”.

INSURANCE AND RISK MANAGEMENT

Our operations are subject to the usual hazards associated with the drilling of oil and gas wells, such as blowouts, explosions and fires. In addition, our equipment is subject to various risks particular to our industry which we seek to mitigate by maintaining insurance. These risks include, among others, capsizing, grounding, collision, leg damage to jackups during positioning and damage from severe weather conditions. Any of these risks could result in damage or destruction of drilling rigs and oil and gas wells, personal injury and property damage, suspension of operations or environmental damage through oil spillage or extensive, uncontrolled fires.

Therefore, in addition to general business insurance policies, we maintain the following insurance relating to our rigs and rig operations, among others: hull and machinery, protection and indemnity, mortgagee’s interest, cargo, war risks, casualty and liability (including excess liability). Our casualty and liability insurance policies are subject to self-insured deductibles. With respect to hull and machinery, we maintain a deductible of $5 million to $7.5 million per occurrence, with a zero deductible in the event of total loss of a unit. For general and marine third-party liabilities, we generally maintain a $50,000 per occurrence deductible. For personal injury liability for crew claims, we generally maintain a $1 million per occurrence deductible. Our rigs are insured at values ranging from book value to estimated market value or replacement cost. We typically insure for windstorm damage in the Gulf of Mexico for a partial amount of the rig's value for those rigs operating in that region. As of November 9, 2016, the Atwood Condor is insured against up to $150 million of damage as a result of a U.S. Gulf of Mexico windstorm. We maintain a $10 million deductible under our U.S. Gulf of Mexico windstorm insurance.

We believe that we are adequately insured against normal and foreseeable risks in our operations in accordance with industry standards; however, such insurance may not be adequate to protect us against liability from all consequences of well disasters, marine perils, extensive fire damage, and damage to the environment or disruption due to terrorism. To date, we have not experienced difficulty in obtaining insurance coverage, although we can provide no assurance as to the future availability of such insurance or the cost thereof. The occurrence of a significant event against which we are not adequately insured could have a material adverse effect on our financial position. See “Operating hazards increase our risk of liability; we may not be able to fully insure against all of these risks.” in Item 1A. “Risk Factors” of this Form 10-K.

CLIENTS

Due to the relatively limited number of clients for which we can perform operations at any given time, our business operations are subject to certain associated risks. The loss of, or a decrease in the drilling programs of these clients may adversely affect our revenues and, therefore, our results of operations and cash flows. Our revenues from individual clients that accounted for 10% or more of our total revenues in fiscal year 2016 are indicated below:

	Percentage of Revenues
Shell Offshore Inc.	21%
Kosmos Energy Ltd.	18%
Noble Energy Inc.	18%
Chevron Australia Pty. Ltd.	12%
Woodside Energy Ltd.	11%

In addition, we have certain clients that make up a significant portion of our accounts receivable at September 30, 2016, as indicated in the table below:

Client	Percentage of Accounts Receivable
Shell Offshore Inc.	31%
Kosmos Energy Ltd.	26%
Woodside Energy Ltd.	15%
Noble Energy Inc.	11%

See Item 1A. "Risk Factors - Our business relies heavily on a limited number of clients and a limited number of drilling units and the loss of a significant client, the loss of a rig, significant downtime for our rigs, or the inability of our clients to perform could materially and adversely impact our business" of this Form 10-K.

COMPETITION

The offshore drilling industry is very competitive, with no single offshore drilling contractor being dominant. We compete with a number of offshore drilling contractors for work, which varies by job requirements and location. Many of our competitors are substantially larger than we are, and possess appreciably greater financial and, other resources and assets than we do. Our competitors include, among others, the six members of our self-determined peer group, namely Diamond Offshore Drilling, Inc., Ensco plc, Noble Corporation, Rowan Companies plc, Seadrill Limited, and Transocean Ltd.

Safety performance, technical capability, location, rig availability and price competition are generally the most important factors in the offshore drilling industry. When there is low worldwide utilization of equipment as we are currently experiencing, price and rig suitability tend to be the driving competitive factors. Other competitive factors include work force experience, efficiency and condition of equipment, reputation and client relations. We believe that we compete favorably with respect to these factors. See Item 1A. "Risk Factors - Our industry is subject to intense price competition and volatility" of this Form 10-K.

INTERNATIONAL OPERATIONS

During our 48 year history, the majority of our drilling units have operated outside of United States waters, and we have conducted drilling operations in most of the major offshore exploration areas of the world. In fiscal year 2016, 61% of our contract revenues were derived from foreign operations. For information relating to the contract revenues and long-lived assets attributable to specific geographic areas of operations, see Note 10 to the Consolidated Financial Statements in Item 8 of this Form 10-K.

For information about risks associated with our foreign operations, see Item 1A, “Risk Factors - Our international operations may involve risks not generally associated with domestic operations.” and “Risk Factors - A change in tax laws in any country in which we operate could result in higher tax expense” of this Form 10-K.

EMPLOYEES

As of September 30, 2016, we had 938 personnel engaged, including those through labor contractors or agencies. In connection with our foreign drilling operations, we are often required by the host country to hire a substantial percentage of our work force in that country and, in some cases, these employees are represented by foreign unions. To date, we have experienced little difficulty in complying with such requirements, and our drilling operations have not been significantly interrupted by strikes or work stoppages. Our success also depends to a significant extent upon the efforts and abilities of our executive officers and other key management personnel. There is no assurance that these individuals will continue in such capacity for any particular period of time. See Item 1A. "Risk Factors - Failure to obtain and retain key personnel could impede our operations" of this Form 10-K.

ENVIRONMENTAL REGULATION

Our operations are subject to a variety of U.S. and foreign environmental regulations and to international environmental conventions. We monitor environmental regulations in each country in which we operate and, while we have experienced an increase in general environmental regulations, we do not believe compliance with such regulations will have a material adverse effect upon our business or results of operations. Past environmental issues, such as the Macondo incident, have led to higher drilling costs, greater regulation, a more difficult and lengthy well permitting process and, in general, have adversely affected decisions of oil and gas companies to drill in certain areas.

In the United States as well as in other jurisdictions in which we operate, laws and regulations applicable to our operations include those that (i) require the acquisition of permits to conduct regulated activities; (ii) restrict the types, quantities and concentration of various substances that can be released into the environment in connection with operations; (iii) limit or prohibit drilling activities in certain protected areas; (iv) require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to plug and abandoned wells; (v) impose specific safety and health criteria addressing worker protection; and (vi) impose substantial liabilities for pollution resulting from drilling and production operations. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of corrective or remedial obligations and the issuance of orders enjoining performance of some of our operations. Laws and regulations protecting the environment have become more 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 such person. Some of these laws and regulations may expose us to liability for the conduct of or conditions caused by others or for acts which were in compliance with all applicable laws at the time they were performed.

The application of these requirements or the adoption of new requirements could have a material adverse effect on our financial position, results of operations or cash flows. We believe all of our rigs satisfy current environmental requirements and certifications, if any, required to operate in the jurisdictions where they currently operate, but can give no assurance that in the future they will satisfy new environmental requirements or certifications, if any, that are enacted or that the costs to satisfy such requirements or certifications, if any, would not materially affect our financial position, results of operations or cash flows. Descriptions of certain of the laws and regulations that may be applicable are provided below:

- Our Mobile Offshore Drilling Units are subject to certain international conventions relating to environmental protection that are adopted, and following entry into force, implemented by the International Maritime Organization (“IMO”). These include, but are not limited to the International Convention for the Prevention of Pollution from Ships (“MARPOL 73/78”) and the International Convention for the Control and Management of Ships' Ballast Water and Sediments (“Ballast Water Management Convention”).

- Our operations in the United States are subject to various U.S. federal environmental laws and regulations including, but are not limited to: the Federal Water Pollution Control Act of 1972 (“Clean Water Act”); the Oil Pollution Act of 1990 (“OPA90”); the Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”); the Resource Conservation and Recovery Act (“RCRA”); the Endangered Species Act (“ESA”); the Marine Mammal Protection Act (“MMPA”); the Migratory Bird Treaty Act (“MBTA”); safety rules promulgated by the Bureau of Ocean Energy Management (“BOEM”) and the Bureau of Safety and Environmental Enforcement (“BSEE”) (see Other Governmental Regulation section below for full discussion); the Outer Continental Shelf Lands Act (“OCSLA”); and the Clean Air Act (“CAA”),as the same are amended, and various state law counterpart legislation.

- Our operations in Australian waters are governed by the Offshore Petroleum and Greenhouse Gas Storage Act 2006; the Offshore Petroleum and Greenhouse Gas Storage (Safety) Regulations 2009 (“OPGGS”); and the Offshore Petroleum and Greenhouse Gas Storage (Environment) Regulations 2009. These regulations cover environmental issues related to production in Australian waters, as well as occupational health and safety. The Environment OPGGS regulations require the submittal of a summary of an environmental plan to the Australian National Offshore Petroleum Safety and Environmental Management Authority (“NOPSEMA”). The Safety regulations require the submittal of a Safety Case to NOPSEMA, and NOPSEMA’s acceptance of the Safety Case, before operating in Australian Waters. The Safety Case is a document we are required to prepare to identify operational hazards and risks, describe how these risks are controlled, and describe the safety management system we put in place.

In addition to international conventions and federal or national laws, state and local environmental laws also apply to our operations. As a result of the Macondo incident, legislation was proposed and ultimately regulations were adopted that increased applicable liability limits under existing U.S. environmental laws and regulations. While laws can vary widely from one jurisdiction to another, each of the laws and regulations described above address environmental issues generally similar to those addressed by laws in most of the other jurisdictions in which we operate.

OTHER GOVERNMENTAL REGULATION

Our operations are subject to various international conventions, laws and regulations in the countries in which we operate, including laws and regulations relating to the importation of and operation of drilling units, currency conversions and repatriation, oil and gas exploration and development, taxation of offshore earnings and earnings of expatriate personnel, environmental protection, the use of local employees and suppliers by foreign contractors and duties on the importation and exportation of drilling units and other equipment. U.S. and foreign governments are continually assessing and proposing new regulations that impact our industry. Some foreign governments have become increasingly active in regulating and controlling the ownership of concessions and companies holding concessions, the exploration for oil and gas and other aspects of the oil and gas industries in their countries. This activity has adversely affected the amount of exploration and development work done by major oil and gas companies in some areas of the world, and may continue to do so. Operations in less developed countries can be subject to legal systems that are not as mature or predictable as those in more developed countries, which can lead to greater uncertainty in legal matters and proceedings.

Our ultra-deepwater, semisubmersible drilling rig, the Atwood Condor, is currently in the U.S. Gulf of Mexico. Our U.S. operations are subject to various U.S. laws and regulations, including drilling safety rules and workplace safety rules put in place by the BOEM and BSEE, which are designed to improve drilling safety by strengthening requirements for safety equipment, well control systems, and blowout prevention practices for offshore oil and gas operations, and to improve workplace safety by reducing the risk of human error. Implementation of new BOEM or BSEE guidelines or regulations may subject us to increased costs or limit the operational capabilities of our U.S. based rigs and could materially and adversely affect our financial position, results of operations or cash flows. Please see Item 1A. “Risk Factors - Government regulation and environmental risks could reduce our business opportunities and increase our costs” of this Form 10-K.

We believe we are in substantial compliance in all material respects with the health, safety, environmental and other regulations affecting the operation of our rigs and the drilling of oil and gas wells in the jurisdictions in which we operate. Historically, we have made significant capital expenditures and incurred additional expenses to ensure that our equipment complies with applicable local and international health, safety and environmental regulations. Although such expenditures may be required to comply with these governmental laws and regulations, such compliance has not, to date, materially adversely affected our earnings, cash flows or competitive position.

AVAILABLE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC. Our SEC filings are available to the public over the Internet at the SEC’s web site at http://www.sec.gov. Our website address is www.atwd.com. We make available free of charge on or through our website our annual report on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. We have adopted a Code of Business Conduct and Ethics and a Code of Ethics for the Chief Executive Officer and Senior Financial Officers which are available on our website. We intend to satisfy the disclosure requirement regarding any changes in or waivers from our codes of ethics by posting such information on our website or by filing a Form 8-K for such event. Unless stated otherwise, information on our website is not incorporated by reference into this report or made a part hereof for any purpose. You may also read and copy any document we file at the SEC’s Public Reference Room at 100 F Street NE, Washington, DC 20549. Please call the SEC at 1-800-SEC-0330 for further information on the Public Reference Room and copy charges.

ITEM 1A. RISK FACTORS

You should carefully consider the following risk factors in addition to the other information included in this Form 10-K. These risks and uncertainties may affect our business, financial position, results of operations or cash flows, as well as an investment in our common stock.

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

Our business depends on the conditions of the offshore oil and natural gas industry. Demand for our services depends on oil and natural gas industry exploration and production activity and expenditure levels, which are directly affected by trends in oil and natural gas prices. Oil and natural gas prices, and market expectations regarding potential changes to these prices, significantly affect oil and natural gas industry activity. Oil and natural gas prices have historically been volatile, and have dropped significantly since late 2014, with Brent recently trading around $50 per barrel as of October 2016. This lengthy decrease in oil prices has in turn caused a sustained decline in the demand for offshore drilling services. Operators have implemented significant declines in capital spending in their budgets, including the cancellation or deferral of existing programs, and are expected to maintain reduced budgets in 2017. These declines in capital spending levels, coupled with additional newbuild supply in recent years, have put significant pressure on day rates and utilization as opportunities for new drilling contracts have substantially decreased and the number of available rigs has increased. The lack of a meaningful recovery of oil and natural gas prices, and the potential for a prolonged delay in the future or further price reductions and volatility in oil and/or natural gas prices, could cause oil and gas companies to maintain historically low levels, or further reduce their overall level, of activity or spending, in which case demand for our services may further decline and revenues may be further adversely affected through lower rig utilization and/or lower day rates. Oil and natural gas prices are impacted by many factors beyond our control, including:

- the demand for oil and natural gas;
- the cost of exploring for, developing, producing and delivering oil and natural gas;
- the strength of the global economy;
- expectations about future prices;
- the ability of The Organization of Petroleum Exporting Countries (“OPEC”) to set and maintain production levels and pricing;
- the level of production by OPEC and non-OPEC countries;
- domestic and international tax policies;
- political and military conflicts in oil producing regions or other geographical areas or acts of terrorism in the U.S. or elsewhere;
- technological advances;
- the development and exploitation of alternative fuels;
- local and international political, economic and weather conditions; and
- environmental and other laws and governmental regulations regarding exploration and development of oil and natural gas reserves.

The level of offshore exploration, development and production activity and the price for oil and natural gas is volatile and is likely to continue to be volatile in the future. Any prolonged reduction in oil and natural gas prices may depress the levels of exploration, development and production activity. Furthermore, higher oil and natural gas prices in the future may not necessarily translate into increased activity, and even during periods of relatively high oil prices, companies exploring for oil and gas may cancel or curtail programs, or reduce their levels of capital expenditures for exploration and production for a variety of reasons. Advances in onshore exploration and development technologies, particularly with respect to onshore shale plays, could result in our clients allocating a higher percentage of their capital expenditure budgets to onshore exploration and production activities and less to offshore activities. These factors could cause our revenues and margins to decline, reduce day rates and utilization of our rigs and limit our future growth prospects and, therefore, could have a material adverse effect on our financial position, results of operations and cash flows.

Our industry is subject to intense price competition and volatility.

The contract drilling business is highly competitive with numerous industry participants. Drilling contracts are traditionally awarded on a competitive bid basis. Price competition is often the primary factor in determining which qualified contractor is awarded a job, although rig availability, the quality and technical capability of service and equipment and safety record are also factors. We compete with a number of offshore drilling contractors, many of which are substantially larger than we are and which may possess appreciably greater financial, other resources and assets than we do.

The industry in which we operate historically has been volatile, marked by periods of low demand, excess rig supply and low day rates, followed by periods of high demand, low rig availability and increasing day rates. Periods of low demand and excess rig supply intensify the competition in the industry and often result in lower day rates and rigs being idled. We have and may in the future be required to idle rigs or accept lower-rate contracts in response to market conditions. Presently, there are numerous recently constructed ultra-deepwater vessels and high-specification jackups that have entered the market and more are under contract for construction. Many of these units do not have drilling contracts in place. The entry into service of these new units has increased and will continue to increase rig supply and could curtail a strengthening, or trigger a further reduction, in day rates and utilization. The deepwater market has experienced a decrease in marketed utilization which has led to lower day rates in 2016, which may continue at depressed levels or experience further downward pressure in 2017 and beyond. Any further increases in construction of new units or reduction in demand may accelerate the negative impact on day rates and utilization. In addition, rigs may be relocated to markets in which we operate, which could result in or exacerbate excess rig supply which may lower day rates in those markets.

We may be required to record impairment charges with respect to our rigs.

We evaluate our property and equipment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. An impairment loss on our property and equipment may exist when the estimated future cash flows are less than the carrying amount of the asset. The significant decline in oil and gas prices and resulting reduction in spending by our customers, together with the over-supply of rigs, is contributing to a reduction in day rates and demand for our rigs, which may continue for some time. Prolonged periods of low utilization and day rates may 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.

For example, the Atwood Falcon completed the contract under which it was working in early March 2016. Based on the lack of contracting opportunities and the further deterioration of commodity prices, we determined that it was not likely that additional work would be obtained in the foreseeable future. Based on our analysis, we concluded that the Atwood Falcon and its materials and supplies were impaired as of December 31, 2015, and we wrote them down to their approximate salvage value. We recorded a non-cash impairment charge of approximately $64.9 million. In the three months ended September 30, 2016, we recorded an additional $38.6 million impairment related to items of drilling equipment intended to support our current and future offshore drilling operations. We may make similar decisions and record additional impairments with regard to other drilling equipment or rigs whose contracts expire if we are unable to obtain additional work for such rigs. Currently, the Atwood Eagle, Atwood Mako, Atwood Manta, Atwood Orca, Atwood Beacon and Atwood Aurora are idled and are being actively marketed. Although we are actively marketing these rigs, there can be no assurance that we will be able to obtain future contracts for these rigs. As of September 30, 2016, we assessed these rigs and determined no impairment charge was necessary. These rigs and other rigs in our fleet may become impaired in the future if the current depressed market conditions are prolonged or if oil and gas prices decrease further.

At September 30, 2016, we performed impairment testing on our fleet of drilling rigs, including our two rigs currently under construction, which have an aggregate net book value of $4.0 billion. We concluded that the net book value of each drilling rig is recoverable through estimated future cash flows. The most significant assumptions used in our undiscounted cash flow model include: timing on awards of future drilling contracts, operating day rates, operating costs, capital expenditures, reactivation costs, drilling rig utilization, estimated remaining economic useful life and net proceeds received upon future sale/disposition. These significant assumptions are classified as Level 3 inputs by ASC Topic 820 Fair Value Measurement and Disclosures as they are based upon unobservable inputs and primarily rely on management assumptions and forecasts. Although we believe the assumptions used in our analysis are reasonable and appropriate, different assumptions and estimates could materially impact the analysis and our resulting conclusion. Our oldest drilling rig may be subject to greater risk of future impairment if the significant assumptions on which we have based our impairment testing at September 30, 2016 do not materialize or if we change those assumptions in future periods as new market conditions may dictate.

Our business relies heavily on a limited number of clients and a limited number of drilling units and the loss of a significant client, the loss of a rig, significant downtime for our rigs, or the inability of our clients to perform could materially and adversely impact our business.

Our client base includes a small number of major and independent oil and gas companies as well as government-owned oil companies. In fiscal year 2016, five clients each accounted for over 10% of our operating revenues: Shell Offshore Inc. - 21%, Kosmos Energy Ltd. - 18%, Noble Energy Inc. - 18%, Chevron Australia Pty. Ltd. - 12% and Woodside Energy Ltd. - 11%. The contract drilling business is subject to the usual risks associated with having a limited number of clients for our services. Further, consolidation among oil and natural gas exploration and production companies may reduce the number of available clients. Our business and results of operations could be materially and adversely affected if any of our major clients terminate their contracts with us, fail to renew our existing contracts, refuse to award new contracts to us or experience difficulties in obtaining financing to fund their drilling programs. We currently own 10 drilling units, of which four are currently in operation and six are idled and being actively marketed. In addition, we have two drilling units under construction and being actively marketed. As a result of the number of rigs in our fleet, if more of our drilling units were idled or if a client were unable to perform due to liquidity or solvency issues, our business and results of operations could be materially and adversely affected.

Our clients may be unable or unwilling to fulfill their contractual commitments to us, including their obligations to pay for losses, damages or other liabilities resulting from operations under the contract.

Certain of our clients are subject to liquidity or solvency risk and such risk could lead them to seek to repudiate, cancel or renegotiate our drilling contracts for various reasons or fail to fulfill their commitments to us under those contracts. These risks are heightened in periods of depressed market conditions. Our drilling contracts provide for varying levels of indemnification from our clients, including with respect to well control and subsurface risks. Our drilling contracts also provide for varying levels of indemnification and allocation of liabilities between our clients and us with respect to loss or damage to property and injury or death to persons arising from the drilling operations we perform. Under our drilling contracts, liability with respect to personnel and property customarily is generally allocated so that we and our clients each assume liability for our respective personnel and property. Our clients typically assume most of the responsibility for and indemnify us from any loss, damage or other liability resulting from pollution or contamination, including clean-up and removal, third-party damages, and fines and penalties arising from operations under the contract when the source of the pollution originates from the well or reservoir, including those resulting from blow-outs or cratering of the well. Notwithstanding a contractual indemnity from a client, there can be no assurance that our clients will be financially able to assume their responsibility, or honor their indemnity to us, for such losses. In addition, under the laws of certain jurisdictions, such indemnities are not enforceable if the cause of the damage was our gross negligence or willful misconduct. This could result in our having to assume liabilities not otherwise contemplated in our contracts.

Our business may experience reduced profitability if our clients terminate, repudiate or seek to renegotiate our drilling contracts.

Currently, our contracts with clients are day rate contracts, in which we charge a fixed amount per day regardless of the number of days needed to drill the well. During depressed market conditions, a client may no longer need a rig that is currently under contract or may be able to obtain a comparable rig at a lower day rate. Clients may seek to reduce or avoid their obligations under their existing drilling contracts by seeking to renegotiate the terms or terminate the contract. In 2015, for example, we renegotiated drilling contracts with respect to several of our rigs. In March 2016, we negotiated with a client to shift its remaining contract backlog from the Atwood Eagle to the Atwood Osprey in order to preserve the continuity of operations for the Atwood Osprey. This shift in backlog did not alter the contractual day rate for the client, but it did lead to the immediate idling of the Atwood Eagle. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations-Market Outlook” in Item 7 of this Form 10-K.

In addition, certain of our contracts may be canceled upon specified notice at the option of the client upon payment of an early termination fee, which is typically a majority of the full operating rate over the remainder of the contract term. Contracts also customarily provide for either automatic termination or termination at the option of the client in the event of total loss of the drilling rig, if a rig is not delivered to the client, if a rig does not pass acceptance testing within the period specified in the contract, if drilling operations are suspended for extended periods of time by reason of excessive rig downtime for repairs, or other specified conditions, including force majeure or failure to meet minimum performance criteria. Early termination of a contract may result in a rig being idle for an extended period of time. The recent decline in oil prices, the perceived risk of a further decline in oil prices, and the resulting downward pressure on utilization is causing some operators to consider early termination of contracts despite having to pay onerous early termination fees in some cases.

Our revenues may be adversely affected by the early termination of contracts, especially if we are unable to re-contract the affected rig within a short period of time. The termination or renegotiation of one or more of our drilling contracts could adversely affect our financial position, results of operations and cash flows.

Our business will be adversely affected if we are unable to secure contracts on economically favorable terms.

The drilling markets in which we compete frequently experience significant fluctuations in the demand for drilling services, as measured by the level of exploration and development expenditures and the supply of capable drilling equipment. The contracts for three of our four rigs currently in operation expire in fiscal year 2017, with no immediate follow-on work currently scheduled. Our ability to extend these contracts or obtain new contracts and the terms of any such contracts will depend on market conditions. We may be unable to extend our expiring contracts or obtain new contracts for the rigs under contracts that have expired or been terminated, and the day rates under any new contracts may be substantially below the existing day rates, which could materially reduce our revenues and profitability. We can, as we have done in the past, relocate drilling rigs from one geographic area to another, but only when such moves are economically justified, or we can idle rigs temporarily to save operating expenses, as we have done with the

Atwood Eagle, Atwood Mako, Atwood Manta, Atwood Orca, Atwood Beacon and Atwood Aurora. If demand for our rigs declines, rig utilization and day rates are generally adversely affected, which in turn, would adversely affect our financial position, results or operations and cash flows.

Our current backlog of contract drilling revenue may not be fully realized, and the periods which revenues are earned may vary.

As of September 30, 2016, our contract drilling backlog was approximately $0.8 billion for future revenues under firm commitments. The amount of actual revenues earned and the actual periods during which revenues are earned will be different from the amounts disclosed in our backlog calculations due to a lack of predictability of various factors, including newbuild rig

delivery dates, client-elected standby periods, unscheduled repairs, maintenance requirements, weather delays and other factors. Such factors may result in lower applicable day rates than the full contractual day rates and/or delays in receiving the full contractual operating rates.
Some of our drilling contracts are cancellable at the option of the client upon payment of a termination fee which may not fully compensate us for the loss of the contract. Our drilling contracts also customarily provide for either automatic termination or termination at the option of the client in the event of total loss of the drilling rig, if a rig is not timely delivered to the client, if a rig does not pass acceptance testing within the period specified in the contract, if drilling operations are suspended for extended periods of time, including excessive rig downtime for repairs, or other specified conditions, including force majeure or failure to meet minimum performance criteria. Our clients may seek to cancel or renegotiate our contracts for various reasons, or we may not be able to perform under our drilling contracts due to events beyond our control. In addition, some of our clients could experience liquidity or solvency issues or could otherwise be unable or unwilling to perform under the contract, which could ultimately lead a client to go into bankruptcy or to otherwise encourage a client to seek to repudiate, cancel or renegotiate a contract. Our inability or the inability of our clients to perform under our or their contractual obligations may have a material adverse effect on our financial position, results of operations or cash flows.
We may not be able to generate sufficient cash to service all of our indebtedness or make payments on our rigs under construction, and may be forced to take other actions to satisfy our obligations under our indebtedness and construction contracts, which may not be successful.

At September 30, 2016 and 2015, we had \$1.23 billion and \$1.68 billion, respectively, of total long-term debt. In addition, we had remaining milestone payments for our rigs under construction totaling approximately \$399.8 million. Our ability to make scheduled payments on or to refinance our obligations depends on our financial position, results of operations and cash flows, which is subject to prevailing economic and competitive conditions, including our ability to obtain new drilling contracts in the event our existing contracts expire or are terminated or our customers attempt to renegotiate terms, and to certain financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay our outstanding obligations. If we breach our covenants under our senior secured revolving credit facility (the “Credit Facility”) and seek a waiver, we may not be able to obtain a required waiver from the lenders. If this occurs, we would be in default under our Credit Facility, the lenders could exercise their rights and we could be forced into bankruptcy or liquidation. See “Management's Discussion and Analysis of Financial Condition and Results of Operations-Liquidity and Capital Resources-Revolving Credit Facility.”

As a result of our substantial level of debt and other obligations, we may be unable to obtain financing in the future for working capital, capital expenditures, acquisitions, debt service obligations or for other purposes. In addition, if our cash flows and capital resources are insufficient to fund our obligations, we may be forced to sell assets, seek additional capital, reduce or delay investment decisions and capital expenditures, restructure or refinance our indebtedness or take other measures. Furthermore, these alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations. Our ability to restructure or refinance our debt will depend on the condition of the capital markets and our financial position at such time. Any refinancing of our debt could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. Any failure to make payments of interest and principal on our outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating. Certain credit rating agencies have recently downgraded the credit ratings of our senior unsecured debt, and any further downgrades could harm our ability to seek additional capital or restructure or refinance our indebtedness. In addition, the terms of the agreements that govern our existing and future indebtedness may restrict us from adopting some of these alternatives. For example, the terms of our existing debt agreements restrict our ability to dispose of assets and use the proceeds therefrom. We may not be able to consummate those dispositions or to obtain the proceeds that we could realize from them and these proceeds may not be adequate to meet any debt service obligations then due.

Capital expenditures may be necessary to keep pace with the bifurcation of the drilling fleet and technological developments in our industry.

The market for our services is characterized by continual and rapid technological developments that have resulted in, and will likely continue to result in, substantial improvements in the functionality and performance of rigs and equipment. Our customers demand the services of newer, higher specification drilling rigs. This has resulted in a bifurcation of the drilling fleet for both the jackup and floater rig classes and is evidenced by the higher specification drilling rigs generally operating at higher overall utilization levels and day rates than the lower specification or standard drilling rigs, and a significant number of lower specification rigs being stacked. In addition, current competitors or new market entrants may adopt or develop new technologies, services or standards that could render some of our services or equipment obsolete. As a result, we may be required to expend capital to maintain and improve existing rigs and equipment, or purchase and construct newer, higher specification drilling rigs in the future, to meet the increasingly sophisticated needs of our customers. If we are not successful in doing so, we could lose market share.

Rig upgrade, repair and construction projects are subject to risks, including delays, cost overruns, and failure to secure drilling contracts.

As of November 2, 2016, there were 31 ultra-deepwater drillships and semisubmersibles under construction for delivery through calendar year 2020 and 106 newbuild jackup rigs under construction with expected delivery dates through calendar year 2020. As a result, shipyards and third-party equipment vendors are under significant resource constraints to meet delivery obligations. Such constraints may lead to delivery and commissioning delays and/or equipment failures and/or quality deficiencies. Furthermore, new drilling rigs may face start-up or other operational complications following completion of construction projects or other unexpected difficulties including equipment failures, design or engineering problems that could result in significant downtime at reduced or zero day rates or the cancellation or termination of drilling contracts.

We currently have two ultra-deepwater drillships under construction. Neither of these drillships have long-term drilling contracts in place. We may also commence the construction of additional rigs for our fleet from time to time without first obtaining drilling contracts covering any such rig. Our failure to secure drilling contracts for rigs under construction, including our remaining uncontracted newbuild drillships, prior to delivery from the shipyard could adversely affect our financial position, results of operations or cash flows. During fiscal year 2016, we postponed the delivery of these drillships. See Note 3 to Consolidated Financial Statements in Item 8 of Part II of this Form 10-K.

Since 2010, we have invested or committed to invest over $4.5 billion in the expansion of our fleet, including ultra-deepwater and jackup rigs. Depending on available opportunities, we may construct additional rigs for our fleet in the future. In addition, we incur significant upgrade, refurbishment and repair expenditures on our fleet from time to time. Some of these expenditures are unplanned. Our projects 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;
- unscheduled delays in the delivery of ordered materials and equipment and failure of third-party equipment to meet quality and/or performance standards;
- unanticipated actual or purported change orders;
- unanticipated increases in the cost of equipment, labor and raw materials, particularly steel;
- damage to shipyard facilities or construction in progress or delays in construction, resulting from fire, explosion, flooding, severe weather, terrorism, war or other armed hostilities;
- difficulties in obtaining necessary permits or in meeting permit conditions;
- design and engineering problems;
- client acceptance delays;
- political, social and economic instability, war and civil disturbances;
- delays in customs clearance of critical parts or equipment;
- financial or other difficulties or failures at shipyards and suppliers;
- claims of force majeure events;
- disputes with shipyards and suppliers;
- work stoppages and other labor disputes; and
- foreign currency exchange rate fluctuations impacting overall cost.

Both of our rigs currently under construction are located at a single shipyard and any such events that affect the shipyard may impact both of our rigs under construction. Delays in the delivery of rigs being constructed or undergoing upgrade, refurbishment or repair may result in delay in contract commencement, resulting in a loss or delay of revenue to us and may cause our clients to seek to terminate or shorten the terms of their contract under applicable late delivery clauses, if any. In the event of termination of any of our contracts, we may not be able to secure a replacement contract on as favorable terms, if at all.

The estimated capital expenditures for rig upgrades, refurbishments and construction projects could materially exceed our planned capital expenditures. Moreover, our rigs undergoing upgrade, refurbishment and repair may not earn a day rate during the period they are out-of-service.

Operating hazards increase our risk of liability; we may not be able to fully insure against all of these risks.
Our operations are subject to various operating hazards and risks, including:
- well blowouts, loss of well control and reservoir damage;
- fires and explosions;
- catastrophic marine disaster;
- adverse sea and weather conditions;
- mechanical failure;
- navigation errors;
- collision;
- oil and hazardous substance spills, containment and clean up;
- lost or stuck drill strings;
- equipment defects;
- security breaches of our information systems or other technological failures;
- labor shortages and strikes;
- damage to and loss of drilling rigs and production facilities; and
- war, sabotage, terrorism and piracy.

These risks present a threat to the safety of personnel and to our rigs, cargo, equipment under tow and other property, as well as the environment. Our operations and those of others could be suspended as a result of these hazards, whether the fault is ours or that of a third party. In certain circumstances, governmental authorities may suspend drilling operations as a result of these hazards, and therefore our clients may cancel or terminate their contracts. Third parties may have significant claims against us for damages due to personal injury, death, property damage, pollution and loss of business if such event were to occur in our operations.
Our offshore drilling operations are also subject to marine hazards, either at offshore sites or while drilling equipment is under tow, such as vessel capsizings, sinkings, collisions or groundings. In addition, raising and lowering jackup drilling rigs, flooding semisubmersible ballast tanks and drilling into high-pressure formations are complex, hazardous activities, and we can encounter problems.
We have had accidents in the past due to some of the hazards described above. Because of the ongoing hazards associated with our operations:
- we may experience accidents;
- our insurance coverage may prove inadequate to cover our losses;
- our insurance deductibles may increase; or
- our insurance premiums may increase to the point where maintaining our current level of coverage is prohibitively expensive or we may be unable to obtain insurance at all.

We maintain insurance coverage against casualty and liability risks and have renewed our primary insurance program through June 30, 2017. Certain risks, however, such as pollution, reservoir damage and environmental risks generally are not fully insurable. Although we believe our insurance is adequate, our policies and contractual indemnity rights may not adequately cover all losses or may have exclusions of coverage for certain losses. We do not have insurance coverage or rights to indemnity for all risks. In addition, we may be unable to renew or maintain our existing insurance coverage at commercially reasonable rates or at all. If a significant accident or other event occurs and is not fully covered by insurance or contractual indemnity, it could adversely affect our financial position, results of operations or cash flows. There is no assurance that our insurance coverage will be available or affordable and, if available, whether it will be adequate to cover future claims that may arise. Additionally, there is no assurance that those parties with contractual obligations to indemnify us will necessarily be financially able or willing to indemnify us against all these risks.

The U.S. Gulf of Mexico experiences hurricanes and other extreme weather conditions on a relatively frequent basis. In recent years, hurricanes have caused damage to a number of rigs in the U.S. Gulf of Mexico. As a result, insurance companies have reduced the nature and amount of insurance coverage available for losses arising from named windstorm damage in the U.S. Gulf of Mexico and have increased the costs of such coverage. Our current windstorm insurance policy for the Atwood Condor has a policy limit of $150 million and a per occurrence deductible of $10 million. Our limited windstorm insurance coverage exposes us to a significant level of risk if the Atwood Condor were to experience significant damage or loss related to severe weather conditions caused by hurricanes or tropical storms in the U.S. Gulf of Mexico.

Our drilling contracts provide for varying levels of indemnification from our clients and in most cases may require us to indemnify our clients. Under offshore drilling contracts, liability with respect to personnel and property is customarily assigned on a "knock-for-knock" basis, which means that we and our clients assume liability for our respective personnel and property. However, in certain cases we may have liability for damage to our client's property and other third-party property on the rig. Our clients typically assume responsibility for and indemnify us from any loss or liability resulting from pollution or contamination, including clean-up and removal and third-party damages, arising from operations under the contract and originating below the surface of the water, including as a result of blow-outs or cratering of the well. In some drilling contracts, however, we may have liability for third-party damages resulting from such pollution or contamination caused by our gross negligence, or, in some cases, ordinary negligence, subject to negotiated caps. We generally indemnify the client for legal and financial consequences of spills of industrial waste and other liquids originating from our rigs or equipment above the surface of the water.
The above description of our insurance program and the indemnification provisions of our drilling contracts is only a summary and is general in nature. Our insurance program and the terms of our drilling contracts may change in the future. In addition, the indemnification provisions of our drilling contracts may be subject to differing interpretations, and enforcement of those provisions may be limited by public policy and other considerations.

Drilling contracts with national oil companies may expose us to greater risks than we normally assume in drilling contracts with non-governmental clients.
Contracts with national oil companies are often non-negotiable and may expose us to greater commercial, political and operational risks than we assume in other contracts, such as exposure to materially greater environmental liability and other claims for damages (including consequential damages) and personal injury related to our operations, or the risk that the contract may be terminated by our client without cause on short-term notice, contractually or by governmental action, under certain conditions that may not provide us an early termination payment, collection risks and political risks. In addition, our ability to resolve disputes or enforce contractual provisions may be negatively impacted with these contracts. While we believe that the financial, commercial and risk allocation terms of these contracts and our operating safeguards mitigate these risks, we can provide no assurance that the increased risk exposure will not have an adverse impact on our future operations or that we will not increase the number of rigs contracted to national oil companies with commensurate additional contractual risks.
Our long-term contracts are subject to the risk of cost increases, which could adversely impact our profitability.
In periods of rising demand for offshore rigs, a drilling contractor generally would prefer to enter into well-to-well or other short-term contracts less than one year in duration that would allow the contractor to profit from increasing day rates, while clients with reasonably definite drilling programs would typically prefer long-term contracts in order to maintain day rates at a consistent level. Conversely, in periods of decreasing demand for offshore rigs, a drilling contractor generally would prefer long-term contracts to preserve day rates and utilization, while clients generally would prefer well-to-well or other short-term contracts that would allow the client to benefit from the decreasing day rates. In the current market, we may not be able to renew long-term contracts that preserve day rates and utilization, or our clients may seek to renegotiate day rates under our existing long-term contracts.
In general, our costs increase as the business environment for drilling services improves and demand for oilfield equipment and skilled labor increases. While many of our contracts include cost escalation provisions that allow changes to our day rate based on stipulated cost increases or decreases, the timing and amount earned from these day rate adjustments may differ from our actual increase in costs. Additionally, if our rigs incur idle time between contracts, we typically do not remove personnel from those rigs because we utilize the crew to prepare the rig for its next contract. During times of reduced activity, reductions in costs may not be immediate as portions of the crew may be required to prepare our rigs for stacking, after which time the crew members are assigned to active rigs or dismissed. Moreover, as our rigs are mobilized from one geographic location to another, the labor and other operating and maintenance costs can vary significantly. In general, labor costs increase primarily due to higher salary levels and inflation. Equipment maintenance expenses fluctuate depending upon the type of activity the rig is performing and the age and condition of the equipment. Contract preparation expenses vary based on the scope and length of contract preparation required and the duration of the firm contractual period over which such expenditures are amortized.

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Covenants in our debt agreements restrict our ability to engage in certain activities.
Our debt agreements restrict our ability to, among other things:
- incur, assume or guarantee additional indebtedness or issue certain stock;
- pay dividends or distributions or redeem, repurchase or retire our capital stock or subordinated debt;
- make loans and other types of investments;
- incur liens;
- receive dividends, loans or asset transfers from our subsidiaries;
- sell or otherwise dispose of assets, including capital stock of subsidiaries;
- consolidate or merge with or into, or sell substantially all of our assets to, another person;
- acquire assets or businesses;
- enter into transactions with affiliates; and
- enter into new lines of business.

In addition, our Credit Facility contains various financial covenants. On March 25, 2016, we entered into an amendment to our Credit Facility (the "Fourth Amendment") that, among other things, effective on March 28, 2016, (i) removed the maximum leverage ratio and maximum secured leverage ratio financial covenants, (ii) amended the minimum interest expense coverage ratio such that it is not applicable until the quarter ending September 30, 2018, and decreased the minimum ratio required to 1.15:1.00, (iii) added a minimum liquidity financial covenant of $150 million, (iv) revised the restricted payments covenant to prohibit us from paying dividends, (v) reduced the total commitments under the Credit Facility by $152 million, and (vi) permits the incurrence of up to $400 million of second lien debt, subject to the parameters set forth therein. As a result of the Fourth Amendment, borrowings under the Credit Facility bear interest at the Eurodollar rate plus a margin ranging from 2.50% to 3.25% and the commitment fee on the unused portion of the underlying commitment ranges from 1.00% to 1.30% per annum, in each case based on our corporate credit ratings.

Our ability to meet these covenants or requirements may be affected by events beyond our control, and there can be no assurance that we will satisfy such covenants and requirements in the future. If market or other economic conditions remain depressed or further deteriorate, our ability to meet these covenants and requirements may be impaired. Such restrictions may limit our ability to successfully execute our business plans, which may have adverse consequences on our operations.

We do not intend to pay, and the covenants contained in the agreements governing our indebtedness include restrictions on our ability to pay, dividends on our common stock.

In February 2016, our board of directors eliminated the payment of a quarterly dividend in order to preserve liquidity. Furthermore, in March 2016, we entered into an amendment to our Credit Facility that, among other things, revised the restricted payments covenant under our credit facility to prohibit us from paying dividends during the term of the facility. Future reinstatement of dividends would require the amendment or waiver of such provision. In addition, the declaration and amount of any future dividends would be at the discretion of our board of directors and would depend on our financial condition, results of operations, cash flows, prospects, industry conditions, capital requirements and other factors and restrictions our board of directors deemed relevant. There can be no assurance that we will pay a dividend in the future.

A change in tax laws in any country in which we operate could result in higher tax expense.

We conduct our worldwide operations through various subsidiaries. Tax laws and regulations are highly complex and subject to interpretation. Consequently, we are subject to changing tax laws, treaties and regulations in and between countries in which we operate. Our income tax expense is based on our interpretation of the tax laws in effect at the time the expense was incurred. Tax legislation is proposed from time to time which could, among other things, limit our ability to defer the taxation of non-U.S. income and would increase current tax expense. A change in tax laws, treaties or regulations, or in the interpretation thereof, could result in a materially higher tax expense or a higher effective tax rate on our worldwide earnings.

We file periodic tax returns that are subject to review and audit by various revenue agencies in the jurisdictions in which we operate. Taxing authorities may challenge any of our tax positions. We are currently contesting tax assessments that could have a material impact on our financial statements and we may contest future assessments where we believe the assessments are in error. Determinations by such authorities that differ materially from our recorded estimates, favorably or unfavorably, may have a material impact on our financial position, results of operations or cash flows.

Government regulations and environmental risks could reduce our business opportunities and increase our costs.

We must comply with extensive government laws and regulations in the form of international conventions, federal, state and local laws and regulations in jurisdictions where our vessels operate and are registered. These conventions, laws and regulations govern oil spills, including oil spill prevention, and matters of environmental protection, worker health and safety, and the manning, construction and operation of vessels, and vessel and port security. We believe that we are in material compliance with all applicable environmental, health and safety and vessel and port security laws and regulations as currently in effect. We are not a party to any pending governmental litigation or similar proceeding, and we are not aware of any threatened governmental litigation or proceeding which, if adversely determined, would have a material adverse effect on our financial position, results of operations or cash flows. However, failure to comply with these laws and regulations or the occurrence of an incident such as an oil spill may result in the assessment of administrative, civil and even criminal penalties, the imposition of remedial obligations and other damages, the denial or revocation of permits or other authorizations and the issuance of injunctions that may limit or prohibit our operations or afford our clients the right to terminate or seek to renegotiate their drilling contracts to our detriment. Some of these laws and regulations impose strict and, with limited exceptions, joint and several liability. In addition, compliance with environmental, health and safety and vessel and port security laws increases our costs of doing business. Further, the offshore drilling industry depends on demand for services from the oil and natural gas exploration, development and production industry, and, accordingly, we also are directly affected by the adoption of laws and regulations that, for economic, environmental or other policy reasons, curtail exploration and development drilling for oil and natural gas.

Environmental, health and safety and vessel and port security laws change frequently, and we may not be able to anticipate such changes or the impact of such changes. There is no assurance that we can avoid significant costs, liabilities and penalties imposed as a result of governmental regulation in the future. Changes in laws or regulations regarding offshore oil and gas exploration, development and production activities, the cost or availability of insurance, and decisions by clients, governmental agencies or other industry participants could reduce demand for our services or increase our costs of operations, which could have a negative impact on our financial position, results of operations or cash flows, but we cannot reasonably or reliably estimate that such changes will occur, when they will occur or if they will impact us. Such changes can occur quickly within a region, similar to the increases in regulatory requirements in the U.S. Gulf of Mexico following the Macondo well incident in April 2010. These changes may impact utilization and day rates both in the affected region and globally. We may not be able to respond quickly, or at all, to mitigate against such changes.

Failure to comply with the U.S. Foreign Corrupt Practices Act or foreign anti-bribery legislation could have an adverse impact on our business.

The U.S. Foreign Corrupt Practices Act ("FCPA") and similar anti-bribery laws in other jurisdictions, including the United Kingdom Bribery Act 2010, generally prohibit companies and their intermediaries from making improper payments to foreign officials for the purpose of obtaining or retaining business. We operate in many parts of the world that have experienced governmental corruption to some degree and, in certain circumstances, strict compliance with anti-bribery laws may conflict with local customs and practices and impact our business. Although we have programs in place covering compliance with anti-bribery legislation, any failure to comply with the FCPA or other anti-bribery legislation could provide a client with termination rights under a contract and could subject us to civil and criminal penalties or other sanctions, which could have a material adverse effect on our business, financial position, results of operations or cash flows. We could also face fines, sanctions and other penalties from authorities in the relevant foreign jurisdictions, including prohibition of our participating in or curtailment of business operations in those jurisdictions, disgorgement of related profits and the seizure of rigs or other assets.

Our international operations may involve risks not generally associated with domestic operations.

We derive a significant portion of our revenues from operations outside the United States. Our operations are subject to risks inherent in conducting business internationally, such as:

- legal and governmental regulatory requirements;
- difficulties and costs of staffing and managing international operations;
- political, social and economic instability;
- terrorist acts, piracy, kidnapping, extortion, war and civil disturbances;
- language and cultural difficulties;
- potential rig seizure, arrest, expropriation or nationalization of assets or confiscatory taxation;
- import-export quotas or other trade barriers;
- renegotiation, nullification or modification of existing contracts;
- difficulties in collecting accounts receivable and longer collection periods;
- foreign and domestic monetary policies;
- work stoppages;
- complications associated with repairing and replacing equipment in remote locations;
- limitations on insurance coverage, such as war risk coverage, in certain areas;
- wage and price controls;
- assaults on property or personnel, including kidnappings;
- travel limitations or operational problems caused by public health issues, epidemics or security threats;
- imposition of currency exchange controls;
- solicitation by governmental officials for improper payments or other forms of corruption;
- currency exchange fluctuations and devaluations; or,
- potentially adverse tax consequences, including those due to changes in laws or interpretation of existing laws.

Our non-U.S. operations are subject to various laws and regulations in certain countries in which we operate, including laws and regulations relating to the import and export, equipment and operation of drilling units, currency conversions and repatriation, oil and gas exploration and development, and taxation of offshore earnings and earnings of expatriate personnel. Governments in some foreign countries have become increasingly active in regulating and controlling the ownership of concessions and companies holding concessions, the exploration for oil and gas and other aspects of the oil and gas industries in their countries, including local content requirements for participating in tenders for certain drilling contracts. Many governments favor or effectively require the awarding of drilling contracts to local contractors or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. In addition, government action, including initiatives by OPEC, may continue to cause oil or gas price volatility. In some areas of the world, this governmental activity has adversely affected the amount of exploration and development work by major oil companies and may continue to do so. Operations in less developed countries can be subject to legal systems which are not as mature or predictable as those in more developed countries, which can lead to greater uncertainty in legal matters and proceedings.

Some of our drilling contracts are partially payable in local currency. Those amounts may exceed our local currency needs, leading to the accumulation of excess local currency, which, in certain instances, may be subject to either temporary blocking or other difficulties converting to U.S. dollars. Excess amounts of local currency may be exposed to the risk of currency exchange losses.

The shipment of goods, services and technology across international borders subjects us to extensive trade and other laws and regulations. Our import and export activities are governed by unique customs laws and regulations in each of the countries where we operate. Moreover, many countries, including the U.S., control the import and export of certain goods, services and technology and impose related import and export recordkeeping and reporting obligations, the laws and regulations related to which are complex and constantly changing. These laws and regulations may be enacted, amended, enforced or interpreted in a manner materially impacting our operations. Shipments may be delayed and denied import or export for a variety of reasons, some of which are outside our control and such delays or denials could cause unscheduled operational downtime. Any failure to comply or alleged failure to comply with these applicable legal and regulatory obligations also could result in criminal and civil penalties and sanctions, such as fines, imprisonment, debarment from government contracts, seizure of rigs and loss of import and export privileges.

In the past, these conditions or events have not materially affected our operations. However, we cannot predict whether any such conditions or events might develop in the future. Also, we organized our subsidiary structure and our operations, in part, based on certain assumptions about various foreign and domestic tax laws, currency exchange requirements and capital and profit repatriation laws. While we believe our assumptions are correct, there can be no assurance that taxing or other authorities will reach the same conclusion. If our assumptions are incorrect, or if the relevant countries change or modify such laws or the current interpretation of such laws, we may suffer adverse tax and financial consequences, including the reduction of cash flow available to meet required debt service and other obligations. Any of these factors could materially adversely affect our international operations and, consequently, our business, financial position, results of operations or cash flows.

Our information technology systems are subject to cybersecurity risks and threats.

We depend on information technology systems to conduct our operations, including critical systems on our drilling units, and these systems are subject to risks associated with cyber incidents or attacks. Due to the nature of cyber attacks, breaches to our systems could go unnoticed for a prolonged period of time. These cybersecurity risks could disrupt our operations and result in downtime, loss of revenue or the loss of critical data as well as result in higher costs to correct and remedy the effects of such incidents. If our systems for protecting against cyber incidents or attacks prove to be insufficient and an incident were to occur, it could have a material adverse effect on our business, financial condition, results of operations or cash flows. Currently we carry limited insurance for losses related to cybersecurity attacks, and may determine not to obtain such insurance in the future.

Our business is subject to war, sabotage, terrorism and piracy, which could have an adverse effect.

Current and future military campaigns may have unforeseen effects on the energy industry in general, or us in particular, in the future. Uncertainty surrounding retaliatory military strikes or a sustained military campaign may affect our operations in unpredictable ways, including changes in the insurance markets, disruptions of fuel supplies and markets, particularly oil, and the possibility that infrastructure facilities, including pipelines, production facilities, refineries, electric generation, transmission and distribution facilities, could be direct targets of, or indirect casualties of, an act of terror. War or risk of war may also have an adverse effect on the economy.

Acts of war, sabotage, terrorism, piracy and social unrest, brought about by world political events or otherwise, have caused instability in the world’s financial and insurance markets in the past and may continue to do so in the future. Such acts could be directed against companies such as ours and could also adversely affect the oil, gas and power industries and restrict their future growth. Insurance premiums could increase and coverage may be unavailable in the future.

Failure to obtain and retain key personnel could impede our operations.

We depend to a significant extent upon the efforts and abilities of our executive officers and other key management personnel. There is no assurance that these individuals will continue in such capacity for any particular period of time. The loss of the services of one or more of our executive officers or other personnel could adversely affect our operations.

We require highly skilled personnel to operate our drilling rigs and provide technical services and support for our business worldwide. Historically, competition for the labor required for drilling operations and construction projects, has intensified as the number of rigs activated, added to worldwide fleets or under construction increased, leading to shortages of qualified personnel in the industry and creating upward pressure on wages and higher turnover. We may experience increased competition for the crews necessary to operate our rigs. If increased competition for labor were to intensify in the future, we may experience increases in costs or reductions in experience levels which could impact operations. The shortages of qualified personnel or the inability to obtain and retain qualified personnel could also negatively affect the quality, safety and timeliness of our work.

Significant parts or equipment shortages, supplier capacity constraints, supplier production disruptions, supplier quality and sourcing issues or price increases could increase our operating costs, decrease our revenues and adversely impact our operations.

Our operations rely on a significant supply of capital equipment and consumable spare parts to maintain and repair our fleet. We also rely on the supply of ancillary services, including supply boats and helicopters. Certain high specification parts and equipment we use in our operations may be available only from a small number of suppliers, manufacturers or service providers, or in some cases must be sourced through a single supplier, manufacturer or service provider. A disruption in the deliveries from such third-party suppliers, manufacturers or service providers, capacity constraints, production disruptions, price increases, quality control issues, recalls or other decreased availability of parts and equipment could adversely affect our ability to meet our commitments to clients, adversely impact our operations and revenues, delay our rig upgrade, repair or construction projects, or increase our operating costs.

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

Certain of our employees and contractors in international markets are represented by labor unions or work under collective bargaining or similar agreements, which are subject to periodic renegotiation. Efforts may be made from time to time to unionize portions of our workforce. In addition, we may be subject to strikes or work stoppages and other labor disruptions in the future. Additional unionization efforts, new collective bargaining agreements or work stoppages could materially increase our costs, reduce our revenues or limit our operational flexibility.

Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas we help our clients discover.

There is a concern that emissions of greenhouse gases (“GHG”) may alter the composition of the global atmosphere in ways that affect the global climate. Climate change, including the impact of global warming, may create physical and financial risk. Physical risks from climate change include an increase in sea level and changes in weather conditions. Given the maritime nature of our business, we do not believe that physical climate change is likely to have a material adverse effect on us. Financial risks relating to climate change are likely to arise from increasing legislation and regulation, as compliance with any new rules could be difficult and costly.

U.S. federal legislation has been proposed in Congress to reduce GHG emissions, but to date efforts to pass federal legislation limiting GHG emissions have not been successful, though it is possible that such legislation may be enacted in the U.S. in the future. Foreign jurisdictions are also addressing climate changes by legislation or regulation. The adoption of legislation and regulatory programs to reduce emissions of GHGs could require us to incur increased fuel, environmental and other costs and capital expenditures to comply. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial position, results of operations or cash flows.

Adverse impacts upon the oil and gas industry relating to climate change may also affect us as demand for our services depends on the level of activity in offshore oil and natural gas exploration, development and production. Although we do not expect that demand for oil and gas will lessen dramatically over the short term, concerns about climate change may reduce the demand for oil and gas in the long term. In addition, increased regulation of GHG may create greater incentives for use of alternative energy sources. Any long term material adverse effect on the oil and gas industry may have a material adverse effect on our financial position, results of operations or cash flows, but we cannot reasonably or reliably estimate if it will occur, when it will occur or that it will impact us.

We are subject to the anti-takeover provisions of our constitutive documents and Texas law.

Holders of the shares of an acquisition target often receive a premium for their shares upon a change of control. Texas law and provisions of constitutive documents could have the effect of delaying or preventing a change of control and could prevent holders of our common stock from receiving such a premium. For example, Texas law prohibits us from engaging in a business combination with any shareholder for three years from the date that person became an affiliated shareholder by beneficially owning 20% or more of our outstanding common stock, in the absence of certain board of director or shareholder approvals.

In addition, under our By-laws, special meetings of shareholders may not be called by anyone other than our Board of Directors, the Chairman of the Board of Directors, our President and Chief Executive Officer, or the holders of at least 10% of the shares of our capital stock entitled to vote at such meeting.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Our property consists primarily of mobile offshore drilling rigs and ancillary equipment. Nine of our rigs are pledged under our Credit Facility. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Revolving Credit Facility” in Item 7 of this Form 10-K.

We lease our office at our corporate headquarters in the United States and own or lease support offices in Australia, Malaysia, Thailand, Singapore, Luxembourg, Mauritius, the United Arab Emirates and the United Kingdom.

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We incorporate by reference in response to this item the information set forth in Item 1, Item 7 and Note 3 to our Consolidated Financial Statements in this Form 10-K.

ITEM 3. LEGAL PROCEEDINGS

We have certain actions, claims and other matters pending as discussed and reported in Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K. As of September 30, 2016, we were also involved in a number of lawsuits which have arisen in the ordinary course of business and for which we do not expect the liability, if any, resulting from these lawsuits to have a material adverse effect on our current financial position, results of operations or cash flows. We cannot predict with certainty the outcome or effect of any of these matters described above or any such other proceeding or threatened litigation or legal proceedings. There can be no assurance that our beliefs or expectations as to the outcome or effect of any lawsuit or other matters will prove correct and the eventual outcome of these matters could materially differ from management's current estimates.

ITEM 4. MINE SAFETY DISCLOSURE

Not applicable.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is traded on the New York Stock Exchange under the symbol "ATW". As of November 9, 2016, there were approximately 58 record owners of our common stock. On November 9, 2016, the closing price of our shares as reported by the NYSE was $7.35 per share.

The following table sets forth the range of high and low closing intraday prices per share of our common stock as reported by the NYSE for the periods indicated.

	Fiscal 2016		Fiscal 2015	
Quarters Ended	Low	High	Low	High
December 31	$9.98	$19.65	$26.36	$43.85
March 31	4.82	11.46	26.12	35.24
June 30	7.52	13.33	25.89	35.66
September 30	6.12	13.79	14.15	26.50

We paid a dividend of $0.25 per share in each of January, April, July and October 2015 that was declared in September 2014, February 2015, May 2015 and August 2015, respectively. We paid a dividend of $0.075 per share in January 2016 that was declared in November 2015. In February 2016, our board of directors eliminated the payment of a quarterly dividend in order to preserve liquidity. In March 2016, we amended our Credit Facility, which amendment, among other things, prohibits us from paying dividends during the term of the Credit Facility. Future reinstatement of dividends would require the amendment or waiver of such provision. In addition, the declaration and amount of any future dividends would be at the discretion of our board of directors and would depend on our financial condition, results of operations, cash flows, prospects, industry conditions, capital requirements and other factors and restrictions our board of directors deemed relevant. There can be no assurance that we will pay a dividend in the future.

Under our long-term incentive plans, employees may elect to have us withhold shares to satisfy minimum statutory federal, state and local tax withholding obligations arising from the vesting of restricted stock awards and exercise of stock options. When we withhold these shares, we are required to remit to the appropriate taxing authorities the market price of the shares withheld, which could be deemed a purchase of shares by us on the date of withholding. During the quarter ended September 30, 2016, we withheld the following shares to satisfy tax withholding obligations:

Period	No. of Shares	Average Price
July 1 - July 31, 2016	762	$ 11.96
August 1 - August 31, 2016	—	—
September 1 - September 30, 2016	—	—
Total	762	

Information concerning securities authorized for issuance under equity compensation plans is incorporated by reference from our definitive Proxy Statement for the 2017 Annual Meeting of Shareholders, to be filed with the SEC not later than 120 days after the end of the fiscal year covered by this Form 10-K.

Performance Graph

Below is a comparison of five-year cumulative total returns among Atwood Oceanics, Inc. and the Center for Research in Security Prices ("CRSP") index for the NYSE/AMEX/NASDAQ stock markets, and our self-determined peer group of drilling companies. Total returns assume that $100 was invested in each on September 30, 2011, dividends, if any, were reinvested and a September 30 fiscal year end.

	Fiscal Year Ended September 30,					
CRSP Total Returns Index for:	2011	2012	2013	2014	2015	2016
Atwood Oceanics, Inc.	100.0	132.3	160.2	127.2	45.0	26.6
NYSE/AMEX/Nasdaq Stock Markets (U.S. Companies)	100.0	129.7	157.8	185.4	182.8	210.5
Self-determined Peer Group	100.0	125.9	137.0	97.2	38.7	28.0

Our self-determined peer group (weighted according to market capitalization as of September 30, 2016) is as follows: Diamond Offshore Drilling, Inc., Ensco plc, Noble Corporation plc, Rowan Companies plc, SeaDrill Limited and Transocean Ltd.

The performance graph above is furnished and not filed for purposes of Section 18 of the Securities Exchange Act of 1934 and will not be incorporated by reference into any registration statement filed under the Securities Act of 1933 unless specifically identified therein as being incorporated therein by reference. The performance graph is not soliciting material subject to Regulation 14A.

ITEM 6. SELECTED FINANCIAL DATA

Selected financial data for each of the last five fiscal years is presented below:

	At or For the Years Ended September 30,				
(In thousands, except per share amounts and ratios)	2016	2015	2014	2013	2012
STATEMENTS OF OPERATIONS DATA:					
Total revenues	$1,020,644	$1,395,851	$1,173,953	$1,063,663	$787,421
Contract drilling costs and reimbursable expenses	(406,826)	(559,165)	(562,353)	(458,925)	(347,179)
Depreciation	(165,669)	(171,947)	(147,358)	(117,510)	(70,599)
General and administrative	(50,550)	(57,229)	(61,461)	(56,786)	(49,776)
Asset impairment	(103,539)	(60,777)	—	—	—
Gain (loss) on sale of assets	(77)	(15,303)	34,139	(971)	(457)
Other, net	299	—	1,864	—	—
Operating income	294,282	531,430	438,784	429,471	319,410
Other expense	18,473	(52,460)	(41,491)	(24,670)	(6,106)
Tax provision	(47,483)	(46,397)	(56,471)	(54,577)	(41,133)
Net Income	$265,272	$432,573	$340,822	$350,224	$272,171
PER SHARE DATA:					
Earnings per common share:					
Basic	$4.09	$6.70	$5.31	$5.38	$4.17
Diluted	$4.09	$6.65	$5.24	$5.32	$4.14
Average common shares outstanding:					
Basic	64,789	64,581	64,240	65,073	65,267
Diluted	64,839	65,030	65,074	65,845	65,781
Cash dividends declared per share	$0.075	$0.75	$0.25	—	—
BALANCE SHEET DATA*:					
Cash	$145,427	$113,983	$80,080	$88,770	$77,871
Working capital	343,686	470,487	330,430	296,888	232,887
Property and equipment, net	4,127,696	4,172,132	3,967,028	3,164,724	2,537,340
Total assets	4,539,792	4,801,333	4,507,228	3,657,266	2,943,762
Total debt	1,227,919	1,678,268	1,742,122	1,263,232	830,000
Shareholders' equity	3,230,386	2,947,170	2,555,524	2,207,371	1,939,422
Ratio of current assets to current liabilities	7.96	4.47	2.97	2.89	2.69

* We reclassified $7.7 million from working capital to Total Debt in the September 30, 2015 Consolidated Balance Sheet presented in this Form 10-K to conform to the current year presentation of debt issuance costs. See Note 2 to the Consolidated Financial Statements in Item 8 of this Form 10-K.

	At or For the Years Ended September 30,				
	2016	2015	2014	2013	2012
FLEET DATA:					
Rig count (at end of period)					
All rigs (1)	10	11	13	13	11
In-service rigs (2)	4	11	12	11	9
Utilization rate - full (3)					
All rigs	72 %	98 %	83 %	83 %	75 %
In-service rigs (2)	98 %	98 %	94 %	100 %	96 %
Utilization rate - available (4)					
All rigs	73 %	99 %	85 %	84 %	78 %
In-service rigs (2)	100 %	99 %	97 %	100 %	100 %
Revenue Efficiency (5)	97 %	94 %	94 %	94 %	95 %

(1) Excludes Atwood Falcon which was sold in April 2016. However, utilization and revenue efficiency includes Atwood Falcon for the period owned.

(2) In-service rigs exclude idled rigs. Subsequent to September 30, 2016, we idled the Atwood Beacon. See "Management's Discussion and Analysis of Financial Condition and Results of Operations-Market Outlook" for further discussion of idled rigs.

(3) Full utilization rate is calculated by dividing the actual number of days a rig was under contract during the year by 365 days.

(4) Available utilization rate is calculated by dividing the actual number of days a rig was under contract during the period by the number of days a rig was available to be under contract during the period, which excludes out of service time for planned regulatory projects between contracts.

(5) Revenue efficiency percentage is derived from total drilling revenue earned (in dollars, excluding mobilization revenue) divided by the full operating dayrate multiplied by the maximum potential revenue earning days on contract. This represents the percentage of operating revenue earned versus the maximum revenue earned in the period. Planned maintenance days, rig unavailable days, and mobilization days are excluded from the calculation of revenue earning days on contract.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion is intended to assist in understanding our financial position as of September 30, 2016 and 2015 and our results of operations for the fiscal years ended September 30, 2016, 2015 and 2014 and should be read in conjunction with the accompanying consolidated financial statements and related notes in Item 8 of this Form 10-K. The following discussion and analysis contains forward-looking statements that involve risks and uncertainties. Our actual results may differ materially from those anticipated in these forward-looking statements as a result of certain factors, including those set forth under Item 1A "Risk Factors" and elsewhere in this Form 10-K. See "Forward-Looking Statements".

OVERVIEW

Financial and operating results for the fiscal year ended September 30, 2016, include:

- Operating revenues totaling $1.0 billion on 2,776 operating days as compared to operating revenues of $1.4 billion on 4,015 operating days for the fiscal year ended September 30, 2015;
- Net income of $265.3 million as compared to net income of $432.6 million for the fiscal year ended September 30, 2015;
- Diluted earnings per share of $4.09 as compared to diluted earnings per share of $6.65 for the fiscal year ended September 30, 2015;
- Net cash provided by operating activities of $625.0 million as compared to net cash provided by operating activities of $604.3 million for the fiscal year ended September 30, 2015;
- Increase in cash on hand of $31.4 million for the fiscal year ended September 30, 2016;
- Capital expenditures of $223.7 million for the fiscal year ended September 30, 2016, as compared to capital expenditures of $448.0 million for the fiscal year ended September 30, 2015;
- Debt to book capitalization ratio of 28% as of September 30, 2016.

MARKET OUTLOOK

Industry Conditions

The level of activity in the offshore drilling industry, which affects the sector's profitability, is cyclical and highly dependent on the offshore capital expenditure levels of E&P companies. In turn, E&P company offshore drilling expenditures are influenced by the current prices of oil and gas, expectations about future prices, company-specific cash flow levels, historical project returns and other capital allocation strategies (e.g., onshore versus offshore drilling).

The offshore drilling industry is in the midst of a very severe downturn that began in the second half of calendar year 2014. Since that time, the industry has experienced declining demand for drilling rigs that has been exacerbated by a sharp decline in oil prices. E&P companies generally reduced their offshore capital spending in 2015 and 2016 by canceling or deferring planned drilling programs. Since declining to multi-year lows below $30 per barrel in January 2016, oil prices have recovered to approximately $50 per barrel in October 2016. However, we expect offshore rig demand to decline further into the first half of calendar year 2017 due to increased rig supply as offshore rigs complete existing contracts or have their contracts shortened or canceled at a faster rate than new drilling programs are initiated. Declines in offshore drilling demand and the associated reductions in rig utilization and day rates could materially and adversely affect our financial position, results of operation or cash flows. See "Our business depends on the level of activity in the oil and natural gas industry, which is significantly impacted by the volatility in oil and natural gas prices" under "Risk Factors" Item 1A of this Form 10-K.

Even as offshore rig demand declined from the peak levels in calendar year 2014, some drilling contractors continued to take delivery of new, more capable rigs that were ordered prior to the current industry downturn. However, over the past year drilling contractors have generally delayed further rig deliveries, especially for uncontracted rigs, through renegotiation of terms with the shipyards that are constructing these rigs. Due to the confluence of an oversupply of offshore rigs and declining rig demand, a lower percentage of marketed rigs are being re-contracted, and day rates and utilization have declined sharply across all offshore rig classes. While clients generally prefer newer, high specification rigs over older, less capable rigs, many newer floaters and jackups have been idled or cold-stacked as drilling demand has declined across all regions, water depths and rig classes. The bifurcation trend of higher utilization rates for newer rigs has been generally muted, and maintained more consistently for floaters than for jackups.

Due to the uncertain duration of the current industry downturn, a growing number of older, less capable rigs have been scrapped or announced for scrapping, and this trend has accelerated throughout calendar year 2016. Even with the removal of approximately 39 floaters and 38 jackups from the supply stack since the beginning of calendar year 2016, further declines in rig utilization and day rates are possible due to the persistent oversupply of offshore rigs relative to demand.

Consistent with our policy, we evaluate our drilling rigs and related equipment for impairment whenever events or changes in circumstances indicate the carrying value of these assets may exceed the estimated future net cash flows. Our evaluation, among other things, includes a review of external market factors and an assessment on the future marketability of a specific drilling unit. Further declines in offshore drilling demand, and/or a lack of improvement in drilling activity or day rates, may result in potential impairments to our drilling rigs and related equipment in the future. See "We may be required to record impairment charges with respect to our rigs" under "Risk Factors" Item 1A of this Form 10-K.

A current trend of some E&P companies to cancel, renegotiate, or repudiate existing drilling contracts has continued throughout 2016 as rig demand and market day rates have declined further. In fiscal year 2015, we renegotiated four drilling contracts with respect to the Atwood Osprey, Atwood Beacon, Atwood Achiever and the Atwood Orca. These four agreements incorporated reduced day rates for some portion of the existing term in exchange for the extensions in the terms of the contracts. In March 2016, we negotiated with a client to shift its remaining contract backlog from the Atwood Eagle to the Atwood Osprey in order to preserve the continuity of operations for the Atwood Osprey.

Some of our contracts with clients may be canceled at the option of the client upon payment of a termination fee which may not fully compensate us for the loss of the contract and may result in a rig being idled for an extended period of time. In addition, some of our clients could experience liquidity or solvency issues or could otherwise be unable or unwilling to perform under a contract, which could ultimately lead a client to enter bankruptcy or otherwise encourage a client to seek to repudiate, cancel or renegotiate a contract. Further deterioration in cash flow generation by E&P companies may accelerate these trends. If our clients seek to cancel or renegotiate our significant contracts and we are unable to negotiate favorable terms or secure new contracts on substantially similar terms, or at all, our revenues and profitability could be materially reduced. See "Our business may experience reduced profitability if our clients terminate or seek to renegotiate our drilling contracts" under "Risk Factors" Item 1A of this Form 10-K.

Ultra-deepwater and Deepwater Rig Markets

Both the ultra-deepwater and deepwater rig markets are experiencing declining demand, utilization and day rates. As of November 2, 2016, 97 ultra-deepwater rigs were under contract industry-wide (versus 128 on November 4, 2015) representing 74% utilization of a total of 131 actively marketed rigs. The number of marketed deepwater rigs under contract decreased to 21 (from 35 on November 4, 2015), which represents 57% utilization of the 37 active rigs. Declines in the percentage of marketed rigs under contract have been driven by reduced rig demand across all geographic regions coupled with an increase in marketed supply due to deliveries of newbuild rigs, primarily from South Korean and Singaporean shipyards.

As of November 2, 2016, 31 ultra-deepwater floaters were under construction with scheduled deliveries through September 2020, eight of which were contracted. However, this figure includes five floaters under long-term contracts with Petrobras, some or all of which may be delayed, repudiated, or canceled due to the extensive financial difficulties of the primary Brazilian rig-owning entity. In response to reduced rig demand and lack of suitable drilling programs, we and other drilling contractors have delayed delivery of uncontracted ultra-deepwater rigs under construction. Three ultra-deepwater rigs are scheduled for delivery during the remainder of calendar year 2016, 19 are scheduled for delivery in calendar year 2017 and an additional nine units are scheduled for delivery in calendar year 2018 and beyond.

The number of idle offshore rigs being cold-stacked and scrapped has continued to increase due to the challenging market conditions. During calendar year 2016, 26 ultra-deepwater rigs and 13 deepwater rigs have been announced for cold-stacking, retirement or scrapping and are no longer being actively marketed. We expect accelerated attrition of marketed supply to continue into calendar year 2017 as there will be limited re-contracting of floaters that complete their drilling programs, leading to a growing supply of idle rigs.

Our Ultra-deepwater Rigs and Deepwater Rigs

The Atwood Achiever, a dynamically positioned, ultra-deepwater drillship, is operating offshore Northwest Africa and is contracted through approximately November 2018. The client has an option, exercisable by February 2017, to revert the contract to its original end date of November 2017 by making a payment approximately equal to the difference in the original day rate for the time periods for which the current reduced operating day rate was invoiced.

The Atwood Advantage, a dynamically positioned, ultra-deepwater drillship, completed operations in the U.S. Gulf of Mexico in September 2016, after which it mobilized to the Mediterranean Sea to resume operations under its existing contract through August 2017.

The Atwood Condor, a dynamically positioned, ultra-deepwater semisubmersible, is operating in the U.S. Gulf of Mexico and is contracted into January 2017.

The Atwood Osprey, an ultra-deepwater semisubmersible, and the Atwood Eagle, a deepwater semisubmersible, were both operating offshore Australia at the beginning of calendar 2016. On March 19, 2016, the Atwood Eagle's drilling services contract with Woodside Energy Ltd. was mutually amended to assign and utilize the Atwood Osprey to perform drilling services for the remaining 165 days under contract. The Atwood Osprey is currently drilling the assigned program for Woodside Energy Ltd., and the material contractual terms and conditions of the Atwood Eagle's original drilling services contract, including day rate, have remained unchanged. The Atwood Eagle was mobilized to Singapore where the rig is currently idle and being actively marketed for a new drilling contract.

The Atwood Admiral and Atwood Archer are DP-3 dynamically-positioned, dual derrick, ultra-deepwater drillships rated to operate in water depths up to 12,000 feet and are currently under construction at the DSME shipyard in South Korea. These drillships will have enhanced technical capabilities, including two seven-ram BOPs, three 100-ton knuckle boom cranes, a 165-ton active heave "tree-running" knuckle boom crane and 200 person accommodations. Total cost, including capitalized interest, project management, drilling and handling tools and spares, is approximately $635 million per drillship.

The Atwood Admiral and Atwood Archer were originally scheduled to be delivered in March 2015 and December 2015, respectively. Due to lack of suitable drilling programs, we have not yet secured the initial drilling contracts for these rigs. As a result, we have entered into amendments to our construction contracts with DSME to delay the required delivery date of these two rigs to September 30, 2017 and June 30, 2018, respectively. We are unable to provide any assurance that we will obtain drilling contracts for these rigs prior to their delivery. See Note 3 to our Consolidated Financial Statements in Item 8 of Part II of this Annual Report on Form 10-K for further details of these amendments.

Jackup Rig Market

The jackup market is experiencing similar utilization, demand and day rate challenges as the floater market. Declining rig demand coupled with delivery of newbuild rigs, primarily from shipyards in China and Singapore, have negatively impacted the jackup rig supply and demand balance worldwide. In the current market downturn, all classes of jackup rigs have experienced lower day rates and utilization. The bifurcation trend that has historically favored utilization of new, higher specification jackups at the expense of older, lower specification jackups is not currently being maintained as clients have become much more price sensitive and are drilling fewer technically challenging wells. As of November 2, 2016, the percentage of marketed high specification jackup rigs (i.e., rigs equal to or greater than 350-foot water depth capability) under contract was approximately 63%, as compared to 69% for the remainder of the global jackup fleet.

We expect that the potential for further increases in global jackup supply due to delivery of high specification newbuild rigs may put additional pressure on jackup rig utilization and day rates. As of November 2, 2016, there were 106 newbuild jackup rigs under construction (from 125 on November 4, 2015), most of which are being constructed in China and many of which are owned by speculators or the constructing shipyards. Of the 23 jackup rigs scheduled for delivery in the remainder of calendar year 2016, only three are contracted, while the remaining 83 rigs are scheduled for delivery primarily in calendar year 2017 and beyond. Similar to what has occurred with newbuild floaters, many of these scheduled jackup deliveries are expected to be delayed and/or canceled. Absent a strong recovery in high specification jackup rig demand and/or a significant reduction in jackup rig supply due to cold-stacking, scrapping or retirements, the marketed supply of jackups is likely to exceed client requirements well into calendar year 2017.

Through November 2, 2016, 13 high specification jackups and 25 standard jackups, were cold-stacked, scrapped or retired during calendar year 2016. This trend of accelerating marketed supply attrition is expected to continue into calendar year 2017 as older rigs face further declines in overall jackup demand and increased competition from newer, more capable rigs.

Our High Specification Jackup Rigs

The Atwood Mako and Atwood Manta, both 400-foot water depth Pacific Class jackup rigs, operated offshore Vietnam through September 2015 and offshore Thailand through October 2015, respectively. Both were idled in October 2015 after they completed their contracts and were unable to obtain follow-on work. We are continuing to actively market these high-specification jackup rigs while they are idle.

The Atwood Aurora, a 350-foot water depth jackup, completed operations offshore West Africa in September 2016 and is scheduled to relocate to Ghana where it will be idled. The Atwood Beacon, a 400-foot water depth jackup, completed operations in the Mediterranean Sea in July 2016 and is currently idle in Malta. The Atwood Orca, a 400-foot water depth Pacific Class jackup completed operations in offshore Thailand in October 2016 and is scheduled to relocate to Singapore where it will be idled. All three of these rigs will be actively marketed while idle.

Sale of Rigs

The Atwood Falcon, a deepwater semisubmersible, was operating offshore Australia through March 2016. Following contract completion and mobilization of the vessel to international waters, on March 24, 2016, we executed a sale and recycling agreement with a third party buyer for the purpose of selling the Atwood Falcon. The agreement required the buyer to demolish and recycle the vessel and associated equipment/machinery. On April 13, 2016, the Atwood Falcon sale and recycling transaction closed and title of the vessel and associated equipment and machinery transferred to a third party buyer.

In December 2014, we completed the sale of our last mid-water floater semisubmersible, the Atwood Southern Cross. The Atwood Hunter, a deepwater semisubmersible, was idled in December 2014 and in January 2015, we made the decision to scrap and recycle the rig. In August 2015, we completed the sale of the Atwood Hunter for recycling.

Contract Backlog

We maintain a backlog of commitments for contract drilling revenues. Our contract backlog as of September 30, 2016 was approximately $0.8 billion representing a 50% decrease compared to our contract backlog of $1.6 billion as of September 30, 2015 primarily due to realization of contract backlog. We calculate our contract backlog by multiplying the day rate under our drilling contracts by the number of days remaining under the contract, assuming full utilization. The calculation does not include any revenues related to mobilization, demobilization, contract preparation, and billing our clients for reimbursable items or bonuses. The amount of actual revenues earned and the actual periods during which revenues are earned will be different from the amounts disclosed in our backlog calculations due to a lack of predictability of various factors, including newbuild rig delivery dates, client-elected standby periods, unscheduled repairs, maintenance requirements, weather delays and other factors. Such factors may result in lower applicable day rates than the full contractual day rates and/or delays in receiving the full contractual operating rates. In addition, under certain circumstances, our clients may seek to terminate, repudiate or renegotiate our contracts, which could have the effect of reducing our contract backlog. See “Our business may experience reduced profitability if our clients terminate, repudiate, or seek to renegotiate our drilling contracts” under "Risk Factors" Item 1A of this Form 10-K.

The following tables set forth the amount of our contract drilling revenue backlog and the percentage of available operating days committed for our fleet, excluding drilling units under construction, for the periods indicated as of September 30, 2016.

Contract Drilling Revenue Backlog	Fiscal 2017	Fiscal 2018	Fiscal 2019	Fiscal 2020	Fiscal 2021 and thereafter	Total
(In millions)						
Ultra-deepwater	$429	$233	$89	$—	$—	$751
Deepwater	—	—	—	—	—	—
Jackups	2	—	—	—	—	2
	$431	$233	$89	$—	$—	$753

Percentage of Available Operating Days Committed	Fiscal 2017	Fiscal 2018	Fiscal 2019	Fiscal 2020	Fiscal 2021 and thereafter
(In millions)					
Ultra-deepwater	62 %	44 %	27 %	~~%~~	~~%~~
Deepwater	— %	— %	— %	~~%~~	~~%~~
Jackups	2 %	— %	— %	~~%~~	~~%~~
	25 %	17 %	11 %	~~%~~	~~%~~

RESULTS OF OPERATIONS

Fiscal Year 2016 versus Fiscal Year 2015

Revenues—Revenues for fiscal year 2016 decreased $375 million, or 27%, compared to the prior fiscal year. Fiscal year 2016 included 2,776 operating days versus 4,015 operating days in fiscal year 2015. A comparative analysis of revenues for fiscal years 2016 and 2015 is as follows:

	REVENUES		
(In millions)	Fiscal 2016	Fiscal 2015	Variance
Ultra-Deepwater	$708	$721	$ (13)
Deepwater	131	336	(205)
Jackups	138	285	(147)
Reimbursable	44	54	(10)
	$1,021	$1,396	$ (375)

Our ultra-deepwater fleet realized average revenues of $495,000 per day on 1,430 operating days for fiscal year 2016, as compared to $501,000 per day on 1,440 operating days for fiscal year 2015. The decrease in revenues for the ultra-deepwater fleet for fiscal year 2016 was primarily due to the commencement of the Atwood Advantage P&A well program at a lower day rate in late 2016 and the rig's 13 days at zero rate to mobilize to Israel for the remainder of the drilling contract.

The deepwater fleet realized average revenues of $426,000 per day on 307 operating days as compared to $425,000 per day on 790 operating days for fiscal year 2016 and 2015, respectively. The decrease in operating days and revenue for fiscal year 2016, compared to fiscal year 2015, is primarily due to the Atwood Falcon and Atwood Eagle completing their contracts in the first half of fiscal year 2016. None of the rigs in our deepwater fleet operated in the second half of fiscal year 2016.

Our jackup fleet realized average revenues of $133,000 per day on 1,039 operating days for fiscal year 2016, as compared to $160,000 per day on 1,785 operating days for fiscal year 2015. The jackup fleet realized lower revenue and operating days for fiscal year 2016, as compared to fiscal year 2015 primarily due to the Atwood Manta and the Atwood Mako being idled early in fiscal year 2016.

Revenue related to reimbursable expenses is primarily driven by our clients' requests for equipment, fuel, services and/or personnel that are not included in the contractual operating day rate. Thus, these revenues vary depending on the timing of the clients' requests and the work performed. Additionally, as a result of a number of our rigs being idled, reimbursable revenues naturally decline while the rigs remain un-contracted. Changes in the amount of revenue related to reimbursable expenses generally do not have a material effect on our financial position, results of operations, or cash flows.

Drilling Costs—Drilling costs for fiscal year 2016 decreased $152 million, or 27%, compared to the prior fiscal year. Fiscal year 2016 included 2,776 operating days versus 4,015 operating days in fiscal year 2015. A comparative analysis of drilling costs for fiscal years 2016 and 2015 is as follows:

	DRILLING COSTS		
(In millions)	Fiscal 2016	Fiscal 2015	Variance
Ultra-Deepwater	$225	$264	$ (39)
Deepwater	73	127	(54)
Jackups	79	126	(47)
Reimbursable	28	39	(11)
Other	2	3	(1)
	$407	$559	$ (152)

Ultra-deepwater drilling costs decreased during fiscal year 2016, as compared to fiscal year 2015. Average drilling costs per calendar day for our ultra-deepwater rigs decreased from approximately $182,000 for fiscal year 2015, to approximately $154,000 for fiscal year 2016. Drilling costs for our ultra-deepwater rigs were lower in 2016 due to cost saving initiatives executed on payroll and repairs and maintenances costs. Additionally, repair costs in fiscal year 2015 were higher due to the unplanned repair costs incurred on the Atwood Osprey as a result of damages from Tropical Cyclone Olwyn.

Deepwater drilling costs decreased during fiscal year 2016, as compared to fiscal year 2015. Average drilling costs per calendar day for our deepwater rigs decreased from approximately $154,000 for fiscal year 2015, to approximately $130,000 for fiscal year 2016. This decrease is primarily due to the Atwood Falcon and Atwood Eagle completing their contracts in the first half of fiscal year 2016.

Jackup drilling costs decreased during fiscal year 2016, as compared to fiscal year 2015, primarily due to the Atwood Mako and Atwood Manta being idled in October 2015. Also due to the idling of these rigs, the average drilling cost per calendar day decreased approximately $26,000 from fiscal year 2015.

Reimbursable costs are primarily driven by our clients' requests for equipment, fuel, services and/or personnel that are not typically included in the contractual operating day rate. Thus, these costs vary depending on the timing of the clients' requests and the work performed. Additionally, as a result of a number of our rigs being idled, reimbursable costs naturally decline while the rigs remain un-contracted. Changes in the amount of reimbursable costs generally do not have a material effect on our financial position, results of operations or cash flows.

During the three and twelve months ended September 30, 2016, we recorded a non-cash charge of $3.9 million, which is reported in Contract Drilling costs to increase our reserve for excessive and/or obsolete materials and supplies. This charge included inventory items throughout our drilling rig fleet.

Depreciation—Depreciation expense for the fiscal year 2016 decreased $6 million, or 3%, compared to the prior fiscal year. A comparative analysis of depreciation expense for fiscal years 2016 and 2015 is as follows:

	DEPRECIATION EXPENSE		
(In millions)	Fiscal 2016	Fiscal 2015	Variance
Ultra-Deepwater	$116	$113 3	$ 3
Deepwater	8	17	(9)
Jackups	35	36	(1)
Other	7	6	1
	$166	$172	$ (6)

Deepwater depreciation decreased $9 million for fiscal year 2016, as compared to fiscal year 2015 due to the impairment of the Atwood Falcon in December 2015.

The amount of depreciation expense we record is dependent upon certain assumptions, including an asset's estimated useful life, rate of consumption and salvage value. We periodically review these assumptions and may change one or more of these assumptions. Changes in our assumptions may require us to recognize, on a prospective basis, increased or decreased depreciation expense. As of September 30, 2016, we shortened the estimated useful life of the Atwood Eagle and as a result, relative to its previous deprecation schedule, this will increase the depreciation expense over the next four fiscal years by $5.8 million per fiscal year, and will decrease by $1.9 million fiscal year 2021.

Asset Impairment—We maintain drilling equipment in warehouse facilities around the world intended to support our current and future offshore drilling operations. As part of our fiscal year end evaluation of the current levels on hand and an assessment as to the expected future demand and likelihood of use, in the three month period ended September 30, 2016, we recorded a non-cash impairment charge of $38.6 million ($38.6 million net of tax or $0.60 per diluted share) in our Consolidated Statements of Operations, included in Asset Impairment to write down these assets to their fair value.

In addition, during fiscal year 2016, we recorded a non-cash impairment charge of approximately $64.9 million ($64.9 million, net of tax, or $1.00 per diluted share) to write the Atwood Falcon and its inventory of materials and supplies down to their approximate salvage value. See Note 3 to Consolidated Financial Statements in Item 8 of Part II of this Annual Report.

During fiscal year 2015, we recorded a non-cash impairment charge of approximately $60.8 million ($56.1 million, net of tax, or $0.86 per diluted share) to write the Atwood Hunter and its inventory of materials and supplies down to their salvage value. See Note 3 to Consolidated Financial Statements in Item 8 of Part II of this Annual Report.

General and Administrative—During fiscal year 2016, general and administrative expenses decreased by approximately $6.6 million to $50.6 million, as compared to $57.2 million for fiscal year 2015. This decrease was primarily due to reductions in payroll and related costs associated with several company-wide cost saving measures.

Loss on sale of assets—Our loss on sale of assets for fiscal year 2015 was primarily due to a loss of approximately $8.0 million ($7.1 million, net of tax, or $0.11 per diluted share) due to the sale of the Atwood Southern Cross and a loss of approximately $5.5 million ($5.5 million, net of tax, or $0.08 per diluted share) due to the sale of Atwood Hunter.

Interest Expense, net of capitalized interest— During fiscal year 2016, interest expense, net of capitalized interest, increased by approximately $16.0 million to $68.6 million, as compared to $52.6 million for fiscal year 2015. These increases were primarily due to a higher interest rate on our Credit Facility borrowings and lower capitalized interest.

Gains on extinguishment of debt—During the year ended September 30, 2016, we repurchased $201.4 million aggregate principal amount of our Senior Notes at an aggregate cost of $135.7 million, that included payment of accrued interest of $3.7 million. As a result of the repurchases, we recognized a total gain on debt retirement, net of the write-off of debt issuance costs and premium, of $69.0 million ($54.7 million net of tax, or $0.84 per diluted share) in Gains on Extinguishment of Debt on the Consolidated Statements of Operations for fiscal year 2016. The repurchases were made using available cash balances.

Other Income—For the fiscal year 2016, we recognized approximately $18.0 million ($18.0 million, net of tax, or $0.28 per diluted share) of expected insurance recoveries related to cyclone damage to the Atwood Osprey.

Income Taxes—Our consolidated effective income tax rate for fiscal year 2016 was approximately 15%, as compared to 10% for fiscal year 2015. The effective tax rate for fiscal year 2016 was higher than the rate for fiscal year 2015 primarily due to a change in the geographical mix of foreign income as well as taxes associated with the gain from the retirement of indebtedness which was taxed at higher domestic rates. As a consequence of that gain coupled with other domestic income, we fully utilized our deferred tax asset related to our U.S. net operating loss carry-forward and we reversed the valuation allowance associated with that deferred tax asset. Our effective tax rate was lower than the U.S. statutory rate of 35% as a result of working in certain lower tax jurisdictions outside the United States.

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Fiscal Year 2015 versus Fiscal Year 2014

Revenues—Revenues for fiscal year 2015 increased $222 million, or 19%, compared to fiscal year 2014. Fiscal year 2015 included 4,015 operating days versus 3,839 operating days in fiscal year 2014. A comparative analysis of revenues for fiscal years 2015 and 2014 is as follows:

(In millions)	REVENUES Fiscal 2015	Fiscal 2014	Variance
Ultra-Deepwater	$721	$462	$ 259
Deepwater	336	333	3
Jackups	285	308	(23)
Reimbursable	54	71	(17)
	$1,396	$1,174	$ 222

Our ultra-deepwater fleet realized average revenues of $501,000 per day on 1,440 operating days for fiscal year 2015, as compared to $440,000 per day on 1,050 operating days for fiscal year 2014. The increase in operating days and average revenue per operating day for fiscal year 2015, is largely due to the Atwood Advantage and Atwood Achiever. The Atwood Advantage was delivered in December 2013 and commenced drilling operations in April 2014 and thus operated a full year in fiscal 2015 versus a partial year in fiscal 2014. The Atwood Achiever was delivered in September 2014 and commenced drilling operations in November 2014.

Our deepwater fleet realized average revenues of $425,000 per day on 790 operating days for fiscal year 2015, as compared to $390,000 per day on 860 operating days for fiscal year 2014. The decrease in operating days for fiscal year 2015, compared to fiscal year 2014, is primarily due to the sale of the Atwood Hunter, which completed its contract in December 2014. This decrease in operating days was offset by higher day rates realized in fiscal year 2015 by the Atwood Eagle and Atwood Falcon.

Our jackup fleet realized average revenues of $160,000 per day on 1,785 operating days for fiscal year 2015, as compared to $160,000 per day on 1,929 operating days for fiscal year 2014. Overall, the jackup fleet realized lower revenue for fiscal year 2015, as compared to fiscal year 2014, due primarily to a lower number of operating days, resulting from the sale of the Vicksburg in January 2014 and uncontracted as well as out of service days on the Atwood Mako.

Reimbursable revenues are primarily driven by our clients' requests for equipment, fuel, services and/or personnel that are not included in the contractual operating day rate. Thus, these revenues vary depending on the timing of the clients' requests and the work performed. Changes in the amount of these reimbursables generally do not have a material effect on our financial position, results of operations, or cash flows.

Drilling Costs - Drilling costs for fiscal year 2015 decreased $3 million, or 1%, compared to fiscal year 2014. Fiscal year 2015 included 4,015 operating days versus 3,839 operating days in fiscal year 2014. A comparative analysis of drilling costs for fiscal years 2015 and 2014 is as follows:

(In millions)	DRILLING COSTS Fiscal 2015	Fiscal 2014	Variance
Ultra-Deepwater	$264	$167	$ 97
Deepwater	127	201	(74)
Jackups	126	132	(6)
Reimbursable	39	56	(17)
Other	3	6	(3)
	$559	$562	$ (3)

Ultra-deepwater drilling costs increased during fiscal year 2015, as compared to fiscal year 2014. Average drilling costs per calendar day for our ultra-deepwater rigs increased from approximately $170,000 for fiscal year 2014, to approximately $182,000 for fiscal year 2015, primarily as a result of the addition of the Atwood Achiever and Atwood Advantage to our fleet and due to cyclone related costs incurred on the Atwood Osprey.

Deepwater drilling costs decreased during fiscal year 2015, as compared to fiscal year 2014. Average drilling costs per calendar day for our deepwater rigs decreased from approximately $185,000 for fiscal year 2014, to approximately $154,000 for fiscal year 2015, primarily as a result of sale of the Atwood Hunter.

Jackup drilling costs decreased during fiscal year 2015, as compared to fiscal year 2014, primarily due to the sale of the Vicksburg in January 2014 and due to costs incurred by the Atwood Beacon to prepare the rig to start on its current contract in Italy in fiscal year 2014. The average drilling cost per calendar day decreased to approximately $69,000 for fiscal year 2015, from approximately $70,000 for fiscal year 2014.

Reimbursable costs are primarily driven by our clients' requests for equipment, fuel, services and/or personnel that are not typically included in the contractual operating day rate. Thus, these costs vary depending on the timing of the clients' requests and the work performed. Changes in the amount of these reimbursables generally do not have a material effect on our financial position, results of operations or cash flows.

Depreciation—Depreciation expense for fiscal year 2015 increased $25 million, or 17%, as compared to fiscal year 2014. A comparative analysis of depreciation expense for fiscal years 2015 and 2014 is as follows:

	DEPRECIATION EXPENSE		
(In millions)	Fiscal 2015	Fiscal 2014	Variance
Ultra-Deepwater	$ 113	$ 84	$ 29
Deepwater	17	21	(4)
Jackups	36	37	(1)
Other	6	5	1
	$ 172	$ 147	$ 25

Ultra-deepwater depreciation increased by $29 million during fiscal year 2015, as compared to fiscal year 2014, due to the delivery of the Atwood Advantage and Atwood Achiever, which were placed into service in December 2013 and September 2014, respectively.

Asset Impairment— During fiscal year 2015, we recorded a non-cash impairment charge of approximately $60.8 million ($56.1 million, net of tax, or $0.86 per diluted share) to write the Atwood Hunter and its materials and supplies down to their salvage value. See Note 3 to Consolidated Financial Statements in Item 8 of Part II of this Annual Report.

General and Administrative— During fiscal year 2015, general and administrative expenses decreased by approximately $4.3 million to $57.2 million, as compared to $61.5 million for fiscal year 2014. These decreases were primarily due to lower payroll related employee expenses, including share-based compensation adjustments.

Loss on sale of assets— Our loss on sale of assets of approximately $15.3 million during fiscal year, 2015 includes $8.0 million ($7.1 million, net of tax, or $0.11 per diluted share) due to the sale of the Atwood Southern Cross and approximately $5.5 million ($5.5 million, net of tax, or $0.08 per diluted share) due to the sale of the Atwood Hunter.

Interest Expense, net of capitalized interest— During fiscal year 2015, interest expense, net of capitalized interest, increased by approximately $10.8 million to $52.6 million, as compared to $41.8 million for fiscal year 2014. These increases were primarily due to lower capitalized interest in fiscal year 2015 as a result of fewer rigs under construction, as compared to fiscal year 2014.

Income Taxes— Our consolidated effective income tax rate for fiscal year 2015 was approximately 10%, as compared to 14% for fiscal year 2014. The effective tax rate for fiscal year 2015 was lower than the rate for fiscal year 2014 primarily due to a change in the geographical mix of income as well as the recognition of certain discrete tax expenses during fiscal year 2014. Our effective tax rate was lower than the U.S. statutory rate of 35% as a result of working in certain lower tax jurisdictions outside the United States.

LIQUIDITY AND CAPITAL RESOURCES

Sources of Liquidity

Our sources of available liquidity include existing cash balances on hand, cash flows from operations and borrowings under our Credit Facility. In addition, we may seek to access the debt and equity capital markets from time to time to raise additional capital, increase liquidity as necessary, fund additional purchases, exchanges or redemptions of Senior Notes, repay amounts under our Credit Facility or otherwise refinance existing debt. Our ability to access the debt and equity capital markets depends on a number of factors, including our credit rating, industry conditions, general economic conditions, our revenue backlog, capital expenditure commitments, market conditions and market perceptions of us and our industry.

Our liquidity requirements include meeting ongoing working capital needs, repaying our outstanding indebtedness, and funding our capital expenditure projects. Our ability to meet these liquidity requirements will depend in large part on our future operating and financial performance.

Our cash flows fluctuate depending on a number of factors, including, among others, the number of our drilling units under contract, the day rates that we receive under those contracts, the efficiency with which we operate our drilling units, the timing of collections on outstanding accounts receivable, timing of payments to our vendors for operating costs, and capital expenditures. We have instituted several company-wide cost savings measures, including the elimination of non-essential personnel and other operational measures, including delaying certain capital expenditure projects to reduce liquidity requirements to a level consistent with the size of our anticipated fleet operating under client contracts over the next twelve months. These activities have had and continue to have a positive impact on our cash flow generation and overall liquidity. We believe that our cash on hand, cash flows from operations and available borrowings under our Credit Facility will provide sufficient liquidity over the next twelve months to fund our working capital needs, interest payments on our outstanding debt and other purposes.

As of September 30, 2016, we had $145.4 million of cash on hand. At any time, we may require a significant portion of our cash on hand for working capital and other purposes. During fiscal year 2016, we relied principally on our cash flows from operations, cash on hand and borrowings under our Credit Facility to meet liquidity needs and fund our cash requirements including capital expenditures of $224 million. To date, general inflationary trends have not had a material effect on our operating revenues or expenses.

Cash Flows

(In thousands)	Fiscal 2016	Fiscal 2015	Fiscal 2014
Net cash provided by operating activities	625,008	$604,287	$442,620
Net cash used in investing activities	(202,939)	(452,421)	(914,215)
Net cash (used in) or provided by financing activities	(390,625)	(117,963)	462,905

Operating Activities

Working capital decreased from $470 million as of September 30, 2015 to $344 million as of September 30, 2016. Net cash from operating activities for the fiscal year 2016 was $625 million, which compared to $604 million for fiscal year 2015.

Investing Activities

Capital Expenditures

Our investing activities are primarily related to capital expenditures for property and equipment. Our capital expenditures for fiscal year 2016, including maintenance capital expenditures, totaled $224 million. Our capital expenditures for fiscal 2015, including maintenance capital expenditures, totaled $448 million.

The Atwood Admiral and Atwood Archer were scheduled to be delivered in March 2015 and December 2015, respectively. Subsequent to the initial construction agreement, we have entered into multiple amendments. On December 17, 2015, we entered into the most recent supplemental agreement No. 4 ("Supplemental Agreement No. 4") for each rig with DSME, which delayed the required delivery date for these rigs to September 30, 2017 and June 30, 2018, respectively. Supplemental Agreement No. 4 amends all material terms of the previous agreements. In consideration of the agreement, we made a payment of $50 million for each drillship on December 31, 2015. All remaining milestone payments, $93.9 million for the Atwood Admiral and $305.9 million for the Atwood Archer, have been extended until their respective delivery dates. As of September 30, 2016, we have expended approximately $845 million on our drilling units under construction. As of September 30, 2016, we estimate the remaining costs including firm commitments, project management, capitalized interest, drilling tools, handling tools and spares for our drilling units under construction to be $425 million. Neither of these drillships have long-term drilling contracts in place and we may seek to delay delivery further to align delivery with anticipated offshore drilling demand. We believe that our future results of operations and cash flows will be sufficient to fund remaining construction costs for our drilling units under construction. However, actual results of operations and cash flow in the future may differ from our current expectations.

Sale of assets

During April 2016, the Atwood Falcon sale and recycling transaction closed and title of the vessel and associated equipment and machinery transferred to a third party buyer. Net proceeds were immaterial.

During August 2015, we completed the sale of our rig, the Atwood Hunter, for recycling. We received $2.9 million in proceeds and we recorded a loss of approximately $5.5 million ($5.5 million, net of tax, or $0.08 per diluted share).

During December 2014, we completed the sale of our rig, the Atwood Southern Cross, for recycling. We received $2.1 million in proceeds and incurred related costs of $2.0 million. We recorded a loss of approximately $8.0 million ($7.1 million, net of tax, or $0.11 per diluted share).

Financing Activities

Our financing activities primarily consist of borrowing and repayment of long-term and short-term debt and, until January 2016, dividend payments. Proceeds received from issuances of long-term debt and borrowings from our bank Credit Facility totaled $45 million for fiscal year 2016, $225 million for fiscal year 2015 and $700 million for fiscal year 2014. Repayments on our Credit Facility was $295 million for fiscal year 2016, $280 million for fiscal year 2015 and $220 million for fiscal year 2014. We had repayments of short-term debt of $12 million for fiscal year 2015 and $14 million for fiscal year 2014. In addition, during the year ended September 30, 2016, we repurchased $201.4 million aggregate principal amount of our Senior Notes at an aggregate purchase price of $132.0 million.

Dividends

We paid a dividend of $0.075 per share in January 2016 that was declared in November 2015. In February 2016, our board of directors eliminated the payment of a quarterly dividend in order to preserve liquidity. In March 2016, we amended the Credit Facility, which amendment, among other things, prohibits us from paying dividends during the remaining term of the Credit Facility. Future reinstatement of dividends would require the amendment or waiver of such provision. In addition, the declaration and amount of any future dividends would be at the discretion of our board of directors and would depend on our financial condition, results of operations, cash flows, prospects, industry conditions, capital requirements and other factors and restrictions our board of directors deemed relevant. There can be no assurance that we will pay a dividend in the future.

Senior Notes (Due February 2020)

During the year ended September 30, 2016, we repurchased $201.4 million aggregate principal amount of our Senior Notes at an aggregate purchase price of $135.7 million, that included payment of accrued interest of $3.7 million. As a result of the repurchases, we recognized a total gain on debt retirement, net of the write-off of debt issuance costs and premium, of $69.0 million ($54.7 million net of tax, or $0.84 per diluted share) in Gains on extinguishment of debt on the Consolidated Statements of Operations for fiscal year 2016. The repurchases were made using available cash balances.

These repurchases, allowed us to reduce our outstanding indebtedness and related interest expense at a significant discount to the face value of our Senior Notes. The gain associated with the repurchases is subject to tax and will increase our effective tax rate. However, due to the availability of operating loss carry-forwards the actual cash tax impact is expected to be minimal. Following these repurchases, the Company has $448.7 million Senior Notes outstanding.

From time to time, we may purchase additional Senior Notes in the open market, in privately negotiated transactions, through tender offers, exchange offers or otherwise, or we may redeem Senior Notes in whole or in part at the redemption price set forth in the indenture governing the Senior Notes. Any future purchases, exchanges or redemptions will depend on various factors existing at that time. There can be no assurance as to which, if any, of these alternatives (or combinations thereof) we may choose to pursue in the future, and there can be no assurance that an active trading market will exist for the Senior Notes following any such transactions.

Revolving Credit Facility

As of September 30, 2016, commitments under the Credit Facility are $1.395 billion through May 2018 and $1.1205 billion through May 2019. Our wholly-owned subsidiary, Atwood Offshore Worldwide Limited ("AOWL"), is the borrower under the Credit Facility, and we and certain of our other subsidiaries are guarantors under the facility. On March 25, 2016, we entered into an amendment to our Credit Facility (the "Fourth Amendment") that, among other things, effective on March 28, 2016, (i) removed the maximum leverage ratio and maximum secured leverage ratio financial covenants, (ii) amended the minimum interest expense coverage ratio such that it is not applicable until the quarter ending September 30, 2018, and decreased the minimum ratio required to 1.15:1.00, (iii) added a minimum liquidity financial covenant of $150 million, (iv) revised the restricted payments covenant to prohibit us from paying dividends, (v) reduced the total commitments under the Credit Facility by $152 million, and (vi) permits the incurrence of up to $400 million of second lien debt, subject to the parameters set forth therein. As a result of the amendment, borrowings under the Credit Facility will bear interest at the Eurodollar rate plus a margin ranging from 2.50% to 3.25% and the commitment fee on the unused portion of the underlying commitment ranges from 1.00% to 1.30% per annum, in each case based on our corporate credit ratings. The Credit Facility contains various financial covenants in addition to the minimum interest expense coverage ratio and minimum liquidity financial covenant discussed above, including a debt to capitalization ratio of 0.5:1.0 and a minimum collateral maintenance covenant of 150% of the aggregate amount outstanding under the Credit Facility. In addition, the Credit Facility contains limitations on our and certain of our subsidiaries' ability to incur liens; merge, consolidate or sell substantially all assets; pay dividends; incur additional indebtedness; make advances, investments or loans; and transaction with affiliates. The Credit Facility also contains customary events of default, including but not limited to delinquent payments, bankruptcy filings, material adverse judgments, guarantees or security documents not being in full effect, non-compliance with the Employee Retirement Income Security Act of 1974, cross-defaults under other debt agreements, or a change of control. We were in compliance with all financial covenants under the Credit Facility as of September 30, 2016, and we anticipate that we will continue to be in compliance for the next fiscal year.

The Credit Facility is secured primarily by first preferred mortgages on nine of our active drilling units (Atwood Aurora, Atwood Beacon, Atwood Condor, Atwood Mako, Atwood Manta, Atwood Osprey, Atwood Achiever, Atwood Advantage and Atwood Orca), as well as liens on the equity interest of our subsidiaries that, directly or indirectly, own such drilling units.

In connection with the Fourth Amendment, we mortgaged the Atwood Achiever, the Atwood Advantage and the Atwood Orca as additional collateral under the Credit Facility, as well as pledged the equity interests in the subsidiaries of the Company that own, directly or indirectly, these three vessels. Additionally, the Atwood Eagle and Atwood Falcon, along with the pledged equity interests in certain of our subsidiaries that, directly or indirectly, own these two vessels, were removed as collateral under the Credit Facility. Our interest in the two drillships under construction remain unencumbered.

As of September 30, 2016, we had $780 million of outstanding borrowings and $0.1 million of letters of credit issued under the Credit Facility. As of September 30, 2016, we had approximately $615 million available for borrowings under the Credit Facility.

The following summarizes our availability under our Credit Facility as of September 30, 2016 (in millions):

Commitment under Credit Facility	$1,395
Borrowings under Credit Facility	780
Letters of Credit Outstanding	—
Availability	$615

In October 2016, we had repayments on our Credit Facility of $55 million. As of October 31, 2016, we had $670 million available for borrowings.

Letter of Credit Facility

In July 2015, we entered into a letter of credit facility with BNP Paribas (“BNP”), pursuant to which BNP may issue letters of credit up to an unlimited stated face amount of such letters of credit. BNP has no commitment under the facility to issue letters of credit, and the facility may be canceled by BNP at any time. The facility contains certain events of default, including but not limited to delinquent payments, bankruptcy filings, material adverse judgments, cross-defaults under other debt agreements, or a change of control. As of September 30, 2016, we had no outstanding letters of credits under this facility.

Repurchase and Retirement of Common Shares

We did not have any active stock repurchase program in fiscal years 2016, 2015 or 2014.

Off-balance Sheet Arrangements

We have no off-balance sheet arrangements as that term is defined in Item 303(a) (4) (ii) of Regulation S-K.

Commitments and Contractual Obligations

The following table summarizes our obligations and commitments as of September 30, 2016 for fiscal years ended September 30.

(In thousands)	Fiscal 2017	Fiscal 2018 and 2019	Fiscal 2020 and 2021	Fiscal 2022 and Thereafter	Total
Debt [1]	$—	$780,000	$448,650	$ —	$1,228,650
Interest [2]	66,897	117,606	9,964	—	194,467
Purchase Commitments [3]	109,100	305,929	—	—	415,029
Operating Leases [4]	2,420	4,295	4,411	4,554	15,680
	$178,417	$1,207,830	$463,025	$ 4,554	$1,853,826

(1) Debt amounts include principal payments on the Senior Notes and Credit Facility. Unamortized premiums on the Senior Notes of $3.2 million are excluded from this presentation as they do represent a future commitment of funds.

(2) Interest amounts include fixed interest payments on the Senior Notes and swaps (assuming September 30, 2016 LIBOR for floating rate) as well as interest and commitment fees on the Credit Facility (assuming September 30, 2016 LIBOR for floating rate and the debt outstanding and the unused portion of the underlying commitment as of September 30, 2016).

(3) Purchase commitment amounts include commitments related to our two drillships under construction (excludes project management, capitalized interest and drilling and handling tools and spares) and the Atwood Condor second Blowout Preventer stack ("BOP") as of September 30, 2016.

(4) We enter into operating leases in the normal course of business. Some lease agreements provide us with the option to renew the leases. Our future operating lease payments would change if we exercised these renewal options and if we entered into additional operating lease agreements.

In May 2016, we entered into an agreement with Hydril USA Distribution, LLC ("GE") to manufacture a complete second BOP and an Auxiliary Stack Test System ("ASTS") for the Atwood Condor. The addition of the second BOP will increase the marketability and operational efficiency of the vessel. Total consideration for this agreement is approximately $19 million with 20% paid upon placement of the purchase order and the remaining 80% due upon delivery. To accelerate the manufacturing and delivery process, which is targeted for February 2017, we provided certain capital spares we maintained to GE to be used in the manufacturing process. These capital spares will be replenished by GE with similar capital spares upon delivery of the BOP.

CRITICAL ACCOUNTING POLICIES

Significant accounting policies are included in Note 2 to our consolidated financial statements for the year ended September 30, 2016. These policies, along with the underlying assumptions and judgments made by management in their application, have a significant impact on our consolidated financial statements. We identify our most critical accounting policies as those that are the most pervasive and important to the portrayal of our financial position and results of operations, and that require the most difficult, subjective and/or complex judgments by management regarding estimates about matters that are inherently uncertain. Our most critical accounting policies are those related to revenue recognition, deferred revenues and costs, property and equipment, fair value and income taxes.

Revenue Recognition

We account for contract drilling revenue in accordance with the terms of the underlying drilling contract. These contracts generally provide that revenue is earned and recognized on a daily rate (i.e. "day rate") basis, and day rates are typically earned for a particular level of service over the life of a contract assuming collectability is reasonably assured. Day rate contracts can be performed for a specified period of time or the time required to drill a specified well or number of wells. Revenues from day rate contracts for drilling and other operations performed during the term of a contract (including during mobilization) are classified under contract drilling services.

Certain fees received as compensation for relocating drilling rigs from one major operating area to another, equipment and upgrade costs reimbursed by the client, as well as receipt of advance billings of day rates are deferred and recognized as earned during the expected term of the related drilling contract, as are the day rates associated with such contracts. If receipt of such fees is not conditional, they will be recognized as earned on a straight-line method over the expected term of the related drilling contract. However, fees received upon termination of a drilling contract are generally recognized as earned during the period termination occurs as the termination fee is usually conditional based on the occurrence of an event as defined in the drilling contract, such as not obtaining follow on work to the contract in progress or relocation beyond a certain distance when the contract is completed.

As of September 30, 2016 and 2015, deferred fees associated with mobilization, related equipment purchases and upgrades and receipt of advance billings of day rates totaled $0.8 million and $4.7 million, respectively. Deferred fees are classified as current or long-term deferred credits in the accompanying consolidated balance sheets based on the expected term of the applicable drilling contracts.

Deferred costs

We defer certain mobilization costs relating to moving a drilling rig to a new area incurred prior to the commencement of the drilling operations and client requested equipment purchases. We amortize such costs on a straight-line basis over the expected term of the applicable drilling contract.

Property and Equipment

Property and equipment is stated at cost. As of September 30, 2016, the carrying value of our property and equipment totaled approximately $4.1 billion, which represents approximately 91% of our total assets. The carrying value reflects the application of our property and equipment accounting policies, which incorporate estimates, assumptions and judgments by management relative to the useful lives and salvage values of our units. Once rigs and related equipment are placed in service, they are depreciated on the straight-line method over their estimated useful lives, with depreciation discontinued only during the period when a drilling unit and/or its related drilling equipment is out-of-service while undergoing a significant upgrade that extends its useful life. The estimated useful lives of our drilling units and related equipment, including drill pipe, can range from 3 years to 35 years and our salvage values are generally estimated at 5% of capitalized costs. Any future increases or decreases in our estimates of useful lives or salvage values will have the effect of decreasing or increasing future depreciation expense, respectively.

We evaluate our property and equipment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable and reduce its carrying amount to recognize economic impairment as necessary. An impairment loss on our property and equipment may exist when the estimated future undiscounted cash flows are less than the carrying amount of the asset. In determining an asset's fair value, we consider a number of factors such as estimated discounted future cash flows, appraisals and current market value analysis. If an asset is determined to be impaired, the loss is measured by the amount by which the carrying value of the asset exceeds its fair value. Asset impairment evaluations are, by nature, highly subjective. Operation of our drilling equipment is subject to the offshore drilling requirements of E&P companies and agencies of foreign governments. These requirements are, in turn, subject to fluctuations in government policies, world demand and price for petroleum products, proved reserves in relation to such demand and the extent to which such demand can be met from onshore sources. The critical estimates which result from these dynamics include projected utilization, day rates, and operating expenses, each of which impacts our estimated future cash flows. Over the last five years, our full utilization rate for in-service rigs has averaged approximately 97%; however, if a drilling unit incurs significant idle time or receives day rates below operating costs, its carrying value could become impaired. See "Item 6: Selected Financial Data" for further discussion on the calculation of full utilization rates.

The estimates, assumptions and judgments used by management in the application of our property and equipment and asset impairment policies reflect both historical experience and expectations regarding future industry conditions and operations. The use of different estimates, assumptions and judgments, especially those involving the useful lives of our rigs and vessels and expectations regarding future industry conditions and operations, would likely result in materially different amounts of assets and results of operations.

Fair value

We have certain assets and liabilities that are required to be measured and disclosed at fair value. 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.

Independent third party services are used to determine the fair value of our financial instruments using quoted market prices and observable inputs. When independent third party services are used, we obtain an understanding of how the fair values are derived and selectively corroborate fair values by reviewing other readily available market based sources of information.

The fair values of our interest rate swaps and our foreign currency forward exchange contracts are based upon valuations calculated by an independent third party. The derivatives were valued according to the "Market approach" where possible, and the "Income approach" otherwise. A third party independently valued each instrument using forward price data obtained from reputable data providers (e.g., Bloomberg and Reuters) and reviewed market activity and similarity of pricing terms to determine appropriate reliability level assertions for each instrument. The contribution of the credit valuation adjustment to total fair value is less than 1% for all derivatives and is therefore not significant.

Income Taxes

We conduct operations and earn income in numerous foreign countries and are subject to the laws of taxing jurisdictions within those countries, as well as U S. federal and state tax laws. As of September 30, 2016, we have an approximate $1 million net deferred income tax liability. This balance reflects the application of our income tax accounting policies. Such accounting policies incorporate estimates, assumptions and judgments by management relative to the interpretation of applicable tax laws, the application of accounting standards, and future levels of taxable income. The estimates, assumptions and judgments used by management in connection with accounting for income taxes reflect both historical experience and expectations regarding future industry conditions and operations. Changes in these estimates, assumptions and judgments could result in materially different provisions for deferred and current income taxes.

A comprehensive model is used to account for uncertain tax positions, which include consideration of how we recognize, measure, present and disclose uncertain tax positions taken or to be taken on a tax return. The income tax laws and regulations are voluminous and are often ambiguous. As such, we are required to make many subjective assumptions and judgments regarding our tax positions that can materially affect amounts recognized in our consolidated balance sheets and statements of income.

Our annual tax provision is based on expected taxable income, statutory rates and tax planning opportunities available to us in the various jurisdictions in which we operate. The determination of our annual tax provision and evaluation of our tax positions involves interpretation of tax laws in the various jurisdictions and requires significant judgment and the use of estimates and assumptions regarding significant future events, such as the amount, timing and character of income, deductions and tax credits. Our tax liability in any given year could be affected by changes in tax laws, regulations, agreements, and treaties, currency exchange restrictions or our level of operations or profitability in each jurisdiction. Additionally, we operate in many jurisdictions where the tax laws relating to the offshore drilling industry are not well developed. Although our annual tax provision is based on the best information available at the time, a number of years may elapse before the ultimate tax liabilities in the various jurisdictions are determined.

In several of the 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 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.

Our international rigs are owned and operated, directly or indirectly, by AOWL, a Cayman Islands subsidiary which we wholly own. It is our intention to indefinitely reinvest historic and future earnings of AOWL and its foreign subsidiaries to finance operating and capital expenditures as well as pay down borrowings. Accordingly, we have not made a provision for U.S. income taxes on approximately $2.9 billion of undistributed foreign earnings and profits. Although we do not intend to repatriate the earnings of AOWL 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. If these earnings were remitted, we estimate approximately $670 million in additional taxes would be incurred.

Recently Issued Accounting Pronouncements

In August 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update (ASU) 2016-15, Statement of Cash Flows (Topic 230) - Classification of Certain Cash Receipts and Cash Payments. The ASU is intended to reduce diversity in practice in how certain cash receipts and cash payments are presented in the statement of cash flows. The new guidance clarifies the classification of cash activity related to: (1) debt prepayment or debt extinguishment costs, (2) settlement of zero-coupon debt instruments, (3) contingent consideration payments made after a business combination, (4) proceeds from the settlement of insurance claims, (5) proceeds from the settlement of corporate and bank-owned life insurance policies, (6) distributions received from equity-method investments, and (7) beneficial interests in securitization transactions. This update is effective for annual and interim periods beginning after December 15, 2019. We are currently evaluating what impact the adoption of this guidance will have on our financial statements or disclosures in our financial statements.

In June, 2016, FASB issued Accounting Standards Update (ASU) 2016-13, Financial Instruments - Credit Losses (Topic 326). The ASU introduces a new model for recognizing credit losses on financial instruments based on an estimate of current expected credit losses. The new model will apply to: (1) loans, accounts receivable, trade receivables, and other financial assets measured at amortized cost, (2) loan commitments and certain other off-balance sheet credit exposures, (3) debt securities and other financial assets measured at fair value through other comprehensive income, and (4) beneficial interests in securitized financial assets. This update is effective for annual and interim periods beginning after December 15, 2019. We are currently evaluating what impact the adoption of this guidance will have on our financial statements or disclosures in our financial statements.

In March 2016, the FASB issued ASU 2016-09, Improvements to Employee Share-Based Payment Accounting, as part of its simplification initiative. The ASU simplifies several aspects of the accounting for employee share-based payment transactions, including the accounting for income taxes, classification of excess tax benefits on the statement of cash flows, forfeitures, statutory tax withholding requirements, classification of awards as either equity or liabilities, and classification of employee taxes paid on the statement of cash flows when an employer withholds shares for tax-withholding purposes. The amendments in this update are effective for annual periods beginning after December 15, 2016, and interim periods within those annual periods. We are currently evaluating what impact the adoption of this guidance will have on our financial statements or disclosures in our financial statements.

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842): Amendments to the FASB Accounting Standards Codification ("Update 2016-02"), which requires an entity to recognize lease assets and lease liabilities on the balance sheet and to disclose key qualitative and quantitative information about the entity's leasing arrangements. This update is effective for annual and interim periods beginning after December 15, 2018, with early adoption permitted. A modified retrospective approach is required. We are currently evaluating what impact the adoption of this guidance will have on our financial statements or disclosures in our financial statements.

In November 2015, the FASB issued ASU 2015-17, Income Taxes (Topic 740): Amendments for the balance sheet classification of deferred income taxes. The amended guidance requires the classification of all deferred tax assets and liabilities as noncurrent on the balance sheet instead of separating deferred taxes into current and noncurrent amounts. Deferred tax assets and liabilities will continue to be offset and presented as a single amount under the amended guidance. The effective date for public business entities is for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. We have not yet adopted nor selected a transition method and are currently evaluating what impact the adoption of this guidance will have on our financial statements or disclosures in our financial statements.

In April 2015, the FASB issued ASU 2015-03, Interest-Imputation of Interest (Subtopic 835-30): Amendments intended to simplify the presentation of debt issuance costs. This new guidance requires that debt issuance costs related to outstanding debt be netted against that liability in the balance sheet, consistent with the treatment of debt discounts. In August 2015, the FASB issued additional guidance to clarify that this presentation change does not address debt issuance costs related to line of credit arrangements. The new presentation guidance is effective for fiscal years and interim periods beginning after December 15, 2015 and early adoption is permitted. We adopted this guidance in the first quarter of fiscal 2016. We reclassified $1.7 million from Prepaid Expenses, Deferred Costs and Other Current Assets and $6.0 million from Deferred Costs and Other Assets to Long-Term Debt in the September 30, 2015 Consolidated Balance Sheet presented in this Form 10-K to conform to the current year presentation of debt issuance costs.

In May 2014, the FASB issued ASU 2014-09, Revenues from Contracts with Customers (Topic 606): A new guidance intended to change the criteria for recognition of revenue. The core principle of the guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to clients in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The guidance is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. We are currently evaluating what impact the adoption of this guidance will have on our financial statements or disclosures in our financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risk, including adverse changes in interest rates and foreign currency exchange rates as discussed below.

Interest Rate Risk

The provisions of our Credit Facility provide for a variable interest rate cost on our $780 million outstanding as of September 30, 2016. However, we have employed an interest rate risk management strategy that utilizes derivative instruments with respect to $250 million of our debt as of September 30, 2016, in order to minimize or eliminate unanticipated fluctuations in earnings and cash flows arising from changes in, and volatility of, interest rates. Effectively, $530 million of our variable long-term debt outstanding as of September 30, 2016 is subject to changes in interest rates. A change of 10% in the interest rate on the floating rate debt would have an immaterial impact on our annual earnings and cash flows.

Foreign Currency Risk

Our functional currency is the U.S. dollar. Certain of our subsidiaries have monetary assets and liabilities that are denominated in a currency other than our functional currency. The majority of our contracts are denominated in U.S. dollars, but occasionally all or a portion of a contract is payable in local currency. To the extent there is a local currency component in a contract, we attempt to match similar revenue in the local currency to the operating costs paid in the local currency such as local labor, shore base expenses, and local taxes, if any, in order to minimize foreign currency fluctuation impact.

From time to time, we enter into foreign currency forward exchange contracts to limit our exposure to fluctuations and volatility due to currency exchange rates. Our functional currency is the U.S. dollar and thus our international operations expose us to foreign currency risk associated with cash flows from transactions denominated in currencies other than our functional currency. We have outstanding foreign currency forward exchange contracts that were entered into to hedge a portion of our anticipated euro receipts associated with revenues earned on a drilling contract. These forward contracts are designated as cash flow hedging instruments. Based on September 30, 2016 amounts, a decrease in the value of 10% in foreign currencies relative to the U.S. dollar would not have a material effect to our annual earnings and cash flows.

Market Risk

Our Senior Notes bear interest at a fixed interest rate. The fair value of our Senior Notes will fluctuate based on changes in prevailing market interest rates and market perceptions of our credit risk. The fair value of our Senior Notes was approximately $355 million as of September 30, 2016, compared to the principal amount of $449 million. The fair value of our Senior Notes was approximately $526 million as of September 30, 2015. If prevailing market interest rates had been 10% lower as of September 30, 2016, the change in fair value of our Senior Notes would not have a material effect to our annual earnings and cash flows.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Atwood Oceanics, Inc. (which together with its subsidiaries is identified as the "Company," "we" or "our" unless stated otherwise or the context requires otherwise) is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Our internal control over financial reporting was designed by management, under the supervision of the Chief Executive Officer and Chief Financial Officer, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America, and includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and

(iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements.

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

Management assessed the effectiveness of the Company's internal control over financial reporting as of September 30, 2016. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework (2013).

Based on our evaluation under the criteria in Internal Control-Integrated Framework (2013), management has concluded that the Company maintained effective internal control over financial reporting as of September 30, 2016.

PricewaterhouseCoopers LLP, our independent registered public accounting firm, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting as of September 30, 2016, which appears on the following page.

ATWOOD OCEANICS, INC.

by

/s/ Robert J. Saltiel	/s/ Mark W. Smith
Robert J. Saltiel	Mark W. Smith
President and	Senior Vice President and
Chief Executive Officer	Chief Financial Officer
November 15, 2016	November 15, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Atwood Oceanics, Inc.

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, comprehensive income, cash flows and changes in shareholders' equity present fairly, in all material respects, the financial position of Atwood Oceanics, Inc. and its subsidiaries at September 30, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2016 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of September 30, 2016, based on criteria established in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

/s/ PricewaterhouseCoopers LLP
Houston, Texas
November 15, 2016

ATWOOD OCEANICS, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended September 30,		
(In thousands, except per share amounts)	2016	2015	2014
REVENUES:			
Contract drilling	$976,348	$1,342,052	$1,103,397
Revenues related to reimbursable expenses	44,296	53,799	70,556
Total revenues	1,020,644	1,395,851	1,173,953
COSTS AND EXPENSES:			
Contract drilling	378,535	520,421	506,128
Reimbursable expenses	28,291	38,744	56,225
Depreciation	165,669	171,947	147,358
General and administrative	50,550	57,229	61,461
Asset impairment	103,539	60,777	—
(Gain)/loss on sale of assets	77	15,303	(34,139)
Other, net	(299)	—	(1,864)
	726,362	864,421	735,169
OPERATING INCOME	294,282	531,430	438,784
OTHER INCOME (EXPENSE):			
Interest expense, net of capitalized interest	(68,566)	(52,551)	(41,803)
Interest income	21	91	312
Gains on extinguishment of debt	69,041	—	—
Other income	17,977	—	—
	18,473	(52,460)	(41,491)
INCOME BEFORE INCOME TAXES	312,755	478,970	397,293
PROVISION FOR INCOME TAXES	47,483	46,397	56,471
NET INCOME	$265,272	$432,573	$340,822
EARNINGS PER COMMON SHARE (NOTE 2):			
Basic	$4.09	$6.70	$5.31
Diluted	$4.09	$6.65	$5.24
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (NOTE 2):			
Basic	64,789	64,581	64,240
Diluted	64,839	65,030	65,074

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

ATWOOD OCEANICS, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended September 30,		
(In thousands)	2016	2015	2014
Net income	$265,272	$432,573	$340,822
Other comprehensive income/(losses):			
Derivative financial instruments:			
Unrealized holding gain/(losses)	(4,690)	(4,061)	4,208
Gains/(losses) reclassified to net income	3,624	(228)	834
Total other comprehensive income (loss)	(1,066)	(4,289)	5,042
Comprehensive income	$264,206	$428,284	$345,864

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

ATWOOD OCEANICS INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

(In thousands, except par value)	September 30, 2016	2015
ASSETS		
Cash	$145,427	$113,983
Accounts receivable, net	113,091	311,514
Income tax receivable	6,095	8,705
Inventories of materials and supplies, net	109,925	137,998
Prepaid expenses, deferred costs and other current assets	18,504	33,735
Total current assets	393,042	605,935
Property and equipment, net	4,127,696	4,172,132
Other receivables	11,831	11,831
Deferred income taxes	165	150
Deferred costs and other assets	7,058	11,285
Total assets	$4,539,792	$4,801,333
LIABILITIES AND SHAREHOLDERS' EQUITY		
Accounts payable	$25,299	$70,161
Accrued liabilities	7,868	23,572
Dividends payable	—	16,164
Interest payable	7,096	7,704
Income tax payable	8,294	13,906
Deferred credits and other liabilities	799	3,941
Total current liabilities	49,356	135,448
Long-term debt	1,227,919	1,678,268
Deferred income taxes	1,202	1,658
Deferred credits	—	800
Other	30,929	37,989
Total long-term liabilities	1,260,050	1,718,715
Commitments and contingencies (Note 9)		
Preferred stock, no par value, 1,000 shares authorized, none outstanding	—	—
Common stock, $1.00 par value, 180,000 shares authorized with 64,799 issued and outstanding at September 30, 2016 and 180,000 shares authorized and 64,654 shares issued and outstanding at September 30, 2015	64,799	64,654
Paid-in capital	237,542	213,096
Retained earnings	2,929,839	2,670,148
Accumulated other comprehensive loss	(1,794)	(728)
Total shareholders' equity	3,230,386	2,947,170
Total liabilities and shareholders' equity	$4,539,792	$4,801,333

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

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ATWOOD OCEANICS, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(In thousands)	Common Stock Shares	Common Stock Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
September 30, 2013	64,057	$64,057	$183,390	$1,961,405	$ (1,481)	$2,207,371
Net income	—	—	—	340,822	—	340,822
Other comprehensive income	—	—	—	—	5,042	5,042
Dividends	—	—	—	(16,090)	—	(16,090)
Vesting of restricted stock awards and performance unit awards	180	180	(180)	—	—	—
Exercise of employee stock options	125	125	3,563	—	—	3,688
Stock compensation expense	—	—	14,691	—	—	14,691
September 30, 2014	64,362	64,362	201,464	2,286,137	3,561	2,555,524
Net income	—	—	—	432,573	—	432,573
Other comprehensive income	—	—	—	—	(4,289)	(4,289)
Dividends	—	—	—	(48,562)	—	(48,562)
Vesting of restricted stock awards and performance unit awards	224	224	(2,192)	—	—	(1,968)
Exercise of employee stock options	68	68	996	—	—	1,064
Stock compensation expense	—	—	12,828	—	—	12,828
September 30, 2015	64,654	64,654	213,096	2,670,148	(728)	2,947,170
Net income	—	—	—	265,272	—	265,272
Other comprehensive income (loss)	—	—	—	—	(1,066)	(1,066)
Dividends	—	—	—	(5,581)	—	(5,581)
Vesting of restricted stock and performance unit awards	145	145	(610)	—	—	(465)
Stock compensations expense	—	—	11,862	—	—	11,862
Stock compensation windfall tax benefits	—	—	13,194	—	—	13,194
September 30, 2016	64,799	$64,799	$237,542	$2,929,839	$ (1,794)	$3,230,386

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

ATWOOD OCEANICS, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended September 30,		
(In thousands)	2016	2015	2014
Cash flows from operating activities:			
Net income	$265,272	$432,573	$340,822
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	165,669	171,947	147,358
Amortization	3,446	6,299	8,634
Provision for doubtful accounts and inventory obsolescence	9,501	4,286	2,826
Deferred income tax benefit	1,632	(2,747)	(1,270)
Share-based compensation expense	11,862	12,828	14,691
Asset impairment	103,539	60,777	—
(Gain) loss on sale of assets	(222)	15,303	(34,139)
(Gain) on extinguishment of debt	(69,041)	—	—
Change in assets and liabilities:			
Accounts receivable	176,614	(72,575)	(43,965)
Income tax receivable	2,610	(2,445)	(1,588)
Inventories of materials and supplies	12,385	(19,068)	(17,220)
Prepaid expenses, deferred costs and other current assets	7,498	(3,655)	15,463
Deferred costs and other assets	(608)	5,917	(11,682)
Accounts payable	(36,227)	(11,967)	1,932
Accrued liabilities	(16,298)	1,637	1,647
Income tax payable	(5,612)	(328)	(2,320)
Deferred credits and other liabilities	(7,012)	5,505	21,431
Net cash provided by operating activities	625,008	604,287	442,620
Cash flows from investing activities:			
Capital expenditures	(223,731)	(448,019)	(975,731)
Net proceeds from sale of assets	20,792	(4,402)	61,516
Net cash used in investing activities	(202,939)	(452,421)	(914,215)
Cash flows from financing activities:			
Proceeds from borrowing of long-term debt	45,000	225,000	700,000
Principal repayments on long-term debt	(426,623)	(280,000)	(220,000)
Repayments on short-term debt, net	—	(11,885)	(13,979)
Dividends paid	(21,745)	(48,562)	—
Proceeds from exercise of stock options	—	1,064	3,688
Debt issuance costs paid	(451)	(3,580)	(6,804)
Windfall tax benefits from share-based payment arrangements	13,194	—	—
Net cash (used in) or provided by financing activities	(390,625)	(117,963)	462,905
Net increase (decrease) in cash and cash equivalents	31,444	33,903	(8,690)
Cash at beginning of period	113,983	80,080	88,770
Cash at end of period	$145,427	$113,983	$80,080
Cash paid during the period for:			
Domestic and foreign income taxes	$35,653	$50,428	$55,777
Interest, net of amounts capitalized	67,958	48,209	35,265
Non-cash activities:			
Decrease in accounts payables related to capital expenditures	(8,028)	(9,532)	(2,804)
Dividends payable	—	16,164	16,090
Increase in short-term debt related to funding of insurance policies	—	—	17,793

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

NOTE 1—NATURE OF OPERATIONS

Atwood Oceanics, Inc. and its subsidiaries, which are collectively referred to herein as the "Company," "we," "us" or "our" except where stated or the context indicates otherwise, are a global offshore drilling contractor engaged in the drilling and completion of exploratory and developmental oil and gas wells. We currently own a diversified fleet of 10 mobile offshore drilling units located in the U.S. Gulf of Mexico, the Mediterranean Sea, offshore West Africa, offshore Southeast Asia and offshore Australia. In addition, we are constructing two ultra-deepwater drillships, currently scheduled for delivery in fiscal years 2017 and 2018. We were founded in 1968 and are headquartered in Houston, Texas with support offices in Australia, Malaysia, Thailand, Singapore, Luxembourg, Mauritius, the Cayman Islands, the United Arab Emirates and the United Kingdom.

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Consolidation

The consolidated financial statements include the accounts of Atwood Oceanics, Inc. and all of its domestic and foreign subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation.

Use of estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States ("GAAP") requires management to make extensive use of 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 amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Accounts receivable

We record accounts receivable at the amount we invoice our clients, net of allowance for doubtful accounts. Our clients are major international corporate entities and government organizations with stable payment experience. Historically, our uncollectible accounts receivable have been immaterial, and typically, we do not require collateral for our receivables. We provide an allowance for uncollectible accounts, as necessary, on a specific identification basis. Our allowance for doubtful accounts as of September 30, 2016 and 2015 was $1.2 million and $3.8 million, respectively. Our provision for doubtful accounts for fiscal years September 30, 2016, 2015 and 2014 was $5.6 million, $3.7 million and $1.0 million, respectively. The provision for doubtful accounts is reported as a component of Contract Drilling costs in our Consolidated Statements of Operations.

Concentrations of market and credit risk

All of our clients are in the oil and gas offshore exploration and production industry. This industry concentration has the potential to impact our overall exposure to market and credit risks, either positively or negatively, in that our clients could be affected by similar changes in economic, industry or other conditions. However, we believe that the credit risk posed by this industry concentration is offset by the creditworthiness of our client base. Revenues from individual clients that are 10% or more of our total revenues are as follows:

(In thousands)	Fiscal 2016	Fiscal 2015	Fiscal 2014
Shell Offshore Inc.	$213,785	$201,190	$179,763
Kosmos Energy	184,475	142,701	12,933
Noble Energy Inc.	179,545	227,682	169,851
Chevron Australia Pty. Ltd.	118,471	156,099	175,334
Woodside Energy Ltd.	109,236	166,796	68,484
Apache Energy Ltd.	—	39,233	209,871

In addition, we have certain clients that make up a significant portion of our Accounts Receivable at September 30, 2016, as indicated in the table below:

	Percentage of Accounts Receivable
Shell Offshore Inc.	31%
Kosmos Energy Ltd.	26%
Woodside Energy Ltd.	15%
Noble Energy Inc.	11%

Inventories of material and supplies

Inventories consist of spare parts, material and supplies held for consumption and are stated principally at average cost, net of reserves for excess and obsolete inventory of $8.8 million and $5.3 million as of September 30, 2016 and 2015, respectively. We maintain our reserves at between 3% and 5% of the balance to provide for non-recoverable costs. During the three and twelve months ended September 30, 2016, we recorded a non-cash charges of $3.9 million, which is reported in Contract Drilling costs to increase our reserve for excessive and/or obsolete materials and supplies. This charge included inventory items throughout our drilling rig fleet.

Property and equipment

Property and equipment are recorded at historical cost. Interest costs related to property under construction are capitalized as a component of construction costs.

Once rigs and related equipment are placed in service, they are depreciated using the straight-line method over their estimated useful lives after deducting their residual values, with depreciation discontinued only during the period when a drilling unit and/or its related drilling equipment is out-of-service while undergoing a significant upgrade that extends its useful life. Any future increases or decreases in our estimates of useful lives or salvage values will be recognized prospectively as decreases or increases in future depreciation expense, respectively. Our estimated useful lives of our various classifications of assets are as follows:

	Years
Drilling vessels and related equipment	5-35
Drill pipe	3
Furniture and other	3-10

Maintenance, repairs and minor replacements are charged against income as incurred. Major replacements and upgrades are capitalized and depreciated over the remaining useful life of the asset, as determined upon completion of the work. The cost and related accumulated depreciation of assets sold, retired or otherwise disposed are removed from the accounts at the time of disposition and any resulting gain or loss is reflected in the Consolidated Statements of Operations for the applicable periods.

Impairment of property and equipment

We evaluate our property and equipment whenever events or changes in circumstance indicate that the carrying amount of an asset may not be recoverable. An impairment loss on our property and equipment exists when the estimated future undiscounted cash flows are less than the carrying amount of the asset. If an asset is determined to be impaired, the loss is measured by the amount by which the carrying value of the asset exceeds its fair value. In determining an asset's fair value, we consider a number of factors such as estimated future cash flows, appraisals and current market value analysis.

Revenue recognition

We account for contract drilling revenue in accordance with accounting guidance and the terms of the underlying drilling contract. These contracts generally provide that revenue is earned and recognized on a daily rate (i.e. “day rate”) basis, and day rates are typically earned for a particular level of service over the life of a contract assuming collectability is reasonably assured. Day rate contracts can be performed for a specified period of time or the time required to drill a specified well or number of wells. Revenues from day rate contracts for drilling and other operations performed during the term of a contract (including during mobilization) are classified under contract drilling services.

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Certain fees received as compensation for relocating drilling rigs from one major operating area to another, equipment and upgrade costs reimbursed by the client, as well as receipt of advance billings of day rates are deferred and recognized as earned during the expected term of the related drilling contract, as are the day rates associated with such contracts. If receipt of such fees is not conditional, they will be recognized as earned on a straight-line method over the expected term of the related drilling contract. However, fees received upon termination of a drilling contract are generally recognized as earned during the period termination occurs as the termination fee is usually conditional based on the occurrence of an event as defined in the drilling contract, such as not obtaining follow on work to the contract in progress or relocation beyond a certain distance when the contract is completed.

As of September 30, 2016 and 2015, deferred fees associated with mobilization, related equipment purchases and upgrades and receipt of advance billings of day rates totaled $0.8 million and $4.7 million, respectively. Deferred fees are classified as current or long-term deferred credits in the accompanying Consolidated Balance Sheets based on the expected term of the applicable drilling contracts.

Reimbursable revenue

We recognize client reimbursable revenues as we bill our clients for reimbursement of costs associated with certain equipment, materials and supplies, subcontracted services, employee bonuses and other expenditures, resulting in little or no net effect on operating income since such recognition is concurrent with the recognition of the respective reimbursable costs in operating and maintenance expense.

Deferred costs

We defer certain mobilization costs relating to moving a drilling rig to a new area incurred prior to the commencement of the drilling operations and client requested equipment purchases. We amortize such costs on a straight-line basis over the expected term of the applicable drilling contract. Contract revenues and drilling costs are reported in the Consolidated Statements of Operations at their gross amounts.

As of September 30, 2016 and 2015, deferred costs associated with mobilization and related equipment purchases totaled $0.5 million and $3.1 million, respectively. Deferred costs are classified as current or long-term deferred costs in the accompanying Consolidated Balance Sheets based on the expected term of the applicable drilling contracts.

Deferred drydocking costs

Certifications from various regulatory bodies are required to operate our drilling rigs and well control systems and we must maintain such certifications through periodic inspections and surveys on an ongoing basis. We defer the periodic survey and drydock costs incurred in connection with obtaining regulatory certifications and we recognize such costs in Contract Drilling Expense over the period until the next survey using the straight-line method. As of September 30, 2016 and 2015, deferred drydocking costs totaling $1.8 million and $1.3 million, respectively, were included in Deferred Costs and Other Assets in the accompanying Consolidated Balance Sheets.

Derivative financial instruments

From time to time we may enter into a variety of derivative financial instruments in connection with the management of our exposure to variability in interest rates and currency exchange rates. We do not engage in derivative transactions for speculative or trading purposes and we are not a party to leveraged derivatives.

We enter into interest rate swaps to limit our exposure to fluctuations and volatility in interest rates. Our credit facility exposes us to short-term changes in market interest rates as our interest obligations on these instruments are periodically re-determined based on the prevailing Eurodollar rate.

Our functional currency is the U.S. dollar and thus our international operations expose us to foreign currency risk associated with cash flows from transactions denominated in currencies other than our functional currency. From time to time, we enter into foreign currency forward exchange contracts to limit our exposure to fluctuations and volatility in currency exchange rates. We have outstanding foreign currency forward exchange contracts that were entered into to hedge a portion of our anticipated euro receipts associated with revenues earned on a drilling contract. These forward contracts are designated as cash flow hedging instruments.

We record our derivative contracts at fair value on our Consolidated Balance Sheets (See Note 5). Each quarter, changes in the fair values of our derivative instruments designated and qualifying as cash flow hedging instruments will adjust the balance sheet asset or liability, with an offset to Accumulated Other Comprehensive Income (“AOCI”) for the effective portion of the

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hedge. The effective portion of the cash flow hedge will remain in AOCI until it is reclassified into earnings in the period or periods during which the hedged transaction affects earnings or when it is probable that the hedged forecasted transaction will not occur by the end of the originally specified time period. Any changes in fair value resulting from ineffectiveness on interest rate swaps and foreign currency forward exchange contracts are recognized immediately into earnings as a component of interest expense and contract drilling, respectively. See our Consolidated Statement of Comprehensive Income for changes in our unrealized holding losses and reclassifications into earnings for fiscal years 2016, 2015 and 2014.

Foreign exchange

Monetary assets and liabilities denominated in foreign currency are re-measured to U.S. Dollars at the rate of exchange in effect at the end of the fiscal year, items of income and expense are re-measured at average monthly rates, and property and equipment and other nonmonetary amounts are re-measured at historical rates. Gains and losses on foreign currency transactions and re-measurements are generally related to and included in contract drilling costs in our Consolidated Statements of Operations. We recorded a foreign exchange loss of $2.4 million during fiscal year 2016, a loss of $2.7 million during fiscal year 2015 and a loss of $3.0 million during fiscal year 2014. The effect of exchange rate changes on cash held in foreign currencies was immaterial.

Income taxes

Deferred income taxes are recorded to reflect the tax consequences, if any, on future years of differences between the tax basis of assets and liabilities and their financial reporting amounts at each year-end given the provisions of enacted tax laws in each respective jurisdiction. We do not record deferred taxes on the basis differences of our drilling rigs working in the U.S. Gulf of Mexico as we do not believe these differences will result in additional U.S. income tax expense. Deferred tax assets are reduced by a valuation allowance when, based upon management's estimates, it is more likely than not that a portion of the deferred tax assets will not be realized in a future period. In addition, we accrue for income tax contingencies, or uncertain tax positions, that we believe are more likely than not to be realized. See Note 8 for further discussion.

Earnings per common share

Basic earnings per share excludes dilution and is computed by dividing net income (loss) by the weighted-average number of common shares outstanding for the period. Diluted earnings per share reflects the assumed effect of the issuance of additional shares in connection with the exercise of stock options and vesting of restricted stock.

The computation of basic and diluted earnings per share for each of the past three fiscal years is as follows:

(In thousands, except per share amounts)	Net Income	Weighted Average Shares	Per Share Amount
Fiscal 2016			
Basic earnings per share	$265,272	64,789	$ 4.09
Effect of dilutive securities:			
Restricted stock and performance units	—	50	—
Diluted earnings per share	$265,272	64,839	$ 4.09
Fiscal 2015			
Basic earnings per share	$432,573	64,581	$ 6.70
Effect of dilutive securities:			
Stock options	—	61	—
Restricted stock and performance units	—	388	(0.05)
Diluted earnings per share	$432,573	65,030	$ 6.65
Fiscal 2014			
Basic earnings per share	$340,822	64,240	$ 5.31
Effect of dilutive securities:			
Stock options	—	239	(0.01)
Restricted stock and performance units	—	595	(0.06)

Diluted earnings per share	$340,822	65,074	$ 5.24

In fiscal year 2016 and 2015 there were 2,471,230 and 866,000 anti-dilutive securities excluded for the calculation of diluted earnings per share, respectively. There were no anti-dilutive securities excluded in fiscal 2014.

Recently issued accounting pronouncements

In August 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update (ASU) 2016-15, Statement of Cash Flows (Topic 230) - Classification of Certain Cash Receipts and Cash Payments. The ASU is intended to reduce diversity in practice in how certain cash receipts and cash payments are presented in the statement of cash flows. The new guidance clarifies the classification of cash activity related to: (1) debt prepayment or debt extinguishment costs, (2) settlement of zero-coupon debt instruments, (3) contingent consideration payments made after a business combination, (4) proceeds from the settlement of insurance claims, (5) proceeds from the settlement of corporate and bank-owned life insurance policies, (6)distributions received from equity-method investments, and (7) beneficial interests in securitization transactions. This update is effective for annual and interim periods beginning after December 15, 2019. We are currently evaluating what impact the adoption of this guidance will have on our financial statements or disclosures in our financial statements.

In June, 2016, the FASB issued ASU 2016-13, Financial Instruments - Credit Losses (Topic 326). The ASU introduces a new model for recognizing credit losses on financial instruments based on an estimate of current expected credit losses. The new model will apply to: (1) loans, accounts receivable, trade receivables, and other financial assets measured at amortized cost, (2) loan commitments and certain other off-balance sheet credit exposures, (3) debt securities and other financial assets measured at fair value through other comprehensive income, and (4) beneficial interests in securitized financial assets. This update is effective for annual and interim periods beginning after December 15, 2019. We are currently evaluating what impact the adoption of this guidance will have on our financial statements or disclosures in our financial statements.

In March 2016, the FASB issued ASU 2016-09, Improvements to Employee Share-Based Payment Accounting, as part of its simplification initiative. The ASU simplifies several aspects of the accounting for employee share-based payment transactions, including the accounting for income taxes, classification of excess tax benefits on the statement of cash flows, forfeitures, statutory tax withholding requirements, classification of awards as either equity or liabilities, and classification of employee taxes paid on the statement of cash flows when an employer withholds shares for tax-withholding purposes. The amendments in this update are effective for annual periods beginning after December 15, 2016, and interim periods within those annual periods. We are currently evaluating what impact the adoption of this guidance will have on our financial statements or disclosures in our financial statements.

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842): Amendments which requires an entity to recognize lease assets and lease liabilities on the balance sheet and to disclose key qualitative and quantitative information about the entity's leasing arrangements. This update is effective for annual and interim periods beginning after December 15, 2018, with early adoption permitted. A modified retrospective approach is required. We are currently evaluating what impact the adoption of this guidance will have on our financial statements or disclosures in our financial statements.

In November 2015, the FASB issued ASU 2015-17, Income Taxes (Topic 740): Amendments for the balance sheet classification of deferred income taxes. The amended guidance requires the classification of all deferred tax assets and liabilities as noncurrent on the balance sheet instead of separating deferred taxes into current and noncurrent amounts. Deferred tax assets and liabilities will continue to be offset and presented as a single amount under the amended guidance. The effective date for public business entities is for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. We have not yet adopted nor selected a transition method and are currently evaluating what impact the adoption of this guidance will have on our financial statements or disclosures in our financial statements.

In April 2015, the FASB issued ASU 2015-03, Interest-Imputation of Interest (Subtopic 835-30): Amendments intended to simplify the presentation of debt issuance costs. This new guidance requires that debt issuance costs related to outstanding debt be netted against that liability in the balance sheet, consistent with the treatment of debt discounts. In August 2015, the FASB issued additional guidance to clarify that this presentation change does not address debt issuance costs related to line of credit arrangements. The new presentation guidance is effective for fiscal years and interim periods beginning after December 15, 2015 and early adoption is permitted. We adopted this guidance in the first quarter of fiscal 2016. We reclassified $1.7 million from Prepaid Expenses, Deferred Costs and Other Current Assets and $6.0 million from Deferred Costs and Other Assets to Long-Term Debt in the September 30, 2015 Consolidated Balance Sheet presented in this Form 10-K to conform to the current year presentation of debt issuance costs.

In May 2014, the FASB issued ASU 2014-09, Revenues from Contracts with Customers (Topic 606): A new guidance intended to change the criteria for recognition of revenue. The core principle of the guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to clients in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The guidance is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. We are currently evaluating what impact the adoption of this guidance will have on our financial statements or disclosures in our financial statements.

NOTE 3—PROPERTY AND EQUIPMENT

A summary of property and equipment by classification is as follows:

	September 30,	
(In thousands)	2016	2015
Drilling vessels and equipment	$3,898,686	$4,003,483
Construction work in progress	857,572	720,852
Drill pipe	52,543	55,248
Office equipment and other	39,213	36,379
Total cost	4,848,014	4,815,962
Less: Accumulated depreciation	(720,318)	(643,830)
Property and equipment, net	$4,127,696	$4,172,132

Impairments

The Atwood Falcon completed the contract it was working under in early March 2016. Based on the lack of contracting opportunities and the further deterioration of commodity prices, we determined that it was not likely that additional work would be obtained in the foreseeable future. Based on our analysis, we concluded that the Atwood Falcon and its materials and supplies were impaired as of December 31, 2015, and we wrote them down to their approximate salvage value. We recorded a non-cash impairment charge of approximately $64.9 million ($64.9 million net of tax, or $1.00 per diluted share), which is included in Asset Impairment on the Consolidated Statement of Operations for the three months ended December 31, 2015. This impairment charge includes a write-down of property and equipment of $53.2 million and a write-down of our inventory of materials and supplies specific to the Atwood Falcon of $11.7 million. In April 2016, we completed the sale of the Atwood Falcon.

The Atwood Hunter completed the contract it was working under in December 2014. Based on the lack of contracting opportunities and the further deterioration of commodity prices, in January 2015, we determined that it was not likely that additional work would be obtained in the foreseeable future. Based on our analysis, in the three months ended December 31, 2014, we determined that the Atwood Hunter and its materials and supplies were impaired, and we wrote them down to their salvage value. We recorded a non-cash impairment charge of approximately $60.8 million ($56.1 million, net of tax, or $0.86 per diluted share), which is included in Asset Impairment on the Consolidated Statement of Operations for the three months ended December 31, 2014. This impairment charge included write-downs of property and equipment of $48.0 million and write-downs of our inventory of materials and supplies that was specific to the Atwood Hunter of $8.4 million. In August 2015, we completed the sale of the Atwood Hunter.

Consistent with our policy, we evaluate our drilling rigs and related equipment for impairment whenever events or changes in circumstances indicate the carrying value of these assets may exceed the estimated undiscounted future net cash flows. Our evaluation, among other things, includes a review of external market factors and an assessment on the future marketability of a specific drilling unit. Given the current level of oil prices, the decline in drilling activity and the continued delivery of new, more capable rigs, we consider these macro-economic factors to be indicators that some of our drilling rigs and/or related equipment may potentially be impaired.

At September 30, 2016, we performed impairment testing on our fleet of drilling rigs, including our two rigs currently under construction, which have an aggregate net book value of $4.0 billion. We concluded that the net book value of each drilling rig is recoverable through estimated future cash flows. The most significant assumptions used in our undiscounted cash flow model include: timing on awards of future drilling contracts, operating day rates, operating costs, capital expenditures, reactivation costs, drilling rig utilization, estimated remaining economic useful life and net proceeds received upon future sale/disposition. These significant assumptions are classified as Level 3 inputs by ASC Topic 820 Fair Value Measurement and Disclosures as they are based upon unobservable inputs and primarily rely on management assumptions and forecasts. Although we believe the assumptions used in our analysis are reasonable and appropriate, different assumptions and estimates could materially impact the analysis and our resulting conclusion. Our oldest drilling rig may be subject to greater risk of future impairment if the significant assumptions on which we have based our impairment testing at September 30, 2016 do not materialize or if we change those assumptions in future periods as new market conditions may dictate.

We maintain in drilling equipment in warehouse facilities around the world intended to support our current and future offshore drilling operations. As part of our fiscal year end evaluation of the current levels on hand and an assessment as to the expected future demand and likelihood of use, in the three month period ended September 30, 2016, we recorded a non-cash impairment charge of $38.6 million ($38.6 million net of tax or $0.60 per diluted share) in our Consolidated Statements of Operations, included in Asset Impairment to write down these assets to their fair value.

Sale of Other Assets

During April 2016, the Atwood Falcon sale and recycling transaction closed and title of the vessel and associated equipment and machinery transferred to a third party buyer. Net proceeds received were immaterial.

During August 2015, we completed the sale of our rig, the Atwood Hunter, for recycling. We received $2.9 million in proceeds and we recorded a loss of approximately $5.5 million ($5.5 million, net of tax, or $0.08 per diluted share), which is included in (Gain) Loss on Sale of Assets on the Consolidated Statement of Operations for fiscal year 2015. We incurred costs of $8.7 million related to the impairment and sale of the Atwood Hunter.

During December 2014, we completed the sale of our rig, the Atwood Southern Cross, for recycling. We received $2.1 million in proceeds and incurred related costs of $2.0 million. We recorded a loss of approximately $8.0 million ($7.1 million, net of tax, or $0.11 per diluted share), which is included in (Gain) Loss on Sale of Assets on the Consolidated Statement of Operations for fiscal year 2015.

During January 2014, we sold our standard jackup drilling unit, the Vicksburg, for a sales price of $55.4 million. The carrying value of the rig and its related inventory was approximately $20.5 million.

During April 2014, we sold a wholly owned subsidiary which owned our semisubmersible tender assist drilling rig, the Seahawk, for a sales price of $4.0 million. The carrying value of the subsidiary after a $2.0 million impairment charge, approximated its sales price.

Depreciation

The amount of depreciation expense we record is dependent upon certain assumptions, including an asset’s estimated useful life, rate of consumption and corresponding salvage value. We periodically review these assumptions and may change one or more of these assumptions. Changes in our assumptions may require us to recognize, on a prospective basis, increased or decreased depreciation expense. As of September 30, 2016, we shortened the estimated useful life of the Atwood Eagle and as a result, relative to its previous deprecation schedule, this will increase the depreciation expense over the next four fiscal years by $5.8 million per fiscal year, and will decrease by $1.9 million fiscal year 2021.

Other Income

For the fiscal year 2016, we recognized approximately $18.0 million ($18.0 million, net of tax, or $0.28 per diluted share) of expected insurance recoveries related to cyclone damage to the Atwood Osprey. This amount is included in Other Income on the Consolidated Statement of Operations. We collected receivables from the insurance company of approximately $18 million during the twelve months ended September 30, 2016.

Construction Projects

As of September 30, 2016, we had expended approximately $845 million towards our two ultra-deepwater drillships under construction at Daewoo Shipbuilding and Marine Engineering Co., ("DSME") yard in South Korea. Remaining expected capital expenditure for these two drillships under construction totaled approximately $425 million at September 30, 2016. On December 17, 2015, we entered into a supplemental agreement (collectively, "Supplemental Agreement No. 4") to the construction contracts with DSME which delay our requirements to take delivery of the Atwood Admiral to September 30, 2017 and the Atwood Archer to June 30, 2018. Supplemental Agreement No. 4 amends all material terms of the previous agreements. In consideration of the agreement, we made a payment of $50 million for each drillship on December 31, 2015. DSME has extended all remaining milestone payments, $93.9 million for the Atwood Admiral and $305.9 million for the Atwood Archer, until their respective delivery dates. We retain the option to take earlier delivery of each vessel, subject to a forty-five-day notice period to DSME. Neither of these drillships have long-term drilling contracts in place and we may seek to delay delivery further to align delivery with anticipated offshore drilling demand.

In May 2016, we entered into an agreement with Hydril USA Distribution, LLC ("GE") to manufacture a complete second Blowout Preventer stack ("BOP") and an Auxiliary Stack Test System ("ASTS") for the Atwood Condor. The addition of the second BOP will increase the marketability and operational efficiency of the vessel. Total consideration for this agreement is approximately $19 million with 20% paid upon placement of the purchase order and the remaining 80% due upon delivery. To accelerate the manufacturing and delivery process, which is targeted for February 2017, we provided certain capital spares we maintained to GE to be used in the manufacturing process. These capital spares will be replenished by GE with similar capital spares upon delivery of the BOP.

NOTE 4—DEBT

A summary of long-term debt is as follows:

	September 30,	
(In thousands)	2016	2015
Senior Notes 6.5% due 2020 ("Senior Notes")	$447,919	$648,268
Revolving Credit Facility	780,000	1,030,000
Total long-term debt	$1,227,919	$1,678,268

Senior Notes (Due February 2020)

As of September 30, 2016, $448.7 million aggregate principal amount of our Senior Notes were outstanding. Our Senior Notes are presented in the table above together with the unamortized premium from their issuance of $3.2 million and $5.9 million and net of unamortized debt issuance costs of $4.0 million and $7.4 million as of September 30, 2016 and September 30, 2015, respectively. Our Senior Notes are unsecured obligations and are not guaranteed by any of our subsidiaries.

Gains on extinguishment of debt

During the year ended September 30, 2016, we repurchased $201.4 million aggregate principal amount of our Senior Notes at an aggregate cost of $135.7 million, that included payment for accrued interest of $3.7 million. As a result of the repurchases, we recognized a total gain on debt retirement, net of the write-off of debt issuance costs and premium, of $69.0 million ($54.7 million net of tax, or $0.84 per diluted share) in Gains on extinguishment of debt on the Consolidated Statements of Operations for fiscal year 2016. The repurchases were made using available cash balances.

Revolving Credit Facility

As of September 30, 2016, our revolving credit facility (the "Credit Facility"), had total commitments of $1.395 billion through May 2018 and $1.120 billion through May 2019. Our wholly-owned subsidiary, Atwood Offshore Worldwide Limited ("AOWL"), is the borrower under the Credit Facility and we and certain of our other subsidiaries are guarantors under the facility.

On March 25, 2016, we entered into an amendment to our Credit Facility (the "Fourth Amendment") that, among other things, effective on March 28, 2016, (i) removed the maximum leverage ratio and maximum secured leverage ratio financial covenants, (ii) amended the minimum interest expense coverage ratio such that it is not applicable until the quarter ending September 30, 2018, and decreased the minimum ratio required to 1.15:1.00, (iii) added a minimum liquidity financial covenant of $150 million, (iv) revised the restricted payments covenant to prohibit us from paying dividends, (v) reduced the total commitments under the Credit Facility by $152 million, and (vi) permits the incurrence of up to $400 million of second lien debt, subject to the parameters set forth therein. As a result of the Fourth Amendment, borrowings under the Credit Facility bear interest at the Eurodollar rate plus a margin ranging from 2.50% to 3.25% and the commitment fee on the unused portion of the underlying commitment ranges from 1.00% to 1.30% per annum, in each case based on our corporate credit ratings.

The Credit Facility was secured primarily by first preferred mortgages on eight of our active drilling units prior to the Fourth Amendment (Atwood Aurora, Atwood Beacon, Atwood Condor, Atwood Eagle, Atwood Falcon, Atwood Mako, Atwood Manta and Atwood Osprey), as well as liens on the equity interests of our subsidiaries that own, directly or indirectly, such drilling units. In connection with the amendment, we mortgaged the Atwood Achiever, the Atwood Advantage and the Atwood Orca as additional collateral under the Credit Facility, as well as pledged the equity interests in our subsidiaries that own, directly or indirectly, these three vessels. Additionally, the Atwood Eagle and Atwood Falcon, along with the pledged equity interests in certain of our subsidiaries that, directly or indirectly, own these two vessels, were removed as collateral under the Credit Facility. Our interest in the two drillships under construction remain unencumbered by the Credit Facility.

As of September 30, 2016, our Credit Facility had $1.395 billion of total commitments and we had $780 million of outstanding borrowings. As of September 30, 2016, we had approximately $615 million available for borrowings under the Credit Facility.

Approximately $275 million of the commitments mature in May 2018 and approximately $1.12 billion of the commitments under the Credit Facility mature in May 2019. We were in compliance with all financial covenants under the Credit Facility as of September 30, 2016 and 2015, and we anticipate that we will continue to be in compliance for the next fiscal year.

Letter of Credit Facility

On July 29, 2015, our subsidiary AOWL, entered into a letter of credit facility with BNP Paribas (“BNP”), pursuant to which BNP may, in its sole and absolute discretion, issue letters of credit from time to time at the request of AOWL, for the account of AOWL and its subsidiaries, up to an unlimited stated face amount of such letters of credit. Certain fees will be payable upon the issuance of each letter of credit under the letter of credit facility, with the amount of such fees depending on whether such letters of credit are performance letters of credit or financial letters of credit. BNP has no commitment under the facility to issue letters of credit, and the facility, as well as BNP’s willingness to receive requests from AOWL with respect to the issuance of letters of credit may be cancelled by BNP at any time. The facility contains certain events of default, including but not limited to delinquent payments, bankruptcy filings, material adverse judgments, cross-defaults under other debt agreements, or a change of control. As of September 30, 2016, we had no outstanding letters of credits under this facility.

Interest

The weighted-average effective interest rate on our long-term debt during fiscal years 2016 and 2015 was 4.94% and 2.60%, respectively. The effective rate was determined after giving consideration to the effect of our interest rate swaps accounted for as hedges and the amortization of premiums or discounts. Interest expense for fiscal years 2016, 2015 and 2014 was $68.6 million, $52.6 million and $41.8 million, respectively. Capitalized interest expense for fiscal 2016, 2015 and 2014 was $17.2 million, $22.2 million and $30.2 million, respectively.

NOTE 5—FAIR VALUE OF FINANCIAL INSTRUMENTS

We have certain assets and liabilities that are required to be measured and disclosed at fair value. 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 prioritizes inputs to valuation techniques used to measure fair value into three levels. Priority is given to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Assets and liabilities measured at fair value are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values, stated below, takes into account the market for our financial assets and liabilities, the associated credit risk and other considerations.

We have classified and disclosed fair value measurements using the following levels of the fair value hierarchy:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities.

Level 2: Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability.

Level 3: Measurement based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable for objective sources (i.e., supported by little or no market activity).

Fair value of Certain Assets and Liabilities

The fair value of cash, accounts receivable and accounts payable approximate fair value because of their short term maturities.

Fair Value of Financial Instruments

Independent third party services are used to determine the fair value of our financial instruments using quoted market prices and observable inputs. When independent third party services are used, we obtain an understanding of how the fair values are derived and selectively corroborate fair values by reviewing other readily available market based sources of information.

Long-term Debt— Our long-term debt consists of both our Senior Notes and our Credit Facility.
Senior Notes - The carrying value of our Senior Notes, net of unamortized premium, is $451.9 million ($448.7 million principal amount) while the fair value of our Senior Notes was $355.3 million at September 30, 2016. The fair value is determined by a market approach using quoted period-end bond prices. We have classified this as a Level 2 fair value measurement as valuation inputs for fair value measurements are quoted market prices at September 30, 2016 that can only be obtained from independent third party sources. The fair value amount has been calculated using these quoted prices. However, no assurance can be given that the fair value would be the amount realized in an active market exchange.

Credit Facility - Our Credit Facility is variable-rate and the carrying amounts of our variable-rate debt approximates fair value because such debt bears short-term, market-based interest rates. We have classified the fair value measurement of this instrument as Level 2 as valuation inputs for purposes of determining our fair value disclosure are readily available published Eurodollar rates.

Derivative financial instruments— Our derivative financial instruments consist of our interest rate swap contracts and our foreign currency forward exchange contracts. We record our derivative contracts at fair value on our consolidated balance sheets. The fair values of our interest rate swaps and our foreign currency forward exchange contracts are based upon valuations calculated by an independent third party. The derivatives were valued according to the "Market approach" where possible, and the "Income approach" otherwise. A third party independently valued each instrument using forward price data obtained from reputable data providers (e.g., Bloomberg and Reuters) and reviewed market activity and similarity of pricing terms to determine appropriate reliability level assertions for each instrument. The contribution of the credit valuation adjustment to total fair value is less than 1% for all derivatives and is therefore not significant. Based on valuation inputs for fair value measurement and independent review performed by third party consultants, we have classified our derivative contracts as Level 2 as they were valued based upon observable inputs from dealer markets.
The following table sets forth the estimated fair value of our derivative financial instruments, for which we elected hedge accounting, as of September 30, 2016 and 2015, by location and hedge type, which are measured and recorded at fair value on a recurring basis:

		September 30,	
(In thousands)	Balance Sheet Classification	2016	2015
Derivative assets designated as cash flow hedging instruments:			
Short-term foreign currency forwards	Prepaid expenses, deferred costs and other current assets	$—	$3,822
Derivative liabilities designated as cash flow hedging instruments:			
Short-term interest rate swaps	Accrued liabilities	(1,312)	(1,326)
Long-term interest rate swaps	Other long-term liabilities	(482)	(974)
Total derivative contracts, net		$(1,794)	$1,522

NOTE 6—SHAREHOLDERS' EQUITY

Dividends

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We paid a dividend of $0.075 per share in January 2016 that was declared in November 2015. In February 2016, our board of directors eliminated the payment of a quarterly dividend in order to preserve liquidity. In March 2016, we amended Credit Facility, which amendment, among other things, prohibits us from paying dividends during the remaining term of the Credit Facility. Future reinstatement of dividends would require the amendment or waiver of such provision. In addition, the declaration and amount of any future dividends would be at the discretion of our board of directors and would depend on our financial condition, results of operations, cash flows, prospects, industry conditions, capital requirements and other factors and restrictions our board of directors deemed relevant. There can be no assurance that we will pay a dividend in the future.

NOTE 7—SHARE-BASED COMPENSATION

Our incentive plans permit the issuance of restricted stock and restricted stock unit awards (which we refer to as "restricted stock awards"), performance awards, stock appreciation rights and stock options. There are 2.5 million shares available for future grants at September 30, 2016. We deliver newly issued shares of common stock for restricted stock awards upon vesting or upon exercise of stock options.

Share-based compensation is recognized as an expense over the requisite service period on a straight-line basis. The total share-based compensation expense is based on the fair value of the award measured at the grant date.

	September 30,		
(In thousands, except average service periods)	2016	2015	2014
Share-based compensation recognized	$11,862	$12,828	$14,691
Unrecognized compensation cost, net of estimated forfeitures	19,406	16,934	16,478
Remaining weighted-average service period (years)	1.7	2.0	1.7

Restricted Stock

We have awarded restricted stock and restricted stock units to certain employees and to our non-employee directors. All current awards of restricted stock to employees are subject to a vesting and restriction period up to three years, as set forth in the terms of the grant. Our restricted stock awards are subject to acceleration for change of control, retirement, death or disability. All awards of restricted stock to non-employee directors are subject to a vesting and restriction period of 13 months, subject to acceleration upon certain events, such as change of control, as set forth in the terms of the grant. We value restricted stock awards based on the fair market value of our common stock on the date of grant. Our restricted stock holders have the right to receive dividend equivalents for their restricted awards that vest. Recipients of restricted stock awards do not have the rights of a shareholder until shares of stock are issued to the recipient.

A summary of restricted stock activity for fiscal year 2016 is as follows:

	Number of Shares (000s)	Weighted Average Fair Value
Unvested as of October 1, 2015	711	$ 43.14
Granted	1,091	13.20
Vested	(195)	45.88
Forfeited	(92)	31.01
Unvested as of September 30, 2016	1,515	21.96

Performance Units

We have made awards to certain employees that are subject to market-based performance conditions ("performance units"). All current awards of performance units are subject to a vesting and restriction period of three years. Our performance unit awards are subject to acceleration for change of control, retirement, death or disability. The number of performance unit awards that vest and the number of shares received upon vesting depends on the degree of achievement of specified corporate market-based performance criteria. The grant date fair value of the performance units we have granted was determined through use of the Monte Carlo simulation method. The Monte Carlo simulation method requires the use of highly subjective assumptions. Our key assumptions in the method include the price and the expected volatility of our and our self-determined peer group companies' stock, risk free rate of return, dividend yields and cross-correlations between our and our self-determined peer group companies

stock. The grant date fair value per share for the performance units we granted in fiscal year 2016, 2015 and 2014 were $15.63, $37.08 and $53.55, respectively. Our performance unit holders have the right to receive dividend equivalents for their performance units that vest. Recipients of performance units do not have the rights of a shareholder until shares of stock are issued to the recipient.
A summary of performance unit stock activity for fiscal year 2016 is as follows:

	Number of Shares (000s)	Weighted Average Fair Value
Unvested as of October 1, 2015	240	$ 43.73
Granted	255	15.63
Vested	—	—
Forfeited	(69)	45.20
Unvested as of September 30, 2016	426	26.69

Stock Options
Under our stock incentive plans, our options have a maximum term of 10 years. Options vest ratably over a period ranging from the end of the first to the fourth year from the date of grant. Each option is for the purchase of one share of our common stock. The total fair value of stock options vested during fiscal years 2016, 2015 and 2014 was $0.5 million, $2.5 million and $2.8 million, respectively. There were no stock options exercised during the fiscal year 2016. Cash proceeds received for the exercise of options for the fiscal years 2015 and 2014 were $1.1 million and $3.7 million, respectively. No stock options were granted during fiscal years 2016, 2015 or 2014.
A summary of stock option activity for fiscal year 2016 is as follows:

	Number of Options (000s)	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (000s)
Outstanding as of October 1, 2015	685	$ 34.90		
Granted	—	—		
Exercised	—	—		
Forfeited	—	—		
Expired	(68)	29.75		
Outstanding as of September 30, 2016	617	35.47	3.4	(16,533)
Exercisable as of September 30, 2016	617	35.47	3.4	(16,533)

NOTE 8—INCOME TAXES
Domestic and foreign income before income taxes for the three-year period ended September 30, 2016 is as follows:

(In thousands)	Fiscal 2016	Fiscal 2015	Fiscal 2014
Domestic income (loss)	$99,822	$22,788	$(36,756)
Foreign income	212,933	456,182	434,049
Income before income taxes	$312,755	$478,970	$397,293

The provision (benefit) for domestic and foreign taxes on income consists of the following:

(In thousands)	Fiscal 2016	Fiscal 2015	Fiscal 2014
Current—domestic	$2,454	$453	$773
Deferred—domestic	13,019	(4,061)	(980)
Current—foreign	32,480	48,691	56,968
Deferred—foreign	(470)	1,314	(290)
Provision for income taxes	$47,483	$46,397	$56,471

Deferred Taxes

The components of the deferred income tax assets (liabilities) as of September 30, 2016 and 2015 are as follows:

	September 30,	
(In thousands)	2016	2015
Deferred tax assets:		
Net operating loss carryforwards	$—	$22,930
Tax credit carryforwards	2,831	2,464
Stock option compensation expense	11,801	10,924
Debt issuance costs	251	221
Basis difference in fleet spares	4,310	—
Book accruals	3,189	3,064
	22,382	39,603
Deferred tax liabilities:		
Difference in book and tax basis of equipment	(209)	(209)
Deferred dividend withholding tax	(1,202)	(907)
Other timing differences	(199)	(1,422)
	(1,610)	(2,538)
Net deferred tax assets (liabilities) before valuation allowance	20,772	37,065
Valuation allowance	(21,808)	(38,573)
Net deferred tax liabilities	$(1,036)	$(1,508)

As of September 30, 2016 and 2015, the valuation allowance of $21.8 million and $38.6 million, respectively, primarily related to our U.S net operating loss carryforward, stock option compensation expense, timing differences and federal tax credit carryforwards. Our net operating loss carryforwards which will begin to expire in 2025, total approximately $5.9 million. Our tax credit carryforwards, which began to expire in 2016, total approximately $5.2 million.

We apply the “with-and-without” approach when utilizing certain tax attributes whereby windfall tax benefits are used last to offset taxable income. We had approximately $19.8 million of windfall tax benefits from previous stock option exercises that have not been recognized as of September 30, 2015. This amount will not be recognized until the deduction would reduce our U.S income taxes payable. At such time, the amount was recorded as an increase to paid-in-capital. During the fiscal year ended September 30, 2016, approximately $13.2 million of these tax benefits were recognized and recorded as an increase to paid-in-capital, as the windfall benefit (embedded in our U.S. net operating loss carry-forward) reduced our income taxes payable as of September 30, 2016. The remaining $6.6 million of windfall tax benefits have not been recognized as of September 30, 2016.

We do not record federal income taxes on the undistributed earnings of our foreign subsidiaries that we consider to be indefinitely reinvested in foreign operations. The cumulative amount of such undistributed earnings was approximately $2.9 billion at September 30, 2016. If these earnings were distributed, we estimate approximately $670.0 million in additional taxes would be incurred. These earnings could also become subject to additional taxes under the anti-deferral provisions within the U.S. Internal Revenue Code. However, we believe this is highly unlikely given our current structure and have not provided deferred income taxes on these foreign earnings as we consider them to be permanently invested abroad.

We record estimated accrued interest and penalties related to uncertain tax positions in income tax expense. As of September 30, 2016, we have approximately $16.1 million of reserves for uncertain tax positions, including estimated accrued interest and

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penalties of $3.8 million, which are included in Other Long Term Liabilities in the Consolidated Balance Sheet. All $16.1 million of the net uncertain tax liabilities would affect the effective tax rate if recognized.

A summary of activity related to the net uncertain tax positions including penalties and interest for fiscal year 2016 is as follows:

(In thousands)	Liability for Uncertain Tax Positions
Balance at October 1, 2015	$ 13,775
Increases as a result of tax positions taken during the current period	1,268
Increases as a result of tax positions taken in prior periods	2,347
Decreases due to the lapse of the applicable statute of limitations	(1,337)
Balance at September 30, 2016	$ 16,053

We believe that it is reasonably possible that approximately $1.0 million of our remaining unrecognized tax benefits may be recognized by the end of fiscal year 2017 as a result of a lapse of the statute of limitations.

Our U.S tax returns for fiscal year 2012 and subsequent years remain subject to examination by tax authorities. As we conduct business globally, we have various tax years remaining open to examination in our international tax jurisdictions, including tax returns in Australia for fiscal years 2009 through 2015. Although we cannot predict the outcome of ongoing or future tax examinations, we do not anticipate that the ultimate resolution of these examinations will have a material impact on our consolidated financial position, results of operations or cash flows.

We have historically earned most of our operating income in certain nontaxable and deemed profit tax jurisdictions, which significantly reduced our effective tax rate for fiscal years 2016, 2015 and 2014 when compared to the United States statutory rate. There were no significant transactions that materially impacted our effective tax rates for fiscal years 2016, 2015 or 2014. The differences between the United States statutory and our effective income tax rate are as follows:

	Fiscal 2016	Fiscal 2015	Fiscal 2014
Statutory income tax rate	35 %	35 %	35 %
Resolution of prior period tax items	—	—	—
Increase in tax rate resulting from:			
Valuation allowance	—	—	2
Increases to the reserve for uncertain tax positions	1	—	1
Decrease in tax rate resulting from:			
Release of valuation allowance	(5)	(3)	—
Foreign tax rate differentials, net of foreign tax credit utilization	(16)	(22)	(24)
Effective income tax rate	15 %	10 %	14 %

NOTE 9—COMMITMENTS AND CONTINGENCIES

Operating Leases

Future minimum lease payments for operating leases for fiscal years ending September 30 are as follows (in thousands):

2017	$2,420
2018	2,143
2019	2,152
2020	2,187
2021 and thereafter	6,777

Total rent expense under operating leases was approximately $8.3 million, $10.1 million and $11.5 million for fiscal years 2016, 2015 and 2014, respectively. The future minimum lease payments for our Houston corporate office is a material portion of the amounts shown in the table above. This lease is for ten years and commenced on January 31, 2014.

Purchase Commitments

As of September 30, 2016, our purchase commitments relating to our drilling units under construction and the Atwood Condor second BOP are $399.8 million and $15.2 million, respectively.

Litigation

We are party to a number of lawsuits which are ordinary, routine litigation incidental to our business, the outcome of which is not expected to have, either individually or in the aggregate, a material adverse effect on our financial position, results of operations or cash flows.

Other Matters

The Atwood Beacon operated in India from early December 2006 to the end of July 2009. A service tax was enacted in India in 2004 on revenues derived from seismic and exploration activities. This service tax law was subsequently amended in June 2007 and again in May 2008 to state that revenues derived from mining services and drilling services were specifically subject to this service tax. The contract terms with our client in India provided that any liability incurred by us related to any taxes pursuant to laws not in effect at the time the contract was executed in 2005 was to be reimbursed by our client. We believe any service taxes assessed by the Indian tax authorities under the 2007 or 2008 amendments are an obligation of our client. Our client is disputing this obligation on the basis of its contention that revenues derived from drilling services were taxable under the initial 2004 law, and are, therefore, our obligation. After reviewing the status of the drilling services we provided to our client, the Indian tax authorities assessed service tax obligations on revenues derived from the Atwood Beacon commencing on June 1, 2007. The relevant Indian tax authority issued an extensive written ruling setting forth the application of the June 1, 2007 service tax regulation and confirming the position that drilling services, including the services performed under our contract with our client prior to June 1, 2007, were not covered by the 2004 service tax law. In August 2012, the Indian Custom Excise and Service Tax Appellate Tribunal issued an Order in our favor confirming our position that service tax did not apply to drilling services performed prior to June 1, 2007. The Indian Service Tax Authority has appealed this ruling to the Indian Supreme Court.

As of September 30, 2016, we had paid to the Indian government $10.5 million in service taxes and have accrued $1.3 million of additional service tax obligations in accrued liabilities on our consolidated balance sheets, for a total of $11.8 million relating to service taxes. We recorded a corresponding $11.8 million long-term other receivable due from our client relating to service taxes due under the contract. We continue to pursue collection of such amounts from our client and expect to collect the amount recorded as receivable.

NOTE 10—OPERATIONS BY GEOGRAPHIC AREAS

Our offshore contract drilling operations are managed and reported as a single reportable segment: Offshore Contract Drilling Services. Our drilling units are often redeployed globally due to changing demands of our clients, which consist largely of major integrated oil and natural gas companies and independent oil and natural gas companies and the geographic areas where we conduct our business can and does change from year to year. Our offshore contract drilling services segment currently conducts offshore contract drilling operations located in the U.S. Gulf of Mexico, the Mediterranean Sea, offshore West Africa, offshore Southeast Asia and offshore Australia. The accounting policies of our reportable segment are the same as those described in the summary of significant accounting policies (see Note 2). We evaluate the performance of our operating segment based on revenues from external clients and segment profit.

A summary of revenues by geographic areas for the fiscal years ended September 30, 2016, 2015 and 2014 is as follows:

(In thousands)	Fiscal 2016	Fiscal 2015	Fiscal 2014
Australia	$296,566	$478,939	$457,281
Cameroon	65,954	70,507	43,389
Equatorial Guinea	—	22,843	41,245
Israel	—	—	2,749
Italy	45,023	60,927	58,912
Malaysia	—	22,545	49,610
Mauritania	122,330	69,691	—
Morocco	—	119,594	18,128
Senegal	62,146	—	—
Thailand	35,295	129,634	149,961
United States	393,330	405,859	352,678
Vietnam	—	15,312	—
Other	—	—	—
Total revenues	$1,020,644	$1,395,851	$1,173,953

A summary of property and equipment, net by geographic areas at September 30, 2016, 2015 and 2014 is as follows:

	September 30,		
(In thousands)	2016	2015	2014
Australia	$528,427	$640,530	$669,845
Cameroon	154,651	160,206	166,464
Equatorial Guinea	—	—	66,045
Italy	—	77,102	82,617
South Korea (1)	845,445	693,575	311,494
Malaysia	192	254	321
Malta	69,711	—	3,332
Mauritania	603,882	629,179	—
Morocco	—	—	627,459
Phillipines	325,575	—	—
Singapore	61,824	—	—
Thailand	168,735	349,972	539,333
United States	1,369,254	1,455,109	1,500,118
Vietnam	—	166,205	—
Total property and equipment, net	$4,127,696	$4,172,132	$3,967,028

(1) Property and equipment, net in South Korea consists of assets under construction.

NOTE 11—QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly results for fiscal years 2016 and 2015 are as follows:

	Fiscal 2016 Quarters Ended			
(In thousands, except per share amounts)	December 31,	March 31,	June 30,	September 30,
Revenues	$307,819	$296,351	$227,797	$188,677
Gross profit	168,881	197,310	141,784	105,843
Income before income taxes	50,295	136,426	120,116	5,918
Net income	39,081	122,437	99,505	4,249
Earnings per common share:				
Basic	0.60	1.89	1.54	0.07
Diluted	0.60	1.89	1.53	0.07

	Fiscal 2015 Quarters Ended			
	December 31,	March 31,	June 30,	September 30,
Revenues	$351,726	$350,387	$330,562	$363,176
Gross profit	203,354	210,602	187,238	235,492
Income before income taxes	55,340	134,976	122,539	166,115
Net income	46,218	122,669	112,992	150,694
Earnings per common share:				
Basic	0.72	1.90	1.75	2.33
Diluted	0.71	1.89	1.73	2.32

The sum of the individual quarterly earnings per common share amounts may not agree with year-to-date earnings per common share as each quarterly computation is based on the weighted-average number of common shares outstanding during that period.

NOTE 12—SUPPLEMENTAL INFORMATION

Accrued liabilities were $7.9 million and $23.6 million at September 30, 2016 and 2015, respectively. Accrued employee costs, which are components of accrued liabilities, were $4.3 million and $13.7 million at September 30, 2016 and 2015, respectively. No other component of accrued liabilities was more than five percent of total current liabilities.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures as of the end of the period covered by this report have been designed and are effective at the reasonable assurance level so that the information required to be disclosed by us in our periodic SEC filings is recorded, processed, summarized and reported within the time periods specific in the SEC's rules, regulations, and forms and is communicated to management. We believe that a controls system, no matter how well designed and operated, cannot provide absolute assurance that the objectives of the controls system are met, and no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within a company have been detected.

(b) Management's Annual Report on Internal Control over Financial Reporting

A copy of our Management's Report on Internal Control over Financial Reporting is included in Item 8 of this Form 10-K.

(c) Attestation Report of the Independent Registered Public Accounting Firm.

A copy of the report of PricewaterhouseCoopers LLP, our independent registered public accounting firm, is included in Item 8 of this Form 10-K

(d) Change in Internal Control over Financial Reporting

None.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

This information is incorporated by reference from our definitive Proxy Statement for the 2017 Annual Meeting of Shareholders, to be filed with the SEC not later than 120 days after the end of the fiscal year covered by this Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

This information is incorporated by reference from our definitive Proxy Statement for the 2017 Annual Meeting of Shareholders, to be filed with the SEC not later than 120 days after the end of the fiscal year covered by this Form 10-K.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

This information is incorporated by reference from our definitive Proxy Statement for the 2017 Annual Meeting of Shareholders, to be filed with the SEC not later than 120 days after the end of the fiscal year covered by this Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

This information is incorporated by reference from our definitive Proxy Statement for the 2017 Annual Meeting of Shareholders, to be filed with the SEC not later than 120 days after the end of the fiscal year covered by this Form 10-K.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

This information is incorporated by reference from our definitive Proxy Statement for the 2017 Annual Meeting of Shareholders, to be filed with the SEC not later than 120 days after the end of the fiscal year covered by this Form 10-K.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENTS

(1) Financial Statements.

Our Consolidated Financial Statements, together with the notes thereto and the report of PricewaterhouseCoopers LLP dated November 15, 2016, are included in Item 8 of this Form 10-K.

(2) Financial Statement Schedules.

All financial statement schedules have been omitted because they are not applicable or not required, the information is not significant, or the information is presented elsewhere in the financial statements.

(3) Exhibits.

3.1	Amended and Restated Certificate of Formation effective as of February 14, 2013 (Incorporated herein by reference to Exhibit 3.1 of our Form 8-K filed on February 14, 2013).
3.2	Amendment No. 1 to Amended and Restated Certificate of Formation dated February 19, 2014 (Incorporated herein by reference to Exhibit 3.1 of our Form 8-K filed on February 21, 2014).
3.3	By-Laws of Atwood Oceanics, Inc., effective March 7, 2013 (Incorporated herein by reference to Exhibit 3.1 to our Form 8-K filed on March 7, 2013).
4.1	Indenture dated January 18, 2012 between Atwood Oceanics, Inc. and Wells Fargo Bank, National Association, as trustee, relating to debt securities (Incorporated herein by reference to Exhibit 4.1 to our Form 10-Q for the quarter ended December 31, 2011).
4.2	First Supplemental Indenture dated January 18, 2012 between Atwood Oceanics, Inc. and Wells Fargo Bank, National Association, as trustee, including the form of 6.50% Senior Notes due 2020 (Incorporated herein by reference to Exhibit 4.2 to our Form 10-Q for the quarter ended December 31, 2011).
4.3	See Exhibit Nos. 3.1 and 3.3 hereof for provisions of our Amended and Restated Certificate of Formation and By-Laws defining the rights of our shareholders (Incorporated herein by reference to Exhibit 3.1 of our Form 8-K filed on February 14, 2013 and Exhibit 3.1 to our Form 8-K filed on March 7, 2013).
4.4	Restatement Agreement, dated as of April 10, 2014, among Atwood Oceanics, Inc., Atwood Offshore Worldwide Limited, the lenders party thereto, Nordea Bank Finland Plc, New York Branch, as existing administrative agent, and Nordea Bank Finland Plc, London Branch, as successor agent (Incorporated herein by reference to Exhibit 10.1 of our Form 8-K filed on April 11, 2014).
4.5	Amended and Restated Credit Agreement dated as of April 10, 2014, among Atwood Oceanics, Inc., Atwood Offshore Worldwide Limited, the lenders party thereto and Nordea Bank Finland Plc, London Branch, as administrative agent (Incorporated herein by reference to Exhibits 4.5 and 10.1 of our Form 10-K for the year ended September 30, 2014).
4.6	

	First Amendment to Amended and Restated Credit Agreement dated as of July 23, 2014, among Atwood Oceanics, Inc., Atwood Offshore Worldwide Limited, the lenders party thereto and Nordea Bank Finland Plc, London Branch, as administrative agent (Incorporated herein by reference to Exhibit 4.1 to our Form 10-Q for the quarter ended December 31, 2014).
4.7	Second Amendment to Amended and Restated Credit Agreement dated as of March 5, 2015, among Atwood Oceanics, Inc., Atwood Offshore Worldwide Limited, the lenders party thereto and Nordea Bank Finland Plc, London Branch, as administrative agent (Incorporated herein by reference to Exhibit 10.1 of our Form 8-K filed March 6, 2015).
4.8	Third Amendment to Amended and Restated Credit Agreement dated as of July 9, 2015, among Atwood Oceanics, Inc., Atwood Offshore Worldwide Limited, the lenders party thereto and Nordea Bank Finland Plc, London Branch, as administrative agent (Incorporated herein by reference to Exhibit 4.8 to our Form 10-K for the year ended September 30, 2015).
4.9	Fourth Amendment to Amended and Restated Credit Agreement dated as of March 25, 2016, by and among Atwood Oceanics, Inc., Atwood Oceanics Worldwide Limited, the lenders party thereto and Nordea Bank AB, London Branch, as administrative agent (Incorporated herein by reference to Exhibit 10.1 to our Form 8-K filed on March 28, 2016).

4.10	Letter of Credit Facility dated July 29, 2015 between Atwood Offshore Worldwide Limited and BNP Paribas (Incorporated herein by reference to Exhibit 4.9 to our Form 10-K for the year ended September 30, 2015).
†10.1	Atwood Oceanics, Inc. Amended and Restated 2001 Stock Incentive Plan (Incorporated herein by reference to Appendix D to our definitive proxy statement on Form DEF 14A filed January 13, 2006).
†10.2	Form of Atwood Oceanics, Inc. Stock Option Agreement - 2001 Stock Incentive Plan (Incorporated herein by reference to Exhibit 10.3.7 of our Form 10-K for the year ended September 30, 2005).
†10.3	Form of Stock Option Agreement - 2007 Long-Term Incentive Plan (Incorporated herein by reference to Exhibit 10.1.1 of our Form 10-Q for the quarter ended March 31, 2007).
†10.4	Form of Restricted Stock Award Agreement - 2007 Long-Term Incentive Plan (Incorporated herein by reference to Exhibit 10.1.2 of our Form 10-Q for the quarter ended March 31, 2007).
†10.5	Form of Non-Employee Director Restricted Stock Award Agreement - 2007 Long-Term Incentive Plan (Incorporated herein by reference to Exhibit 10.1.15 of our Form 10-K for the year ended September 30, 2009).
†10.6	Atwood Oceanics, Inc. Amended and Restated 2007 Long-Term Incentive Plan (Incorporated herein by reference to our definitive proxy statement on Form DEF14A filed January 14, 2011).
†10.7	First Amendment to Atwood Oceanics, Inc. Amended and Restated 2007 Long-Term Incentive Plan (Incorporated herein by reference to Exhibit 10.3 to our Form 10-Q for the quarter ended December 31, 2011).
†10.8	Second Amendment to Atwood Oceanics, Inc. Amended and Restated 2007 Long-Term Incentive Plan, effective November 21, 2013 (Incorporated herein by reference to Exhibit 10.1 of our Form 10-Q for the quarter ended December 31, 2013).
†10.9	Form of Notice of Restricted Stock Grant - 2007 Long-Term Incentive Plan (Incorporated herein by reference to Exhibit 10.4 to our Form 10-Q for the quarter ended December 31, 2011).
†10.10	Form of Notice of Non-employee Director Restricted Stock Grant - 2007 Long-Term Incentive Plan (Incorporated herein by reference to Exhibit 10.5 to our Form 10-Q for the quarter ended December 31, 2011).
†10.11	Form of Notice of Option Grant - 2007 Long-Term Incentive Plan (Incorporated herein by reference to Exhibit 10.6 to our Form 10-Q for the quarter ended December 31, 2011).

†10.12	Form of Notice of Performance Unit Grant - 2007 Long-Term Incentive Plan (Incorporated herein by reference to Exhibit 10.7 to our Form 10-Q for the quarter ended December 31, 2011).
†10.13	Atwood Oceanics, Inc. 2013 Long-Term Incentive Plan (Incorporated herein by reference to Appendix A to our definitive proxy statement on Form DEF14A filed on January 3, 2013).
†10.14	Amendment No.1 to Atwood Oceanics, Inc. 2013 Long-Term Incentive Plan (Incorporated herein by reference to Exhibit 4.5 of our Registration Statement on Form S-8 (No. 333-209686)).
†10.15	Second Amendment to Atwood Oceanics, Inc. 2013 Long-Term Incentive Plan (Incorporated herein by reference to Exhibit 10.2 to our Form 8-K filed on May 27, 2016).
†10.16	Form of Notice of Restricted Stock Unit Award - 2013 Long-Term Incentive Plan (Incorporated herein by reference to Exhibit 10.2 to our Form 10-Q for the quarter ended March 31, 2013).
†10.17	Form of Notice of Non-employee Director Restricted Stock Unit Award - 2013 Long-Term Incentive Plan (Incorporated herein by reference to Exhibit 10.3 to our Form 10-Q for the quarter ended March 31, 2013).
†10.18	Form of Notice of Option Grant - 2013 Long-Term Incentive Plan (Incorporated herein by reference to Exhibit 10.4 to our Form 10-Q for the quarter ended March 31, 2013).
†10.19	Form of Notice of Performance Unit Grant - 2013 Long-Term Incentive Plan (Incorporated herein by reference to Exhibit 10.5 to our Form 10-Q for the quarter ended March 31, 2013).
†10.20	Revised Form of Notice of Restricted Stock Unit Award - 2013 Long Term Incentive Plan (Incorporated herein by reference to Exhibit 10.2 to our Form 10-Q for the quarter ended December 31, 2013).
†10.21	Revised Form of Notice of Performance Unit Grant - 2013 Long Term Incentive Plan (Incorporated herein by reference to Exhibit 10.3 to our Form 10-Q for the quarter ended December 31, 2013).
†10.22	Second Revised Form of Notice of Performance Unit Grant - 2013 Long Term Incentive Plan (Incorporated herein by reference to Exhibit 10.4 to our Form 10-Q for the quarter ended December 31, 2014).

†10.23	Revised Form of Notice of Non-Employee Director Restricted Stock Unit Award - 2013 Long Term Incentive Plan (Incorporated herein by reference to Exhibit 10.4 to our Form 10-Q for the quarter ended December 31, 2013).
†10.24	Form of Executive Change of Control Agreement (Incorporated herein by reference to Exhibit 10.1 to our Form 8-K filed on May 30, 2012).
†10.25	Form of First Amendment to Executive Change of Control Agreement (Incorporated herein by reference to Exhibit 10.1 to our Form 8-K filed on January 2, 2015).
†10.26	Form of Indemnification Agreement for Directors and Executive Officers (Incorporated herein by reference to Exhibit 10.1 to our Form 10-Q for the quarter ended March 31, 2012).
†10.27	Atwood Oceanics, Inc. Restated Executive Life Insurance Plan dated as of March 19, 1999 (Incorporated herein by reference to Exhibit 10.22 to our Form 10-K for the year ended September 30, 2011).
†10.28	First Amendment, dated as of May 24, 2012, to the Atwood Oceanics, Inc. Salary Continuation Plan (formerly known as the Restated Executive Life Insurance Plan) (Incorporated herein by reference to Exhibit 10.2 to our Form 8-K filed on May 30, 2012).
†10.29	Form of Salary Continuation Agreement (Incorporated herein by reference to Exhibit 10.3 to our Form 8-K filed on May 30, 2012).
†10.30	Atwood Oceanics, Inc. Benefits Equalization Plan Amended and Restated Effective as of January 1, 2013 (Incorporated herein by reference to Exhibit 10.1 to our Form 10-Q for the quarter ended December 31, 2012).
†10.31	Amended and Restated Atwood Oceanics, Inc. 2007 Nonemployee Directors' Elective Deferred Compensation Plan (Incorporated herein by reference to Exhibit 10.6 to our Form 10-Q for the quarter ended March 31, 2013).
†10.32	Form of Non-Competition and Non-Solicitation Agreement (Incorporated herein by reference to Exhibit 10.1 to our Form 8-K filed on May 27, 2016).
10.33	Contract for Construction and Sale of Drillship by and between Alpha Admiral Company and Daewoo Shipbuilding & Marine Engineering Co. Ltd., dated September 27, 2012 (Incorporated herein by reference to Exhibit 10.42 to our Form 10-K for the year ended September 30, 2012).
10.34	Supplemental Agreement No. 1 dated 1 November 2014 to Drillship Contract dated 27 September 2012 by and between Alpha Admiral Company and Daewoo Shipbuilding & Marine Engineering Co., Ltd. (Incorporated

	herein by reference to Exhibit 10.1 to our Form 10-Q for the quarter ended December 31, 2014).
10.35	Supplemental Agreement No. 2 dated 6 February 2015 to Drillship Contract dated 27 September 2012 by and between Alpha Admiral Company and Daewoo Shipbuilding & Marine Engineering Co., Ltd. (Incorporated herein by reference to Exhibit 10.2 to our Form 10-Q for the quarter ended March 31, 2015).
10.36	Supplemental Agreement No. 3 dated 18 May 2015 to Drillship Contract dated 27 September 2012 by and between Alpha Admiral Company and Daewoo Shipbuilding & Marine Engineering Co., Ltd. (Incorporated herein by reference to Exhibit 10.1 to our Form 10-Q for the quarter ended June 30, 2015).
10.37	Supplemental Agreement No. 4 dated 17 December 2015 to the Drillship Contract dated 27 September 2012 by and between Alpha Admiral Company and Daewoo Shipbuilding & Marine Engineering Co., Ltd. (Incorporated herein by reference to Exhibit 10.1 to our Form 8-K filed on December 18, 2015).
10.38	Contract for Construction and Sale of Drillship by and between Alpha Archer Company and Daewoo Shipbuilding & Marine Engineering Co., Ltd., dated June 24, 2013 (Incorporated herein by reference to Exhibit 10.1 to our Form 10-Q for the quarter ended June 30, 2013).
10.39	Supplemental Agreement No. 1 dated 1 November 2014 to Drillship Contract dated 24 June 2013 by and between Alpha Archer Company and Daewoo Shipbuilding & Marine Engineering Co., Ltd. (Incorporated herein by reference to Exhibit 10.2 to our Form 10-Q for the quarter ended December 31, 2014).
10.40	Supplemental Agreement No. 2 dated 6 February 2015 to Drillship Contract dated 24 June 2013 by and between Alpha Archer Company and Daewoo Shipbuilding & Marine Engineering Co., Ltd. (Incorporated herein by reference to Exhibit 10.3 to our Form 10-Q for the quarter ended March 31, 2015).
10.41	Supplemental Agreement No. 3 dated 18 May 2015 to Drillship Contract dated 24 June 2013 by and between Alpha Archer Company and Daewoo Shipbuilding & Marine Engineering Co., Ltd. (Incorporated herein by reference to Exhibit 10.2 to our Form 10-Q for the quarter ended June 30, 2015).

10.42	Supplemental Agreement No. 4 dated 17 December 2015 to Drillship Contract dated 24 June 2013 by and between Alpha Archer Company and Daewoo Shipbuilding & Marine Engineering Co., Ltd. (Incorporated herein by reference to Exhibit 10.2 to our Form 8-K filed on December 18, 2015).
10.43	First Amendment to Stock Purchase Agreement, dated June 13, 2013, by and among Atwood Oceanics, Inc. and Helmerich & Payne International Drilling Co. (Incorporated herein by reference to Exhibit 10.1 to our Form 8-K filed on June 17, 2013).
*21.1	List of Subsidiaries.
*23	Consent of Independent Registered Public Accounting Firm.
*31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
**32.1	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**32.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*101	Interactive data files.
*	Filed herewith
**	Furnished herewith
†	Management contract or compensatory plan or arrangement

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.

ATWOOD OCEANICS, INC.

/S/ ROBERT J. SALTIEL
ROBERT J. SALTIEL
President and Chief Executive Officer

November 15, 2016

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.

/S/ MARK W. SMITH MARK W. SMITH Senior Vice President, Chief Financial Officer (Principal Financial Officer and Accounting Officer)	/S/ ROBERT J. SALTIEL ROBERT J. SALTIEL President and Chief Executive Officer; Director (Principal Executive Officer)
November 15, 2016	November 15, 2016
/S/ DEBORAH A. BECK DEBORAH A. BECK Director	/S/ JEFFREY A. MILLER JEFFREY A. MILLER Director
November 15, 2016	November 15, 2016
/S/ GEORGE S. DOTSON GEORGE S. DOTSON Director	/S/ JAMES R. MONTAGUE JAMES R. MONTAGUE Director
November 15, 2016	November 15, 2016
/S/ JACK E. GOLDEN JACK E. GOLDEN Director	/S/ PHIL D. WEDEMEYER PHIL D. WEDEMEYER Director
November 15, 2016	November 15, 2016
/S/ HANS HELMERICH HANS HELMERICH Director	
November 15, 2016	