Helmerich & Payne, Inc.
Form 10-K
November 22, 2017

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended September 30, 2017
OR
TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission file number 1 4221

HELMERICH & PAYNE, INC.

(Exact Name of Registrant as Specified in Its Charter)

Delaware	73 0679879
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
1437 S. Boulder Ave., Suite 1400, Tulsa, Oklahoma	74119 3623
(Address of Principal Executive Offices)	(Zip Code)
(918) 742 5531	
Registrant’s telephone number, including area code	

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock ($0.10 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

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

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

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S T during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S K is not contained herein, and will not be contained, to the best of 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.

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

Large accelerated filer	Accelerated filer	Non accelerated filer (Do not check if a smaller reporting company)
Smaller reporting company	Emerging Growth Company	

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

Exchange Act.

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

At March 31, 2017, the aggregate market value of the voting stock held by non affiliates was approximately $7.03 billion.

Number of shares of common stock outstanding at November 10, 2017: 108,605,547

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's 2018 Proxy Statement for the Annual Meeting of Stockholders to be held on March 7, 2018 are incorporated by reference into Part III of this Form 10 K. The 2018 Proxy Statement will be filed with the U.S. Securities and Exchange Commission ("SEC") within 120 days after the end of the fiscal year to which this Form 10 K relates.

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DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

This Annual Report on Form 10 K ("Form 10 K") includes "forward looking statements" within the meaning of the Securities Act of 1933, as amended, and the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included in this Form 10 K, including, without limitation, statements regarding the Registrant's future financial position, business strategy, budgets, projected costs and plans and objectives of management for future operations, are forward looking statements. In addition, forward looking statements generally can be identified by the use of forward looking terminology such as "may", "will", "expect", "intend", "estimate", "anticipate", "believe", or "continue" or the negative thereof or similar terminology. Although the Registrant believes that the expectations reflected in such forward looking statements are reasonable, it can give no assurance that such expectations will prove to be correct. Important factors that could cause actual results to differ materially from the Registrant's expectations or results discussed in the forward looking statements are disclosed in this Form 10 K under Item 1A—"Risk Factors", as well as in Item 7—"Management's Discussion and Analysis of Financial Condition and Results of Operations." All subsequent written and oral forward looking statements attributable to the Registrant, or persons acting on its behalf, are expressly qualified in their entirety by such cautionary statements. The Registrant assumes no duty to update or revise its forward looking statements based on changes in internal estimates, expectations or otherwise, except as required by law.

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HELMERICH & PAYNE, INC.

FORM 10 K

YEAR ENDED SEPTEMBER 30, 2017

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PART I

Item 1. BUSINESS

Helmerich & Payne, Inc. (which together with its subsidiaries is identified as the "Company", "we", "us" or "our," except where stated or the context requires otherwise), was incorporated under the laws of the State of Delaware on February 3, 1940, and is successor to a business originally organized in 1920. We are primarily engaged in contract drilling of oil and gas wells for oil and gas exploration and production companies and this business accounts for almost all of our operating revenues.

Our contract drilling business is composed of three reportable business segments: U.S. Land, Offshore and International Land. During fiscal 2017, our U.S. Land operations drilled primarily in Colorado, Louisiana, Ohio, Oklahoma, New Mexico, North Dakota, Pennsylvania, Texas, Utah, West Virginia and Wyoming. Offshore operations were conducted in the Gulf of Mexico. Our International Land segment conducted drilling operations in four international locations during fiscal 2017: Argentina, Bahrain, Colombia and United Arab Emirates ("UAE").

We are also engaged in the ownership, development and operation of commercial real estate and the research, development and lease for use in the oil and gas drilling industry of rotary steerable technology. Our real estate investments located exclusively within Tulsa, Oklahoma, include a shopping center containing approximately 441,000 leasable square feet, multi tenant industrial warehouse properties containing approximately one million leasable square feet and approximately 210 acres of undeveloped real estate. Since 2008, our subsidiary, TerraVici Drilling Solutions, Inc., has pursued the development of patented rotary steerable technology as a means to enhance our horizontal and directional drilling services. We expect to continue research and development of this and other technology in 2018. In addition, in June of 2017, we acquired MOTIVE Drilling Technologies, Inc. ("MOTIVE"). MOTIVE has a proprietary Bit Guidance System that is an algorithm-driven system that considers the total economic consequences of directional drilling decisions and has proven to consistently lower drilling costs through more efficient drilling and increase hydrocarbon production through smoother wellbores and more accurate well placement. We intend to utilize and continue to advance this technology to provide benefits for the drilling industry. Each of the businesses operates independently of the others through wholly owned subsidiaries. This operating decentralization is balanced by centralized finance, legal, human resources and information technology organizations.

CONTRACT DRILLING

General

We believe that we are one of the major land and offshore platform drilling contractors in the western hemisphere. Operating principally in North and South America, we specialize in shallow to deep drilling in oil and gas producing basins of the United States and in drilling for oil and gas in international locations. In the United States, we draw our customers primarily from the major oil companies and the larger independent oil companies. In South America, our current customers include major international and national oil companies.

In fiscal 2017, we received approximately 55 percent of our consolidated operating revenues from our ten largest contract drilling customers. EOG Resources, Inc., Continental Resources and Occidental Oil and Gas Corporation (respectively, "EOG", "Continental" and "Oxy"), including their affiliates, are our three largest contract drilling customers. We perform drilling services for EOG and Continental in U.S. land operations and Oxy on a world-wide basis. Revenues from drilling services performed for EOG, Continental and Oxy in fiscal 2017 accounted for approximately 9 percent, 9 percent and 7 percent, respectively, of our consolidated operating revenues for the same period.

Rigs, Equipment, R&D, Facilities, and Environmental Compliance

We provide drilling rigs, equipment, personnel and related ancillary services on a contract basis. These services are provided so that our customers may explore for and develop oil and gas from onshore areas and from fixed platforms, tension leg platforms and spars in offshore areas. Each of the drilling rigs consists of engines, drawworks, a mast, pumps, blowout preventers, a drill string and related equipment. The intended well depth and the drilling site conditions are the principal factors that determine the size and type of rig most suitable for a particular drilling job. A land drilling rig may be moved from location to location without modification to the rig. A platform rig is specifically

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designed to perform drilling operations upon a particular platform. While a platform rig may be moved from its original platform, significant expense is incurred to modify a platform rig for operation on each subsequent platform. In addition to traditional platform rigs, we operate self moving platform drilling rigs and drilling rigs to be used on tension leg platforms and spars. The self moving rig is designed to be moved without the use of expensive derrick barges. The tension leg platforms and spars allow drilling operations to be conducted in much deeper water than traditional fixed platforms.

Mechanical rigs rely on belts, pulleys and other mechanical devices to control drilling speed and other rig processes. As such, mechanical rigs are not highly efficient or precise in their operation. In contrast to mechanical rigs, SCR rigs rely on direct current for power. This enables motor speed to be controlled by changing electrical voltage. Compared to mechanical rigs, SCR rigs operate with greater efficiency, more power and better control. AC rigs provide for even greater efficiency and flexibility than what can be achieved with mechanical or SCR rigs. AC rigs use a variable frequency drive that allows motor speed to be manipulated via changes to electrical frequency. The variable frequency drive permits greater control of motor speed for more precision. Among other attributes, AC rigs are electrically more efficient, produce more torque, utilize regenerative braking, have digital controls and AC motors require less maintenance.

During the mid 1990's, we undertook an initiative to use our land and offshore platform drilling experience to develop a new generation of drilling rigs that would be safer, faster moving and higher performing than mechanical rigs. In 1998, we put to work a new generation of highly mobile/depth flexible land drilling rigs (individually the "FlexRig®"). Since the introduction of our FlexRigs, we have focused on designing, building, and periodically upgrading, high performance, high efficiency rigs to be used exclusively in our contract drilling business. We believed that over time FlexRigs would displace older less capable rigs. With the advent of unconventional shale plays, our AC drive FlexRigs have proven to be particularly well suited for more complex horizontal drilling requirements. The FlexRig has been able to significantly reduce average rig move and drilling times compared to similar depth rated traditional land rigs. In addition, the FlexRig allows greater depth flexibility and provides greater operating efficiency. The original rigs were designated as FlexRig1 and FlexRig2 rigs and were designed to drill wells with a depth of between 8,000 and 18,000 feet. In 2001, we announced that we would build the next generation of FlexRigs, known as "FlexRig3", which incorporated new drilling technology and new environmental and safety design. This new design included integrated top drive, AC electric drive, hydraulic BOP handling system, hydraulic tubular make up and break out system, split crown and traveling blocks and an enlarged drill floor that enables simultaneous crew activities. In 2004, we deployed the first FlexRig3 skidding systems to enable efficient multi-well pad developments. Over 135 of these systems have since been installed on FlexRig3's operating in both the United States and international locations. In 2017, we announced and began to deploy FlexRig3 walking system conversions as a second FlexRig3 solution for multi-well pad designs. FlexRig3s are designed to target well depths of between 8,000 and 25,000 feet.

In 2006, we placed into service our first FlexRig4. While FlexRig4s are similar to our FlexRig3s, the FlexRig4s are designed to efficiently drill more shallow depth wells of between 4,000 and 18,000 feet. The FlexRig4 design includes a trailerized version and a skidding version, which incorporate additional environmental and safety designs. While the FlexRig4 trailerized version provides for more efficient well site to well site rig moves, the skidding version allows for drilling of up to 22 wells from a single pad which results in reduced environmental impact.

In 2011, we announced the introduction of the FlexRig5 design. The FlexRig5 is suited for long lateral drilling of multiple wells from a single location, which is well suited for unconventional shale reservoirs. The new design preserves the key performance features of FlexRig3 combined with a bi directional pad drilling system and equipment capacities suitable for wells in excess of 25,000 feet of measured depth.

Industry trends toward more complex drilling have accelerated the retirement of less capable mechanical rigs. Over time our mechanical rigs have been sold or decommissioned as we added new AC drive rigs to our fleet. The decommission of our remaining seven mechanical rigs in fiscal 2011 marked the end of a multi year evolution in the high grading of our fleet from mechanical rigs to high efficiency, high performance rigs. In fiscal 2015, we also decommissioned 23 of our 37 remaining SCR rigs including six of the eight 3,000 horsepower conventional rigs in our U.S. Land fleet, all six of our FlexRig1 SCR rigs and all 11 of our FlexRig2 SCR rigs. In fiscal 2016 and 2017, we did not decommission any of our remaining 14 SCR rigs.

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Since 1998, we have built 232 FlexRig3s, 88 FlexRig4s, and 53 FlexRig5s with all 373 of those delivered to the field. Of the total 373 AC drive FlexRigs built through September 30, 2017, 110 have been built in the last five fiscal years.

The effective use of technology is important to the maintenance of our competitive position within the drilling industry. We expect to continue to focus on new technology solutions and applications in the future. Our research and development expense totaled $12.0 million in fiscal 2017, $10.3 million in fiscal 2016, and $16.1 million in fiscal 2015.

We currently have three facilities that provide vertically integrated solutions for drilling rig fabrication, upgrades, retrofits and modifications, as well as overhauling and repairing of drilling rigs, equipment and associated component parts. We have a gulf coast fabrication and assembly facility near Houston, Texas as well as a 123,000 square foot fabrication facility located on approximately 11 acres near Tulsa, Oklahoma. Additionally, we lease a 150,000 square foot industrial facility near Tulsa, Oklahoma.

Our business is subject to various federal, state and local laws enacted or adopted regulating the discharge of materials into the environment, or otherwise relating to the protection of the environment. We do not anticipate that compliance with currently applicable environmental regulations and controls will significantly change our competitive position, capital spending or earnings during fiscal 2018. For further information on environmental laws and regulations applicable to our operations, see Item 1A—"Risk Factors."

Industry / Competitive Conditions

Our business largely depends on the level of capital spending by oil and gas companies for exploration, development and production activities. Sustained increases or decreases in the price of oil and natural gas generally have a material impact on the exploration, development and production activities of our customers. As such, significant declines in the price of oil and natural gas may have a material adverse effect on our business, financial condition and results of operations. Oil prices have declined significantly since 2014 when prices exceeded $100 per barrel. Oil prices have rebounded modestly from lows below $30 per barrel in early 2016 to ranges between approximately $43 and $54 per barrel in fiscal 2017. The decline in prices continued to negatively affect demand for services in fiscal 2016 before showing some recovery in 2017. At the close of fiscal 2017 we had 218 contracted rigs, compared to 118 contracted rigs at the close of fiscal 2016 and 168 contracted rigs at the close of fiscal 2015. In addition, and in light of the price of oil and the status of the drilling industry and our rig fleet, in fiscal 2015 we performed an impairment evaluation of all our long lived drilling assets in accordance with ASC 360, Property, Plant, and Equipment. Our evaluation resulted in $39.2 million of impairment charges to reduce the carrying value of seven SCR land rigs within our International Land segment to their estimated fair value. Similarly, during fiscal 2016 we recorded a $6.3 million impairment charge to reduce the carrying value of certain rig and rig related equipment on previously decommissioned rigs to their estimated fair values. While we continue to periodically perform impairment evaluations, no additional impairments were identified in fiscal 2017 for any rigs in our domestic, international or offshore fleets. For further information concerning risks associated with our business, including volatility surrounding oil and natural gas prices and the impact of low oil prices on our business, see Item 1A—"Risk Factors" and Item 7—"Management's Discussion and Analysis of Financial Condition and Results of Operations" included in this Form 10 K.

Our industry is highly competitive. The land drilling market is generally more competitive than the offshore market due to the larger number of drilling rigs and market participants. While we strive to differentiate our services based upon the quality of our FlexRigs and our engineering design expertise, operational efficiency, safety and environmental awareness, the number of available rigs generally exceeds demand in many of our markets, resulting in strong price competition. In all of our geographic markets the ability to deliver rigs with new technology and features is also a significant factor in determining which drilling contractor is awarded a job. In recent years, rigs equipped with moving systems and configured to accommodate drilling of multiple wells on a single site have offered a competitive advantage. Other factors include quality of service and safety record, the availability and condition of equipment, the availability of trained personnel possessing specialized skills, experience in operating in certain environments, and relationships with customers.

We compete against many drilling companies and certain competitors are present in more than one of our operating regions. In the United States, we compete with Nabors Industries Ltd., Patterson UTI Energy, Inc. and many other competitors with regional operations. Internationally, we compete directly with various contractors at each location

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where we operate. In the Gulf of Mexico platform rig market, we primarily compete with Nabors Industries Ltd. and Blake International Rigs, LLC.

Drilling Contracts

Our drilling contracts are obtained through competitive bidding or as a result of negotiations with customers, and often cover multi well and multi year projects. Each drilling rig operates under a separate drilling contract. During fiscal 2017, all drilling services were performed on a “daywork” contract basis, under which we charged a fixed rate per day, with the price determined by the location, depth and complexity of the well to be drilled, operating conditions, the duration of the contract, and the competitive forces of the market. We have previously performed contracts on a combination “footage” and “daywork” basis, under which we charged a fixed rate per foot of hole drilled to a stated depth, usually no deeper than 15,000 feet, and a fixed rate per day for the remainder of the hole. Contracts performed on a “footage” basis involve a greater element of risk to the contractor than do contracts performed on a “daywork” basis. Also, we have previously accepted “turnkey” contracts under which we charge a fixed sum to deliver a hole to a stated depth and agree to furnish services such as testing, coring and casing the hole which are not normally done on a “footage” basis. “Turnkey” contracts entail varying degrees of risk greater than the usual “footage” contract. We have not accepted any “footage” or “turnkey” contracts in over twenty years. We believe that under current market conditions, “footage” and “turnkey” contract rates do not adequately compensate us for the added risks. The duration of our drilling contracts are “well to well” or for a fixed term. “Well to well” contracts are cancelable at the option of either party upon the completion o drilling at any one site. Fixed term contracts generally have a minimum term of at least six months but customarily provide for termination at the election of the customer, with an “early termination payment” to be paid to us if a contract is terminated prior to the expiration of the fixed term. However, under certain limited circumstances such as destruction of a drilling rig, our bankruptcy, sustained unacceptable performance by us or delivery of a rig beyond certain grace and/or liquidated damage periods, no early termination payment would be paid to us.

Contracts generally contain renewal or extension provisions exercisable at the option of the customer at prices mutually agreeable to us and the customer. In most instances contracts provide for additional payments for mobilization and demobilization.

As of September 30, 2017, we had 112 existing rigs under fixed term contracts. While the original duration for these current fixed term contracts are for six month to five year periods, some fixed term and well to well contracts are expecte to be extended for longer periods than the original terms. However, the contracting parties have no legal obligation to extend these contracts and some customers may elect to early terminate fixed term contracts as discussed above.

Backlog

Our contract drilling backlog, being the expected future revenue from executed contracts with original terms in excess of one year, as of September 30, 2017 and 2016 was $1.3 billion and $1.8 billion, respectively. The decrease in backlog at September 30, 2017 from September 30, 2016, is primarily due to the revenue earned since September 30, 2016. Approximately 41.7 percent of the total September 30, 2017 backlog is not reasonably expected to be filled in fiscal 2018. Included in backlog is early termination revenue expected to be recognized after the periods presented in which early termination notice was received prior to the end of the period.

The following table sets forth the total backlog by reportable segment as of September 30, 2017 and 2016, and the percentage of the September 30, 2017 backlog not reasonably expected to be filled in fiscal 2018:

Total Backlog

Reportable Segment	Revenue 9/30/2017	9/30/2016	Percentage Not Reasonably Expected to be Filled in Fiscal 2018	
	(in billions)			
U.S. Land	$ 0.9	$ 1.2	36.4	%
Offshore	—	0.1	—	%
International	0.4	0.5	58.0	%
	$ 1.3	$ 1.8		

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As noted above, under certain limited circumstances a customer is not required to pay an early termination fee. There may also be instances where a customer is financially unable or refuses to pay an early termination fee. Accordingly, the actual amount of revenue earned may vary from the backlog reported. For further information, see Item 1A—"Risk Factors."

U.S. Land Drilling

At the end of September 2017, 2016, and 2015, we had 350, 348 and 343, respectively, of our land rigs available for work in the United States. The total number of rigs at the end of fiscal 2017 increased by a net of two rigs from the end of fiscal 2016. The net increase is due to two new FlexRigs completed in 2017. Our U.S. Land operations contributed approximately 80 percent ($1.4 billion) of our consolidated operating revenues during fiscal 2017, compared with approximately 77 percent ($1.2 billion) of consolidated operating revenues during fiscal 2016 and approximately 80 percent ($2.5 billion) of consolidated operating revenues during fiscal 2015. Rig utilization was approximately 45 percent in fiscal 2017, approximately 30 percent in fiscal 2016 and approximately 62 percent in fiscal 2015. A rig is considered to be utilized when it is operated (or otherwise deployed for a customer) or being moved, assembled or dismantled under contract. At the close of fiscal 2017, 197 out of an available 350 land rigs were generating revenue.

Offshore Drilling

Our Offshore operations contributed approximately 8 percent in fiscal year 2017 ($136.3 million) of our consolidated operating revenues compared to approximately 9 percent ($138.6 million) of consolidated operating revenues during fiscal 2016 and 8 percent ($241.7 million) of consolidated operating revenues during fiscal 2015. Rig utilization in fiscal 2017 was approximately 74 percent compared to approximately 82 percent in fiscal 2016 and 93 percent in fiscal 2015. At the end of fiscal 2017, we had five of our eight offshore platform rigs under contract compared to seven of an available nine at the end of fiscal 2016. We continued to work under management contracts for two customer owned rigs at the close of fiscal 2017. Revenues from drilling services performed for our largest offshore drilling customer totaled approximately 60 percent ($81.1 million) of offshore revenues during fiscal 2017.

International Land Drilling

General

At the end of September 2017, 2016 and 2015, we had 38 land rigs available for work in locations outside of the United States. Our International Land operations contributed approximately 12 percent ($213.0 million) of our consolidated operating revenues during fiscal 2017, compared with approximately 14 percent ($229.9 million) of consolidated operating revenues during fiscal 2016 and 12 percent ($382.3 million) of consolidated operating revenues during fiscal 2015. Rig utilization was 36 percent in fiscal 2017, 39 percent in fiscal 2016 and 51 percent in fiscal 2015. Our international operations are subject to various political, economic and other uncertainties not typically encountered in U.S. operations. For further information on various risks associated with doing business in foreign countries, see Item 1A—"Risk Factors."

Argentina

At the end of fiscal 2017, we had 19 rigs in Argentina. Our utilization rate was approximately 55 percent during fiscal 2017, approximately 54 percent during fiscal 2016 and approximately 57 percent during fiscal 2015. Revenues generated by Argentine drilling operations contributed approximately 9 percent in fiscal 2017 ($157.3 million) of our consolidated operating revenues compared to approximately 10 percent ($159.4 million) of our consolidated operating revenues during fiscal 2016 and approximately 6 percent ($178.0 million) of our consolidated operating revenues during fiscal 2015. Revenues from drilling services performed for our two largest customers in Argentina totaled approximately 8 percent of consolidated operating revenues and approximately 70 percent of international operating revenues during fiscal 2017. The Argentine drilling contracts are primarily with large international or national oil companies.

Colombia

At the end of fiscal 2017, we had eight rigs in Colombia. Our utilization rate was approximately 25 percent during fiscal 2017, approximately 13 percent during fiscal 2016 and approximately 48 percent during fiscal 2015. Revenues generated by Colombian drilling operations contributed approximately 2 percent in fiscal 2017 ($37.6 million)

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of our consolidated operating revenues compared to approximately 1 percent ($20.5 million) of our consolidated operating revenues during fiscal 2016 and approximately 2 percent ($70.1 million) of our consolidated operating revenues during fiscal 2015. Revenues from drilling services performed for our two customers in Colombia totaled approximately 2 percent of consolidated operating revenues and approximately 18 percent of international operating revenues during fiscal 2017. The Colombian drilling contracts are primarily with large international or national oil companies.

Ecuador

At the end of fiscal 2017, we had six rigs in Ecuador. At the end of fiscal 2017 and 2016, all of our rigs in Ecuador were idle. The utilization rate in Ecuador was 4 percent in fiscal 2016 and 29 percent in fiscal 2015. Revenues generated by Ecuadorian drilling operations were insignificant during fiscal 2017 compared to contributing less than 1 percent during fiscal 2016 ($4.9 million) of our consolidated operating revenues and 1 percent in fiscal 2015 ($31.0 million) of our consolidated operating revenues.

UAE—Abu Dhabi

At the end of fiscal 2017, we had two rigs in the UAE. The utilization rate in the UAE was 8 percent in fiscal 2017, compared to 100 percent in fiscal 2016 and in fiscal 2015. Revenues generated by drilling operations in the UAE contributed less than 1 percent ($8.2 million) during fiscal 2017 of our consolidated operating revenues compared to approximately 2 percent during fiscal 2016 and fiscal 2015 ($34.6 million and $47.7 million, respectively) of our consolidated operating revenues. The UAE drilling contracts are with a single national oil company that contributed approximately 4 percent of international operating revenues during fiscal 2017.

Bahrain

At the end of fiscal 2017, we had three rigs in Bahrain. The utilization rate in Bahrain was 33 percent in fiscal 2017 and fiscal 2016, compared to 56 percent in fiscal 2015. Revenues generated by drilling operations in Bahrain contributed 1 percent during fiscal 2017, fiscal 2016 and fiscal 2015 ($10.0 million, $10.2 million and $41.9 million, respectively) of our consolidated operating revenues. Bahrain drilling contracts are with a single national oil company that contributed approximately 5 percent of international operating revenues during fiscal 2017.

FINANCIAL

For information relating to revenues, total assets and operating income by reportable operating segments, see Note 15—"Segment Information" included in Item 8—"Financial Statements and Supplementary Data" of this Form 10 K.

EMPLOYEES

We had 7,270 employees within the United States (5 of which were part time employees) and 853 employees in international operations as of September 30, 2017.

AVAILABLE INFORMATION

Our website is located at www.hpinc.com. Annual reports on Form 10 K, quarterly reports on Form 10 Q, current reports on Form 8 K, and amendments to those reports, earnings releases, and financial statements are made available free of charge on the investor relations section of our website as soon as reasonably practicable after we electronically file such materials with, or furnish it to, the SEC. The information contained on our website, or available by hyperlink from our website, is not incorporated into this Form 10 K or other documents we file with, or furnish to, the SEC.

Annual reports, quarterly reports, current reports, amendments to those reports, earnings releases, financial statements and our various corporate governance documents are also available free of charge upon written request.

Item 1A. RISK FACTORS

In addition to the risk factors discussed elsewhere in this Form 10 K, we caution that the following "Risk Factors" could have a material adverse effect on our business, financial condition and results of operations.

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

Our business depends on the conditions of the land and 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 and market expectations regarding such prices.

Oil prices declined significantly during the second half of 2014. Volatility and the overall decline in prices continued through 2015 and into early 2016. For example, in July of 2014 oil prices exceeded $100 per barrel. Oil prices dropped below $30 per barrel in early 2016. In fiscal 2016 oil prices rebounded but nevertheless remained volatile and continued to fluctuate in fiscal 2017 above and below $50 per barrel. The precipitous drop in oil prices and volatility over the last three years significantly affected the capital spending budgets of our customers, particularly in 2015 and 2016. As such, demand for our drilling services significantly declined from late 2014 through the first half of fiscal 2016. At December 31, 2014, 294 out of an available 337 land rigs were working in the U.S. Land segment. In contrast, at June 30, 2016, 89 out of an available 348 land rigs were contracted in the U.S. Land segment. Due to the modest rebound in oil prices we have experienced an increase in the demand for our drilling services since May of 2016. Nevertheless, our active rig count has remained below the height of drilling activity experienced in 2014 when oil prices were significantly higher. As of November 16, 2017, 200 rigs were contracted in the U.S. Land segment. In the event oil prices remain depressed for a sustained period, or decline again, our U.S. Land, International Land and Offshore segments may again experience significant declines in both drilling activity and spot dayrate pricing which could have a material adverse effect on our business, financial condition and results of operations.

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 worldwide economy;
- expectations about future oil and natural gas prices;
- the desire and 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;
- the continued development of shale plays which may influence worldwide supply and prices;
- 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;
- legal and other limitations or restrictions on exportation and/or importation of oil and natural gas;
- local and international political, economic and weather conditions; and
- the environmental and other laws and governmental regulations regarding exploration and development of oil and natural gas reserves.

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The level of land and 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. Higher oil and natural gas prices do not necessarily translate into increased activity because demand for our services is typically driven by our customer's expectations of future commodity prices. However, a sustained decline in worldwide demand for oil and natural gas or prolonged low oil or natural gas prices would likely result in reduced exploration and development of land and offshore areas and a decline in the demand for our services, which could have a material adverse effect on our business, financial condition and results of operations.

Our offshore and land operations are subject to a number of operational risks, including environmental and weather risks, which could expose us to significant losses and damage claims. We are not fully insured against all of these risks and our contractual indemnity provisions may not fully protect us.

Our drilling operations are subject to the many hazards inherent in the business, including inclement weather, blowouts, well fires, loss of well control, pollution, and reservoir damage. These hazards could cause significant environmental damage, personal injury and death, suspension of drilling operations, serious damage or destruction of equipment and property and substantial damage to producing formations and surrounding lands and waters.

Our Offshore drilling operations are also subject to potentially greater environmental liability, including pollution of offshore waters and related negative impact on wildlife and habitat, adverse sea conditions and platform damage or destruction due to collision with aircraft or marine vessels. Our Offshore operations may also be negatively affected by blowouts or uncontrolled release of oil by third parties whose offshore operations are unrelated to our operations. We operate several platform rigs in the Gulf of Mexico. The Gulf of Mexico experiences hurricanes and other extreme weather conditions on a frequent basis, the frequency of which may increase with any climate change. Damage caused by high winds and turbulent seas could potentially curtail operations on such platform rigs for significant periods of time until the damage can be repaired. Moreover, even if our platform rigs are not directly damaged by such storms, we may experience disruptions in operations due to damage to customer platforms and other related facilities in the area.

We have a facility located near the Houston, Texas ship channel where we upgrade and repair rigs and perform fabrication work, and our principal fabricator and other vendors are also located in the gulf coast region. Due to their location, these facilities are exposed to potentially greater hurricane damage.

We have indemnification agreements with many of our customers and we also maintain liability and other forms of insurance. In general, our drilling contracts contain provisions requiring our customers to indemnify us for, among other things, pollution and reservoir damage. However, our contractual rights to indemnification may be unenforceable or limited due to negligent or willful acts by us, our subcontractors and/or suppliers or by reason of state anti indemnity laws. Our customers and other third parties may also dispute, or be unable to meet, their contractual indemnification obligations to us. Accordingly, we may be unable to transfer these risks to our drilling customers and other third parties by contract or indemnification agreements. Incurring a liability for which we are not fully indemnified or insured could have a material adverse effect on our business, financial condition and results of operations.

With the exception of "named wind storm" risk in the Gulf of Mexico, we insure rigs and related equipment at values that approximate the current replacement cost on the inception date of the policies. However, we self insure large deductibles under these policies. We also carry insurance with varying deductibles and coverage limits with respect to offshore platform rigs and "named wind storm" risk in the Gulf of Mexico.

We have insurance coverage for comprehensive general liability, automobile liability, worker's compensation and employer's liability, and certain other specific risks. Insurance is purchased over deductibles to reduce our exposure to catastrophic events. We retain a significant portion of our expected losses under our worker's compensation, general liability and automobile liability programs. The Company self insures a number of other risks including loss of earnings and business interruption, and most cyber risks. We are unable to obtain significant amounts of insurance to cover risks of underground reservoir damage.

If a significant accident or other event occurs and is not fully covered by insurance or an enforceable or recoverable indemnity from a customer, it could have a material adverse effect on our business, financial condition and results of operations. Our insurance will not in all situations provide sufficient funds to protect us from all liabilities that could result from our drilling operations. Our coverage includes aggregate policy limits. As a result, we retain the risk for any loss in excess of these limits. No assurance can be given that all or a portion of our coverage will not be cancelled during fiscal 2018, that insurance coverage will continue to be available at rates considered reasonable or that our coverage will respond to a specific loss. Further, we may experience difficulties in collecting from our insurers or our insurers may deny all or a portion of our claims for insurance coverage.

Global economic conditions may adversely affect our business.

Global economic conditions and volatility in oil and natural gas prices may impact the ability or desire of our customers to maintain or increase spending on exploration and development drilling and whether customers and/or vendors and suppliers will be able to access financing necessary to sustain or increase their current level of operations, fulfill their commitments and/or fund future operations and obligations. In the event the strength of the global economic environment fails to gain momentum or deteriorates in 2018, industry fundamentals may be impacted and result in stagnant or reduced demand for drilling rigs. Furthermore, these factors may result in certain of our customers experiencing bankruptcy or otherwise becoming unable to pay vendors, including us. The global economic environment in the past has experienced significant deterioration in a relatively short period of time and there can be no assurance that the global economic environment will not quickly deteriorate again due to one or more factors. These conditions could have a material adverse effect on our business, financial condition and results of operations.

The contract drilling business is highly competitive and an excess of available drilling rigs may adversely affect our rig utilization and profit margins.

Competition in contract drilling involves such factors as price, rig availability and excess rig capacity in the industry, efficiency, condition and type of equipment, reputation, operating safety, environmental impact, and customer relations. Competition is primarily on a regional basis and may vary significantly by region at any particular time. Land drilling rigs can be readily moved from one region to another in response to changes in levels of activity, and an oversupply of rigs in any region may result, leading to increased price competition.

Although many contracts for drilling services are awarded based solely on price, we have been successful in establishing long term relationships with certain customers which have allowed us to secure drilling work even though we may not have been the lowest bidder for such work. We have continued to attempt to differentiate our services based upon our FlexRigs and our engineering design expertise, operational efficiency, safety and environmental awareness. However, development of new drilling technology by competitors has increased in recent years and future improvements in operational efficiency and safety by our competitors could further negatively affect our ability to differentiate our services. Also, the strategy of differentiation is less effective during low commodity price environments when lower demand for drilling services intensifies price competition and makes it more difficult or impossible to compete on any basis other than price.

The oil and natural gas services industry in the United States has experienced downturns in demand during the last decade, including a significant downturn that started in 2014 and bottomed out in 2016. Today, as was the case following past downturns, there are substantially more drilling rigs available than necessary to meet the modest rebound in demand observed in 2016 and 2017. As a result of the current excess of available and more competitive drilling rigs, we may continue to experience difficulty in replacing fixed term contracts, extending expiring contracts or obtaining new contracts in the spot market, and the day rates (and other material terms) under new contracts may be on substantially less favorable rates and terms. As such, we may have difficulty sustaining or increasing rig utilization and profit margins in the future, we may lose market share and price may be a primary factor in the award of contracts for drilling services.

The loss of one or a number of our large customers could have a material adverse effect on our business, financial condition and results of operations.

In fiscal 2017, we received approximately 55 percent of our consolidated operating revenues from our ten largest contract drilling customers and approximately 25 percent of our consolidated operating revenues from our three largest customers (including their affiliates). We believe that our relationship with all of these customers is good; however, the loss of one or more of our larger customers could have a material adverse effect on our business, financial condition and results of operations.

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New technologies may cause our drilling methods and equipment to become less competitive, higher levels of capital expenditures may be necessary to keep pace with the bifurcation of the drilling industry, and growth through the building of new drilling rigs and improvement of existing rigs is not assured.

The market for our services is characterized by continual 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 increasingly demand the services of newer, higher specification drilling rigs. This results in a bifurcation of the drilling fleet and is evidenced by the higher specification drilling rigs (e.g., AC rigs) generally operating at higher overall utilization levels and day rates than the lower specification drilling rigs (e.g., mechanical or SCR rigs). In addition, a significant number of lower specification rigs are being stacked and/or removed from service. As a result of this bifurcation, a higher level of capital expenditures will be required to maintain and improve existing rigs and equipment and purchase and construct newer, higher specification drilling rigs to meet the increasingly sophisticated needs of our customers.

Since the late 1990's we have increased our drilling rig fleet through new construction. We also continue to modify our existing rig fleet to meet customer requirements. We have upgraded FlexRigs to super-spec rigs, developed walking rigs, and made other improvements. Although we take measures to ensure that we use advanced oil and natural gas drilling technology, changes in technology or improvements in competitors' equipment could make our equipment less competitive. There can be no assurance that we will:

- have sufficient capital resources to improve existing rigs or build new, technologically advanced drilling rigs;
- avoid cost overruns inherent in large fabrication projects resulting from numerous factors such as shortages of equipment, materials and skilled labor, unscheduled delays in delivery of ordered equipment and materials, unanticipated increases in costs of equipment, materials and labor, design and engineering problems, and financial or other difficulties;
- successfully deploy idle, stacked, new or upgraded drilling rigs;
- effectively manage the increased size or future growth of our organization and drilling fleet;
- maintain crews necessary to operate existing or additional drilling rigs; or
- successfully improve our financial condition, results of operations, business or prospects as a result of improving existing drilling rigs or building new drilling rigs.

If we are not successful in upgrading existing rigs and equipment or building new rigs in a timely and cost effective manner suitable to customer needs, we could lose market share. One or more technologies that we may implement in the future may not work as we expect and we may be adversely affected. Additionally, new technologies, services or standards could render some of our services, drilling rigs or equipment obsolete, which could have a material adverse impact on our business, financial condition and results of operation.

Technology disputes could negatively impact our operations or increase our costs.

Drilling rigs use proprietary technology and equipment which can involve potential infringement of a third party's rights, including patent rights. The majority of the intellectual property rights relating to our drilling rigs are owned by us or certain of our supplying vendors. However, in the event that we or one of our supplying vendors becomes involved in a dispute over infringement rights relating to equipment owned or used by us, we may lose access to important equipment, or we could be required to cease use of some equipment or forced to modify our drilling rigs. We could also be required to pay license fees or royalties for the use of equipment. Technology disputes involving us or our supplying vendors could have a material adverse impact on our business, financial condition and results of operation.

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New legislation and regulatory initiatives relating to hydraulic fracturing or other aspects of the oil and gas industry could negatively impact the drilling programs of our customers and, consequently, delay, limit or reduce the drilling services we provide.

It is a common practice in our industry for our customers to recover natural gas and oil from shale and other formations through the use of horizontal drilling combined with hydraulic fracturing. Hydraulic fracturing is the process of creating or expanding cracks, or fractures, in formations using water, sand and other additives pumped under high pressure into the formation. The hydraulic fracturing process is typically regulated by state oil and natural gas commissions. Several states have adopted or are considering adopting regulations that could impose more stringent permitting, public disclosure, waste disposal and/or well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. In addition to state laws, some local municipalities have adopted or are considering adopting land use restrictions, such as city ordinances, that may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. Members of the U.S. Congress and a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing and the possibility of more stringent regulation. Further, we conduct drilling activities in numerous states, including Oklahoma. In recent years, Oklahoma has experienced an increase in earthquakes. Some parties believe that there is a correlation between hydraulic fracturing related activities and the increased occurrence of seismic activity. The extent of this correlation, if any, is the subject of studies of both state and federal agencies the results of which remain uncertain. Depending on the outcome of these or other studies pertaining to the impact of hydraulic fracturing, federal and state legislatures and agencies may seek to further regulate, restrict or prohibit hydraulic fracturing activities. Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to oil and gas production activities using hydraulic fracturing techniques, operational delays or increased operating and compliance costs in the production of oil and natural gas from shale plays, added difficulty in performing hydraulic fracturing, and potentially a decline in the completion of new oil and gas wells.

We do not engage in any hydraulic fracturing activities. However, any new laws, regulations or permitting requirements regarding hydraulic fracturing could negatively impact the drilling programs of our customers and, consequently, delay, limit or reduce the drilling services we provide. Widespread regulation significantly restricting or prohibiting hydraulic fracturing by our customers could have a material adverse impact on our business, financial condition and results of operation.

We may be required to record impairment charges with respect to our drilling rigs and other assets.

We evaluate our drilling rigs and other assets whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. An impairment loss may exist when the estimated future cash flows are less than the carrying amount of the asset. Lower utilization and day rates adversely affect our revenues and profitability. 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, in fiscal 2015, we performed an impairment evaluation of all our long lived drilling assets. Our evaluation resulted in $39.2 million of impairment charges to reduce the carrying value of seven SCR land rigs within our International Land segment to their estimated fair value. Similarly, during the third quarter of fiscal 2016 we recorded a $6.3 million impairment charge to reduce the carrying value of certain rig and rig related equipment classified as held for sale in our U.S. Land segment to their estimated fair values. Although we are actively marketing idle drilling rigs in our fleet, there can be no assurance that we will be able to obtain future contracts for all of our rigs. As of September 30, 2017, we assessed our idle drilling rigs and determined no additional impairment charges were necessary. However, drilling rigs in our fleet may become impaired in the future if market conditions deteriorate or if oil and gas prices decline further or remain low for a prolonged period.

Department of Interior investigation could adversely affect our business.

On November 8, 2013, the United States District Court for the Eastern District of Louisiana approved the previously disclosed October 30, 2013 plea agreement between our wholly owned subsidiary, Helmerich & Payne International Drilling Co. (“H&PIDC”), and the United States Department of Justice, United States Attorney’s Office for the Eastern District of Louisiana (“DOJ”). The court’s approval of the plea agreement resolved the DOJ’s investigation into certain choke manifold testing irregularities that occurred in 2010 at one of H&PIDC’s offshore platform rigs in the Gulf of Mexico. We also engaged in discussions with the Inspector General’s office of the Department of Interior

("DOI") regarding the same events that were the subject of the DOJ's investigation. Although we do not presently anticipate any further action by the DOI in this matter, we can provide no assurances as to the timing or eventual outcome of the DOI's consideration of the matter. Refer also to Item 3—"Legal Proceedings" and Note 14—"Commitments and Contingencies" included in Item 8—"Financial Statements and Supplementary Data" of this Form 10 K for discussion of this subject.

Our business and results of operations may be adversely affected by foreign political, economic and social instability risks, foreign currency restrictions and devaluation, and various local laws associated with doing business in certain foreign countries.

We currently have drilling operations in South America and the Middle East. In the future, we may further expand the geographic reach of our operations. As a result, we are exposed to certain political, economic and other uncertainties not encountered in U.S. operations, including increased risks of social unrest, strikes, terrorism, war, kidnapping of employees, nationalization, forced negotiation or modification of contracts, difficulty resolving disputes and enforcing contract provisions, expropriation of equipment as well as expropriation of oil and gas exploration and drilling rights, taxation policies, foreign exchange restrictions and restrictions on repatriation of income and capital, currency rate fluctuations, increased governmental ownership and regulation of the economy and industry in the markets in which we operate, economic and financial instability of national oil companies, and restrictive governmental regulation, bureaucratic delays and general hazards associated with foreign sovereignty over certain areas in which operations are conducted.

South American countries, in particular, have historically experienced uneven periods of economic growth, as well as recession, periods of high inflation and general economic and political instability. From time to time these risks have impacted our business. For example, on June 30, 2010, the Venezuelan government expropriated 11 rigs and associated real and personal property owned by our Venezuelan subsidiary. Prior thereto, we also experienced currency devaluation losses in Venezuela and difficulty repatriating U.S. dollars to the United States. Today, our contracts for work in foreign countries generally provide for payment in U.S. dollars. However, in Argentina we are paid in Argentine pesos. The Argentine branch of one of our second-tier subsidiaries then remits U.S. dollars to its U.S. parent by converting the Argentine pesos into U.S. dollars through the Argentine Foreign Exchange Market and repatriating the U.S. dollars.

Estimates from published sources indicate that Argentina is a highly inflationary country, which is defined as cumulative inflation rates exceeding 100 percent in the most recent three-year period based on inflation data published by the respective governments. Regardless, all of our foreign operations use the U.S. dollar as the functional currency and local currency monetary assets and liabilities are remeasured into U.S. dollars with gains and losses resulting from foreign currency transactions included in current results of operations.

In December 2015, the Argentine peso experienced a sharp devaluation resulting in a foreign currency loss of $8.4 million for fiscal 2016. Subsequent to the sharp devaluation, the Argentine peso significantly stabilized and the Argentine Foreign Exchange Market controls now place fewer restrictions on repatriating U.S. dollars. For fiscal 2017, we experienced a foreign currency loss of $4.0 million in Argentina. Our aggregate foreign currency losses for fiscal 2016 and 2017 were $9.3 million and $7.1 million, respectively. In the future, other contracts or applicable law may require payments to be made in foreign currencies. As such, there can be no assurance that we will not experience in Argentina or elsewhere a devaluation of foreign currency, foreign exchange restrictions or other difficulties repatriating U.S. dollars even if we are able to negotiate contract provisions designed to mitigate such risks. In the event of future payments in foreign currencies and an inability to timely exchange foreign currencies for U.S. dollars, we may incur currency devaluation losses which could have a material adverse impact on our business, financial condition and results of operations.

Additionally, there can be no assurance that there will not be changes in local laws, regulations and administrative requirements or the interpretation thereof which could have a material adverse effect on the profitability of our operations or on our ability to continue operations in certain areas. Because of the impact of local laws, our future operations in certain areas may be conducted through entities in which local citizens own interests and through entities (including joint ventures) in which we hold only a minority interest or pursuant to arrangements under which we conduct operations under contract to local entities. While we believe that neither operating through such entities nor pursuant to such arrangements would have a material adverse effect on our operations or revenues, there can be no assurance that we

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will in all cases be able to structure or restructure our operations to conform to local law (or the administration thereof) on terms we find acceptable.

Although we attempt to minimize the potential impact of such risks by operating in more than one geographical area, during fiscal 2017, approximately 12 percent of our consolidated operating revenues were generated from the international contract drilling business. During fiscal 2017, approximately 92 percent of the international operating revenues were from operations in South America. Substantially all of the South American operating revenues were from Argentina and Colombia. The future occurrence of one or more international events arising from the types of risks described above could have a material adverse impact on our business, financial condition and results of operation.

Drilling contracts with national oil companies may expose us to greater risks than we normally assume in drilling contracts with non-governmental customers.

We currently own and operate rigs that are contracted with foreign national oil companies. In the future we may expand our international operations and enter into additional, significant contracts with national oil companies. The terms of these contracts may contain non-negotiable provisions and may expose us to greater commercial, political, operational and other risks than we assume in other contracts. Foreign contracts may expose us 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 customer without cause on short-term notice, contractually or by governmental action, or under certain conditions that may not provide us with an early termination payment. We can provide no assurance that 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. Risks that accompany contracts with national oil companies could ultimately have a material adverse impact on our business, financial condition and results of operation

Failure to comply with the U.S. Foreign Corrupt Practices Act or foreign anti bribery legislation could adversely affect 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 subject us to civil and criminal penalties or other sanctions, which could have a material adverse impact on our business, financial condition and results of operation. 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 and the seizure of drilling rigs or other assets.

Failure to comply with governmental and environmental laws could adversely affect our business.

Many aspects of our operations are subject to government regulation, including those relating to drilling practices, pollution, disposal of hazardous substances and oil field waste. The United States and various other countries have environmental regulations which affect drilling operations. The cost of compliance with these laws could be substantial. A failure to comply with these laws and regulations could expose us to substantial civil and criminal penalties. In addition, environmental laws and regulations in the United States impose a variety of requirements on "responsible parties" related to the prevention of oil spills and liability for damages from such spills. As an owner and operator of drilling rigs, we may be deemed to be a responsible party under these laws and regulations.

We believe that we are in substantial compliance with all legislation and regulations affecting our operations in the drilling of oil and gas wells and in controlling the discharge of wastes. To date, compliance costs have not materially affected our capital expenditures, earnings, or competitive position, although compliance measures may add to the costs of drilling operations. Additional legislation or regulation may reasonably be anticipated, and the effect thereof on our operations cannot be predicted.

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Our current backlog of contract drilling revenue may continue to decline and may not be ultimately realized as fixed term contracts may in certain instances be terminated without an early termination payment.

Fixed term drilling contracts customarily provide for termination at the election of the customer, with an “early termination payment” to be paid to us if a contract is terminated prior to the expiration of the fixed term. However, under certain limited circumstances, such as destruction of a drilling rig, our bankruptcy, sustained unacceptable performance by us or delivery of a rig beyond certain grace and/or liquidated damage periods, no early termination payment would be paid to us. Even if an early termination payment is owed to us, a customer may be unable or may refuse to pay the early termination payment. We also may not be able to perform under these contracts due to events beyond our control, and our customers may seek to cancel or renegotiate our contracts for various reasons, such as depressed market conditions. As of September 30, 2017, our contract drilling backlog was approximately $1.3 billion for future revenues under firm commitments. Our contract drilling backlog may continue to decline over time as existing contract term coverage may not be offset by new term contracts as a result of any number of factors, such as low or declining oil prices and capital spending reductions by our customers. Our inability or the inability of our customers to perform under our or their contractual obligations may have a material adverse impact on our business, financial condition and results of operations.

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

Our contract drilling expense includes all direct and indirect costs associated with the operation, maintenance and support of our drilling equipment, which is often not affected by changes in dayrates and utilization. During periods of reduced revenue and/or activity, certain of our fixed costs (such as depreciation) may not decline and often we may incur additional costs. During times of reduced utilization, reductions in costs may not be immediate as we may incur additional costs associated with maintaining and cold stacking a rig, or we may not be able to fully reduce the cost of our support operations in a particular geographic region due to the need to support the remaining drilling rigs in that region. Accordingly, a decline in revenue due to lower dayrates and/or utilization may not be offset by a corresponding decrease in contract drilling expense which could have a material adverse impact on our business, financial condition and results of operations.

Our securities portfolio may lose significant value due to a decline in equity prices and other market related risks, thus impacting our debt ratio and financial strength.

At September 30, 2017, we had a portfolio of securities with a total fair value of approximately $70.1 million, consisting of Atwood Oceanics, Inc. (“Atwood”) and Schlumberger, Ltd. The total fair value of the portfolio of securities was $71.5 million at September 30, 2016. In May of 2017, Ensco plc (“Ensco”) announced that it entered into a definitive merger agreement under which Ensco would acquire Atwood in an all-stock transaction. The transaction closed on October 6, 2017. Under the terms of the merger agreement, we received 1.60 shares of Ensco for each share of our Atwood common stock. The securities in our portfolio are subject to a wide variety of market related risks that could substantially reduce or increase the fair value of the holdings. In general, the portfolio is recorded at fair value on the balance sheet with changes in unrealized after tax value reflected in the equity section of the balance sheet. However, where a decline in fair value below our cost basis is considered to be other than temporary, the change in value is recorded as a charge through earnings. During the fourth quarter of fiscal 2016, we determined that a loss was other than temporary and we recognized a $26.0 million impairment charge. No such impairment charge was recognized in fiscal 2017. At November 16, 2017, the fair value of the portfolio had decreased to approximately $63.2 million.

We may reduce or suspend our dividend in the future.

We have paid a quarterly dividend for many years. Our most recent, quarterly dividend was $0.70 per share. In the future, our Board of Directors may, without advance notice, determine to reduce or suspend our dividend in order to maintain our financial flexibility and best position the Company for long term success. The declaration and amount of future dividends is at the discretion of our Board of Directors and will depend on our financial condition, results of operations, cash flows, prospects, industry conditions, capital requirements and other factors and restrictions our Board of Directors deems relevant. The likelihood that dividends will be reduced or suspended is increased during periods of prolonged market weakness. In addition, our ability to pay dividends may be limited by agreements governing our indebtedness now or in the future. There can be no assurance that we will continue to pay a dividend in the future.

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Legal proceedings could have a negative impact on our business.

The nature of our business makes us susceptible to legal proceedings and governmental investigations from time to time. In addition, during periods of depressed market conditions we may be subject to an increased risk of our customers, vendors, former employees and others initiating legal proceedings against us. Lawsuits or claims against us could have a material adverse effect on our business, financial condition and results of operations. Any litigation or claims, even if fully indemnified or insured, could negatively affect our reputation among our customers and the public, and make it more difficult for us to compete effectively or obtain adequate insurance in the future.

We depend on a limited number of vendors, some of which are thinly capitalized and the loss of any of which could disrupt our operations.

Certain key rig components, parts and equipment are either purchased from or fabricated by a single or limited number of vendors, and we have no long term contracts with many of these vendors. Shortages could occur in these essential components due to an interruption of supply, the acquisition of a vendor by a competitor, increased demands in the industry or other reasons beyond our control. Similarly, certain key rig components, parts and equipment are obtained from vendors that are, in some cases, thinly capitalized, independent companies that generate significant portions of their business from us or from a small group of companies in the energy industry. These vendors may be disproportionately affected by any loss of business, downturn in the energy industry or reduction or unavailability of credit. If we are unable to procure certain of such rig components, parts or equipment, our ability to maintain, improve, upgrade or construct drilling rigs could be impaired, which could have a material adverse effect on our business, financial condition and results of operations.

We may have additional tax liabilities and/or be limited in our use of net operating losses and tax credits.

We are subject to income taxes in the United States and numerous other jurisdictions. Significant judgment is required in determining our worldwide provision for income taxes. In the ordinary course of our business, there are many transactions and calculations where the ultimate tax determination is uncertain. We are regularly audited by tax authorities. Although we believe our tax estimates are reasonable, the final determination of tax audits and any related litigation could be materially different than what is reflected in income tax provisions and accruals. An audit or litigation could materially affect our financial position, income tax provision, net income, or cash flows in the period or periods challenged. It is also possible that future changes to tax laws (including tax treaties) could impact our ability to realize the tax savings recorded to date. Our ability to benefit from our deferred tax assets depends on us having sufficient future taxable income to utilize our net operating loss and tax credit carryforwards before they expire. Our net operating loss and tax credit carryforwards are subject to review and potential disallowance upon audit by the tax authorities of the jurisdictions where these tax attributes are incurred. Future changes to tax laws (including tax treaties) could also impact our effective rate.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital.

Our ability to access capital markets or to otherwise obtain sufficient financing is enhanced by our senior unsecured debt ratings as provided by major U.S. credit rating agencies. Factors that may impact our credit ratings include debt levels, liquidity, asset quality, cost structure, commodity pricing levels and other considerations. A ratings downgrade could adversely impact our ability in the future to access debt markets, increase the cost of future debt, and potentially require us to post letters of credit for certain obligations.

Our ability to access capital markets could be limited.

From time to time, we may need to access capital markets to obtain financing. Our ability to access capital markets for financing could be limited by, among other things, oil and gas prices, our existing capital structure, our credit ratings, the state of the economy, the health of the drilling and overall oil and gas industry, and the liquidity of the capital markets. Many of the factors that affect our ability to access capital markets are outside of our control. No assurance can be given that we will be able to access capital markets on terms acceptable to us when required to do so, which could have a material adverse impact on our business, financial condition and results of operations.

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We may not be able to generate cash to service all of our indebtedness, and may be forced to take other actions to satisfy our obligations.

Our ability to make future, scheduled payments on or to refinance our debt obligations depends on our financial position, results of operations and cash flows. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal and interest on our indebtedness. If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay investment decisions and capital expenditures, sell assets, seek additional capital or restructure or refinance our indebtedness. 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 be a default (if not waived) and would likely result in a reduction of our credit rating, which could harm our ability to seek additional capital or restructure or refinance our indebtedness.

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

Scientific studies have suggested that emissions of certain gases, commonly referred to as “greenhouse gases” (“GHGs”) and including carbon dioxide and methane, may be contributing to warming of the earth’s atmosphere and other climatic changes. In response to such studies, the issue of climate change and the effect of GHG emissions, in particular emissions from fossil fuels, is attracting increasing attention worldwide. We are aware of the increasing focus of local, state, national and international regulatory bodies on GHG emissions and climate change issues. The United States Congress may consider legislation to reduce GHG emissions. Although it is not possible at this time to predict whether proposed legislation or regulations will be adopted, any such future laws and regulations could result in increased compliance costs or additional operating restrictions. If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse impact on our business, financial condition and results of operations. Further, to the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of or access to capital. Climate change and GHG regulation could also reduce the demand for hydrocarbons and, ultimately, demand for our services.

Reliance on management and competition for experienced personnel may negatively impact our operations or financial results.

We greatly depend on the efforts of our executive officers and other key employees to manage our operations. The loss of members of management could have a material effect on our business. Similarly, we utilize highly skilled personnel in operating and supporting our businesses. In times of high utilization, it can be difficult to retain, and in some cases find, qualified individuals. Although to date our operations have not been materially affected by competition for personnel, an inability to obtain or find a sufficient number of qualified personnel could have a material adverse effect on our business, financial condition and results of operations.

Shortages of drilling equipment and supplies could adversely affect our operations.

The contract drilling business is highly cyclical. During periods of increased demand for contract drilling services, delays in delivery and shortages of drilling equipment and supplies can occur. These risks are intensified during periods when the industry experiences significant new drilling rig construction or refurbishment. Any such delays or shortages could have a material adverse effect on our business, financial condition and results of operations.

Our business is subject to cybersecurity risks.

Threats to information technology systems associated with cybersecurity risks and cyber incidents or attacks continue to grow. Cybersecurity attacks could include, but are not limited to, malicious software, attempts to gain unauthorized access to our data and the unauthorized release, corruption or loss of our data and personal information, loss of our intellectual property, theft of our FlexRig and other technology, loss or damage to our data delivery systems, other electronic security breaches that could lead to disruptions in our critical systems, and increased costs to prevent, respond to or mitigate cybersecurity events. It is possible that our business, financial and other systems could be

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compromised, which might not be noticed for some period of time. Although we utilize various procedures and controls to mitigate our exposure to such risk, cybersecurity attacks are evolving and unpredictable. The occurrence of such an attack could lead to financial losses and have a material adverse effect on our business, financial condition and results of operations. We are not aware that any material cybersecurity breaches have occurred to date.

Unexpected events could disrupt our business and adversely affect our results of operations.

Unexpected and entirely unanticipated events, including, without limitation, computer system disruptions, unplanned power outages, fires or explosions at drilling rigs, natural disasters such as hurricanes and tornadoes, war or terrorist activities, supply disruptions, failure of equipment, changes in laws and/or regulations impacting our businesses, pandemic illness and other unforeseeable circumstances that may arise from our increasingly connected world or otherwise could adversely affect our business. It is not possible for us to predict the occurrence or consequence of any such events. However, any such events could reduce our ability to provide drilling services, reduce demand for our services, or make it more difficult or costly to provide services which ultimately may have a material adverse effect on our business, financial condition and results of operations.

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

Efforts may be made from time to time to unionize portions of our workforce. In addition, we may in the future be subject to strikes or work stoppages and other labor disruptions. Additional unionization efforts, new collective bargaining agreements or work stoppages could materially increase our costs, reduce our revenues or limit our flexibility.

Any future implementation of price controls on oil and natural gas would affect our operations.

The United States Congress may in the future impose some form of price controls on either oil, natural gas, or both. Any future limits on the price of oil or natural gas could negatively affect the demand for our services and, consequently, have a material adverse effect on our business, financial condition and results of operations.

Covenants in our debt agreements restrict our ability to engage in certain activities.

Our debt agreements pertaining to certain long term unsecured debt and our unsecured revolving credit facility contain various covenants that may in certain instances restrict our ability to, among other things, incur, assume or guarantee additional indebtedness, incur liens, sell or otherwise dispose of assets, enter into new lines of business, and merge or consolidate. In addition, our credit facility requires us to maintain a funded leverage ratio (as defined) of less than 50 percent and certain priority debt (as defined) may not exceed 17.5% of our net worth (as defined). Such restrictions may limit our ability to successfully execute our business plans, which may have adverse consequences on our operations.

Improvements in or new discoveries of alternative energy technologies could have a material adverse effect on our financial condition and results of operations.

Since our business depends on the level of activity in the oil and natural gas industry, any improvement in or new discoveries of alternative energy technologies that increase the use of alternative forms of energy and reduce the demand for oil and natural gas could have a material adverse effect on our business, financial condition and results of operations.

Item 1B. UNRESOLVED STAFF COMMENTS

We have received no written comments regarding our periodic or current reports from the staff of the SEC that were issued 180 days or more preceding the end of our 2017 fiscal year and that remain unresolved.

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Item 2. PROPERTIES

CONTRACT DRILLING

The following table sets forth certain information concerning our U.S. land and offshore drilling rigs as of September 30, 2017:

Location	Rig	Optimum Depth (Feet)*	Rig Type	Drawworks: Horsepower
FlexRigs				
Texas	212	22,000	AC (FlexRig3)	1,500
Texas	214	22,000	AC (FlexRig3)	1,500
Utah	215	22,000	AC (FlexRig3)	1,500
Texas	216	22,000	AC (FlexRig3)	1,500
Texas	218	22,000	AC (FlexRig3)	1,500
Texas	220	22,000	AC (FlexRig3)	1,500
Texas	221	22,000	AC (FlexRig3)	1,500
Texas	222	22,000	AC (FlexRig3)	1,500
Texas	223	22,000	AC (FlexRig3)	1,500
Pennsylvania	225	22,000	AC (FlexRig3)	1,500
Texas	226	22,000	AC (FlexRig3)	1,500
Texas	227	22,000	AC (FlexRig3)	1,500
Texas	228	22,000	AC (FlexRig3)	1,500
Texas	231	22,000	AC (FlexRig3)	1,500
Texas	232	22,000	AC (FlexRig3)	1,500
Texas	233	22,000	AC (FlexRig3)	1,500
Texas	236	22,000	AC (FlexRig3)	1,500
North Dakota	239	22,000	AC (FlexRig3)	1,500
Texas	240	22,000	AC (FlexRig3)	1,500
Pennsylvania	241	22,000	AC (FlexRig3)	1,500
Texas	242	22,000	AC (FlexRig3)	1,500
Texas	244	22,000	AC (FlexRig3)	1,500
Texas	245	22,000	AC (FlexRig3)	1,500
Texas	246	22,000	AC (FlexRig3)	1,500
Texas	247	22,000	AC (FlexRig3)	1,500
Texas	248	22,000	AC (FlexRig3)	1,500
Texas	249	22,000	AC (FlexRig3)	1,500
Oklahoma	250	22,000	AC (FlexRig3)	1,500
Texas	251	22,000	AC (FlexRig3)	1,500
Texas	252	22,000	AC (FlexRig3)	1,500
Texas	253	22,000	AC (FlexRig3)	1,500
Texas	254	22,000	AC (FlexRig3)	1,500
North Dakota	255	22,000	AC (FlexRig3)	1,500
North Dakota	256	22,000	AC (FlexRig3)	1,500
Wyoming	257	22,000	AC (FlexRig3)	1,500
North Dakota	258	22,000	AC (FlexRig3)	1,500

North Dakota	259	22,000	AC (FlexRig3)	1,500
Texas	260	22,000	AC (FlexRig3)	1,500
California	261	22,000	AC (FlexRig3)	1,500
New Mexico	262	22,000	AC (FlexRig3)	1,500
Texas	263	22,000	AC (FlexRig3)	1,500
Texas	264	22,000	AC (FlexRig3)	1,500
Texas	265	22,000	AC (FlexRig3)	1,500
Texas	266	22,000	AC (FlexRig3)	1,500
Texas	267	22,000	AC (FlexRig3)	1,500
Texas	268	22,000	AC (FlexRig3)	1,500
Texas	269	22,000	AC (FlexRig3)	1,500
Colorado	271	18,000	AC (FlexRig4)	1,500

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Location	Rig	Optimum Depth (Feet)*	Rig Type	Drawworks: Horsepower
North Dakota	272	18,000	AC (FlexRig4)	1,500
Colorado	273	18,000	AC (FlexRig4)	1,500
Texas	274	18,000	AC (FlexRig4)	1,500
Colorado	275	18,000	AC (FlexRig4)	1,500
Colorado	276	18,000	AC (FlexRig4)	1,500
Colorado	277	18,000	AC (FlexRig4)	1,500
Colorado	278	18,000	AC (FlexRig4)	1,500
Texas	279	18,000	AC (FlexRig4)	1,500
Colorado	280	18,000	AC (FlexRig4)	1,500
Texas	281	8,000	AC (FlexRig4)	1,150
Texas	282	8,000	AC (FlexRig4)	1,150
Texas	283	8,000	AC (FlexRig4)	1,150
Pennsylvania	284	18,000	AC (FlexRig4)	1,500
Pennsylvania	285	18,000	AC (FlexRig4)	1,500
North Dakota	286	18,000	AC (FlexRig4)	1,500
Pennsylvania	287	18,000	AC (FlexRig4)	1,500
Texas	288	18,000	AC (FlexRig4)	1,500
Texas	289	18,000	AC (FlexRig4)	1,500
Colorado	290	18,000	AC (FlexRig4)	1,500
North Dakota	293	18,000	AC (FlexRig4)	1,500
North Dakota	294	18,000	AC (FlexRig4)	1,500
North Dakota	295	18,000	AC (FlexRig4)	1,500
Texas	296	18,000	AC (FlexRig4)	1,500
Oklahoma	297	18,000	AC (FlexRig4)	1,500
Colorado	298	18,000	AC (FlexRig4)	1,500
Texas	299	18,000	AC (FlexRig4)	1,500
Texas	300	18,000	AC (FlexRig4)	1,500
Texas	302	8,000	AC (FlexRig4)	1,150
Texas	303	8,000	AC (FlexRig4)	1,150
Texas	304	8,000	AC (FlexRig4)	1,150
Texas	305	8,000	AC (FlexRig4)	1,150
Texas	306	8,000	AC (FlexRig4)	1,150
Colorado	307	18,000	AC (FlexRig4)	1,500
Colorado	308	18,000	AC (FlexRig4)	1,500
North Dakota	309	18,000	AC (FlexRig4)	1,500
Colorado	310	18,000	AC (FlexRig4)	1,500
Colorado	311	18,000	AC (FlexRig4)	1,500
Texas	312	18,000	AC (FlexRig4)	1,500
Texas	313	18,000	AC (FlexRig4)	1,500
Texas	314	18,000	AC (FlexRig4)	1,500
Colorado	315	18,000	AC (FlexRig4)	1,500
North Dakota	316	18,000	AC (FlexRig4)	1,500
North Dakota	317	18,000	AC (FlexRig4)	1,500
Colorado	318	18,000	AC (FlexRig4)	1,500
Colorado	319	18,000	AC (FlexRig4)	1,500
North Dakota	320	18,000	AC (FlexRig4)	1,500

Colorado	321	18,000	AC (FlexRig4)	1,500
Colorado	322	18,000	AC (FlexRig4)	1,500
Texas	323	18,000	AC (FlexRig4)	1,500
North Dakota	324	18,000	AC (FlexRig4)	1,500
North Dakota	325	18,000	AC (FlexRig4)	1,500
Colorado	326	18,000	AC (FlexRig4)	1,500
Texas	327	18,000	AC (FlexRig4)	1,500
Texas	328	18,000	AC (FlexRig4)	1,500
Colorado	329	18,000	AC (FlexRig4)	1,500
Colorado	330	18,000	AC (FlexRig4)	1,500

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Location	Rig	Optimum Depth (Feet)*	Rig Type	Drawworks: Horsepower
Texas	331	18,000	AC (FlexRig4)	1,500
Texas	332	18,000	AC (FlexRig4)	1,500
Texas	340	8,000	AC (FlexRig4)	1,150
Texas	341	18,000	AC (FlexRig4)	1,500
Texas	342	18,000	AC (FlexRig4)	1,500
Colorado	343	18,000	AC (FlexRig4)	1,500
Texas	344	8,000	AC (FlexRig4)	1,150
Texas	345	8,000	AC (FlexRig4)	1,150
Texas	346	8,000	AC (FlexRig4)	1,150
Texas	347	8,000	AC (FlexRig4)	1,150
Texas	348	8,000	AC (FlexRig4)	1,150
Texas	349	8,000	AC (FlexRig4)	1,150
Texas	351	8,000	AC (FlexRig4)	1,150
Texas	352	8,000	AC (FlexRig4)	1,150
North Dakota	353	18,000	AC (FlexRig4)	1,500
Pennsylvania	354	18,000	AC (FlexRig4)	1,500
Texas	355	8,000	AC (FlexRig4)	1,150
Texas	356	8,000	AC (FlexRig4)	1,150
Texas	360	8,000	AC (FlexRig4)	1,150
Texas	361	8,000	AC (FlexRig4)	1,150
Texas	362	8,000	AC (FlexRig4)	1,150
Texas	370	22,000	AC (FlexRig3)	1,500
West Virginia	371	22,000	AC (FlexRig3)	1,500
Texas	372	22,000	AC (FlexRig3)	1,500
Texas	373	22,000	AC (FlexRig3)	1,500
Texas	374	22,000	AC (FlexRig3)	1,500
Oklahoma	375	22,000	AC (FlexRig3)	1,500
Oklahoma	376	22,000	AC (FlexRig3)	1,500
Oklahoma	377	22,000	AC (FlexRig3)	1,500
Oklahoma	378	22,000	AC (FlexRig3)	1,500
Texas	379	22,000	AC (FlexRig3)	1,500
Texas	380	22,000	AC (FlexRig3)	1,500
Texas	381	22,000	AC (FlexRig3)	1,500
Texas	382	22,000	AC (FlexRig3)	1,500
Louisiana	383	22,000	AC (FlexRig3)	1,500
Texas	384	22,000	AC (FlexRig3)	1,500
Pennsylvania	385	22,000	AC (FlexRig3)	1,500
North Dakota	386	22,000	AC (FlexRig3)	1,500
Oklahoma	387	22,000	AC (FlexRig3)	1,500
Texas	388	22,000	AC (FlexRig3)	1,500
Texas	389	22,000	AC (FlexRig3)	1,500
Texas	390	22,000	AC (FlexRig3)	1,500
Texas	391	22,000	AC (FlexRig3)	1,500
North Dakota	392	22,000	AC (FlexRig3)	1,500
New Mexico	393	22,000	AC (FlexRig3)	1,500
Texas	394	22,000	AC (FlexRig3)	1,500

New Mexico	395	22,000	AC (FlexRig3)	1,500
New Mexico	396	22,000	AC (FlexRig3)	1,500
Louisiana	397	22,000	AC (FlexRig3)	1,500
Texas	398	22,000	AC (FlexRig3)	1,500
Texas	399	22,000	AC (FlexRig3)	1,500
Texas	415	22,000	AC (FlexRig3)	1,500
Texas	416	22,000	AC (FlexRig3)	1,500
Texas	417	22,000	AC (FlexRig3)	1,500
Louisiana	418	22,000	AC (FlexRig3)	1,500
Texas	419	22,000	AC (FlexRig3)	1,500

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Location	Rig	Optimum Depth (Feet)*	Rig Type	Drawworks: Horsepower
Texas	420	22,000	AC (FlexRig3)	1,500
Texas	421	22,000	AC (FlexRig3)	1,500
Oklahoma	422	22,000	AC (FlexRig3)	1,500
Texas	423	22,000	AC (FlexRig3)	1,500
California	424	22,000	AC (FlexRig3)	1,500
Oklahoma	425	22,000	AC (FlexRig3)	1,500
California	426	22,000	AC (FlexRig3)	1,500
Texas	427	22,000	AC (FlexRig3)	1,500
Texas	428	22,000	AC (FlexRig3)	1,500
Texas	429	22,000	AC (FlexRig3)	1,500
Texas	430	22,000	AC (FlexRig3)	1,500
Texas	431	22,000	AC (FlexRig3)	1,500
Texas	432	22,000	AC (FlexRig3)	1,500
Texas	433	22,000	AC (FlexRig3)	1,500
Texas	434	22,000	AC (FlexRig3)	1,500
Oklahoma	435	22,000	AC (FlexRig3)	1,500
Texas	436	22,000	AC (FlexRig3)	1,500
Texas	437	22,000	AC (FlexRig3)	1,500
Wyoming	438	22,000	AC (FlexRig3)	1,500
Texas	439	22,000	AC (FlexRig3)	1,500
California	440	22,000	AC (FlexRig3)	1,500
Texas	441	22,000	AC (FlexRig3)	1,500
Oklahoma	442	22,000	AC (FlexRig3)	1,500

Texas	443	22,000	AC (FlexRig3)	1,500
California	444	22,000	AC (FlexRig3)	1,500
Texas	445	22,000	AC (FlexRig3)	1,500
North Dakota	446	22,000	AC (FlexRig3)	1,500
Oklahoma	447	22,000	AC (FlexRig3)	1,500
Colorado	448	22,000	AC (FlexRig3)	1,500
North Dakota	449	22,000	AC (FlexRig3)	1,500
Oklahoma	450	22,000	AC (FlexRig3)	1,500
Texas	451	22,000	AC (FlexRig3)	1,500
Louisiana	452	22,000	AC (FlexRig3)	1,500
Texas	453	22,000	AC (FlexRig3)	1,500
North Dakota	454	22,000	AC (FlexRig3)	1,500
Texas	455	22,000	AC (FlexRig3)	1,500
North Dakota	456	22,000	AC (FlexRig3)	1,500
North Dakota	457	22,000	AC (FlexRig3)	1,500
Texas	458	22,000	AC (FlexRig3)	1,500
Texas	459	22,000	AC (FlexRig3)	1,500
Texas	460	22,000	AC (FlexRig3)	1,500
Texas	461	22,000	AC (FlexRig3)	1,500
Texas	462	22,000	AC (FlexRig3)	1,500
Texas	463	22,000	AC (FlexRig3)	1,500
Oklahoma	464	22,000	AC (FlexRig3)	1,500
Texas	465	22,000	AC (FlexRig3)	1,500
New Mexico	466	22,000	AC (FlexRig3)	1,500
Texas	467	22,000	AC (FlexRig3)	1,500
Texas	468	22,000		1,500

			AC (FlexRig3)	
Texas	469	22,000	AC (FlexRig3)	1,500
Oklahoma	470	22,000	AC (FlexRig3)	1,500
Ohio	471	22,000	AC (FlexRig3)	1,500
Texas	472	22,000	AC (FlexRig3)	1,500
New Mexico	473	22,000	AC (FlexRig3)	1,500
Texas	474	22,000	AC (FlexRig3)	1,500
Texas	475	22,000	AC (FlexRig3)	1,500

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Location	Rig	Optimum Depth (Feet)*	Rig Type	Drawworks: Horsepower
Texas	477	22,000	AC (FlexRig3)	1,500
Texas	478	22,000	AC (FlexRig3)	1,500
Texas	479	22,000	AC (FlexRig3)	1,500
New Mexico	480	22,000	AC (FlexRig3)	1,500
Texas	481	22,000	AC (FlexRig3)	1,500
New Mexico	482	22,000	AC (FlexRig3)	1,500
Texas	483	22,000	AC (FlexRig3)	1,500
Oklahoma	485	22,000	AC (FlexRig3)	1,500
Texas	486	22,000	AC (FlexRig3)	1,500
Texas	487	22,000	AC (FlexRig3)	1,500
Texas	488	22,000	AC (FlexRig3)	1,500
Texas	489	22,000	AC (FlexRig3)	1,500
Texas	490	22,000	AC (FlexRig3)	1,500
Louisiana	491	22,000	AC (FlexRig3)	1,500
North Dakota	492	22,000	AC (FlexRig3)	1,500
Oklahoma	493	22,000	AC (FlexRig3)	1,500
Texas	494	22,000	AC (FlexRig3)	1,500
Texas	495	22,000	AC (FlexRig3)	1,500
Oklahoma	496	22,000	AC (FlexRig3)	1,500
Texas	497	22,000	AC (FlexRig3)	1,500
New Mexico	498	22,000	AC (FlexRig3)	1,500
Texas	499	22,000	AC (FlexRig3)	1,500
Pennsylvania	500	25,000	AC (FlexRig5)	1,500
Texas	501	25,000	AC (FlexRig5)	1,500
Texas	502	25,000	AC (FlexRig5)	1,500
Texas	503	25,000	AC (FlexRig5)	1,500
Oklahoma	504	25,000	AC (FlexRig5)	1,500
Texas	505	25,000	AC (FlexRig5)	1,500
Texas	506	25,000	AC (FlexRig5)	1,500
Texas	507	25,000	AC (FlexRig5)	1,500
Texas	508	25,000	AC (FlexRig5)	1,500
Texas	509	25,000	AC (FlexRig5)	1,500
Texas	510	25,000	AC (FlexRig5)	1,500
Texas	511	25,000	AC (FlexRig5)	1,500
Texas	512	25,000	AC (FlexRig5)	1,500
Pennsylvania	513	25,000	AC (FlexRig5)	1,500
Texas	514	25,000	AC (FlexRig5)	1,500
North Dakota	515	25,000	AC (FlexRig5)	1,500
North Dakota	516	25,000	AC (FlexRig5)	1,500
Colorado	517	25,000	AC (FlexRig5)	1,500
Texas	518	25,000	AC (FlexRig5)	1,500
Ohio	519	25,000	AC (FlexRig5)	1,500
Wyoming	520	25,000	AC (FlexRig5)	1,500
Ohio	521	25,000	AC (FlexRig5)	1,500
Colorado	522	25,000	AC (FlexRig5)	1,500
Texas	523	25,000	AC (FlexRig5)	1,500

Colorado	524	25,000	AC (FlexRig5)	1,500
Oklahoma	525	25,000	AC (FlexRig5)	1,500
Oklahoma	526	25,000	AC (FlexRig5)	1,500
Oklahoma	527	25,000	AC (FlexRig5)	1,500
Louisiana	528	25,000	AC (FlexRig5)	1,500
Oklahoma	529	25,000	AC (FlexRig5)	1,500
Oklahoma	530	25,000	AC (FlexRig5)	1,500
Ohio	531	25,000	AC (FlexRig5)	1,500
Texas	532	25,000	AC (FlexRig5)	1,500
Louisiana	533	25,000	AC (FlexRig5)	1,500

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Location	Rig	Optimum Depth (Feet)*	Rig Type	Drawworks: Horsepower
Louisiana	534	25,000	AC (FlexRig5)	1,500
North Dakota	535	25,000	AC (FlexRig5)	1,500
Texas	536	25,000	AC (FlexRig5)	1,500
Texas	537	25,000	AC (FlexRig5)	1,500
Oklahoma	538	25,000	AC (FlexRig5)	1,500
Texas	539	25,000	AC (FlexRig5)	1,500
Oklahoma	540	25,000	AC (FlexRig5)	1,500
Oklahoma	541	25,000	AC (FlexRig5)	1,500
Oklahoma	542	25,000	AC (FlexRig5)	1,500
Oklahoma	543	25,000	AC (FlexRig5)	1,500
Oklahoma	544	25,000	AC (FlexRig5)	1,500
Oklahoma	545	25,000	AC (FlexRig5)	1,500
Oklahoma	546	25,000	AC (FlexRig5)	1,500
Oklahoma	547	25,000	AC (FlexRig5)	1,500
Oklahoma	548	25,000	AC (FlexRig5)	1,500
Texas	551	25,000	AC (FlexRig5)	1,500
Texas	552	25,000	AC (FlexRig5)	1,500
Texas	553	25,000	AC (FlexRig5)	1,500
Texas	556	25,000	AC (FlexRig5)	1,500
Texas	600	22,000	AC (FlexRig3)	1,500
Texas	601	22,000	AC (FlexRig3)	1,500
Texas	602	22,000	AC (FlexRig3)	1,500
Texas	603	22,000	AC (FlexRig3)	1,500

Texas	604	22,000	AC (FlexRig3)	1,500
Texas	605	22,000	AC (FlexRig3)	1,500
Texas	606	22,000	AC (FlexRig3)	1,500
Texas	607	22,000	AC (FlexRig3)	1,500
Ohio	608	22,000	AC (FlexRig3)	1,500
Texas	609	22,000	AC (FlexRig3)	1,500
New Mexico	610	22,000	AC (FlexRig3)	1,500
Ohio	611	22,000	AC (FlexRig3)	1,500
Oklahoma	612	22,000	AC (FlexRig3)	1,500
Texas	613	22,000	AC (FlexRig3)	1,500
Texas	614	22,000	AC (FlexRig3)	1,500
Texas	615	22,000	AC (FlexRig3)	1,500
Texas	616	22,000	AC (FlexRig3)	1,500
New Mexico	617	22,000	AC (FlexRig3)	1,500
Texas	618	22,000	AC (FlexRig3)	1,500
Texas	619	22,000	AC (FlexRig3)	1,500
New Mexico	620	22,000	AC (FlexRig3)	1,500
New Mexico	621	22,000	AC (FlexRig3)	1,500
Texas	622	22,000	AC (FlexRig3)	1,500
Texas	623	22,000	AC (FlexRig3)	1,500
Texas	624	22,000	AC (FlexRig3)	1,500
Texas	625	22,000	AC (FlexRig3)	1,500
Texas	626	22,000	AC (FlexRig3)	1,500
Texas	627	22,000	AC (FlexRig3)	1,500
Ohio	628	22,000	AC (FlexRig3)	1,500
Texas	629	22,000		1,500

			AC (FlexRig3)	
Texas	630	22,000	AC (FlexRig3)	1,500
Oklahoma	631	22,000	AC (FlexRig3)	1,500
Texas	632	22,000	AC (FlexRig3)	1,500
Texas	633	22,000	AC (FlexRig3)	1,500
Texas	634	22,000	AC (FlexRig3)	1,500
Texas	635	22,000	AC (FlexRig3)	1,500
New Mexico	636	22,000	AC (FlexRig3)	1,500

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Location	Rig	Optimum Depth (Feet)*	Rig Type	Drawworks: Horsepower
Texas	637	22,000	AC (FlexRig3)	1,500
Texas	638	22,000	AC (FlexRig3)	1,500
New Mexico	639	22,000	AC (FlexRig3)	1,500
North Dakota	640	22,000	AC (FlexRig3)	1,500
Texas	641	22,000	AC (FlexRig3)	1,500
New Mexico	642	22,000	AC (FlexRig3)	1,500
Texas	643	22,000	AC (FlexRig3)	1,500
Texas	644	22,000	AC (FlexRig3)	1,500
Texas	645	22,000	AC (FlexRig3)	1,500
Texas	646	22,000	AC (FlexRig3)	1,500
New Mexico	647	22,000	AC (FlexRig3)	1,500
Texas	648	22,000	AC (FlexRig3)	1,500
Texas	649	22,000	AC (FlexRig3)	1,500
New Mexico	650	22,000	AC (FlexRig3)	1,500
Texas	651	22,000	AC (FlexRig3)	1,500
Texas	652	22,000	AC (FlexRig3)	1,500
New Mexico	653	22,000	AC (FlexRig3)	1,500
New Mexico	656	22,000	AC (FlexRig3)	1,500
New Mexico	657	22,000	AC (FlexRig3)	1,500
Texas	659	22,000	AC (FlexRig3)	1,500
Conventional Rigs				
Texas	139	30,000	SCR	3,000
Louisiana	161	30,000	SCR	3,000
Offshore Platform Rigs				
Louisiana	100	30,000	Conventional	3,000
Louisiana	105	30,000	Conventional	3,000
Gulf of Mexico	107	30,000	Conventional	3,000
Gulf of Mexico	201	30,000	Tension-leg	3,000
Gulf of Mexico	203	20,000	Self-Erecting	2,500
Gulf of Mexico	204	30,000	Tension-leg	3,000
Gulf of Mexico	205	20,000	Self-Erecting	2,000
Louisiana	206	20,000	Self-Erecting	2,000

* From time to time we may modify certain FlexRigs to increase the setback capacity of a rig. As such, the stated “optimum depth” as listed above may be higher in certain instances depending on modifications to certain rigs.

The following table sets forth information with respect to the utilization of our U.S. land and offshore drilling rigs for the periods indicated:

Year ended September 30,

	2013	2014	2015	2016	2017
U.S. Land Rigs					
Number of rigs at end of period	302	329	343	348	350
Average rig utilization rate during period (1)	82 %	86 %	62 %	30 %	45 %
U.S. Offshore Platform Rigs					
Number of rigs at end of period	9	9	9	9	8
Average rig utilization rate during period (1)	89 %	89 %	93 %	82 %	74 %

(1) A rig is considered to be utilized when it is operated or being moved, assembled or dismantled under contract.

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The following table sets forth certain information concerning our international drilling rigs as of September 30, 2017:

Location	Rig	Optimum Depth (Feet)*	RigType	Drawworks: Horsepower
Argentina	123	26,000	SCR	2,100
Argentina	151	30,000 +	SCR	3,000
Argentina	175	30,000	SCR	3,000
Argentina	177	30,000	SCR	3,000
Argentina	210	22,000	AC (FlexRig3)	1,500
Argentina	211	22,000	AC (FlexRig3)	1,500
Argentina	213	22,000	AC (FlexRig3)	1,500
Argentina	217	22,000	AC (FlexRig3)	1,500
Argentina	219	22,000	AC (FlexRig3)	1,500
Argentina	224	22,000	AC (FlexRig3)	1,500
Argentina	229	22,000	AC (FlexRig3)	1,500
Argentina	230	22,000	AC (FlexRig3)	1,500
Argentina	234	22,000	AC (FlexRig3)	1,500
Argentina	235	22,000	AC (FlexRig3)	1,500
Argentina	238	22,000	AC (FlexRig3)	1,500
Argentina	335	8,000	AC (FlexRig4)	1,150
Argentina	336	8,000	AC (FlexRig4)	1,150
Argentina	337	8,000	AC (FlexRig4)	1,150
Argentina	338	8,000	AC (FlexRig4)	1,150
Bahrain	292	8,000	AC (FlexRig4)	1,150
Bahrain	301	8,000	AC (FlexRig4)	1,150
Bahrain	339	8,000	AC (FlexRig4)	1,150
Colombia	133	30,000	SCR	3,000
Colombia	152	30,000 +	SCR	3,000
Colombia	237	18,000	AC (FlexRig3)	1,500
Colombia	243	22,000	AC (FlexRig3)	1,500
Colombia	291	8,000	AC (FlexRig4)	1,150
Colombia	333	8,000	AC (FlexRig4)	1,150
Colombia	334	8,000	AC (FlexRig4)	1,150
Colombia	900	30,000 +	AC Drive	3,000
Ecuador	117	26,000	SCR	2,500
Ecuador	121	20,000	SCR	1,700
Ecuador	132	18,000	SCR	1,500
Ecuador	138	26,000	SCR	2,500
Ecuador	176	18,000	SCR	1,500
Ecuador	190	26,000	SCR	2,000
UAE	476	22,000	AC (FlexRig3)	1,500
UAE	484	22,000	AC (FlexRig3)	1,500

* From time to time we may modify certain FlexRigs to increase the setback capacity of a rig. As such, the stated "optimum depth" as listed above may be higher in certain instances depending on modifications to certain rigs.

The following table sets forth information with respect to the utilization of our international drilling rigs for the periods indicated:

	Years ended September 30,				
	2013	2014	2015	2016	2017
Number of rigs at end of period	29	36	38	38	38
Average rig utilization rate during period (1)(2)	82 %	74 %	51 %	39 %	36 %

(1) A rig is considered to be utilized when it is operated or being moved, assembled or dismantled under contract.
(2) Does not include rigs returned to the United States for major modifications and upgrades.

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STOCK PORTFOLIO

Information required by this item regarding our stock portfolio may be found in, and is incorporated by reference to, Item 7—"Management's Discussion and Analysis of Financial Condition and Results of Operations—Stock Portfolio Held" included in this Form 10 K.

Item 3. LEGAL PROCEEDINGS

1.Investigation by the Department of the Interior.

On November 8, 2013, the United States District Court for the Eastern District of Louisiana approved the previously disclosed October 30, 2013 plea agreement between our wholly owned subsidiary, Helmerich & Payne International Drilling Co. ("H&PIDC"), and the United States Department of Justice, United States Attorney's Office for the Eastern District of Louisiana ("DOJ"). The court's approval of the plea agreement resolved the DOJ's investigation into certain choke manifold testing irregularities that occurred in 2010 at one of H&PIDC's offshore platform rigs in the Gulf of Mexico. We also engaged in discussions with the Inspector General's office of the Department of the Interior ("DOI") regarding the same events that were the subject of the DOJ's investigation. Although we do not presently anticipate any further action by the DOI, we can provide no assurance as to the timing or eventual outcome of the DOI's consideration of the matter.

2.Venezuela Expropriation.

Our wholly owned subsidiaries, H&PIDC and Helmerich & Payne de Venezuela, C.A. filed a lawsuit in the United States District Court for the District of Columbia on September 23, 2011 against the Bolivarian Republic of Venezuela, Petroleos de Venezuela, S.A. and PDVSA Petroleo, S.A. We are seeking damages for the taking of our Venezuelan drilling business in violation of international law and for breach of contract. While there exists the possibility of realizing a recovery, we are currently unable to determine the timing or amounts we may receive, if any, or the likelihood of recovery.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

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EXECUTIVE OFFICERS OF THE COMPANY

The following table sets forth the names and ages of our executive officers, together with all positions and offices held by such executive officers with the Company or the Company's wholly owned subsidiary, Helmerich & Payne International Drilling Co. Except as noted below, all positions and offices held are with the Company. Officers are elected to serve until the meeting of the Board of Directors following the next Annual Meeting of Stockholders and until their successors have been duly elected and have qualified or until their earlier resignation or removal.

John W. Lindsay, 56	President and Chief Executive Officer since March 2014; President and Chief Operating Officer from September 2012 to March 2014; Director since September 2012; Executive Vice President and Chief Operating Officer from 2010 to September 2012; Executive Vice President, U.S. and International Operations of Helmerich & Payne International Drilling Co. from 2006 to 2012; Vice President of U.S. Land Operations of Helmerich & Payne International Drilling Co. from 1997 to 2006
Juan Pablo Tardio, 52	Vice President and Chief Financial Officer since April 2010; Director of Investor Relations from January 2008 to April 2010; Manager of Investor Relations from August 2005 to January 2008
Robert L. Stauder, 55	Senior Vice President and Chief Engineer, Helmerich & Payne International Drilling Co., since January 2012; Vice President and Chief Engineer of Helmerich & Payne International Drilling Co. from July 2010 to January 2012; Vice President, Engineering of Helmerich & Payne International Drilling Co. from 2006 to July 2010
Wade W. Clark, 53	Vice President U.S. Land, Helmerich & Payne International Drilling Co., since August 2017; Regional Vice President U.S. Land, Helmerich & Payne International Drilling Co. from July 2012 to August 2017; Vice President, North Region U.S. Land Operations of Helmerich & Payne International Drilling Co. from March 2008 to July 2012
Michael P. Lennox, 37	Vice President U.S. Land, Helmerich & Payne International Drilling Co., since August 2017; District Manager of Helmerich & Payne International Drilling Co. from December 2012 to August 2017
John R. Bell, 47	Vice President, International and Offshore Operations, Helmerich & Payne International Drilling Co., since August 2017; Vice President, Corporate Services from January 2015 to August 2017; Vice President of Human Resources from March 2012 to January 2015; Director of Human Resources from July 2002 to March 2012
Cara M. Hair, 41	Vice President, Corporate Services and Chief Legal Officer since August 2017; Vice President, General Counsel and Chief Compliance Officer from March 2015 to August 2017; Deputy General Counsel from June 2014 to March 2015; Senior Attorney from December 2012 to June 2014; Attorney from 2006 to December 2012

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PART II

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

Market Information

The principal market on which our common stock is traded is the New York Stock Exchange under the symbol "HP." As of November 10, 2017, there were 620 record holders of our common stock as listed by our transfer agent's records. The high and low sale prices per share for the common stock for each quarterly period during the past two fiscal years as reported in the NYSE Composite Transaction quotations follow:

	2016		2017	
Quarter	High	Low	High	Low
First	$ 61.70	$ 46.32	$ 85.78	$ 60.39
Second	64.06	40.02	81.30	63.66
Third	69.20	55.75	69.97	49.46
Fourth	70.28	56.19	58.64	42.16

Dividends

We paid quarterly cash dividends during the past two fiscal years as shown in the table below. Payment of future dividends will depend on earnings and other factors.

	Paid per Share		Total Payment	
	Fiscal		Fiscal	
Quarter	2016	2017	2016	2017
First	$ 0.6875	$ 0.7000	$ 74,560,506	$ 76,176,075
Second	0.6875	0.7000	74,739,803	76,441,828
Third	0.6875	0.7000	74,740,993	76,443,228
Fourth	0.7000	0.7000	76,111,240	76,453,820

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Performance Graph

The following performance graph reflects the yearly percentage change in our cumulative total stockholder return on common stock as compared with the cumulative total return on the S&P 500 Index, the S&P 500 Oil & Gas Drilling Index, and the S&P 1500 Oil and Gas Drilling Index. We are changing from using the S&P 500 Oil & Gas Drilling Index to the S&P 1500 Oil and Gas Drilling Index because the latter includes 10 other peer companies and we recently became the only remaining company in the previously used S&P 500 Oil and Gas Drilling Index. All cumulative returns assume an initial investment of $100, the reinvestment of dividends and are calculated on a fiscal year basis ending on September 30 of each year.

		INDEXED RETURNS				
	Base Period	Years Ending				
Company / Index	Sep 12	Sep 13	Sep 14	Sep 15	Sep 16	Sep 17
Helmerich & Payne, Inc.	100	146.85	213.72	107.52	160.53	130.54
S&P 500 Index	100	119.34	142.89	142.02	163.93	194.44
S&P 500 Oil & Gas Drilling Index	100	110.74	97.25	43.87	47.72	38.09
S&P 1500 Oil & Gas Drilling Index	100	112.55	103.39	44.91	47.75	40.37

The above performance graph and related information shall not be deemed to be “soliciting material” or to be “filed” with the SEC or subject to Regulation 14A or 14C under the Securities Exchange Act of 1934 or to the liabilities of Section 18 of the Securities Exchange Act of 1934, and shall not be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent we specifically incorporate it by reference into such a filing.

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Item 6. SELECTED FINANCIAL DATA

The following table summarizes selected financial information and should be read in conjunction with Item 7—“Management’s Discussion and Analysis of Financial Condition and Results of Operations” and Item 8—“Financial Statements and Supplementary Data” included in this Form 10 K.

Five year Summary of Selected Financial Data

	2017	2016	2015	2014	2013
	(in thousands except per share amounts)				
Operating revenues	$ 1,804,741	$ 1,624,232	$ 3,161,702	$ 3,715,968	$ 3,392,932
Income (loss) from continuing operations	(127,863)	(52,990)	420,474	706,610	720,653
Income (loss) from discontinued operations	(349)	(3,838)	(47)	(47)	15,186
Net income (loss)	(128,212)	(56,828)	420,427	706,563	735,839
Basic earnings (loss) per share from continuing operations	(1.20)	(0.50)	3.88	6.52	6.74
Basic earnings (loss) per share from discontinued operations	—	(0.04)	—	—	0.14
Basic (loss) earnings per share	(1.20)	(0.54)	3.88	6.52	6.88
Diluted earnings (loss) per share from continuing operations	(1.20)	(0.50)	3.85	6.44	6.65
Diluted earnings (loss) per share from discontinued operations	—	(0.04)	—	—	0.14
Diluted earnings (loss) per share	(1.20)	(0.54)	3.85	6.44	6.79
Total assets*	6,439,988	6,832,019	7,147,242	6,725,316	6,265,923
Long term debt	492,902	491,847	492,443	39,502	79,137
Cash dividends declared per common share	2.800	2.775	2.750	2.625	1.300

*Total assets for all years include amounts related to discontinued operations. Our Venezuelan subsidiary was classified as discontinued operations on June 30, 2010, after the seizure of our drilling assets in that country by the Venezuelan government.

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

Risk Factors and Forward Looking Statements

The following discussion should be read in conjunction with Part I of this Form 10 K as well as the Consolidated Financial Statements and related notes thereto included in Item 8—"Financial Statements and Supplementary Data" of this Form 10 K. Our future operating results may be affected by various trends and factors which are beyond our control. These include, among other factors, fluctuations in oil and natural gas prices, unexpected expiration or termination of drilling contracts, currency exchange gains and losses, expropriation of real and personal property, changes in general economic conditions, disruptions to the global credit markets, rapid or unexpected changes in technologies, risks of foreign operations, uninsured risks, changes in domestic and foreign policies, laws and regulations and uncertain business conditions that affect our businesses. Accordingly, past results and trends should not be used by investors to anticipate future results or trends.

With the exception of historical information, the matters discussed in Management's Discussion and Analysis of Financial Condition and Results of Operations include forward looking statements. These forward looking statements are based on various assumptions. We caution that, while we believe such assumptions to be reasonable and make them in good faith, assumed facts almost always vary from actual results. The differences between assumed facts and actual results can be material. We are including this cautionary statement to take advantage of the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995 for any forward looking statements made by us or persons acting on our behalf. The factors identified in this cautionary statement and those factors discussed under Item 1A—"Risk Factors" of this Form 10 K are important factors (but not necessarily inclusive of all important factors) that could cause actual results to differ materially from those expressed in any forward looking statement made by us or persons acting on our behalf. Except as required by law, we undertake no duty to update or revise our forward looking statements based on changes of internal estimates or expectations or otherwise.

Executive Summary

Helmerich & Payne, Inc. is primarily a contract drilling company with a total fleet of 396 drilling rigs at September 30, 2017. Our contract drilling segments consist of the U.S. Land segment with 350 rigs, the Offshore segment with 8 offshore platform rigs and the International Land segment with 38 rigs at September 30, 2017. At the close of fiscal 2017, we had 218 contracted rigs, compared to 118 contracted rigs at the same time during the prior year. As the U.S. land drilling industry recovered from an all-time low of approximately 380 active rigs in the summer of 2016 to over 900 rigs as of September 30, 2017, we led the way in reactivating rigs in the U.S. and gained significant market share in the process. Our success during this time frame was clear validation of having what we consider to be the most capable land drilling fleet in the market, supplemented by our ability to deliver best-in-class field performance and customer satisfaction. Our long term strategy remains focused on innovation, technology, safety, operational excellence and reliability. As we move forward, we believe that our advanced rig fleet, financial strength, long term contract backlog and strong customer base position us very well to take advantage of future opportunities.

Except as specifically discussed, the following results of operations pertain only to our continuing operations. Unless otherwise indicated, references to 2017, 2016 and 2015 in the following discussion are referring to fiscal years 2017, 2016 and 2015.

Results of Operations

All per share amounts included in the Results of Operations discussion are stated on a diluted basis. Our net loss for 2017 was $128.2 million ($1.20 loss per share), compared with net loss of $56.8 million ($0.54 loss per share) for 2016 and $420.4 million net income ($3.85 per share) for 2015. Net loss in 2017 and 2016 includes after-tax income from early termination revenue associated with drilling contracts terminated prior to the expiration of their fixed term of $20.2 million ($0.18 per share) and $139.3 million ($1.29 per share), respectively. Net income in 2015 includes after-tax income from early termination revenue of $140.9 ($1.30 per share). Net loss in 2017 and 2016 includes after tax gains from the sale of assets of $14.3 million ($0.13 per share) and $6.1 million ($0.06 per share), respectively, while net income in 2015 includes after tax gains from the sale of assets of $7.4 million ($0.07 per share). Included in our 2016 net loss is an after tax loss of $15.9 million ($0.15 loss per share) from an other than temporary impairment of our marketable equity security position in Atwood Oceanics, Inc. (“Atwood”). Net loss in 2016 also includes an after tax loss of $12.0 million ($0.11 loss per share) from the settlement of litigation and a $3.8 million loss ($0.04 loss per share) from discontinued operations.

Consolidated operating revenues were $1.8 billion in 2017, $1.6 billion in 2016 and $3.2 billion in 2015, including early termination revenue of $29.4 million, $219.0 million and $222.3 million in each respective year. Excluding early termination revenue, operating revenue increased $370.1 million in 2017 compared to 2016. Oil prices steeply declined from over $106 per barrel in June 2014 to below $30 per barrel in early 2016. During the second half of calendar 2016, oil prices increased and have since been mostly fluctuating within a $45 to $55 per barrel price range. Primarily as a result of the impact of oil prices on drilling activity by exploration and production companies during that time frame, the number of revenue days in our U.S. Land segment totaled 57,120 in 2017, compared to 36,984 in 2016 and 75,866 in 2015. Our U.S. land rig utilization was 45 percent in 2017, 30 percent in 2016 and 62 percent in 2015. The average number of U.S. land rigs available was 349 rigs in 2017, 339 rigs in 2016 and 336 rigs in 2015. Rig utilization for offshore rigs was 74 percent in 2017, compared to 82 percent in 2016 and 93 percent in 2015. The International Land segment has been subject to a more prolonged impact so far from the decline in oil prices, causing revenue days to decline to 4,951 in 2017 from 5,364 in 2016 and 7,284 in 2015. Rig utilization in our International Land segment was 36 percent in 2017, 39 percent in 2016 and 51 percent in 2015.

In 2016, we recorded a $26.0 million other than temporary impairment charge as our marketable equity security position in Atwood remained in a loss position during most of the fiscal year. Atwood is in the offshore drilling industry which was severely impacted by the downturn in the energy sector. In May 2017, Ensco plc ("Ensco") announced that it entered into a definitive merger agreement under which Ensco would acquire Atwood in an all-stock transaction. The transaction closed on October 6, 2017. Under the terms of the merger agreement, we received 1.60 shares of Ensco for each share of our Atwood common stock.

Interest and dividend income was $5.9 million, $3.2 million and $5.8 million in 2017, 2016 and 2015, respectively. The higher income in 2017 was primarily due to higher earnings on available cash equivalents and short-term investments. The higher income in 2015 was primarily the result of Atwood declaring dividends during 2015. Those dividends ceased in early 2016.

Direct operating costs in 2017 were $1.2 billion, compared with $0.9 billion in 2016 and $1.7 billion in 2015. The increase in 2017 from 2016 was primarily attributable to a higher level of activity in 2017 as well as start-up expenses related to reactivating over 100 FlexRigs returning to work during 2017. The decrease in 2016 from 2015 was primarily due to the sharp decline in drilling activity.

Depreciation and amortization expense was $585.5 million in 2017, $598.6 million in 2016 and $608.0 million in 2015. Depreciation and amortization includes amortization of $1.1 million in 2017 and abandonments of equipment of $42.6 million in 2017, $39.3 million in 2016 and $43.6 million in 2015. Additionally, we recorded impairment charges on rig and rig related equipment of $6.3 million in 2016 and $39.2 million in 2015. Depreciation expense, exclusive of abandonments, decreased three percent in 2017 from 2016 and one percent in 2016 from 2015. The decreases are primarily due to lower levels of capital expenditures during 2017 and 2016 and legacy assets reaching the end of their depreciable lives. Abandonments in the three year period were primarily due to the abandonment of used drilling equipment in all years and the decommissioning of 23 rigs in 2015.

Management monitors industry market conditions impacting its long lived assets, intangible assets and goodwill. When required, an impairment analysis is performed to determine if any impairment exists. We did not record any impairment in 2017. In 2016, we recorded a $6.3 million impairment charge to reduce the carrying value of used drilling equipment from rigs that were decommissioned from service in prior fiscal periods and written down to their estimated recoverable value at the time of decommissioning. In 2015, we recorded $39.2 million of impairment charges to reduce the carrying value of seven SCR rigs in our International Land segment to their estimated fair value.

General and administrative expenses totaled $151.0 million in 2017, $146.2 million in 2016 and $134.7 million in 2015. During 2017, we incurred transaction costs of $3.2 million related to our acquisition of MOTIVE Drilling Technologies, Inc. Contributing to the increase in 2016 from 2015 were expenses related to employee work force reductions including employee severance expenses, additional pension expense and additional employer match to our 401(k)/Employee Thrift Plan due to a partial plan termination status whereby affected participants were fully vested in their 401(k) accounts.

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Interest expense net of amounts capitalized totaled $19.7 million in 2017, $22.9 million in 2016 and $15.0 million in 2015. Interest expense is primarily attributable to fixed rate debt outstanding. There was a favorable adjustment to interest expense of $5.2 million in 2017 related to the reversal of previously booked uncertain tax positions where the statute of limitations has expired. Interest expense increased in 2016 from 2015 primarily due to the issuance of $500 million unsecured senior notes in March 2015. Capitalized interest was $0.3 million, $2.8 million and $7.0 million in 2017, 2016 and 2015, respectively. All of the capitalized interest is attributable to our rig construction program.

We had an income tax benefit of $56.7 million in 2017 compared to an income tax benefit of $19.7 million in 2016 and income tax expense of $241.4 million in 2015. The effective income tax rate was 30.7 percent in 2017 compared to 27.1 percent in 2016 and 36.5 percent in 2015. Deferred income taxes are provided for temporary differences between the financial reporting basis and the tax basis of our assets and liabilities. Recoverability of any tax assets are evaluated and necessary allowances are provided. The carrying value of the net deferred tax assets is based on management's judgments using certain estimates and assumptions that we will be able to generate sufficient future taxable income in certain tax jurisdictions to realize the benefits of such assets. If these estimates and related assumptions change in the future, additional valuation allowances may be recorded against the deferred tax assets resulting in additional income tax expense in the future. (See Note 5 of the Consolidated Financial Statements for additional income tax disclosures.)

During 2017, 2016 and 2015, we incurred $12.0 million, $10.3 million and $16.1 million, respectively, of research and development expenses primarily related to the ongoing development of the rotary steerable system tools. We anticipate research and development expenses to continue during 2018.

On June 2, 2017, we completed a merger transaction ("MOTIVE Merger") pursuant to which an unaffiliated drilling technology company, MOTIVE Drilling Technologies, Inc., a Delaware corporation ("MOTIVE"), was merged with and into our wholly owned subsidiary Spring Merger Sub, Inc., a Delaware corporation. MOTIVE survived the transaction and is now a wholly owned subsidiary of the Company. The operations for MOTIVE are included with all other non-reportable business segments. The MOTIVE Merger was accounted for as a business combination in accordance with Accounting Standards Codification ("ASC") 805, Business Combinations, which requires the assets acquired and liabilities assumed to be recorded at their acquisition date fair values.

MOTIVE has a proprietary Bit Guidance System that is an algorithm-driven system that considers the total economic consequences of directional drilling decisions and has proven to consistently lower drilling costs through more efficient drilling and increase hydrocarbon production through smoother wellbores and more accurate well placement. Given our strong and longstanding technology and innovation focus, we believe the technology will continue to advance and provide further benefits for the industry.

At the effective time of the MOTIVE Merger, MOTIVE shareholders received aggregate cash consideration of $74.3 million, net of customary closing adjustments, and may receive up to an additional $25.0 million in potential earnout payments based on future performance. Transaction costs related to the MOTIVE Merger incurred during fiscal 2017 were $3.2 million. We recorded revenue of $3.3 million and a net loss of $2.2 million related to the MOTIVE Merger during fiscal 2017. Additional information regarding the MOTIVE acquisition is described in Note 2 "Business Combinations" to our consolidated financial statements.

Expenses incurred within the country of Venezuela are reported as discontinued operations. In March 2016, the Venezuelan government implemented the previously announced plans for a new foreign currency exchange system. The implementation of this system resulted in a reported loss from discontinued operations of $3.8 million in fiscal 2016, all of which corresponds to the Company's former operations in Venezuela.

Our wholly owned subsidiaries, Helmerich & Payne International Drilling Co. and Helmerich & Payne de Venezuela, C.A., filed a lawsuit in the United States District Court for the District of Columbia on September 23, 2011 against the Bolivarian Republic of Venezuela, Petroleos de Venezuela, S.A. and PDVSA Petroleo, S.A. We are seeking damages for the taking of our Venezuelan drilling business in violation of international law and for breach of contract. While there exists the possibility of realizing a recovery, we are currently unable to determine the timing or amounts we may receive, if any, or the likelihood of recovery.

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The following tables summarize operations by reportable operating segment.

Comparison of the years ended September 30, 2017 and 2016

	2017	2016	% Change
	(in thousands, except operating statistics)		
U.S. LAND OPERATIONS			
Operating revenues	$ 1,439,523	$ 1,242,462	15.9 %
Direct operating expenses	984,205	603,800	63.0
General and administrative expense	50,712	50,057	1.3
Depreciation	499,486	508,237	(1.7)
Asset impairment charge	—	6,250	(100.0)
Segment operating income (loss)	$ (94,880)	$ 74,118	(228.0)
Operating Statistics:			
Revenue days	57,120	36,984	54.4 %
Average rig revenue per day	$ 22,607	$ 31,369	(27.9)
Average rig expense per day	$ 14,623	$ 14,117	3.6
Average rig margin per day	$ 7,984	$ 17,252	(53.7)
Number of rigs at end of period	350	348	0.6
Rig utilization	45 %	30 %	50.0

Operating statistics for per day revenue, expense and margin do not include reimbursements of "out of pocket" expenses of $148,218 and $82,337 for 2017 and 2016, respectively.

In 2017, the U.S. Land segment had an operating loss of $94.9 million compared to operating income of $74.1 million in 2016. Included in U.S. land revenues for 2017 and 2016 is approximately $24.5 million and $219.0 million, respectively, from early termination of fixed term contracts. Fixed term contracts customarily provide for termination at the election of the customer, with an early termination payment to be paid to us if a contract is terminated prior to the expiration of the fixed term (except in limited circumstances including sustained unacceptable performance by us).

Excluding early termination revenue of $428 and $5,921 per day for 2017 and 2016, respectively, average revenue per day for 2017 decreased by $3,269 to $22,179 from $25,448 in 2016. Our activity has increased year-over-year in response to higher commodity prices resulting in a 54 percent increase in revenue days when comparing 2017 to 2016. However, legacy term contracts at high dayrates make up a lower proportion of our 2017 activity due to continued contract expirations. Further, newly contracted rigs which made up the majority of our 2017 activity were priced at relatively lower levels which reflected 2017 market conditions.

Average rig expense increased $506 per day to $14,623 in 2017 from $14,117 in 2016. This increase was primarily attributable to start-up expenses related to rigs returning to work during 2017.

Depreciation includes charges for abandoned equipment of $42.2 million and $38.8 million in 2017 and 2016, respectively. Included in abandonments in 2017 are older rig components that were replaced by upgrades to our rig fleet to meet customer demands for additional capabilities. Included in abandonments in 2016 is the retirement of used drilling equipment. During fiscal 2016, we recorded an asset impairment charge in the U.S. Land segment of $6.3 million to reduce the carrying value of rig and rig related equipment classified as held for sale to their estimated fair values, based on expected sales prices. Excluding the abandonments, depreciation in 2017 decreased from 2016, primarily due to lower levels of capital expenditures during 2017 and 2016 and certain legacy assets reaching the end of their depreciable lives in 2017 and 2016.

Rig utilization increased to 45 percent in 2017 from 30 percent in 2016. The total number of rigs at September 30, 2017 was 350 compared to 348 rigs at September 30, 2016. The net increase is due to two new FlexRigs completed in 2017 and included in our operating statistics.

At September 30, 2017, 197 out of 350 existing rigs in the U.S. Land segment were generating revenue. Of the 197 rigs generating revenue, 100 were under fixed term contracts, and 97 were working in the spot market. At

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November 16, 2017, the number of existing rigs under fixed term contracts in the segment was 103 and the number of rigs working in the spot market was 97.

Comparison of the years ended September 30, 2017 and 2016

	2017	2016	% Change
	(in thousands, except operating statistics)		
OFFSHORE OPERATIONS			
Operating revenues	$ 136,263	$ 138,601	(1.7) %
Direct operating expenses	96,593	106,983	(9.7)
General and administrative expense	3,705	3,464	7.0
Depreciation	11,764	12,495	(5.9)
Segment operating income	$ 24,201	$ 15,659	54.6
Operating Statistics:			
Revenue days	2,277	2,708	(15.9) %
Average rig revenue per day	$ 34,332	$ 26,973	27.3
Average rig expense per day	$ 23,172	$ 19,381	19.6
Average rig margin per day	$ 11,160	$ 7,592	47.0
Number of rigs at end of period	8	9	(11.1)
Rig utilization	74 %	82 %	(9.8)

Operating statistics for per day revenue, expense and margin do not include reimbursements of "out of pocket" expenses of $21,578 and $23,138 for 2017 and 2016, respectively. The operating statistics only include rigs owned by us and exclude offshore platform management and labor service contracts and currency revaluation expense.

Average rig revenue per day and average rig margin per day increased in 2017 compared to 2016 primarily due to several rigs moving to higher pricing from previous standby or other special dayrates.

During the second quarter of fiscal 2017, we sold one of our offshore rigs. At September 30, 2017, five of our eight platform rigs were contracted compared to seven of nine available rigs at September 30, 2016.

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Comparison of the years ended September 30, 2017 and 2016

	2017	2016	% Change
	(in thousands, except operating statistics)		
INTERNATIONAL LAND OPERATIONS			
Operating revenues	$ 212,972	$ 229,894	(7.4) %
Direct operating expenses	163,486	183,969	(11.1)
General and administrative expense	3,088	2,909	6.2
Depreciation	53,622	57,102	(6.1)
Segment operating loss	$ (7,224)	$ (14,086)	48.7
Operating Statistics:			
Revenue days	4,951	5,364	(7.7) %
Average rig revenue per day	$ 40,979	$ 39,044	5.0
Average rig expense per day	$ 29,761	$ 28,638	3.9
Average rig margin per day	$ 11,218	$ 10,406	7.8
Number of rigs at end of period	38	38	—
Rig utilization	36 %	39 %	(7.7)

Operating statistics for per day revenue, expense and margin do not include reimbursements of "out of pocket" expenses of $10,074 and $20,458 for 2017 and 2016, respectively. Also excluded are the effects of currency revaluation income and expense.

The International Land segment had an operating loss of $7.2 million for 2017 compared to $14.1 million for 2016.

Excluding early termination revenue of $955 per day in 2017, the average rig margin per day for 2017 compared to 2016 decreased by $143 to $10,263. Low oil prices during 2016 and 2017 continue to have a negative effect on customer spending. We experienced an 8 percent decrease in revenue days when comparing 2017 to 2016. The average number of active rigs was 13.6 during 2017 compared to 14.7 during 2016.

Although direct operating expenses decreased in 2017 to $163.5 million from $184.0 million in 2016, the average rig expense per day increased $1,123 or 4 percent as compared to the 2016 average rig expense.

Included in direct operating expenses are foreign currency transaction losses of $6.0 million and $9.8 million for 2017 and 2016, respectively. The 2016 losses were primarily due to a devaluation of the Argentine peso in December 2015.

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Comparison of the years ended September 30, 2016 and 2015

	2016	2015	% Change
	(in thousands, except operating statistics)		
U.S. LAND OPERATIONS			
Operating revenues	$ 1,242,462	$ 2,523,518	(50.8) %
Direct operating expenses	603,800	1,254,424	(51.9)
General and administrative expense	50,057	50,769	(1.4)
Depreciation	508,237	519,950	(2.3)
Asset impairment charge	6,250	—	100.0
Segment operating income	$ 74,118	$ 698,375	(89.4)
Operating Statistics:			
Revenue days	36,984	75,866	(51.3) %
Average rig revenue per day	$ 31,369	$ 30,211	3.8
Average rig expense per day	$ 14,117	$ 13,483	4.7
Average rig margin per day	$ 17,252	$ 16,728	3.1
Number of rigs at end of period	348	343	1.5
Rig utilization	30 %	62 %	(51.6)

Operating statistics for per day revenue, expense and margin do not include reimbursements of “out of pocket” expenses of $82,337 and $231,528 for 2016 and 2015, respectively.

Rig utilization in 2016 excludes four FlexRigs completed and ready for delivery at September 30, 2016.

Operating income in the U.S. Land segment decreased to $74.1 million in 2016 from $698.4 million in 2015. Included in U.S. land revenues for 2016 and 2015 is approximately $219.0 million and $203.6 million, respectively, from early termination of fixed-term contracts.

Excluding early termination related revenue, the average revenue per day for 2016 decreased by $2,080 to $25,448 from $27,528 in 2015. Low oil prices had a negative effect on customer spending. Some customers did not renew expiring contracts while others elected to terminate fixed-term contracts early. As a result, we experienced a 51 percent decrease in revenue days when comparing 2016 to 2015. Fixed-term contracts customarily provide for termination at the election of the customer, with an early termination payment to be paid to us if a contract is terminated prior to the expiration of the fixed term (except in limited circumstances including sustained unacceptable performance by us).

The average rig expense per day increased to $14,117 in 2016 from $13,483 in 2015. In September 2016, we entered into a settlement agreement, subsequently approved by the court, regarding a lawsuit filed by an employee who was injured while working on a U.S. land rig. After taking into account amounts to be paid by our various insurers, we recorded an $18.8 million expense which reduced operating income and negatively impacted the 2016 average rig expense per day by $508.

Depreciation includes charges for abandoned equipment of $38.8 million and $42.6 million in 2016 and 2015, respectively. Included in abandonments in 2016 is the retirement of used drilling equipment. Included in abandonments in 2015 is the decommissioning of 23 SCR rigs, including six conventional rigs, six FlexRig1s and 11 FlexRig2s, and spare equipment for drilling rigs. We recorded in fiscal 2016 a $6.3 million impairment charge to reduce the carrying value in rig and rig related equipment classified as held for sale to their estimated fair values, based on expected sales prices. The used drilling equipment is from rigs that were decommissioned from service in prior fiscal periods and written down to their estimated recoverable value at the time of decommissioning. Excluding the abandonment, depreciation in 2016 decreased from 2015, primarily due to low levels of capital expenditures in 2016 and the decommissioning of rigs in 2015.

Rig utilization decreased to 30 percent in 2016 from 62 percent in 2015. The total number of rigs at September 30, 2016 was 348 compared to 343 rigs at September 30, 2015. The net increase is due to five new FlexRigs completed in 2016 and included in our operating statistics.

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At September 30, 2016, 95 out of 348 existing rigs in the U.S. Land segment were generating revenue. Of the 95 rigs generating revenue, 72 were under fixed-term contracts, and 23 were working in the spot market.

Comparison of the years ended September 30, 2016 and 2015

	2016	2015	% Change
	(in thousands, except operating statistics)		
OFFSHORE OPERATIONS			
Operating revenues	$ 138,601	$ 241,666	(42.6) %
Direct operating expenses	106,983	158,488	(32.5)
General and administrative expense	3,464	3,517	(1.5)
Depreciation	12,495	11,659	7.2
Segment operating income	$ 15,659	$ 68,002	(77.0)
Operating Statistics:			
Revenue days	2,708	3,067	(11.7) %
Average rig revenue per day	$ 26,973	$ 44,125	(38.9)
Average rig expense per day	$ 19,381	$ 27,246	(28.9)
Average rig margin per day	$ 7,592	$ 16,879	(55.0)
Number of rigs at end of period	9	9	—
Rig utilization	82 %	93 %	(11.8)

Operating statistics for per day revenue, expense and margin do not include reimbursements of "out of pocket" expenses of $23,138 and $33,254 for 2016 and 2015, respectively. The operating statistics only include rigs owned by us and exclude offshore platform management and labor service contracts and currency revaluation expense.

Average rig revenue per day, average rig expense per day and average rig margin per day decreased in 2016 compared to 2015 primarily due to several rigs moving to lower pricing while on standby or other special dayrates.

At September 30, 2016 seven of our nine platform rigs were contracted compared to eight at September 30, 2015.

Comparison of the years ended September 30, 2016 and 2015

	2016	2015	% Change
	(in thousands, except operating statistics)		
INTERNATIONAL LAND OPERATIONS			
Operating revenues	$ 229,894	$ 382,331	(39.9) %
Direct operating expenses	183,969	289,700	(36.5)
General and administrative expense	2,909	3,148	(7.6)
Depreciation	57,102	57,334	(0.4)
Asset impairment charge	—	39,242	(100.0)
Segment operating loss	$ (14,086)	$ (7,093)	(98.6)
Operating Statistics:			
Revenue days	5,364	7,284	(26.4) %
Average rig revenue per day	$ 39,044	$ 47,352	(17.5)
Average rig expense per day	$ 28,638	$ 34,848	(17.8)
Average rig margin per day	$ 10,406	$ 12,504	(16.8)
Number of rigs at end of period	38	38	—

Rig utilization	39	%	51	%	(23.5)

Operating statistics for per day revenue, expense and margin do not include reimbursements of "out of pocket" expenses of $20,458 and $37,420 for 2016 and 2015, respectively. Also excluded are the effects of currency revaluation income and expense.

The International Land segment had an operating loss of $14.1 million for 2016 compared to $7.1 million for 2015. Included in International land revenues in 2015 is approximately $18.7 million related to early termination of fixed-term contracts.

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Excluding early termination revenue of $2,566 per day in 2015, the average rig margin per day for 2016 compared to 2015 increased by $468 to $10,406. Low oil prices continued to have a negative effect on customer spending. As a result, we experienced a 26 percent decrease in revenue days when comparing 2016 to 2015. The average number of active rigs was 14.7 during 2016 compared to 20.0 during 2015.

The average rig expense per day decreased $6,210 or 18 percent as compared to the 2015 average rig expense that was impacted by expenses on rigs that had become idle and other costs associated with rigs transitioning between locations.

During the fourth fiscal quarter of 2015, we recorded a $39.2 million impairment charge to reduce the carrying value of seven SCR rigs located in our International Land segment to their estimated fair value.

Included in direct operating expenses for 2016 is $9.8 million of foreign currency transaction losses, primarily due to a devaluation of the Argentine peso in December 2015.

LIQUIDITY AND CAPITAL RESOURCES

Our capital spending was $397.6 million in 2017, $257.2 million in 2016 and $1.1 billion in 2015. Net cash provided from operating activities was $357.2 million in 2017, $753.6 million in 2016 and $1.4 billion in 2015. Our 2018 capital spending is currently estimated to be between $250 million and $300 million. This estimate includes capital maintenance requirements, tubulars and other special projects primarily related to upgrading our existing rig fleet.

Historically, we have financed operations primarily through internally generated cash flows. In periods when internally generated cash flows are not sufficient to meet liquidity needs, we will either borrow from available credit sources or we may sell portfolio securities. Likewise, if we are generating excess cash flows, we may invest in short term money market securities or short term marketable securities. Starting in 2015, we began investing in short term investments classified as trading securities. We have reinvested maturities and earnings during 2017 and 2016. The investments include U.S. Treasury securities, U.S. Agency issued debt securities, corporate bonds, certificates of deposit and money market funds. The securities are all very highly rated and recorded at fair value.

We manage a portfolio of marketable securities that, at the close of fiscal 2017, had a fair value of $70.2 million consisting of common shares of Atwood and Schlumberger, Ltd. The value of the portfolio is subject to fluctuation in the market and may vary considerably over time. The portfolio is recorded at fair value on our balance sheet. During the fourth quarter of 2016, we determined that the decline in fair value below our cost basis in Atwood was other than temporary. As a result, we recorded a non cash charge totaling $26.0 million.

Our proceeds from asset sales totaled $23.4 million in 2017, $21.8 million in 2016 and $22.6 million in 2015. Income from asset sales in 2017 totaled $20.6 million, $9.9 million in 2016 and $11.8 million in 2015. During 2017, we sold one offshore rig. In each year we had sales of old or damaged rig equipment and drill pipe used in the ordinary course of business.

During 2017, we paid dividends of $2.80 per share, or a total of $305.5 million. During 2016, we paid dividends of $2.763 per share, or a total of $300.2 million. We paid dividends of $2.75 per share or $298.4 million in 2015. Adjusting for stock splits accordingly, we have increased the effective annual dividend per share every year for well over 40 years.

On March 19, 2015, we issued $500 million of 4.65 percent 10-year unsecured senior notes. Interest is payable semi-annually on March 15 and September 15. The debt discount is being amortized to interest expense using the effective interest method. The debt issuance costs are amortized straight-line over the stated life of the obligation, which approximates the effective interest method.

We have a $300 million unsecured revolving credit facility which will mature on July 13, 2021. The credit facility has $75 million available to use as letters of credit. The majority of any borrowings under the facility would accrue interest at a spread over the London Interbank Offered Rate (LIBOR). We also pay a commitment fee based on the unused balance of the facility. Borrowing spreads as well as commitment fees are determined according to a scale based on a ratio of our total debt to total capitalization. The spread over LIBOR ranges from 1.125 percent to 1.75 percent per annum and commitment fees range from .15 percent to .30 percent per annum. Based on our debt to total

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capitalization on September 30, 2017, the spread over LIBOR and commitment fees would be 1.125 percent and .15 percent, respectively. There is one financial covenant in the facility which requires us to maintain a funded leverage ratio (as defined) of less than 50 percent. The credit facility contains additional terms, conditions, restrictions and covenants that we believe are usual and customary in unsecured debt arrangements for companies of similar size and credit quality including a limitation that priority debt (as defined in the agreement) may not exceed 17.5% of the net worth of the Company. As of September 30, 2017, there were no borrowings, but there were three letters of credit outstanding in the amount of $38.8 million. At September 30, 2017, we had $261.2 million available to borrow under our $300 million unsecured credit facility. Subsequent to September 30, 2017, the Company increased one of the three letters of credit by $0.5 million, which reduced availability under the facility to $260.7 million.

Subsequent to September 30, 2017, the Company entered into a $12 million unsecured standalone line of credit facility, which is purposed for the issuance of bid and performance bonds, as needed, for international operations. The Company currently has two bonds issued under this line for a total value of approximately $5.4 million.

The applicable agreements for all unsecured debt contain additional terms, conditions and restrictions that we believe are usual and customary in unsecured debt arrangements for companies that are similar in size and credit quality. At September 30, 2017, we were in compliance with all debt covenants.

At September 30, 2017, we had 112 existing rigs with fixed term contracts with original term durations ranging from six months to five years, with some expiring in fiscal 2018. The contracts provide for termination at the election of the customer, with an early termination payment to be paid if a contract is terminated prior to the expiration of the fixed term. While most of our customers are primarily major oil companies and large independent oil companies, a risk exists that a customer, especially a smaller independent oil company, may become unable to meet its obligations and may exercise its early termination election in the future and not be able to pay the early termination fee. Although not expected at this time, our future revenue and operating results could be negatively impacted if this were to happen.

Our operating cash requirements, scheduled debt repayments, interest payments, any stock repurchases and estimated capital expenditures, including our rig upgrade construction program, for fiscal 2018 are expected to be funded through current cash and cash to be provided from operating activities. However, there can be no assurance that we will continue to generate cash flows at current levels.

The current ratio was 3.6 at September 30, 2017 and 4.8 at September 30, 2016. The long term debt to total capitalization ratio was 10.6 percent at September 30, 2017 compared to 9.7 percent at September 30, 2016.

Stock Portfolio Held

September 30, 2017	Number of Shares	Cost Basis	Market Value
	(in thousands, except share amounts)		
Atwood Oceanics, Inc.	4,000,000	$ 34,760	$ 37,560
Schlumberger, Ltd.	467,500	3,713	32,613
Total		$ 38,473	$ 70,173

Material Commitments

We have no off balance sheet arrangements other than operating leases discussed below. Our contractual obligations as of September 30, 2017, are summarized in the table below in thousands:

	Payments due by year						
Contractual Obligations	Total	2018	2019	2020	2021	2022	After 2022
Long term debt and estimated interest (a)	$ 673,406	$ 23,250	$ 23,250	$ 23,250	$ 23,250	$ 23,250	$ 557,156
Operating leases (b)	29,959	8,015	5,454	3,795	2,944	2,926	6,825
Purchase obligations (b)	56,219	56,219	—	—	—	—	—
Total contractual obligations	$ 759,584	$ 87,484	$ 28,704	$ 27,045	$ 26,194	$ 26,176	$ 563,981

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(a) Interest on fixed rate debt was estimated based on principal maturities. See Note 4 “Debt” to our Consolidated Financial Statements.
(b) See Note 14 “Commitments and Contingencies” to our Consolidated Financial Statements.
The above table does not include obligations for our pension plan or amounts recorded for uncertain tax positions.

In 2017 and 2016, we did not make any contributions to the pension plan. Contributions may be made in fiscal 2018 to fund unexpected distributions in lieu of liquidating pension assets. Future contributions beyond fiscal 2018 are difficult to estimate due to multiple variables involved.

At September 30, 2017, we had $7.5 million recorded for uncertain tax positions and related interest and penalties. However, the timing of such payments to the respective taxing authorities cannot be estimated at this time. Income taxes are more fully described in Note 5 to the Consolidated Financial Statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Consolidated Financial Statements are impacted by the accounting policies used and by the estimates and assumptions made by management during their preparation. These estimates and assumptions are evaluated on an on going basis. Estimates are based on historical experience and on various other assumptions that we believe to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates under different assumptions or conditions. The following is a discussion of the critical accounting policies and estimates used in our financial statements. Other significant accounting policies are summarized in Note 1 to the Consolidated Financial Statements.

Property, Plant and Equipment Property, plant and equipment, including renewals and betterments, are stated at cost, while maintenance and repairs are expensed as incurred. The interest expense applicable to the construction of qualifying assets is capitalized as a component of the cost of such assets. We account for the depreciation of property, plant and equipment using the straight line method over the estimated useful lives of the assets considering the estimated salvage value of the property, plant and equipment. Both the estimated useful lives and salvage values require the use of management estimates. Certain events, such as unforeseen changes in operations, technology or market conditions, could materially affect our estimates and assumptions related to depreciation or result in abandonments. Management believes that these estimates have been materially accurate in the past. For the years presented in this report, no significant changes were made to the determinations of useful lives or salvage values. Upon retirement or other disposal of fixed assets, the cost and related accumulated depreciation are removed from the respective accounts and any gains or losses are recorded in the results of operations.

Impairment of Long lived Assets and Finite-lived Intangibles Management assesses the potential impairment of our long lived assets and finite-lived intangibles whenever events or changes in conditions indicate that the carrying value may not be recoverable. Changes that could prompt such an assessment may include equipment obsolescence, changes in the market demand, periods of relatively low rig utilization, declining revenue per day, declining cash margin per day, completion of specific contracts and/or overall changes in general market conditions. If a review of the long lived assets and finite-lived intangibles indicates that the carrying value of certain of these assets is more than the estimated undiscounted future cash flows, an impairment charge is made, as required, to adjust the carrying value to the estimated fair value. The fair value of drilling rigs is determined based upon either an income approach using estimated discounted future cash flows or a market approach. Cash flows are estimated by management considering factors such as prospective market demand, recent changes in rig technology and its effect on each rig’s marketability, any cash investment required to make a rig marketable, suitability of rig size and makeup to existing platforms, and competitive dynamics including utilization. Fair value is estimated, if applicable, considering factors such as recent market sales of rigs of other companies and our own sales of rigs, appraisals and other factors. The use of different assumptions could increase or decrease the estimated fair value of assets and could therefore affect any impairment measurement.

During the third fiscal quarter of 2016, we recorded a $6.3 million impairment charge to reduce the carrying values in used drilling equipment in our U.S. Land segment to its estimated fair value. The rig and rig related equipment fair value was estimated based on expected sales prices.

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Self Insurance Accruals We self insure a significant portion of expected losses relating to worker's compensation, general liability, employer's liability and automobile liability. Generally, deductibles range from $1 million to $5 million per occurrence depending on the coverage and whether a claim occurs outside or inside of the United States. Insurance is purchased over deductibles to reduce our exposure to catastrophic events but there can be no assurance that such coverage will respond or be adequate in all circumstances. Estimates are recorded for incurred outstanding liabilities for worker's compensation and other casualty claims. Retained losses are estimated and accrued based upon our estimates of the aggregate liability for claims incurred. Estimates for liabilities and retained losses are based on adjusters' estimates, our historical loss experience and statistical methods that we believe are reliable. Nonetheless, insurance estimates include certain assumptions and management judgments regarding the frequency and severity of claims, claim development and settlement practices. Unanticipated changes in these factors may produce materially different amounts of expense that would be reported under these programs.

Our wholly owned captive insurance company finances a significant portion of the physical damage risk on company owned drilling rigs as well as international casualty deductibles. With the exception of "named wind storm" risk in the Gulf of Mexico, we insure rigs and related equipment at values that approximate the current replacement cost on the inception date of the policy. We self insure a number of other risks including loss of earnings and business interruption, and most cyber risks.

Pension Costs and Obligations Our pension benefit costs and obligations are dependent on various actuarial assumptions. We make assumptions relating to discount rates and expected return on plan assets. Our discount rate is determined by matching projected cash distributions with the appropriate corporate bond yields in a yield curve analysis. The discount rate was increased to 3.79 percent from 3.64 percent as of September 30, 2017 to reflect changes in the market conditions for high quality fixed income investments. The expected return on plan assets is determined based on historical portfolio results and future expectations of rates of return. Actual results that differ from estimated assumptions are accumulated and amortized over the estimated future working life of the plan participants and could therefore affect the expense recognized and obligations in future periods. As of September 30, 2006, the Pension Plan was frozen and benefit accruals were discontinued. As a result, the rate of compensation increase assumption has been eliminated from future periods. We anticipate pension expense to decrease by approximately $3.1 million in 2018 from 2017.

Stock Based Compensation Historically, we have granted stock based awards to key employees and non employee directors as part of their compensation. We estimate the fair value of all stock option awards as of the date of grant by applying the Black Scholes option pricing model. The application of this valuation model involves assumptions, some of which are judgmental and highly sensitive. These assumptions include, among others, the expected stock price volatility, the expected life of the stock options and the risk free interest rate. Expected volatilities were estimated using the historical volatility of our stock based upon the expected term of the option. The expected term of the option was derived from historical data and represents the period of time that options are estimated to be outstanding. The risk free interest rate for periods within the estimated life of the option was based on the U.S. Treasury Strip rate in effect at the time of the grant. The fair value of each award is amortized on a straight line basis over the vesting period for awards granted to employees and non-employee directors.

The fair value of restricted stock awards is determined based on the closing price of our common stock on the date of grant. We amortize the fair value of restricted stock awards to compensation expense on a straight line basis over the vesting period. At September 30, 2017, unrecognized compensation cost related to unvested restricted stock was $21.4 million. The cost is expected to be recognized over a weighted average period of 2.2 years.

Revenue Recognition Contract drilling revenues are comprised of daywork drilling contracts for which the related revenues and expenses are recognized as services are performed and collection is reasonably assured. For certain contracts, we receive payments contractually designated for the mobilization of rigs and other drilling equipment.

Mobilization payments received, and direct costs incurred for the mobilization, are deferred and recognized over the term of the related drilling contract. Costs incurred to relocate rigs and other drilling equipment to areas in which a contract has not been secured are expensed as incurred. Reimbursements received for out of pocket expenses are recorded as both revenues and direct costs. For contracts that are terminated prior to the specified term, early termination payments received by us are recognized as revenues when all contractual requirements are met.

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NEW ACCOUNTING STANDARDS

See Note 1 of the Consolidated Financial Statements for recently adopted accounting standards and new accounting standards not yet adopted.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Foreign Currency Exchange Rate Risk Our contracts for work in foreign countries generally provide for payment in U.S. dollars. However, in Argentina we are paid in Argentine pesos. The Argentine branch of one of our second tier subsidiaries then remits U.S. dollars to its U.S. parent by converting the Argentine pesos into U.S. dollars through the Argentine Foreign Exchange Market and repatriating the U.S. dollars. In the future, other contracts or applicable law may require payments to be made in foreign currencies. As such, there can be no assurance that we will not experience in Argentina or elsewhere a devaluation of foreign currency, foreign exchange restrictions or other difficulties repatriating U.S. dollars even if we are able to negotiate the contract provisions designed to mitigate such risks. In December 2015, the Argentine peso experienced a sharp devaluation resulting in an aggregate foreign currency loss of $8.5 million for the three months ended December 31, 2015. Subsequent to the devaluation, the Argentine peso stabilized and the Argentine Foreign Exchange Market controls now place fewer restrictions on repatriating U.S. dollars. These changes have reduced our current foreign currency exchange rate risk in Argentina. However, in the future, we may incur currency devaluations, foreign exchange restrictions or other difficulties repatriating U.S. dollars in Argentina or elsewhere which could have a material adverse impact on our business, financial condition and results of operations. At September 30, 2017, a hypothetical decrease in value of 10 percent would result in an insignificant decrease in value of our monetary assets and liabilities denominated in Argentine pesos by approximately $133,000.

Estimates from published sources indicate that Argentina is a highly inflationary country, which is defined as cumulative inflation rates exceeding 100 percent in the most recent three year period based on inflation data published by the respective governments. Regardless, all of our foreign operations use the U.S. dollar as the functional currency and local currency monetary assets and liabilities are remeasured into U.S. dollars with gains and losses resulting from foreign currency transactions included in current results of operations.

Commodity Price Risk The demand for contract drilling services is derived from exploration and production companies spending money to explore and develop drilling prospects in search of crude oil and natural gas. Their spending is driven by their cash flow and financial strength, which is affected by trends in crude oil and natural gas commodity prices. Crude oil prices are determined by a number of factors including global supply and demand, the establishment of and compliance with production quotas by oil exporting countries, worldwide economic conditions and geopolitical factors. Crude oil and natural gas prices have historically been volatile and very difficult to predict with any degree of certainty. While current energy prices are important contributors to positive cash flow for customers, expectations about future prices and price volatility are generally more important for determining future spending levels. This volatility can lead many exploration and production companies to base their capital spending on much more conservative estimates of commodity prices. As a result, demand for contract drilling services is not always purely a function of the movement of commodity prices.

Credit and Capital Market Risk Customers may finance their exploration activities through cash flow from operations, the incurrence of debt or the issuance of equity. Any deterioration in the credit and capital markets, as experienced in the past, can make it difficult for customers to obtain funding for their capital needs. A reduction of cash flow resulting from declines in commodity prices or a reduction of available financing may result in customer credit defaults or reduced demand for drilling services which could have a material adverse effect on our business, financial condition and results of operations. Similarly, we may need to access capital markets to obtain financing. Our ability to access capital markets for financing could be limited by, among other things, oil and gas prices, our existing capital structure, our credit ratings, the state of the economy, the health of the drilling and overall oil and gas industry, and the liquidity of the capital markets. Many of the factors that affect our ability to access capital markets are outside of our control. No assurance can be given that we will be able to access capital markets on terms acceptable to us when required to do so, which could have a material adverse impact on our business, financial condition and results of operations.

Further, we attempt to secure favorable prices through advanced ordering and purchasing for drilling rig components. While these materials have generally been available at acceptable prices, there is no assurance the prices

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will not vary significantly in the future. Any fluctuations in market conditions causing increased prices in materials and supplies could have a material adverse effect on future operating costs.

Interest Rate Risk Our interest rate risk exposure results primarily from short term rates, mainly LIBOR based, on borrowings from our commercial banks. Because all of our debt at September 30, 2017 has fixed rate interest obligations, there is no current risk due to interest rate fluctuation.

The following tables provide information as of September 30, 2017 and 2016 about our interest rate risk sensitive instruments:

INTEREST RATE RISK AS OF SEPTEMBER 30, 2017 (dollars in thousands)

	2018	2019	2020	2021	2022	After 2022	Total	Fair Value 9/30/2017
Fixed Rate Debt	$ —	$ —	$ —	$ —	$ —	$ 500,000	$ 500,000	$ 528,960
Average Interest Rate	—%	—%	—%	—%	—%	4.65 %	4.65 %	
Variable Rate Debt	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Average Interest Rate								

INTEREST RATE RISK AS OF SEPTEMBER 30, 2016 (dollars in thousands)

	2017	2018	2019	2020	2021	After 2021	Total	Fair Value 9/30/2016
Fixed Rate Debt	$ —	$ —	$ —	$ —	$ —	$ 500,000	$ 500,000	$ 529,550
Average Interest Rate	—%	—%	—%	—%	—%	4.65 %	4.65 %	
Variable Rate Debt	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Average Interest Rate								

Equity Price Risk On September 30, 2017, we had a portfolio of securities with a total fair value of $70.2 million. The total fair value of the portfolio of securities was $71.5 million at September 30, 2016. A hypothetical 10% decrease in the market prices for all securities in our portfolio as of September 30, 2017 would decrease the fair value of our available for sale securities by $7.2 million. We make no specific plans to sell securities, but rather sell securities based on market conditions and other circumstances. These securities are subject to a wide variety and number of market related risks that could substantially reduce or increase the fair value of our holdings. The portfolio is recorded at fair value on the balance sheet with changes in unrealized after tax value reflected in the equity section of the balance sheet unless a decline in fair value below our cost basis is considered to be other than temporary in which case the change is recorded through earnings. Subsequent to September 30, 2017, the Atwood shares were converted to

Ensco shares under a merger agreement whereby we received 1.60 shares of Ensco plc for each share of our Atwood common stock. At November 16, 2017, the total fair value of our securities had decreased to approximately $63.2 million. Currently, the fair value exceeds the cost of the investments. We continually monitor the fair value of the investments but are unable to predict future market volatility and any potential impact to the Consolidated Financial Statements.

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Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Information required by this item may be found in Item 1A—“Risk Factors” and in Item 7—“Management’s Discussion and Analysis of Financial Condition and Results of Operations—Quantitative and Qualitative Disclosures About Market Risk” included in this Form 10 K.

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Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of

Helmerich & Payne, Inc.

We have audited the accompanying consolidated balance sheets of Helmerich & Payne, Inc. as of September 30, 2017 and 2016, and the related consolidated statements of operations, comprehensive income (loss), shareholders' equity and cash flows for each of the three years in the period ended September 30, 2017. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Helmerich & Payne, Inc. at September 30, 2017 and 2016, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2017, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Helmerich & Payne, Inc.'s internal control over financial reporting as of September 30, 2017, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated November 22, 2017 expressed an unqualified opinion thereon.

/s/Ernst & Young LLP

Tulsa, Oklahoma

November 22, 2017

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Consolidated Statements of Operations

HELMERICH & PAYNE, INC.

	Year Ended September 30,		
	2017	2016	2015
	(in thousands, except per share amounts)		
Operating revenues			
Drilling - U.S. Land	$ 1,439,523	$ 1,242,462	$ 2,523,518
Drilling - Offshore	136,263	138,601	241,666
Drilling - International Land	212,972	229,894	382,331
Other	15,983	13,275	14,187
	1,804,741	1,624,232	3,161,702
Operating costs and expenses			
Operating costs, excluding depreciation and amortization	1,249,317	898,805	1,703,476
Depreciation and amortization	585,543	598,587	608,039
Asset impairment charge	—	6,250	39,242
Research and development	12,047	10,269	16,104
General and administrative	151,002	146,183	134,712
Income from asset sales	(20,627)	(9,896)	(11,834)
	1,977,282	1,650,198	2,489,739
Operating income (loss) from continuing operations	(172,541)	(25,966)	671,963
Other income (expense)			
Interest and dividend income	5,915	3,166	5,840
Interest expense	(19,747)	(22,913)	(15,023)
Loss on investment securities	—	(25,989)	—
Other	1,775	(965)	(901)
	(12,057)	(46,701)	(10,084)
Income (loss) from continuing operations before income taxes	(184,598)	(72,667)	661,879
Income tax provision (benefit)	(56,735)	(19,677)	241,405
Income (loss) from continuing operations	(127,863)	(52,990)	420,474
Income (loss) from discontinued operations before income taxes	3,285	2,360	(124)
Income tax provision (benefit)	3,634	6,198	(77)
Loss from discontinued operations	(349)	(3,838)	(47)
NET INCOME (LOSS)	$ (128,212)	$ (56,828)	$ 420,427
Basic earnings per common share:			
Income (loss) from continuing operations	$ (1.20)	$ (0.50)	$ 3.88
Loss from discontinued operations	$ —	$ (0.04)	$ —
Net income (loss)	$ (1.20)	$ (0.54)	$ 3.88
Diluted earnings per common share:			
Income (loss) from continuing operations	$ (1.20)	$ (0.50)	$ 3.85
Loss from discontinued operations	$ —	$ (0.04)	$ —
Net income (loss)	$ (1.20)	$ (0.54)	$ 3.85
Weighted average shares outstanding (in thousands):			
Basic	108,500	107,996	107,754
Diluted	108,500	107,996	108,570

The accompanying notes are an integral part of these statements.

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Consolidated Statements of Comprehensive Income (Loss)

HELMERICH & PAYNE, INC.

	Year Ended September 30,		
	2017	2016	2015
	(in thousands)		
Net income (loss)	$ (128,212)	$ (56,828)	$ 420,427
Other comprehensive income (loss), net of income taxes:			
Unrealized appreciation (depreciation) on securities, net of income taxes of ($0.5) million at September 30, 2017, $1.7 million at September 30, 2016 and ($50.6) million at September 30, 2015	(829)	2,772	(80,217)
Reclassification of realized losses in net income, net of income taxes of $0.6 million at September 30, 2016	—	926	—
Minimum pension liability adjustments, net of income taxes of $1.9 million at September 30, 2017, ($1.4) million at September 30, 2016 and ($2.5) million at September 30, 2015	3,333	(2,525)	(4,286)
Other comprehensive income (loss)	2,504	1,173	(84,503)
Comprehensive income (loss)	$ (125,708)	$ (55,655)	$ 335,924

The accompanying notes are an integral part of these statements.

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Consolidated Balance Sheets

HELMERICH & PAYNE, INC.

	September 30, 2017	2016
	(in thousands)	
Assets		
CURRENT ASSETS:		
Cash and cash equivalents	$ 521,375	$ 905,561
Short-term investments	44,491	44,148
Accounts receivable, less reserve of $5,721 in 2017 and $2,696 in 2016	477,074	375,169
Inventories	137,204	124,325
Prepaid expenses and other	55,120	78,067
Assets held for sale	—	45,352
Current assets of discontinued operations	3	64
Total current assets	1,235,267	1,572,686
INVESTMENTS	84,026	84,955
PROPERTY, PLANT AND EQUIPMENT, at cost:		
Contract drilling equipment	8,197,572	7,881,544
Construction in progress	169,326	98,313
Real estate properties	66,005	62,929
Other	450,031	444,843
	8,882,934	8,487,629
Less-Accumulated depreciation	3,881,883	3,342,896
Net property, plant and equipment	5,001,051	5,144,733
NONCURRENT ASSETS:		
Goodwill	51,705	4,718
Intangible assets, net of amortization	50,785	919
Other assets	17,154	24,008
Total noncurrent assets	119,644	29,645
TOTAL ASSETS	$ 6,439,988	$ 6,832,019

The accompanying notes are an integral part of these statements.

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Consolidated Balance Sheets (Continued)

HELMERICH & PAYNE, INC.

	September 30, 2017	2016
	(in thousands, except share data and per share amounts)	
Liabilities and Shareholders' Equity		
CURRENT LIABILITIES:		
Accounts payable	$ 135,628	$ 95,422
Accrued liabilities	208,683	234,639
Current liabilities of discontinued operations	74	59
Total current liabilities	344,385	330,120
NONCURRENT LIABILITIES:		
Long-term debt	492,902	491,847
Deferred income taxes	1,332,689	1,342,456
Other	101,409	102,781
Noncurrent liabilities of discontinued operations	4,012	3,890
Total noncurrent liabilities	1,931,012	1,940,974
SHAREHOLDERS' EQUITY:		
Common stock, $.10 par value, 160,000,000 shares authorized, 111,956,875 and 111,400,339 shares issued as of September 30, 2017 and 2016, respectively, and 108,604,047 and 108,077,916 shares outstanding as of September 30, 2017 and 2016, respectively	11,196	11,140
Preferred stock, no par value, 1,000,000 shares authorized, no shares issued	—	—
Additional paid-in capital	487,248	448,452
Retained earnings	3,855,686	4,289,807
Accumulated other comprehensive income (loss)	2,300	(204)
	4,356,430	4,749,195
Less treasury stock, 3,352,828 shares in 2017 and 3,322,423 shares in 2016, at cost	(191,839)	(188,270)
Total shareholders' equity	4,164,591	4,560,925
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 6,439,988	$ 6,832,019

The accompanying notes are an integral part of these statements.

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Consolidated Statements of Shareholders' Equity

HELMERICH & PAYNE, INC.

	Common Stock		Additional Paid-In	Retained	Accumulated Other Comprehensive	Treasury Stock		
	Shares	Amount	Capital	Earnings	Loss	Shares	Amount	Total
	(in thousands, except per share amounts)							
lance, ptember 30, 2014	110,509	$ 11,051	$ 383,972	$ 4,525,989	$ 83,126	2,276	$ (112,969)	$ 4,891,169
mprehensive come:								
t income				420,427				420,427
her mprehensive loss					(84,503)			(84,503)
vidends declared 2.75 per share)				(298,070)				(298,070)
ercise of stock tions	255	26	7,223			64	(4,599)	2,650
x benefit of ck-based awards			3,772					3,772
ock issued for sted restricted ck, net of shares thheld for ployee taxes	223	22	(21)			70	(5,141)	(5,140)
purchase of mmon stock						810	(59,654)	(59,654)
ock-based mpensation			25,195					25,195
lance, ptember 30, 2015	110,987	11,099	420,141	4,648,346	(1,377)	3,220	(182,363)	4,895,846
mprehensive come:								
t loss				(56,828)				(56,828)
her mprehensive come					1,173			1,173
vidends declared 2.775 per share)				(301,711)				(301,711)
ercise of stock tions	220	22	6,937			99	(5,919)	1,040
x benefit of ck-based awards			934					934
ock issued for sted restricted ck, net of shares	193	19	(3,943)			3	12	(3,912)

thheld for ployee taxes								
ock-based mpensation			24,383					24,383
lance, ptember 30, 2016	111,400	11,140	448,452	4,289,807	(204)	3,322	(188,270)	4,560,925
mprehensive loss:								
t loss				(128,212)				(128,212)
her mprehensive loss					2,504			2,504
vidends declared 2.80 per share)				(305,909)				(305,909)
ercise of stock tions	415	42	15,738			88	(5,246)	10,534
x benefit of ck-based awards			4,414					4,414
ock issued for sted restricted ck, net of shares thheld for ployee taxes	142	14	(7,539)			(57)	1,677	(5,848)
ock-based mpensation			26,183					26,183
lance, ptember 30, 2017	111,957	$ 11,196	$ 487,248	$ 3,855,686	$ 2,300	3,353	$ (191,839)	$ 4,164,591

The accompanying notes are an integral part of these statements.

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Consolidated Statements of Cash Flows

HELMERICH & PAYNE, INC.

	Year Ended September 30,		
	2017	2016	2015
	(in thousands)		
OPERATING ACTIVITIES:			
Net income (loss)	$ (128,212)	$ (56,828)	$ 420,427
Adjustment for loss from discontinued operations	349	3,838	47
Income (loss) from continuing operations	(127,863)	(52,990)	420,474
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	585,543	598,587	608,039
Asset impairment charge	—	6,250	39,242
Amortization of debt discount and debt issuance costs	1,055	1,168	749
Provision for (recovery of) bad debt	2,016	(2,013)	6,034
Stock-based compensation	26,183	24,383	25,195
Pension settlement charge	1,640	4,964	2,873
Loss on investment securities	—	25,989	—
Income from asset sales	(20,627)	(9,896)	(11,834)
Deferred income tax (benefit) expense	(24,111)	60,088	131,431
Other	543	151	(368)
Change in assets and liabilities:			
Accounts receivable	(97,114)	72,792	259,024
Inventories	(10,607)	1,944	(23,052)
Prepaid expenses and other	31,434	(2,460)	(4,457)
Accounts payable	39,412	(10,907)	(38,983)
Accrued liabilities	(36,120)	49,562	(24,756)
Deferred income taxes	(942)	2,769	688
Other noncurrent liabilities	(13,075)	(16,831)	38,322
Net cash provided by operating activities from continuing operations	357,367	753,550	1,428,621
Net cash provided by (used in) operating activities from discontinued operations	(150)	47	(47)
Net cash provided by operating activities	357,217	753,597	1,428,574
INVESTING ACTIVITIES:			
Capital expenditures	(397,567)	(257,169)	(1,131,445)
Purchase of short-term investments	(69,866)	(57,276)	(45,607)
Payment for acquisition of business, net of cash acquired	(70,416)	—	—
Proceeds from sale of short-term investments	69,449	58,381	—
Proceeds from asset sales	23,412	21,845	22,643
Net cash used in investing activities	(444,988)	(234,219)	(1,154,409)
FINANCING ACTIVITIES:			
Payments on long-term debt	—	(40,000)	(40,000)
Proceeds from senior notes, net of discount	—	—	497,125
Debt issuance costs	—	(1,111)	(5,474)
Proceeds on short-term debt	—	—	1,002

Payments on short-term debt	—	—	(1,002)
Repurchase of common stock	—	—	(59,654)
Dividends paid	(305,515)	(300,152)	(298,367)
Exercise of stock options, net of tax withholding	10,534	1,040	2,650
Tax withholdings related to net share settlements of restricted stock	(5,848)	(3,912)	(5,140)
Excess tax benefit from stock-based compensation	4,414	934	3,772
Net cash provided by (used in) financing activities	(296,415)	(343,201)	94,912
Net increase (decrease) in cash and cash equivalents	(384,186)	176,177	369,077
Cash and cash equivalents, beginning of period	905,561	729,384	360,307
Cash and cash equivalents, end of period	$ 521,375	$ 905,561	$ 729,384

The accompanying notes are an integral part of these statements.

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Notes to Consolidated Financial Statements

HELMERICH & PAYNE, INC.

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of Helmerich & Payne, Inc. and its wholly-owned subsidiaries.

BASIS OF PRESENTATION

We classified our former Venezuelan operation as a discontinued operation in the third quarter of fiscal 2010, as more fully described in Note 3. Unless indicated otherwise, the information in the Notes to Consolidated Financial Statements relates only to our continuing operations.

FOREIGN CURRENCIES

The functional currency for all our foreign operations is the U.S. dollar. Nonmonetary assets and liabilities are translated at historical rates and monetary assets and liabilities are translated at exchange rates in effect at the end of the period. Income statement accounts are translated at average rates for the period presented. Aggregate foreign currency gains and losses from remeasurement of foreign currency financial statements and foreign currency translations into U.S. dollars included in direct operating costs total losses of $7.1 and $9.3 million in fiscal 2017 and 2016, respectively, and a transaction gain of $1.6 million in fiscal 2015.

USE OF ESTIMATES

The preparation of our financial statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect reported amounts of assets and liabilities, 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.

RECENTLY ADOPTED ACCOUNTING STANDARDS

In January 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2017-04, Intangibles-Goodwill and Other (Topic 350). The objective of this ASU is to simplify how an entity is required to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. Step 2 measures a goodwill impairment loss by comparing the implied fair value of a reporting unit's goodwill with the carrying amount of that goodwill. Instead, under this ASU, an entity should perform its annual, or interim, goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; however, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. Additionally, an entity should consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable. As permitted, we early adopted this guidance effective June 30, 2017 with no impact on our consolidated financial statements.

In August 2014, the FASB issued ASU No. 2014-15, Presentation of Financial Statements — Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern. The guidance provides principles and definitions for management that are intended to reduce diversity in the timing and content of disclosures provided in footnotes. Under the standard, management is required to evaluate for each annual and interim reporting period whether it is probable that the entity will not be able to meet its obligations as they become due within one year after the date that financial statements are issued (or are available to be issued, where applicable). We adopted ASU No. 2014-15, as required, on September 30, 2017 with no impact on the consolidated financial statements.

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CASH AND CASH EQUIVALENTS

Cash equivalents consist of investments in short-term, highly liquid securities having original maturities of three months or less. The carrying values of these assets approximate their fair values. We utilize a cash management system with a series of separate accounts consisting of lockbox accounts for receiving cash, concentration accounts, and several "zero-balance" disbursement accounts for funding payroll and accounts payable.

RESTRICTED CASH AND CASH EQUIVALENTS

We had restricted cash and cash equivalents of $39.1 million and $29.6 million at September 30, 2017 and 2016, respectively. Of the total at September 30, 2017, $9.4 million is related to the MOTIVE acquisition described in Note 2, $2.0 million is from the initial capitalization of the captive insurance company, and $27.7 million represents an additional amount management has elected to restrict for the purpose of potential insurance claims in our wholly-owned captive insurance company. The restricted amounts are primarily invested in short-term money market securities.

The restricted cash and cash equivalents are reflected in the balance sheet as follows:

	September 30,	
	2017	2016
	(in thousands)	
Prepaid expenses and other	$ 32,439	$ 27,631
Other assets	$ 6,695	$ 2,000

INVENTORIES

Inventories are primarily replacement parts and supplies held for use in our drilling operations. Inventories are valued at the lower of weighted average cost or market value.

INVESTMENTS

We maintain investments in equity securities of certain publicly traded companies. The cost of securities used in determining realized gains and losses is based on the average cost basis of the security sold.

We regularly review investment securities for impairment based on criteria that include the extent to which the investment's carrying value exceeds its related fair value, the duration of the market decline and the financial strength and specific prospects of the issuer of the security. Unrealized losses that are other than temporary are recognized in earnings.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are stated at cost less accumulated depreciation. Substantially all property, plant and equipment are depreciated using the straight-line method based on the estimated useful lives of the assets (contract drilling equipment, 4-15 years; real estate buildings and equipment, 10-45 years; and other, 2-23 years). Depreciation in the Consolidated Statements of Operations includes abandonments of $42.6 million, $39.3 million and $43.6 million for fiscal 2017, 2016 and 2015, respectively. During fiscal 2017, upgrades to our fleet to meet customer demands for additional capabilities resulted in the abandonment of older rig components. During fiscal 2016, we abandoned used drilling equipment removed from service. During fiscal 2015, we decommissioned 23 idle rigs. The cost of maintenance and repairs is charged to direct operating cost, while betterments and refurbishments are capitalized.

We lease office space and equipment for use in operations. Leases are evaluated at inception or upon any subsequent material modification and, depending on the lease terms, are classified as either capital leases or operating leases as appropriate under Accounting Standards Codification ("ASC") 840, Leases. We do not have significant capital leases.

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CAPITALIZATION OF INTEREST

We capitalize interest on major projects during construction. Interest is capitalized based on the average interest rate on related debt. Capitalized interest for fiscal 2017, 2016 and 2015 was $0.3 million, $2.8 million and $7.0 million, respectively.

VALUATION OF LONG-LIVED ASSETS

We review long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Changes that could prompt such an assessment include a significant decline in revenue or cash margin per day, extended periods of low rig utilization, changes in market demand for a specific asset, obsolescence, completion of specific contracts and/or overall general market conditions. If a review of the long-lived assets indicates that the carrying value of certain of these assets is more than the estimated undiscounted future cash flows, an impairment charge is made, as required, to adjust the carrying value down to the estimated fair value of the asset. The fair value of drilling rigs is determined based upon either an income approach using estimated discounted future cash flows or a market approach. Cash flows are estimated by management considering factors such as prospective market demand, recent changes in rig technology and its effect on each rig's marketability, any cash investment required to make a rig marketable, suitability of rig size and make up to existing platforms, and competitive dynamics including industry utilization. Long-lived assets that are held for sale are recorded at the lower of carrying value or the fair value less costs to sell. Fair value is estimated, if applicable, considering factors such as recent market sales of rigs of other companies and our own sales of rigs, appraisals and other factors.

Beginning in the first fiscal quarter of fiscal 2015 and continuing into fiscal 2016, domestic and international oil prices declined significantly but have since largely stabilized at lower levels. This decline in pricing resulted in lower demand for our drilling services. For any asset group for which an impairment indicator was present, we performed an impairment evaluation in accordance with ASC 360, Property, Plant, and Equipment by estimating our future undiscounted cash flows from the use and eventual disposal of the asset group using probability weighted scenarios. The most significant assumptions used in our analysis are expected margin per day, utilization and expected value upon disposal. We believe the assumptions and estimates used in our impairment analysis, including the development of probability weighted cash flow projections, are reasonable and appropriate; however, different assumptions and estimates could materially impact the analysis and resulting conclusions in some cases.

During fiscal 2016, we recorded an asset impairment charge in the U.S. Land segment of $6.3 million to reduce the carrying value of rig and rig related equipment classified as held for sale to their estimated fair values, based on expected sales prices. The assets were originally classified as held for sale with the intent of selling them into an international location. The outlook on U.S. trade policies with the targeted international location subsequently shifted, causing sale negotiations to stall. Thus, during the second quarter of fiscal 2017, we determined the equipment no longer met the held for sale criteria and reclassified it to property, plant and equipment. There was no impact on our results of operations from this decision. The rig equipment is from rigs that were decommissioned from service in prior fiscal years and written down to their estimated recoverable value at the time of decommissioning and is recorded at its carrying value which is lower than its estimated fair value.

During fiscal 2015, our valuation of long-lived assets resulted in $39.2 million of impairment charges to reduce the carrying value of seven SCR land rigs within our International Land segment to their estimated fair value of $20.6 million which was based on a discounted cash flow analysis. Our discounted cash flow analysis consisted of creating projected cash flows that a market participant would reasonably develop and then applying an appropriate risk adjusted rate. Six of these rigs along with other rig related assets were classified as held for sale at September 30, 2016. When the assets were originally classified as held for sale, the Latin American drilling market appeared to be trending upward. As marketing efforts continued, buyer interest diminished due to the Latin American market remaining flat in terms of rig counts and oil prices. Since that point, the market remained flat in terms of rig counts and oil prices. During the third quarter of fiscal 2017, we determined the equipment no longer met the held for sale criteria and reclassified it to property, plant and equipment. Our 2017 results of operations reflect a $2.2 million depreciation catch-up adjustment as a result of this decision. The equipment is recorded at its carrying value which is lower than its estimated fair value.

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GOODWILL AND INTANGIBLE ASSETS

Goodwill represents the excess of cost over the fair value of net assets acquired in a business combination. Goodwill is not amortized but is tested for potential impairment at the reporting unit level, at a minimum on an annual basis, or when indications of potential impairment exist. If an impairment is determined to exist, an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value is recognized, limited to the total amount of goodwill allocated to that reporting unit. The reporting unit level is defined as an operating segment or one level below an operating segment. All of our goodwill is within our other non-reportable business segment. We assess goodwill for impairment in the fourth fiscal quarter. Our assessment in fiscal 2017, 2016 and 2015 did not result in any impairment charge. The following is a summary of changes in goodwill (in thousands):

Balance at September 30, 2015	$ 4,718
Additions	—
Balance at September 30, 2016	4,718
Additions	46,987
Balance at September 30, 2017	$ 51,705

Intangible assets with indefinite lives are tested for impairment at least annually in the fourth fiscal quarter and if events occur or circumstances change that would indicate that the value of the asset may be impaired. Impairment is measured as the difference between the fair value of the asset and its carrying value. Finite-lived intangible assets are amortized using the straight-line method over the period in which these assets contribute to our cash flows, generally estimated to be 15 years and are evaluated for impairment in accordance with our policies for valuation of long-lived assets. No impairment of intangible assets was recorded in fiscal 2017, 2016 or 2015. The following is a summary of our finite-lived and indefinite-lived intangible assets other than goodwill at September 30:

	September 30, 2017		September 30, 2016	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in thousands)			
Finite-lived intangible asset:				
Developed technology	$ 51,000	$ 1,134	$ —	$ —
Indefinite-lived intangible asset:				
Trademark	$ 919		$ 919	

Amortization expense was $1.1 million for the year ended September 30, 2017 and is estimated to be $3.4 million in each of the next five fiscal years.

SELF-INSURANCE ACCRUALS

We have accrued a liability for estimated worker's compensation and other casualty claims incurred based upon case reserves plus an estimate of loss development and incurred but not reported claims. The estimate is based upon historical trends. Insurance recoveries related to such liability are recorded when considered probable.

DRILLING REVENUES

Contract drilling revenues are comprised of daywork drilling contracts for which the related revenues and expenses are recognized as services are performed and collection is reasonably assured. For certain contracts, we receive payments contractually designated for the mobilization of rigs and other drilling equipment. Mobilization payments received, and direct costs incurred for the mobilization, are deferred and recognized on a straight-line basis over the term of the related drilling contract. Costs incurred to relocate rigs and other drilling equipment to areas in which a contract has not been secured are expensed as incurred. Reimbursements received for out-of-pocket expenses are recorded as both revenues and direct costs. Reimbursements for fiscal 2017, 2016 and 2015 were $179.9 million, $125.9 million and $302.2 million, respectively. For contracts that are terminated by customers prior to the expirations of their fixed terms, contractual provisions customarily require early termination amounts to be paid to us. Revenues

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from early terminated contracts are recognized when all contractual requirements have been met. Early termination revenue for fiscal 2017, 2016 and 2015 was approximately $29.4 million, $219.0 million and $222.3 million, respectively.

RENT REVENUES

We enter into leases with tenants in our rental properties consisting primarily of retail and multi-tenant warehouse space. The lease terms of tenants occupying space in the retail centers and warehouse buildings generally range from three to ten years. Minimum rents are recognized on a straight-line basis over the term of the related leases. Overage and percentage rents are based on tenants' sales volume. Recoveries from tenants for property taxes and operating expenses are recognized in other operating revenues in the Consolidated Statements of Operations. Our rent revenues are as follows:

	Year Ended September 30,		
	2017	2016	2015
	(in thousands)		
Minimum rents	$ 9,735	$ 9,196	$ 9,608
Overage and percentage rents	$ 936	$ 1,211	$ 1,030

At September 30, 2017, minimum future rental income to be received on noncancelable operating leases was as follows:

Fiscal Year	Amount
	(in thousands)
2018	$ 7,845
2019	6,100
2020	4,961
2021	3,973
2022	2,032
Thereafter	5,293
Total	$ 30,204

Leasehold improvement allowances are capitalized and amortized over the lease term.

At September 30, 2017 and 2016, the cost and accumulated depreciation for real estate properties were as follows:

	September 30,	
	2017	2016
	(in thousands)	
Real estate properties	$ 66,005	$ 62,929
Accumulated depreciation	(42,169)	(40,777)
	$ 23,836	$ 22,152

INCOME TAXES

Current income tax expense is the amount of income taxes expected to be payable for the current year. Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial basis and the tax basis of our assets and liabilities.

We provide for uncertain tax positions when such tax positions do not meet the recognition thresholds or measurement standards prescribed in ASC 740, Income Taxes, which is more fully discussed in Note 5. Amounts for uncertain tax positions are adjusted in periods when new information becomes available or when positions are effectively settled. We recognize accrued interest related to unrecognized tax benefits in interest expense and penalties in other expense in the Consolidated Statements of Operations.

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EARNINGS PER SHARE

Basic earnings per share is computed utilizing the two-class method and is calculated based on the weighted-average number of common shares outstanding during the periods presented. Diluted earnings per share is computed using the weighted-average number of common and common equivalent shares outstanding during the periods utilizing the two-class method for stock options and nonvested restricted stock.

STOCK-BASED COMPENSATION

Stock-based compensation expense is determined using a fair-value-based measurement method for all awards granted. In computing the impact, the fair value of each option is estimated on the date of grant based on the Black-Scholes options-pricing model utilizing assumptions for a risk free interest rate, volatility, dividend yield and expected remaining term of the awards. The assumptions used in calculating the fair value of stock-based payment awards represent management's best estimates, but these estimates involve inherent uncertainties and the application of management judgment. Stock-based compensation is recognized on a straight-line basis over the requisite service periods of the stock awards, which is generally the vesting period. Compensation expense related to stock options is recorded as a component of general and administrative expenses in the Consolidated Statements of Operations.

TREASURY STOCK

Treasury stock purchases are accounted for under the cost method whereby the cost of the acquired stock is recorded as treasury stock. Gains and losses on the subsequent reissuance of shares are credited or charged to additional paid-in capital using the average-cost method.

COMPREHENSIVE INCOME OR LOSS

Other comprehensive income or loss refers to revenues, expenses, gains, and losses that are included in comprehensive income or loss but excluded from net income or loss. We report the components of other comprehensive income or loss, net of tax, by their nature and disclose the tax effect allocated to each component in the Consolidated Statements of Comprehensive Income (Loss).

NEW ACCOUNTING STANDARDS NOT YET ADOPTED

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers, which supersedes virtually all existing revenue recognition guidance. Throughout 2016 and in early 2017, additional accounting guidance was issued to clarify the not yet effective revenue recognition guidance issued in May 2014. The ASU provides for full retrospective, modified retrospective, or use of the cumulative effect method during the period of adoption. During 2017, we established an implementation team and began a detailed analysis of our contracts in place during the retrospective period. We are currently evaluating changes to our business processes, systems and controls to support recognition and disclosure under the new standard. Upon adoption of the new revenue standard, our drilling revenue associated with our drilling contracts will be disaggregated into a lease component and a service component. The requirements in this ASU are effective during interim and annual periods beginning after December 15, 2017. In fiscal 2017, we performed an initial assessment of the impact of ASU 2014-09 with the assistance of an outside consultant. Our assessment was based on a bottoms-up approach, in which we analyzed our existing contracts and current accounting policies and practices to identify potential differences that would result from applying the requirements of the new standard to our contracts. In fiscal 2018, we will implement appropriate changes to our business processes, systems or controls to support recognition and disclosure under the new standard. Our findings and progress toward implementation of the standard are periodically reported to management. Currently, we do not expect the impact of adopting ASU 2014-09 to be material to our total net revenues and operation income (loss) or to our consolidated balance sheet because our performance obligations, which determine when and how revenue is recognized, are not materially changed under the new standard, thus, revenue associated with the majority of our contracts will continue to be recognized as control of products is transferred to the customer. We will adopt this standard on October 1, 2018 and, based on our evaluation to date, we anticipate using the modified retrospective method; however, we are still in the process of finalizing our documentation and assessment of the impact of the standard on our financial results and related disclosures. We anticipate additional disclosures in future filings related to our planned adoption of this standard.

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In July 2015, the FASB issued ASU No 2015-11, Inventory (Topic 330): Simplifying the Measurement of Inventory. This update simplifies the subsequent measurement of inventory. It replaces the current lower of cost or market test with the lower of cost or net realizable value test. Net realizable value is defined as the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The new standard should be applied prospectively and is effective for annual reporting periods beginning after December 15, 2016 and interim periods within those annual periods, with early adoption permitted. We will adopt ASU No. 2015-11 on October 1, 2017 and do not expect the adoption of this standard to have a material impact on our consolidated financial statements.

In January 2016, the FASB issued ASU No. 2016-01, Financial Instruments – Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities. The standard requires entities to measure equity investments that do not result in consolidation and are not accounted for under the equity method at fair value and recognize any changes in fair value in net income. The provisions of ASU 2016-01 are effective for interim and annual periods starting after December 15, 2017. At adoption, a cumulative-effect adjustment to beginning retained earnings will be recorded. We will adopt this standard on October 1, 2018. Subsequent to adoption, changes in the fair value of our available-for-sale investments will be recognized in net income and the effect will be subject to stock market fluctuations.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842). ASU 2016-02 will require organizations that lease assets — referred to as "lessees" — to recognize on the balance sheet the assets and liabilities for the rights and obligations created by those leases. Under ASU 2016-02, a lessee will be required to recognize assets and liabilities for leases with lease terms of more than 12 months. Lessor accounting remains substantially similar to current GAAP. In addition, disclosures of leasing activities are to be expanded to include qualitative along with specific quantitative information. For public entities, ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. ASU 2016-02 mandates a modified retrospective transition method with an option to use certain practical expedients. Since a portion of our contract drilling revenue will be subject to this new leasing guidance, we expect to adopt this new lease guidance utilizing the modified retrospective method of adoption in the first quarter of fiscal 2019 concurrently with ASU 2014-09. We are currently evaluating changes to our business processes, systems and controls to support recognition and disclosure under the new standard. Our findings are periodically reported to management. We have performed a scoping and preliminary assessment of the impact of this new standard. As a lessor, we expect the adoption of this new standard will apply to our drilling contracts and as a result, we expect to have a lease component and a service component of our revenues derived from drilling contracts. As a lessee, this standard will primarily impact us in situations where we lease real estate and equipment, for which we will recognize a right-of-use asset and a corresponding lease liability on our consolidated balance sheet. We are currently evaluating the potential impact of adopting this guidance on our consolidated financial statements.

In March 2016, the FASB issued ASU No. 2016-09, Compensation — Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting. ASU 2016-09 simplifies several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. For public entities, ASU 2016-09 is effective for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. We will adopt ASU No. 2016-09 on October 1, 2017. We do not expect the adoption of this guidance to have a material impact on our consolidated financial statements.

In June 2016, the FASB issued ASU No. 2016-13, Financial Instruments – Credit Losses. The ASU sets forth a "current expected credit loss" (CECL) model which requires companies to measure all expected credit losses for financial instruments held at the reporting date based on historical experience, current conditions and reasonable supportable forecasts. This replaces the existing incurred loss model and is applicable to the measurement of credit losses on financial assets measured at amortized cost and applies to some off-balance sheet credit exposures. This standard is effective for interim and annual periods beginning after December 15, 2019. We are currently assessing the impact this standard will have on our consolidated financial statements and disclosures.

In August 2016, the FASB issued ASU No. 2016-15, Classification of Certain Cash Receipts and Cash Payments (a consensus of the Emerging Issues Task Force). The ASU is intended to reduce diversity in practice in presentation and classification of certain cash receipts and cash payments by providing guidance on eight specific cash flow issues. The ASU is effective for interim and annual periods beginning after December 15, 2017 and early adoption

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is permitted, including adoption during an interim period. We are currently assessing the impact this standard will have on our consolidated statement of cash flows.

In November 2016, the FASB issued ASU No. 2016-18, Statement of Cash Flows - Restricted Cash. The ASU requires amounts generally described as restricted cash and restricted cash equivalents be included with cash and cash equivalents when reconciling the total beginning and ending amounts for the periods shown on the statement of cash flows. The ASU is effective for interim and annual periods beginning after December 31, 2017 and early adoption is permitted, including adoption during an interim period. We will adopt the guidance beginning October 1, 2018 applied retrospectively to all periods presented. The adoption is not expected to have a material impact on our consolidated financial position or cash flows.

In March 2017, the FASB issued ASU No. 2017-07, Compensation - Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost. ASU 2017-07 will change how employers that sponsor defined benefit pension and/or other post-retirement benefit plans present the net periodic benefit cost in the income statement. Employers will present the service cost component of net periodic benefit cost in the same income statement line item(s) as other employee compensation costs arising from services rendered during the period. Employers will present the other components of the net periodic benefit cost separately from the line item(s) that includes the service cost and outside of any subtotal of operating income, if one is presented. This standard is effective for public business entities for annual periods or any interim periods beginning after December 15, 2017, including interim periods within those periods. Early adoption is permitted. We do not expect the new guidance to have a material impact on our financial condition or results of operation.

We have evaluated all new accounting standards that are in effect and may impact our financial statements and do not believe that there are any other new accounting standards that have been issued that might have a material impact on our financial position or results of operations.

NOTE 2 BUSINESS COMBINATIONS

On June 2, 2017, we completed a merger transaction (“MOTIVE Merger”) pursuant to which an unaffiliated drilling technology company, MOTIVE Drilling Technologies, Inc., a Delaware corporation (“MOTIVE”), was merged with and into our wholly owned subsidiary Spring Merger Sub, Inc., a Delaware corporation. MOTIVE survived the transaction and is now a wholly owned subsidiary of the Company. The operations for MOTIVE are included with all other non-reportable business segments. At the effective time of the MOTIVE Merger, MOTIVE shareholders received aggregate cash consideration of $74.3 million, net of customary closing adjustments, and may receive up to an additional $25.0 million in potential earnout payments based on future performance. At closing, $9.4 million of the cash consideration was placed in escrow, with one-half to be released to the seller on each of the twelve and eighteen month anniversaries of the merger completion date. Transaction costs related to the MOTIVE Merger incurred during fiscal 2017 were $3.2 million and are recorded in the Consolidated Statement of Operations within the general and administrative expense line item. We recorded revenue of $3.3 million and a net loss of $2.2 million related to the MOTIVE Merger during fiscal 2017.

MOTIVE has a proprietary Bit Guidance System that is an algorithm-driven system that considers the total economic consequences of directional drilling decisions and has proven to consistently lower drilling costs through more efficient drilling and increase hydrocarbon production through smoother wellbores and more accurate well placement. Given our strong and longstanding technology and innovation focus, we believe the technology will continue to advance and provide further benefits for the industry.

The MOTIVE Merger is accounted for as a business combination in accordance with ASC 805, Business Combinations, which requires the assets acquired and liabilities assumed to be recorded at their acquisition date fair values. The following table summarizes the purchase price and the allocation of the fair values of assets acquired and liabilities assumed and separately identifiable intangible assets at the acquisition date (in thousands):

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Purchase Price	
Consideration given	
Cash consideration	$ 74,275
Long-term contingent earnout liability (Other noncurrent liabilities)	14,509
Total consideration given	$ 88,784
Allocation of Purchase Price	
Fair value of assets acquired	
Current assets	$ 4,425
Property, plant and equipment	300
Intangible asset - developed technology (Intangible assets, net of amortization)	51,000
Goodwill	46,987
Total assets acquired	$ 102,712
Fair value of liabilities assumed	
Current liabilities	$ 25
Deferred income taxes	13,903
Total liabilities acquired	$ 13,928
Fair value of total assets and liabilities acquired	$ 88,784

The fair value of the contingent consideration of $14.5 million at June 2, 2017 and $14.9 million at September 30, 2017 was calculated using a Monte Carlo simulation which evaluates numerous potential earnings and pay out scenarios and is considered a level 3 measurement under the fair value hierarchy. The developed technology is an intangible asset that will be amortized on a straight-line basis over an estimated 15-year life. During fiscal 2017, we recorded $1.1 million of amortization related to the developed technology. We expect annual amortization to be approximately $3.4 million. The developed technology intangible asset was valued using an income approach, considering the estimated discounted future cash flows expected to be realized over the life of the asset, which is considered a level 3 measurement under the fair value hierarchy. Goodwill represents the residual of the purchase price paid and consists largely of the synergies and economies of scale expected from the drilling technology providing more efficient drilling and directional drilling services, the first mover advantage obtained through the acquisition and expected future developments resulting from the assembled workforce. The goodwill is reported in the Other segment and will not be allocated to any other reporting unit. The goodwill is not subject to amortization but will be evaluated at least annually for impairment or more frequently if impairment indicators are present. The developed technology and goodwill are not deductible for income tax purposes. An associated deferred tax liability has been recorded in regards to the developed technology.

The following unaudited pro forma combined financial information is provided for fiscal 2017 and fiscal 2016, as though the MOTIVE Merger had been completed as of October 1, 2015. These pro forma combined results of operations have been prepared by adjusting our historical results to include the historical results of MOTIVE and reflect pro forma adjustments based on available information and certain assumptions that we believe are reasonable, including application of an appropriate income tax to MOTIVE pre-tax loss. Additionally, pro forma earnings for fiscal 2017 were adjusted to exclude $2.1 million of after-tax transaction costs. The unaudited pro forma combined financial information is provided for illustrative purposes only and is not necessarily indicative of the actual results that would have been achieved by the combined company for the periods presented or that may be achieved by the combined company in the future. Future results may vary significantly from the results reflected in this pro forma financial information.

	Pro Forma 2017 (unaudited)	2016
Revenues	$ 1,807,950	$ 1,626,305
Net loss	$ (127,093)	$ (59,776)

NOTE 3 DISCONTINUED OPERATIONS

Current assets of discontinued operations consist of restricted cash to meet remaining current obligations within the country of Venezuela. Current and noncurrent liabilities consist of municipal and income taxes payable and social obligations due within the country in Venezuela.

Expenses incurred for in-country obligations are reported as discontinued operations.

In March 2016, the Venezuelan government implemented the previously announced plans for a new foreign currency exchange system. The implementation of this system resulted in a reported loss from discontinued operations of $3.8 million in fiscal 2016, all of which corresponds to the Company's former operations in Venezuela.

NOTE 4 DEBT

At September 30, 2017 and 2016, we had the following unsecured long-term debt outstanding at rates and maturities shown in the following table:

	Principal		Unamortized Discount and Debt Issuance Costs	
	September 30, 2017 (in thousands)	September 30, 2016	September 30, 2017	September 30, 2016
Unsecured senior notes issued March 19, 2015:				
Due March 19, 2025	$ 500,000	$ 500,000	$ (7,098)	$ (8,153)
	500,000	500,000	(7,098)	(8,153)
Less long-term debt due within one year	—	—	—	—
Long-term debt	$ 500,000	$ 500,000	$ (7,098)	$ (8,153)

On March 19, 2015, we issued $500 million of 4.65 percent 10-year unsecured senior notes. Interest is payable semi-annually on March 15 and September 15. The debt discount is being amortized to interest expense using the effective interest method. The debt issuance costs are amortized straight-line over the stated life of the obligation, which approximates the effective interest method.

We have a $300 million unsecured revolving credit facility which will mature on July 13, 2021. The credit facility has $75 million available to use as letters of credit. The majority of any borrowings under the facility would accrue interest at a spread over the London Interbank Offered Rate (LIBOR). We also pay a commitment fee based on the unused balance of the facility. Borrowing spreads as well as commitment fees are determined according to a scale based on a ratio of our total debt to total capitalization. The spread over LIBOR ranges from 1.125 percent to 1.75 percent per annum and commitment fees range from .15 percent to .30 percent per annum. Based on our debt to total capitalization on September 30, 2017, the spread over LIBOR and commitment fees would be 1.125 percent and .15 percent, respectively. There is one financial covenant in the facility which requires us to maintain a funded leverage ratio (as defined) of less than 50 percent. The credit facility contains additional terms, conditions, restrictions and covenants that we believe are usual and customary in unsecured debt arrangements for companies of similar size and credit quality including a limitation that priority debt (as defined in the agreement) may not exceed 17.5% of the net worth of the Company. As of September 30, 2017, there were no borrowings, but there were three letters of credit outstanding in the amount of $38.8 million. At September 30, 2017, we had $261.2 million available to borrow under our $300 million unsecured credit facility. Subsequent to September 30, 2017, the Company increased one of the three letters of credit by $0.5 million, which reduced availability under the facility to $260.7 million.

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Subsequent to September 30, 2017, the Company entered into a $12 million unsecured standalone line of credit facility, which is purposed for the issuance of bid and performance bonds, as needed, for international operations. The Company currently has two bonds issued under this line for a total value of approximately $5.4 million.

The applicable agreements for all unsecured debt contain additional terms, conditions and restrictions that we believe are usual and customary in unsecured debt arrangements for companies that are similar in size and credit quality. At September 30, 2017, we were in compliance with all debt covenants.

At September 30, 2017, aggregate maturities of long-term debt are as follows (in thousands):

Years ending September 30,	
2018	$ —
2019	—
2020	—
2021	—
2022	—
Thereafter	$ 500,000
	$ 500,000

NOTE 5 INCOME TAXES

The components of the provision (benefit) for income taxes are as follows:

	Year Ended September 30,		
	2017	2016	2015
	(in thousands)		
Current:			
Federal	$ (36,260)	$ (86,010)	$ 84,229
Foreign	4,108	9,987	14,864
State	(472)	(3,742)	10,881
	(32,624)	(79,765)	109,974
Deferred:			
Federal	(14,953)	58,136	165,491
Foreign	(7,827)	408	(34,410)
State	(1,331)	1,544	350
	(24,111)	60,088	131,431
Total provision (benefit)	$ (56,735)	$ (19,677)	$ 241,405

The amounts of domestic and foreign income (loss) before income taxes are as follows:

Years Ended September 30,		
2017	2016	2015

	(in thousands)		
Domestic	$ (173,157)	$ (49,636)	$ 675,425
Foreign	(11,441)	(23,031)	(13,546)
	$ (184,598)	$ (72,667)	$ 661,879

Deferred income taxes are provided for the temporary differences between the financial reporting basis and the tax basis of our assets and liabilities. Recoverability of any tax assets are evaluated and necessary allowances are provided. The carrying value of the net deferred tax assets is based on management's judgments using certain estimates and assumptions that we will be able to generate sufficient future taxable income in certain tax jurisdictions to realize the benefits of such assets. If these estimates and related assumptions change in the future, additional valuation allowances may be recorded against the deferred tax assets resulting in additional income tax expense in the future.

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The components of our net deferred tax liabilities are as follows:

	September 30, 2017	2016
	(in thousands)	
Deferred tax liabilities:		
Property, plant and equipment	$ 1,386,512	$ 1,411,139
Available-for-sale securities	24,940	25,470
Other	21,609	2,326
Total deferred tax liabilities	1,433,061	1,438,935
Deferred tax assets:		
Pension reserves	7,614	8,330
Self-insurance reserves	19,461	15,282
Net operating loss, foreign tax credit, and other federal tax credit carryforwards	62,478	71,778
Financial accruals	62,971	67,594
Other	6,003	4,952
Total deferred tax assets	158,527	167,936
Valuation allowance	(58,155)	(71,457)
Net deferred tax assets	100,372	96,479
Net deferred tax liabilities	$ 1,332,689	$ 1,342,456

The change in our net deferred tax assets and liabilities is impacted by foreign currency remeasurement.

As of September 30, 2017, we had federal, state and foreign net operating loss carryforwards for income tax purposes of $12.6 million, $29.9 million and $77.8 million, respectively, and foreign tax credit carryforwards of approximately $34.9 million (of which $30.2 million is reflected as a deferred tax asset in our Consolidated Financial Statements prior to consideration of our valuation allowance) which will expire in fiscal 2018 through 2037. The valuation allowance is primarily attributable to state and foreign net operating loss carryforwards of $2.0 million and $25.4 million, respectively, and foreign tax credit carryforwards of $30.2 million, and foreign minimum tax credit carryforwards of $0.6 million which more likely than not will not be utilized.

The federal net operating loss carryforward of $12.6 million and other federal tax credit carryforward of $0.3 million resulted from the acquisition of MOTIVE, which closed during the third quarter of fiscal 2017. The acquisition represented an ownership change under Internal Revenue Code Section 382 for which both are subject to an annual limitation. Both tax attributes begin to expire in 2034 and it is more likely than not both will be utilized.

For the fiscal year ended September 30, 2017, the Company is estimating a federal net operating loss for income tax purposes of approximately $125.1 million. At this time, the Company is anticipating carrying back the federal net operating loss to the fiscal year ended September 30, 2015 and has recorded an estimated income tax receivable of $39.8 million. The Company has until the filing of the federal income tax return for the fiscal year ended September 30, 2017 to decide whether to carryback or carryforward the net operating loss.

Effective income tax rates as compared to the U.S. Federal income tax rate are as follows:

	Year Ended September 30,		
	2017	2016	2015

U.S. Federal income tax rate	35.0 %	35.0 %	35.0 %
Effect of foreign taxes	1.8	(13.8)	(3.2)
State income taxes, net of federal tax benefit	0.6	3.2	0.8
U.S. domestic production activities	(2.1)	(10.4)	(1.2)
Other impact of foreign operations	(2.9)	14.7	4.5
Other	(1.7)	(1.6)	0.6
Effective income tax rate	30.7 %	27.1 %	36.5 %

Effective tax rates differ from the U.S. federal statutory rate of 35.0 percent primarily due to state and foreign income taxes. The effective tax rate for the twelve months ended September 30, 2017 was also impacted by a reduction

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to the benefit of the carryback of the federal net operating loss generated in the fiscal year ended September 30, 2017 resulting from the reduction of the Internal Revenue Code Section 199 deduction in the carryback year.

We recognize accrued interest related to unrecognized tax benefits in interest expense, and penalties in other expense in the Consolidated Statements of Operations. As of September 30, 2017 and 2016, we had accrued interest and penalties of $2.8 million and $6.8 million, respectively.

A reconciliation of the change in our gross unrecognized tax benefits for the fiscal years ended September 30, 2017 and 2016 is as follows:

	September 30,	
	2017	2016
	(in thousands)	
Unrecognized tax benefits at October 1,	$ 9,551	$ 11,211
Gross decreases - tax positions in prior periods	(1)	—
Gross decreases - current period effect of tax positions	(170)	(1,173)
Gross increases - current period effect of tax positions	300	969
Expiration of statute of limitations for assessments	(4,907)	(679)
Settlements	—	(777)
Unrecognized tax benefits at September 30,	$ 4,773	$ 9,551

As of September 30, 2017 and 2016, our liability for unrecognized tax benefits includes $3.7 million and $3.8 million, respectively, of unrecognized tax benefits related to discontinued operations that, if recognized, would not affect the effective tax rate. The remaining unrecognized tax benefits would affect the effective tax rate if recognized. The liabilities for unrecognized tax benefits and related interest and penalties are included in other noncurrent liabilities in our Consolidated Balance Sheets.

For the next 12 months, we cannot predict with certainty whether we will achieve ultimate resolution of any uncertain tax position associated with our U.S. and international operations that could result in increases or decreases of our unrecognized tax benefits. However, we do not expect the increases or decreases to have a material effect on our results of operations or financial position.

We file a consolidated U.S. federal income tax return, as well as income tax returns in various states and foreign jurisdictions. The tax years that remain open to examination by U.S. federal and state jurisdictions include fiscal 2013 through 2016, with exception of certain state jurisdictions currently under audit. The tax years remaining open to examination by foreign jurisdictions include 2003 through 2017.

NOTE 6 SHAREHOLDERS' EQUITY

The Company has authorization from the Board of Directors for the repurchase of up to four million common shares in any calendar year. The repurchases may be made using our cash and cash equivalents or other available sources. During fiscal 2015, we purchased 810,097 common shares at an aggregate cost of $59.7 million, which are held as treasury shares. We had no purchases of common shares in fiscal years 2017 and 2016.

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ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

Components of accumulated other comprehensive income (loss) were as follows:

	September 30, 2017	2016	2015
	(in thousands)		
Pre-tax amounts:			
Unrealized appreciation on securities	$ 31,700	$ 33,051	$ 27,021
Unrealized actuarial loss	(28,873)	(34,112)	(30,144)
	$ 2,827	$ (1,061)	$ (3,123)
After-tax amounts:			
Unrealized appreciation on securities	$ 20,070	$ 20,899	$ 17,201
Unrealized actuarial loss	(17,770)	(21,103)	(18,578)
	$ 2,300	$ (204)	$ (1,377)

The following is a summary of the changes in accumulated other comprehensive income (loss), net of tax, by component for the year ended September 30, 2017:

Unrealized
Appreciation