Helmerich & Payne, Inc.
Form 10-K
November 23, 2016

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended September 30, 2016

OR

o **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 ý No o

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 o No ý

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

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 ý No o

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. o

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

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

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

At March 31, 2016, the aggregate market value of the voting stock held by non-affiliates was approximately $6.2 billion.

Number of shares of common stock outstanding at November 11, 2016: 108,177,217.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's 2017 Proxy Statement for the Annual Meeting of Stockholders to be held on March 1, 2017 are incorporated by reference into Part III of this Form 10-K. The 2017 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.

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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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 others 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 2016, our U.S. Land operations drilled primarily in Oklahoma, California, Texas, Wyoming, Colorado, Louisiana, Mississippi, Pennsylvania, Ohio, New Mexico and North Dakota. Offshore operations were conducted in the Gulf of Mexico and Equatorial Guinea. Our International Land segment conducted drilling operations in five international locations during fiscal 2016: Ecuador, Colombia, Argentina, Bahrain and United Arab Emirates ("UAE").

We are also engaged in the ownership, development and operation of commercial real estate and the research and development 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 2017. Each of the businesses operates independently of the others through wholly-owned subsidiaries. This operating decentralization is balanced by centralized finance and legal 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 2016, we received approximately 68 percent of our consolidated operating revenues from our ten largest contract drilling customers. Occidental Oil and Gas Corporation, Continental Resources and Yacimientos Petroliferos Fiscales (respectively, "Oxy", "Continental" and "YPF"), including their affiliates, are our three largest contract drilling customers. We perform drilling services for Oxy on a world-wide basis, Continental in U.S. land operations and YPF in Argentina. Revenues from drilling services performed for Oxy, Continental and YPF in fiscal 2016 accounted for approximately 30 percent, 18 percent and 15 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 camps 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

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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 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 more capable 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 and building 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. FlexRig3s are designed to target well depths of between 8,000 and 22,000 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. This design permits the installation of a pipe handling system which allows the rig to be more efficiently operated and eliminates the need for a casing stabber in the mast. 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

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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, we did not decommission any of our remaining 14 SCR rigs.

Since 1998, we have built 232 FlexRig3s, 88 FlexRig4s, and 52 FlexRig5s with 367 of those delivered to the field. Of the total 372 AC drive FlexRigs built through September 30, 2016, 157 have been built in the last five fiscal years. As of November 17, 2016, there was one additional FlexRig under construction. Additionally, five previously completed FlexRigs are scheduled for delivery to the field at a later date per the request of certain customers.

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 $10.3 million in fiscal 2016, $16.1 million in fiscal 2015, and $15.9 million in fiscal 2014.

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 2017. 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. While oil prices have rebounded modestly from lows observed in early 2016, the decline in prices continued to negatively affect demand for services in fiscal 2016. Specifically, at the close of fiscal 2016 we had 118 contracted rigs, compared to 168 contracted rigs at the close of fiscal 2015 and 325 contracted rigs at the close of fiscal 2014. 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 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. While we continue to periodically perform impairment evaluations, no additional impairments were identified in fiscal 2016 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 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 2016, all drilling services were performed on a "daywork" contract basis, under which we charge 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 fifteen 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 of 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.

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As of September 30, 2016, we had 88 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 expected 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, 2016 and 2015 was $1.8 billion and $3.1 billion, respectively. The decrease in backlog at September 30, 2016 from September 30, 2015, is primarily due to the revenue earned since September 30, 2015 and the expiration and termination of long-term contracts. Approximately 53.2 percent of the total September 30, 2016 backlog is not reasonably expected to be filled in fiscal 2017. A small portion of the backlog represents term contracts for new rigs that will begin operations in the future.

The following table sets forth the total backlog by reportable segment as of September 30, 2016 and 2015, and the percentage of the September 30, 2016 backlog not reasonably expected to be filled in fiscal 2017:

Reportable Segment	Total Backlog Revenue 9/30/2016	Total Backlog Revenue 9/30/2015	Percentage Not Reasonably Expected to be Filled in Fiscal 2017
	(in billions)		
U.S. Land	$ 1.2	$ 2.2	47.5%
Offshore	0.1	0.1	44.4%
International	0.5	0.8	68.8%
	$ 1.8	$ 3.1	

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 2016, 2015, and 2014, we had 348, 343 and 329, respectively, of our land rigs available for work in the United States. The total number of rigs at the end of fiscal 2016 increased by a net of five rigs from the end of fiscal 2015. The net increase is due to five new FlexRigs completed in 2016. Our U.S. Land operations contributed approximately 77 percent ($1.2 billion) of our consolidated operating revenues during fiscal 2016, compared with approximately 80 percent ($2.5 billion) of consolidated operating revenues during fiscal 2015 and approximately 83 percent ($3.1 billion) of consolidated operating revenues during fiscal 2014. Rig utilization was approximately 30 percent in fiscal 2016, approximately 62 percent in fiscal 2015 and approximately 86 percent in fiscal 2014. A rig is considered to be utilized when it is operated or being mobilized or demobilized under contract. At the close of fiscal 2016, 95 out of an available 348 land rigs were generating revenue.

Offshore Drilling

Our Offshore operations contributed approximately 9 percent in fiscal year 2016 ($138.6 million) of our consolidated operating revenues compared to approximately 8 percent ($241.7 million) of consolidated operating revenues during fiscal 2015 and 7 percent ($251.3 million) of consolidated operating revenues during fiscal 2014. Rig utilization in fiscal 2016 was approximately 82 percent

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compared to approximately 93 percent in fiscal 2015 and 89 percent in fiscal 2014. At the end of fiscal 2016, we had seven of our nine offshore platform rigs under contract compared to eight at the end of fiscal 2015. We continued to work under management contracts for two customer-owned rigs at the close of fiscal 2016. Revenues from drilling services performed for our largest offshore drilling customer totaled approximately 61percent ($84.1 million) of offshore revenues during fiscal 2016.

International Land Drilling

General

Prior to September 30, 2015, for financial reporting purposes, fiscal years of our foreign operations ended on August 31 to facilitate reporting of consolidated results, resulting in a one-month reporting lag when compared to the remainder of the Company. Starting October 1, 2015, the reporting year-end of these foreign operations was changed from August 31 to September 30 eliminating the previously existing one-month reporting lag. Accordingly, the results of operations below have been changed to reflect the period-specific effects of this change, unless otherwise noted. See Note 1 "Summary of Significant Accounting Policies" included in Item 8 "Financial Statements and Supplementary Data" of this Form 10-K for additional information regarding this change.

At the end of September 2016 and 2015, we had 38 land rigs available for work in locations outside of the United States compared to 36 land rigs at the end of 2014. Our International Land operations contributed approximately 14 percent ($229.9 million) of our consolidated operating revenues during fiscal 2016, compared with approximately 12 percent ($382.3 million) of consolidated operating revenues during fiscal 2015 and 9 percent ($351.3 million) of consolidated operating revenues during fiscal 2014. Rig utilization in fiscal 2016 was 39 percent, 51 percent in fiscal 2015 and 74 percent in fiscal 2014. 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 2016, we had 19 rigs in Argentina. Our utilization rate was approximately 54 percent during fiscal 2016, approximately 57 percent during fiscal 2015 and approximately 77 percent during fiscal 2014. Revenues generated by Argentine drilling operations contributed approximately 10 percent in fiscal 2016 ($159.4 million) of our consolidated operating revenues compared to approximately 6 percent ($178.0 million) of our consolidated operating revenues during fiscal 2015 and approximately 3 percent ($107.2 million) of our consolidated operating revenues during fiscal 2014. Revenues from drilling services performed for our two largest customers in Argentina totaled approximately 9 percent of consolidated operating revenues and approximately 66 percent of international operating revenues during fiscal 2016. The Argentine drilling contracts are primarily with large international or national oil companies.

Colombia

At the end of fiscal 2016, we had eight rigs in Colombia. Our utilization rate was approximately 13 percent during fiscal 2016, approximately 48 percent during fiscal 2015 and approximately 62 percent during fiscal 2014. Revenues generated by Colombian drilling operations contributed approximately 1 percent in fiscal 2016 ($20.5 million) of our consolidated operating revenues compared to approximately 2 percent ($70.1 million) of our consolidated operating revenues during fiscal 2015 and approximately 2 percent ($81.2 million) of our consolidated operating revenues during fiscal 2014. Revenues from drilling services performed for our two customers in Colombia totaled approximately 1 percent of consolidated operating revenues and approximately 9 percent of international operating

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revenues during fiscal 2016. The Colombian drilling contracts are primarily with large international or national oil companies.

Ecuador

At the end of fiscal 2016, we had six rigs in Ecuador. The utilization rate in Ecuador was 4 percent in fiscal 2016, compared to 29 percent in fiscal 2015 and 83 percent in fiscal 2014. Revenues generated by Ecuadorian drilling operations contributed less than 1 percent ($4.9 million) during fiscal 2016 of our consolidated operating revenues compared to approximately 1 percent during fiscal 2015 ($31.0 million) of our consolidated operating revenues and 2 percent in fiscal 2014 ($68.0 million) of our consolidated operating revenues. At the end of fiscal 2016 all of our rigs in Ecuador were idle. The rigs in Ecuador, along with other rig related assets, were classified as held for sale at September 30, 2016.

UAE Abu Dhabi

At the end of fiscal 2016, we had two rigs in the UAE. The utilization rate in the UAE was 100 percent in fiscal 2016, fiscal 2015 and in fiscal 2014. Revenues generated by drilling operations in the UAE contributed 2 percent ($34.6 million) during fiscal 2016 of our consolidated operating revenues compared to approximately 2 percent during fiscal 2015 ($47.7 million) of our consolidated operating revenues and 1 percent during fiscal 2014 ($48.5 million) of our consolidated operating revenues. The UAE drilling contracts are with a single national oil company that contributed approximately 15 percent of international operating revenues during fiscal 2016.

Bahrain

At the end of fiscal 2016, we had three rigs in Bahrain. The utilization rate in Bahrain was 33 percent in fiscal 2016, compared to 56 percent in fiscal 2015 and 100 percent in fiscal 2014. Revenues generated by drilling operations in Bahrain contributed 1 percent during fiscal 2016, fiscal 2015 and fiscal 2014 ($10.2 million, $41.9 million and $33.2 million, respectively) of our consolidated operating revenues. Bahrain drilling contracts are with a single national oil company that contributed approximately 4 percent of international operating revenues during fiscal 2016.

FINANCIAL

For information relating to revenues, total assets and operating income by reportable operating segments, see Note 14 "Segment Information" included in Item 8 "Financial Statements and Supplementary Data" of this Form 10-K.

EMPLOYEES

We had 4,116 employees within the United States (5 of which were part-time employees) and 724 employees in international operations as of September 30, 2016.

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

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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.

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. Oil and natural gas prices, and market expectations regarding potential changes to these prices, significantly affect oil and natural gas industry activity.

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 recent months oil prices have generally remained below $50 per barrel. In response to the downward trend in prices, many of our customers reduced their capital spending budgets for 2015 and 2016. As such, demand for our drilling services declined further in the first half of fiscal 2016. We have, however, experienced an increase in demand and activity since May of 2016. At December 31, 2014, 294 out of an available 337 land rigs were working in the U.S. Land segment. In contrast, at September 30, 2016, 95 out of an available 348 land rigs were contracted in the U.S. Land segment. As of November 17, 2016, 105 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.

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

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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 2017, 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.

A tepid or deteriorating global economy may affect our business.

As a result of volatility in oil and natural gas prices and a tepid global economic environment, we are unable to determine whether our customers will maintain or increase spending on exploration and development drilling or 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 global economic environment remains tepid or deteriorates, 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

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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. Today, as was the case in past downturns, there are substantially more drilling rigs available than necessary to meet demand. As a result of the current excess of available and more competitive drilling rigs, we may be unable to replace fixed-term contracts that were terminated early, extend expiring contracts or obtain new contracts in the spot market, and the day rates (and other material terms) under any new contracts may be on substantially less favorable rates and terms. As such, we may have difficulty sustaining rig utilization and profit margins in the future, we may lose market share and price may become the 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 2016, we received approximately 68 percent of our consolidated operating revenues from our ten largest contract drilling customers and approximately 30 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.

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. 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

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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 or new 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.

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.

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

We evaluate our drilling rigs and other property 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, 2016, 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 current depressed market conditions are prolonged or if oil and gas prices remain low or decline further.

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 have been engaged in discussions with the Inspector General's office of the Department of Interior regarding the same events that were the subject of the DOJ's investigation. Although we presently believe that the outcome of our discussions will not have a material adverse effect on us, we can provide no assurances as to the timing or eventual outcome of these discussions. Refer to Item 3 "Legal Proceedings" and Note 13 "Commitments and Contingencies" included in Item 8 "Financial Statements and Supplementary Data" of this Form 10-K for additional discussion of this subject.

We are subject to the political, economic and social instability risks and local laws associated with doing business in certain foreign countries.

We currently have operations in South America, the Middle East and Africa. 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.

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 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 2016, approximately 14 percent of our consolidated operating revenues were generated from the international contract drilling business. During fiscal 2016, approximately 80 percent of the international operating revenues were from operations in South America. All of the South American operating revenues were from Argentina, Colombia and Ecuador. 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.

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.

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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.

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, 2016, our contract drilling backlog was approximately $1.8 billion for future revenues under firm commitments. Our contract drilling backlog may continue to decline as contract term coverage over time may not be offset by new term contracts as a result of the decline in the price of oil 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 securities portfolio may lose significant value due to a decline in equity prices and other market-related risks, thus impacting our debt ratio, financial strength, and possibly financial results.

At September 30, 2016, we had a portfolio of securities with a total fair value of approximately $71.5 million, consisting of Atwood Oceanics, Inc. and Schlumberger, Ltd. The total fair value of the portfolio of securities was $91.5 million at September 30, 2015. These securities are subject to a wide variety of market-related risks that could substantially reduce or increase the fair value of the 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. Our position in Atwood Oceanics, Inc. (an offshore drilling company severely impacted by the downturn in the energy sector) was in an unrealized loss position for under 30 days at September 30, 2015, and then dropped below cost again in December 2015 and continued to be in a loss position through fiscal 2016. During the fourth quarter of fiscal 2016, we determined the loss was other-than-temporary. As a result, we recognized a $26.0 million other-than-temporary impairment charge. At November 17, 2016, the fair value of the portfolio had decreased to approximately $68.8 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.

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, such as the one we are currently experiencing, 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, 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.

Our business and results of operations may be adversely affected by foreign currency restrictions and devaluation.

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 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 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 sharp devaluation, the Argentine peso has significantly stabilized and the Argentine Foreign Exchange Market controls place fewer restrictions on repatriating U.S. dollars. 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.

We may have additional tax liabilities.

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

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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.

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.

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

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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 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.

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.

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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 2016 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, 2016:

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
COLORADO	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
NORTH DAKOTA	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
TEXAS	262	22,000	AC (FlexRig3)	1,500
TEXAS	263	22,000	AC (FlexRig3)	1,500
TEXAS	264	22,000	AC (FlexRig3)	1,500

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Location	Rig	Optimum Depth (Feet)	Rig Type	Drawworks: Horsepower
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
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

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Location	Rig	Optimum Depth (Feet)	Rig Type	Drawworks: Horsepower
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
NORTH DAKOTA	329	18,000	AC (FlexRig4)	1,500
COLORADO	330	18,000	AC (FlexRig4)	1,500
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
PENNSYLVANIA	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
NEW MEXICO	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

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Location	Rig	Optimum Depth (Feet)	Rig Type	Drawworks: Horsepower
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
TEXAS	393	22,000	AC (FlexRig3)	1,500
TEXAS	394	22,000	AC (FlexRig3)	1,500
TEXAS	395	22,000	AC (FlexRig3)	1,500
TEXAS	396	22,000	AC (FlexRig3)	1,500
TEXAS	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
TEXAS	418	22,000	AC (FlexRig3)	1,500
TEXAS	419	22,000	AC (FlexRig3)	1,500
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
NORTH DAKOTA	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
WYOMING	448	22,000	AC (FlexRig3)	1,500

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Location	Rig	Optimum Depth (Feet)	Rig Type	Drawworks: Horsepower
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
TEXAS	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
TEXAS	464	22,000	AC (FlexRig3)	1,500
TEXAS	465	22,000	AC (FlexRig3)	1,500
TEXAS	466	22,000	AC (FlexRig3)	1,500
TEXAS	467	22,000	AC (FlexRig3)	1,500
TEXAS	468	22,000	AC (FlexRig3)	1,500
TEXAS	469	22,000	AC (FlexRig3)	1,500
TEXAS	470	22,000	AC (FlexRig3)	1,500
NORTH DAKOTA	471	22,000	AC (FlexRig3)	1,500
TEXAS	472	22,000	AC (FlexRig3)	1,500
TEXAS	473	22,000	AC (FlexRig3)	1,500
TEXAS	474	22,000	AC (FlexRig3)	1,500
TEXAS	475	22,000	AC (FlexRig3)	1,500
TEXAS	477	22,000	AC (FlexRig3)	1,500
TEXAS	478	22,000	AC (FlexRig3)	1,500
TEXAS	479	22,000	AC (FlexRig3)	1,500
TEXAS	480	22,000	AC (FlexRig3)	1,500
TEXAS	481	22,000	AC (FlexRig3)	1,500
TEXAS	482	22,000	AC (FlexRig3)	1,500
TEXAS	483	22,000	AC (FlexRig3)	1,500
TEXAS	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
TEXAS	493	22,000	AC (FlexRig3)	1,500
TEXAS	494	22,000	AC (FlexRig3)	1,500
TEXAS	495	22,000	AC (FlexRig3)	1,500
TEXAS	496	22,000	AC (FlexRig3)	1,500
TEXAS	497	22,000	AC (FlexRig3)	1,500
TEXAS	498	22,000	AC (FlexRig3)	1,500
TEXAS	499	22,000	AC (FlexRig3)	1,500

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Location	Rig	Optimum Depth (Feet)	Rig Type	Drawworks: Horsepower
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
TEXAS	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
TEXAS	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
TEXAS	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
OKLAHOMA	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
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	547	25,000	AC (FlexRig5)	1,500
TEXAS	551	25,000	AC (FlexRig5)	1,500
TEXAS	552	25,000	AC (FlexRig5)	1,500

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Location	Rig	Optimum Depth (Feet)	Rig Type	Drawworks: Horsepower
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
PENNSYLVANIA	608	22,000	AC (FlexRig3)	1,500
TEXAS	609	22,000	AC (FlexRig3)	1,500
TEXAS	610	22,000	AC (FlexRig3)	1,500
OKLAHOMA	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
TEXAS	620	22,000	AC (FlexRig3)	1,500
TEXAS	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	AC (FlexRig3)	1,500
TEXAS	630	22,000	AC (FlexRig3)	1,500
TEXAS	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
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
TEXAS	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

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Location	Rig	Optimum Depth (Feet)	Rig Type	Drawworks: Horsepower
TEXAS	647	22,000	AC (FlexRig3)	1,500
TEXAS	648	22,000	AC (FlexRig3)	1,500
TEXAS	649	22,000	AC (FlexRig3)	1,500
TEXAS	650	22,000	AC (FlexRig3)	1,500
NEW MEXICO	651	22,000	AC (FlexRig3)	1,500
TEXAS	652	22,000	AC (FlexRig3)	1,500
TEXAS	653	22,000	AC (FlexRig3)	1,500
TEXAS	656	22,000	AC (FlexRig3)	1,500
TEXAS	657	22,000	AC (FlexRig3)	1,500
NEW MEXICO	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				
GULF OF MEXICO	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	202	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

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

	Years ended September 30,				
	2012	2013	2014	2015	2016
U.S. Land Rigs					
Number of rigs at end of period	282	302	329	343	348
Average rig utilization rate during period (1)	89%	82%	86%	62%	30%
U.S. Offshore Platform Rigs					
Number of rigs at end of period	9	9	9	9	9
Average rig utilization rate during period (1)	79%	89%	89%	93%	82%

(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, 2016:

Location	Rig	Optimum Depth (Feet)	Rig Type	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

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

	Years ended September 30,				
	2012	**2013**	**2014**	**2015**	**2016**
Number of rigs at end of period	29	29	36	38	38
Average rig utilization rate during period (1)(2)(3)	78%	82%	74%	51%	39%

(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.

(3) Utilization for years prior to 2016 have been changed due to the change in reporting year-end from August 31 to September 30 effective October 1, 2015

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., 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 Helmerich & Payne International Drilling Co.'s offshore platform rigs in the Gulf of Mexico. We have been 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. We can provide no assurances as to the timing or eventual outcome of these discussions and are unable to determine the amount of penalty, if any, that may be assessed or the effect of any terms that may be required by an administrative agreement with the DOI. However, we presently believe that the outcome of our discussions will not have a material adverse effect on us.

2. *Venezuela Expropriation.*

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. ("PDVSA") and PDVSA Petroleo, S.A. ("Petroleo"). 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.

3. *Environmental Claim*.

On or about August 28, 2015, we received a *Notice of Intent to File a Civil Administrative Complaint* from the United States Environmental Protection Agency indicating that the EPA planned to file an

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Administrative Complaint against us in connection with an incident that occurred in May of 2014 at a customer's location in Ohio, where one of our domestic land rigs was working (the "NOI"). Specifically, the EPA alleges that we violated certain portions of the Clean Water Act and the oil pollution prevention regulations when oil was discharged from the well and migrated into an unnamed tributary. The EPA is proposing a penalty in the amount of $186,868. We have disputed the NOI and are currently awaiting a response from the EPA. In the event that the EPA finds against us and imposes a penalty, we will seek indemnification from our customer.

4.

Keel Litigation.

As previously disclosed, on or about April 28, 2015, Joshua Keel ("Keel"), an employee of Helmerich & Payne International Drilling Co. ("HPIDC"), filed a petition in the 152nd Judicial Court for Harris County, Texas (Cause No. 2015-24531) against us, our customer and several subcontractors of our customer. The suit arose from injuries Keel sustained in an accident that occurred while he was working on HPIDC Rig 223 in New Mexico in July of 2014. Keel alleged that the defendants were negligent and negligent *per se*, acted recklessly, intentionally, and/or with an utterly wanton disregard for the rights and safety of the plaintiff and was seeking damages well in excess of $100 million.

On September 14, 2016, the parties in the *Keel* litigation entered into a global settlement agreement, which was approved by the court on October 14, 2016. The total settlement amount of $72 million will be paid by the Company and its insurers on behalf of all defendants pursuant to industry standard contractual indemnification obligations. After taking into account amounts to be paid by the Company's various insurers, $18.8 million was recorded as an operating cost in our U.S. Land segment. At September 30, 2016, we have recorded in our Consolidated Balance Sheet a $72.0 million accrued liability and a $50.2 million accounts receivable from insurance. The settlement payment is due on or before December 24, 2016.

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, 55	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, 51	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, 54	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
John R. Bell, 46	Vice President, Corporate Services since January 2015; Vice President of Human Resources from March 2012 to January 2015; Director of Human Resources from July 2002 to March 2012
Cara M. Hair, 40	Vice President, General Counsel and Chief Compliance Officer since March 2015; 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 11, 2016, there were 592 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:

	2015		2016	
Quarter	**High**	**Low**	**High**	**Low**
First	$ 98.47	$ 59.24	$ 61.70	$ 46.32
Second	71.55	54.00	64.06	40.02
Third	79.90	67.60	69.20	55.75
Fourth	70.34	46.16	70.28	56.19

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	**2015**	**2016**	**2015**	**2016**
First	$ .6875	$ .6875	$ 74,822,055	$ 74,560,506
Second	.6875	.6875	74,525,525	74,739,803
Third	.6875	.6875	74,478,918	74,740,993
Fourth	.6875	.7000	74,540,202	76,111,240

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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 and the S&P 500 Oil & 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	**Sep11**	**Sep12**	**Sep13**	**Sep14**	**Sep15**	**Sep16**
Helmerich & Payne, Inc.	**100**	117.91	173.15	251.99	126.77	189.28
S&P 500 Index	**100**	130.20	155.39	186.05	184.91	213.44
S&P 500 Oil & Gas Drilling Index	**100**	119.98	132.87	116.68	52.63	57.26

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+

	2016	2015	2014	2013	2012
	(in thousands except per share amounts)				
Operating revenues	$ 1,624,232	$ 3,161,702	$ 3,715,968	$ 3,392,932	$ 3,158,543
Income (loss) from continuing operations	(52,990)	420,474	706,610	720,653	571,305
Income (loss) from discontinued operations	(3,838)	(47)	(47)	15,186	7,436
Net income (loss)	(56,828)	420,427	706,563	735,839	578,741
Basic earnings (loss) per share from continuing operations	(0.50)	3.88	6.52	6.74	5.33
Basic earnings (loss) per share from discontinued operations	(0.04)			0.14	0.07
Basic (loss) earnings per share	(0.54)	3.88	6.52	6.88	5.40
Diluted earnings (loss) per share from continuing operations	(0.50)	3.85	6.44	6.65	5.25
Diluted earnings (loss) per share from discontinued operations	(0.04)			0.14	0.07
Diluted earnings (loss) per share	(0.54)	3.85	6.44	6.79	5.32
Total assets*^	6,832,019	7,147,242	6,725,316	6,265,923	5,724,313
Long-term debt^	491,847	492,443	39,502	79,137	193,737
Cash dividends declared per common share	2.775	2.750	2.625	1.300	0.280

+ Results for 2015 and prior periods have been changed due to the change in reporting year-end for our international subsidiaries from August 31 to September 30 effective October 1, 2015.

* 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.

^ Total assets and Long-term debt for 2014 and prior periods restated to reflect the retrospective adoption of Accounting Standards Update No. 2015-03 "*Interest Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs"* issued by the Financial Accounting Standards Board in April 2015.

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 395 drilling rigs at September 30, 2016. Our contract drilling segments consist of the U.S. Land segment with 348 rigs, the Offshore segment with nine offshore platform rigs and the International Land segment with 38 rigs at September 30, 2016. During fiscal 2016, we placed into service ten new FlexRigs and completed another five new FlexRigs. At the close of fiscal 2016, we had 118 contracted rigs, compared to 168 contracted rigs at the same time during the prior year. During fiscal years 2015 and 2016, the drilling industry experienced significant declines in activity as over 1,400 drilling rigs were idled in the U.S. This decline caused dramatic reductions in personnel and investment in the industry and significantly impacted financial results across oilfield services and other companies. Nevertheless, late in fiscal 2016 we began to see the U.S. land active rig count increase and customers increasing their drilling budgets. Throughout the downturn, our long-term strategy remained focused on innovation, technology, safety and customer satisfaction. We believe that our advanced rig fleet, financial strength, long-term contract backlog, strong customer base, and best-in-class reputation position us very well to effectively manage the Company during these challenging times and take advantage of opportunities that lie ahead.

Prior to October 1, 2015, for financial reporting purposes, fiscal years of our foreign operations ended on August 31 to facilitate reporting of consolidated results, resulting in a one-month reporting lag when compared to the remainder of the Company. Starting October 1, 2015, the reporting year-end of these foreign operations was changed from August 31 to September 30 eliminating the previously existing one-month reporting lag. Accordingly, the results of operations that follow have been changed to reflect the period-specific effects of this change. (See Note 1 of the Consolidated Financial Statements for additional information regarding this change.)

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. Except as specifically discussed, the following results of operations pertain only to our continuing operations. Unless otherwise indicated, references to 2016, 2015 and 2014 in the following discussion are referring to fiscal years 2016, 2015 and 2014.

Results of Operations

All per share amounts included in the Results of Operations discussion are stated on a diluted basis. Our net loss for 2016 was $56.8 million ($0.54 loss per share), compared with net income of $420.4 million ($3.85 per share) for 2015 and $706.6 million ($6.44 per share) for 2014. 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. Our 2014 net income includes after-tax gains from the sale of investment securities of $27.8 million ($0.25 per share). Net loss in 2016 includes after-tax gains from the sale of assets of $6.1 million ($0.06 per share) while net income in 2015 and 2014 include after-tax gains from the sale of assets of $7.4 million ($0.07 per share) and $12.1 million ($0.11 per share), respectively. Net loss in 2016 includes a $3.8 million loss ($0.04 loss per share) from discontinued operations.

Consolidated operating revenues were $1.6 billion in 2016, $3.2 billion in 2015 and $3.7 billion in 2014. As oil prices steeply declined during 2015 and remained low during 2016, customers aggressively reduced drilling budgets. As a result, we experienced a significant decline in rig activity. The number of revenue days in our U.S. Land segment totaled 36,984 in 2016, compared to 75,866 in 2015 and 100,638 in 2014. Our U.S. land rig utilization was 30 percent in 2016, 62 percent in 2015 and 86 percent in 2014. The average number of U.S. land rigs available was 339 rigs in 2016, 336 rigs in 2015 and 319 rigs in 2014. Revenue in the Offshore segment decreased in 2016 from 2015 as several rigs moved to lower pricing while on standby and one less average rig operated in 2016 compared to 2015. Rig utilization for offshore rigs was 82 percent in 2016, compared to 93 percent in 2015 and 89 percent in 2014. The International Land segment has also been affected by the decline in oil prices causing revenue days to decline to 5,364 in 2016 from 7,284 in 2015 and 8,262 in 2014. Rig utilization in our International Land segment was 39 percent in 2016, 51 percent in 2015 and 74 percent in 2014.

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 has been severely impacted by the downturn in the energy sector. In 2014, we had $45.2 million in gains from the sale of investment securities. Interest and dividend income was $3.2 million, $5.8 million and $1.5 million in 2016, 2015 and 2014, respectively. 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 2016 were $898.8 million or 55 percent of operating revenues, compared with $1.7 billion or 54 percent of operating revenues in 2015 and $2.0 billion or 54 percent of operating revenues in 2014.

Depreciation expense was $598.6 million in 2016, $608.0 million in 2015 and $524.0 million in 2014. Included in depreciation are abandonments of equipment of $39.3 million in 2016, $43.6 million in 2015 and $23.0 million in 2014. 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 the abandonments, decreased in 2016 from 2015 by one percent after increasing in both 2015 and 2014 from the previous comparative year due to lower levels of capital expenditures in 2016. Depreciation expense in 2017 is expected to decline from 2016 as capital expenditures are expected to continue to decrease. (See Liquidity and Capital Resources.) 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 and 9 rigs in 2014.

As conditions warrant, management performs an analysis of the industry market conditions impacting its long-lived assets in each drilling segment. The overall down turn in our industry, primarily caused by low oil and gas prices, served as an impairment indicator and an impairment analysis was performed. Based on this analysis, management determines if any impairment is required. In 2016, we recorded 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. The impairment charge is not expected to have an impact on our liquidity or debt covenants. In 2015, we recorded $39.2 million of impairment charges to reduce the carrying values of seven SCR rigs in our International Land segment to their estimated fair value. In 2014, no impairment was recorded. Six of the seven international rigs impaired in 2015 along with other rig related assets were classified as held for sale at September 30, 2016. We plan to sell these assets in their current condition.

General and administrative expenses totaled $146.2 million in 2016, $134.7 million in 2015 and $135.3 million in 2014. 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.

Interest expense net of amounts capitalized totaled $22.9 million in 2016, $15.0 million in 2015 and $4.7 million in 2014. Interest expense is primarily attributable to fixed-rate debt outstanding. Interest expense increased in 2016 from 2015 and in 2015 from 2014 primarily due to the issuance of $500 million unsecured senior notes in March 2015. Capitalized interest was $2.8 million, $7.0 million and $7.7 million in 2016, 2015 and 2014, respectively. All of the capitalized interest is attributable to our rig construction program.

We had an income tax benefit of $19.7 million in 2016 compared to income tax expense of $241.4 million in 2015 and $388.0 million in 2014. The effective income tax rate was 27.1 percent in 2016 compared to 36.5 percent in 2015 and 35.4 percent in 2014. 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 4 of the Consolidated Financial Statements for additional income tax disclosures.)

During 2016, 2015 and 2014, we incurred $10.3 million, $16.1 million and $15.9 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 2017.

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.

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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 Venezuelan government, Petroleos de Venezuela, S.A. and PDVSA Petroleo, S.A. Our subsidiaries seek damages for the taking of their 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. No gain contingencies are recognized in our Consolidated Financial Statements.

The following tables summarize operations by reportable operating segment.

Comparison of the years ended September 30, 2016 and 2015

	2016	2015 (as adjusted)	% 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)

	2016	2015	% Change
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 have continued to have 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).

Direct operating expenses as a percentage of revenue were 49 percent in 2016 and 50 percent 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

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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 average rig expense per day by $508. (See Note 13 of the Consolidated Financial Statements for additional disclosure regarding this lawsuit.)

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. We anticipate depreciation expense to decline in fiscal 2017 as capital expenditures are expected to continue to decrease in fiscal 2017.

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. We have two FlexRigs expected to be delivered to the field in the first quarter of 2017.

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. At November 17, 2016, the number of existing rigs under fixed-term contracts in the segment was 72 and the number of rigs working in the spot market was 33.

Comparison of the years ended September 30, 2016 and 2015

	2016	2015 (as adjusted)	% 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.

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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 (as adjusted)	% 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.

Excluding early termination per day revenue of $2,566 in 2015, the average rig margin per day for 2016 compared to 2015 increased by $468 to $10,406. Low oil prices have 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 values of seven SCR rigs located in our International Land segment to their estimated fair value. Six of these rigs along with other rig related assets were classified as held for sale at September 30, 2016. We plan to sell these assets in their current condition.

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.

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Comparison of the years ended September 30, 2015 and 2014

	2015 (as adjusted)	2014 (as adjusted)	% Change
	(in thousands, except operating statistics)		
U.S. LAND OPERATIONS			
Operating revenues	$ 2,523,518	$ 3,099,954	(18.6)%
Direct operating expenses	1,254,424	1,576,702	(20.4)
General and administrative expense	50,769	41,573	22.1
Depreciation	519,950	455,934	14.0
Segment operating income	$ 698,375	$ 1,025,745	(31.9)
Operating Statistics:			
Revenue days	75,866	100,638	(24.6)%
Average rig revenue per day	$ 30,211	$ 28,194	7.2
Average rig expense per day	$ 13,483	$ 13,058	3.3
Average rig margin per day	$ 16,728	$ 15,136	10.5
Number of rigs at end of period	343	329	4.3
Rig utilization	62%	86%	(27.9)

Operating statistics for per day revenue, expense and margin do not include reimbursements of "out-of-pocket" expenses of $231,528 and $262,532 for 2015 and 2014, respectively.

Rig utilization in 2015 excludes nine FlexRigs completed and ready for delivery at September 30, 2015.

Operating income in the U.S. Land segment decreased to $698.4 million in 2015 from $1.0 billion in 2014 primarily due to a decrease in revenue days and the decommissioning of 23 rigs. Included in U.S. land revenues for 2015 and 2014 is approximately $203.6 million and $11.7 million, respectively, from early termination of fixed-term contracts. Excluding early termination related revenue, the average revenue per day for 2015 decreased by $550 to $27,528 from $28,078 in 2014 which was also a factor in the decrease of operating income during the comparative periods. Direct operating expenses as a percentage of revenue were 50 percent in 2015 and 51 percent in 2014.

Rig utilization decreased to 62 percent in 2015 from 86 percent in 2014. The total number of rigs at September 30, 2015 was 343 compared to 329 rigs at September 30, 2014. The net increase is due to 30 new FlexRigs completed and placed into service, nine new FlexRigs completed and ready for delivery, five FlexRigs transferred to the International Land segment, two FlexRigs transferred from the International Land segment, one conventional rig transferred from the International Land segment and 23 older rigs removed from service.

Depreciation includes charges for abandoned equipment of $42.6 million and $21.5 million in 2015 and 2014, respectively. 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. Included in abandonments in 2014 is the decommissioning of nine conventional rigs and spare equipment for drilling rigs. Excluding the abandonment amounts, depreciation in 2015 increased 10 percent from 2014 due to the increase in available rigs.

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Comparison of the years ended September 30, 2015 and 2014

	2015 (as adjusted)	2014 (as adjusted)	% Change
	(in thousands, except operating statistics)		
OFFSHORE OPERATIONS			
Operating revenues	$ 241,666	$ 251,341	(3.8)%
Direct operating expenses	158,488	159,214	(0.5)
General and administrative expense	3,517	9,858	(64.3)
Depreciation	11,659	12,300	(5.2)
Segment operating income	$ 68,002	$ 69,969	(2.8)
Operating Statistics:			
Revenue days	3,067	2,920	5.0%
Average rig revenue per day	$ 44,125	$ 63,094	(30.1)
Average rig expense per day	$ 27,246	$ 37,653	(27.6)
Average rig margin per day	$ 16,879	$ 25,441	(33.7)
Number of rigs at end of period	9	9	
Rig utilization	93%	89%	4.5

Operating statistics for per day revenue, expense and margin do not include reimbursements of "out-of-pocket" expenses of $33,254 and $18,889 for 2015 and 2014, respectively. The operating statistics only include rigs owned by us and exclude offshore platform management and labor service contracts and currency revaluation expense.

Total revenue and segment operating income in our Offshore segment decreased in 2015 from 2014 primarily due to one rig being idle over half of the year, a contractual decrease in a dayrate for one rig and several other rigs moving to lower pricing while on standby or other standby-type dayrate. At September 30, 2015 and 2014, eight of our nine rigs were contracted.

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Comparison of the years ended September 30, 2015 and 2014

	2015 (as adjusted)	2014 (as adjusted)	% Change
	(in thousands, except operating statistics)		
INTERNATIONAL LAND OPERATIONS			
Operating revenues	$ 382,331	$ 351,263	8.8%
Direct operating expenses	289,700	271,328	6.8
General and administrative expense	3,148	4,423	(28.8)
Depreciation	57,334	40,367	42.0
Asset Impairment charge	39,242		100.0
Segment operating income (loss)	$ (7,093)	$ 35,145	(120.2)

	2015	2014	% Change
Operating Statistics:			
Revenue days	7,284	8,262	(11.8)%
Average rig revenue per day	$ 47,352	$ 37,038	27.8
Average rig expense per day	$ 34,848	$ 27,297	27.7
Average rig margin per day	$ 12,504	$ 9,741	28.4
Number of rigs at end of period	38	36	5.6
Rig utilization	51%	74%	(31.1)

Operating statistics for per day revenue, expense and margin do not include reimbursements of "out-of-pocket" expenses of $37,420 and $45,258 for 2015 and 2014, respectively. Also excluded are the effects of currency revaluation income and expense.

The International Land segment had an operating loss of $7.1 million for 2015 compared to operating income of $35.1 million for 2014. Included in International land revenues in 2015 is approximately $18.7 million related to early termination of fixed-term contracts.

Excluding early termination per day revenue of $2,566 in 2015, the average rig margin per day for 2015 compared to 2014 increased by $197 to $9,938. Rigs transferred into the segment during 2015 and 2014 favorably impacted average rig revenue and revenue per day. The average number of active rigs was 20.0 during 2015 compared to 22.6 during 2014.

The average rig expense per day increase was attributable to expenses incurred on rigs that had become idle and other costs associated with rigs transitioning between locations. The average rig expense in 2015 was also impacted by approximately $690 per day related to a charge for allowance for doubtful accounts.

During 2015, the total number of available rigs increased by two due to five FlexRigs transferred from the U.S. Land segment, two FlexRigs transferred to the U.S. Land segment and one conventional rig transferred to the U.S. Land segment. At the close of 2015 and 2014, we had 15 and 22 rigs working, respectively.

During the fourth fiscal quarter of 2015, we recorded a $39.2 million impairment charge to reduce the carrying values of seven SCR rigs located in our International Land segment to their estimated fair value. The impairment charge did not have an impact on our liquidity or debt covenants.

LIQUIDITY AND CAPITAL RESOURCES

Our capital spending was $257.2 million in 2016, $1.1 billion in 2015 and $951.5 million in 2014. Net cash provided from operating activities was $0.8 billion in 2016, $1.4 billion in 2015 and $1.1 billion in 2014. Our 2017 capital spending is currently estimated to be approximately $200 million, depending primarily on drilling market conditions. This estimate includes capital maintenance requirements, tubulars and other special projects primarily related to further upgrading our existing rig fleet.

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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. In 2015, we invested $45.6 million in short-term investments classified as trading securities. We have reinvested maturities and earnings during 2016 resulting in short-term investments totaling $44.1 million at September 30, 2016. The investments include U.S. Treasury securities, U.S. Agency issued debt securities, corporate bonds, certificate of deposit and money market funds. The securities are recorded at fair value.

We manage a portfolio of marketable securities that, at the close of fiscal 2016, had a fair value of $71.5 million consisting of common shares of Atwood Oceanics, Inc. 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.

During 2016 and 2015, we did not sell any marketable available-for-sale securities. During 2014, we had cash proceeds from the sale of available-for-sale securities of $49.2 million.

Our proceeds from asset sales totaled $21.8 million in 2016, $22.6 million in 2015 and $30.2 million in 2014. Income from asset sales in 2016 totaled $9.9 million, $11.8 million in 2015 and $19.1 million in 2014. In each year we had sales of old or damaged rig equipment and drill pipe used in the ordinary course of business.

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 2015, we purchased 810,097 common shares at an aggregate cost of $59.7 million, which are held as treasury shares. During 2016 we did not repurchase any shares of common stock.

During 2016, we paid dividends of $2.763 per share, or a total of $300.2 million. We paid $2.75 per share or $298.4 million in 2015 and $2.438 per share or $264.4 million in 2014. Adjusting for stock splits accordingly, we have increased the effective annual dividend per share every year for well over 40 years.

We had $40 million of senior unsecured fixed-rate notes outstanding that matured in July 2016. The final annual principal repayment of $40 million along with interest was paid with cash on hand in July 2016.

On March 19, 2015, we issued $500 million of 4.65 percent 10-year unsecured senior notes. The net proceeds, after discount and issuance cost, have been or will be used for general corporate purposes, including capital expenditures associated with our rig construction program, capital maintenance requirements and other projects. 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 yield method.

On July 13, 2016, we terminated our previous $300 million unsecured revolving credit facility with no borrowings, and its $40.3 million of letters of credit were transferred to a new $300 million unsecured revolving credit facility which will mature on July 13, 2021. The new 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, 2016, 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, 2016, there were no borrowings, but there were three letters of credit outstanding in the amount of $38.8 million. At September 30, 2016, we had $261.2 available to borrow under our $300 million unsecured credit facility. Subsequent to September 30, 2016, another letter of credit was issued for $1.5 million lowering the amount available to borrow to $259.7 million.

In addition to the letters of credit mentioned in the preceding paragraph, at September 30, 2016, we had two letters of credit outstanding, totaling $12 million that were issued to support international operations. These additional letters of credit were issued separately from the $300 million credit facility discussed in the preceding paragraph and do not reduce the available borrowing capacity of that facility.

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, 2016, we were in compliance with all debt covenants.

At September 30, 2016, we had 88 existing rigs with fixed term contracts with original term durations ranging from six months to five years, with some expiring in fiscal 2017. 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 2017 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 4.8 at September 30, 2016 and 4.2 at September 30, 2015. The long-term debt to total capitalization ratio was 9.7 percent at September 30, 2016 compared to 9.8 percent at September 30, 2015.

Stock Portfolio Held

September 30, 2016	**Number of Shares**	**Cost Basis**	**Market Value**
	(in thousands, except share amounts)		
Atwood Oceanics, Inc.	4,000,000	$ 34,760	$ 34,760
Schlumberger, Ltd.	467,500	3,713	36,764
Total		$ 38,473	$ 71,524

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Material Commitments

We have no off balance sheet arrangements other than operating leases discussed below. Our contractual obligations as of September 30, 2016, are summarized in the table below in thousands:

		Payments due by year					
Contractual Obligations	**Total**	**2017**	**2018**	**2019**	**2020**	**2021**	**After 2021**
Long-term debt and estimated interest (a)	$ 696,656	$ 23,250	$ 23,250	$ 23,250	$ 23,250	$ 23,250	$ 580,406
Operating leases (b)	36,573	8,550	5,680	5,214	4,401	3,049	9,679
Purchase obligations (b)	44,022	44,022					
Total contractual obligations	$ 777,251	$ 75,822	$ 28,930	$ 28,464	$ 27,651	$ 26,299	$ 590,085

(a) Interest on fixed-rate debt was estimated based on principal maturities. See Note 3 "Debt" to our Consolidated Financial Statements.

(b) See Note 13 "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 2016, we did not make any contributions to the pension plan. Contributions may be made in fiscal 2017 to fund unexpected distributions in lieu of liquidating pension assets. Future contributions beyond fiscal 2017 are difficult to estimate due to multiple variables involved.

At September 30, 2016, we had $16.3 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 4 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.

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Impairment of Long-lived Assets Management assesses the potential impairment of our long-lived assets whenever events or changes in conditions indicate that the carrying value of an asset may not be recoverable. Changes that could prompt such an assessment may include equipment obsolescence, changes in the market demand for a specific asset, 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 indicates that the carrying value of certain of these assets is more than the estimated undiscounted future cash flows, an impairment charge is made to adjust the carrying value to the estimated fair value of the asset. The fair value of drilling rigs is determined based upon an income approach using estimated discounted future cash flows or a market approach, if available. 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 classified as held for sale in our U.S. Land segment to their estimated fair value. The rig and rig related equipment fair value was estimated based on expected sales prices.

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 $3 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 rig 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 lowered to 3.64 percent from 4.27 percent as of September 30, 2016 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 $4.7 million in 2017 from 2016.

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. Stock-based awards granted to non-employee directors are expensed immediately upon grant.

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, 2016, unrecognized compensation cost related to unvested restricted stock was $19.2 million. The cost is expected to be recognized over a weighted-average period of 2.1 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.

NEW ACCOUNTING STANDARDS

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2014-09, *Revenue from Contracts with Customers*, which supersedes virtually all existing revenue recognition guidance. In May 2016, accounting guidance was issued to clarify the not yet effective revenue recognition guidance issued in May 2014. This additional guidance does not change the core principle of the revenue recognition guidance issued by the FASB in May 2014. Rather, it provides clarification of accounting for collections of sales taxes as well as recognition of revenue (i) associated with contract modifications, (ii) for noncash consideration, and (iii) based on the collectability of the consideration from the customer. The ASU provides for full retrospective, modified retrospective, or use of the cumulative effect method during the period of adoption. We have not yet determined which adoption method we will employ. In July 2015, the FASB extended the effective date of this standard to interim and annual periods beginning on or after December 15, 2017. We are currently evaluating the potential effects of the adoption of this update on our financial statements.

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

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is effective for annual reporting periods beginning after December 15, 2016 and interim periods within those annual periods, with early adoption permitted. We do not expect the adoption of this standard to have a material impact on our 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. 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. Early adoption is permitted. We are currently evaluating the potential impact of adopting this guidance 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 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.

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

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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 limited 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. For example, assuming we encounter future foreign exchange restrictions or other difficulties repatriating U.S. dollars in Argentina resulting in a substantial accumulation of Argentine pesos, a hypothetical 10% decrease in the value of our Argentine pesos relative to the U.S. dollar could result in a $1.8 million decrease in the fair value of our monetary assets and liabilities denominated in Argentine pesos.

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 In addition, 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.

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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 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, 2016 has fixed-rate interest obligations, there is no current risk due to interest rate fluctuation.

The following tables provide information as of September 30, 2016 and 2015 about our interest rate risk sensitive instruments:

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

	2017	2018	2019	2020	2021	After 2021	Total	Fair Value 9/30/16
Fixed-Rate Debt	$	$	$	$	$	$ 500,000	$ 500,000	$ 529,550
Average Interest Rate	%	%	%	%	%	4.65%	4.65%	
Variable Rate Debt	$	$	$	$	$	$	$	$
Average Interest Rate								

INTEREST RATE RISK AS OF SEPTEMBER 30, 2015 (dollars in thousands)

	2016	2017	2018	2019	2020	After 2020	Total	Fair Value 9/30/15
Fixed-Rate Debt	$ 40,000	$	$	$	$	$ 500,000	$ 540,000	$ 553,546
Average Interest Rate	6.1%	%	%	%	%	4.65%	4.78%	
Variable Rate Debt	$	$	$	$	$	$	$	$
Average Interest Rate								

Equity Price Risk On September 30, 2016, we had a portfolio of securities with a total fair value of $71.5 million. The total fair value of the portfolio of securities was $91.5 million at September 30, 2015. A hypothetical 10% decrease in the market prices for all securities in our portfolio as of September 30, 2016 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. At November 17, 2016, the total fair value of the remaining securities had decreased to approximately $68.8 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.

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

Index to Consolidated Financial Statements

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Report of Independent Registered Public Accounting Firm
HELMERICH & PAYNE, INC.

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, 2016 and 2015, 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, 2016. 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, 2016 and 2015, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2016, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, the Company has elected to change its method of accounting to eliminate the one-month lag previously used to consolidate its foreign operations in 2016.

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, 2016, 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 23, 2016 expressed an unqualified opinion thereon.

/s/Ernst & Young LLP

Tulsa, Oklahoma
November 23, 2016

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Consolidated Statements of Operations

HELMERICH & PAYNE, INC.

	Years Ended September 30, 2016	2015 (as adjusted)	2014 (as adjusted)
	(in thousands, except per share amounts)		
Operating revenues			
Drilling U.S. Land	$ 1,242,462	$ 2,523,518	$ 3,099,954
Drilling Offshore	138,601	241,666	251,341
Drilling International Land	229,894	382,331	351,263
Other	13,275	14,187	13,410
	1,624,232	3,161,702	3,715,968
Operating costs and expenses			
Operating costs, excluding depreciation	898,805	1,703,476	2,006,715
Depreciation	598,587	608,039	523,984
Asset impairment charge	6,250	39,242	
Research and development	10,269	16,104	15,905
General and administrative	146,183	134,712	135,273
Income from asset sales	(9,896)	(11,834)	(19,083)
	1,650,198	2,489,739	2,662,794
Operating income (loss) from continuing operations	**(25,966)**	**671,963**	**1,053,174**
Other income (expense)			
Interest and dividend income	3,166	5,840	1,543
Interest expense	(22,913)	(15,023)	(4,657)
Gain (loss) on investment securities	(25,989)		45,234
Other	(965)	(901)	(636)
	(46,701)	(10,084)	41,484
Income (loss) from continuing operations before income taxes	(72,667)	661,879	1,094,658
Income tax provision (benefit)	(19,677)	241,405	388,048
Income (loss) from continuing operations	(52,990)	420,474	706,610
Income (loss) from discontinued operations before income taxes	2,360	(124)	2,758
Income tax provision (benefit)	6,198	(77)	2,805
Loss from discontinued operations	(3,838)	(47)	(47)
NET INCOME (LOSS)	**$ (56,828)**	**$ 420,427**	**$ 706,563**
Basic earnings per common share:			
Income (loss) from continuing operations	$ (0.50)	$ 3.88	$ 6.52
Loss from discontinued operations	$ (0.04)	$	$

Net income (loss)	$	(0.54)	$	3.88	$	6.52
Diluted earnings per common share:						
Income (loss) from continuing operations	$	(0.50)	$	3.85	$	6.44
Loss from discontinued operations	$	(0.04)	$		$	
Net income (loss)	$	(0.54)	$	3.85	$	6.44
Weighted average shares outstanding (in thousands):						
Basic		107,996		107,754		107,800
Diluted		107,996		108,570		109,141

The accompanying notes are an integral part of these statements.

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Consolidated Statements of Comprehensive Income (Loss)

HELMERICH & PAYNE, INC.

	Years Ended September 30,		
	2016	2015 (as adjusted)	2014 (as adjusted)
		(in thousands)	
Net income (loss)	$ (56,828)	$ 420,427	$ 706,563
Other comprehensive income, net of income taxes:			
Unrealized appreciation (depreciation) on securities, net of income taxes of $1.7 million at September 30, 2016, ($50.6) million at September 30, 2015 and ($15.5) million at September 30, 2014	2,772	(80,217)	(19,006)
Reclassification of realized (gains) losses in net income, net of income taxes of $0.6 million at September 30, 2016 and ($17.5) million at September 30, 2014	926		(27,737)
Minimum pension liability adjustments, net of income taxes of $1.4 million at September 30, 2016, ($2.5) million at September 30, 2015 and ($1.5) million at September 30, 2014	(2,525)	(4,286)	(2,661)
Other comprehensive income (loss)	1,173	(84,503)	(49,404)
Comprehensive income (loss)	$ (55,655)	$ 335,924	$ 657,159

The accompanying notes are an integral part of these statements.

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Consolidated Balance Sheets

HELMERICH & PAYNE, INC.

	September 30, 2016	September 30, 2015 (as adjusted)
	(in thousands)	
Assets		
CURRENT ASSETS:		
Cash and cash equivalents	$ 905,561	$ 729,384
Short-term investments	44,148	45,543
Accounts receivable, less reserve of $2,696 in 2016 and $6,181 in 2015	375,169	445,948
Inventories	124,325	128,541
Deferred income taxes		17,206
Prepaid expenses and other	78,067	64,475
Assets held for sale	45,352	
Current assets of discontinued operations	64	8,097
Total current assets	1,572,686	1,439,194
INVESTMENTS	84,955	104,354
PROPERTY, PLANT AND EQUIPMENT, at cost:		
Contract drilling equipment	7,881,544	7,985,362
Construction in progress	98,313	95,518
Real estate properties	62,929	65,466
Other	444,843	457,802
	8,487,629	8,604,148
Less-Accumulated depreciation	3,342,896	3,040,978
Net property, plant and equipment	5,144,733	5,563,170
NONCURRENT ASSETS:		
Other assets	29,645	40,524
TOTAL ASSETS	$ 6,832,019	$ 7,147,242

The accompanying notes are an integral part of these statements.

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Consolidated Balance Sheets (Continued)

HELMERICH & PAYNE, INC.

	September 30, 2016	2015 (as adjusted)
	(in thousands, except share data and per share amounts)	
Liabilities and Shareholders' Equity		
CURRENT LIABILITIES:		
Long-term debt due within one year	$	$ 39,094
Accounts payable	95,422	108,169
Accrued liabilities	234,639	197,557
Current liabilities of discontinued operations	59	3,377
Total current liabilities	330,120	348,197
NONCURRENT LIABILITIES:		
Long-term debt	491,847	492,443
Deferred income taxes	1,342,456	1,295,916
Other	102,781	110,120
Noncurrent liabilities of discontinued operations	3,890	4,720
Total noncurrent liabilities	1,940,974	1,903,199
SHAREHOLDERS' EQUITY:		
Common stock, $.10 par value, 160,000,000 shares authorized, 111,400,339 and 110,987,546 shares issued as of September 30, 2016 and 2015, respectively, and 108,077,916 and 107,767,915 shares outstanding as of September 30, 2016 and 2015, respectively	11,140	11,099
Preferred stock, no par value, 1,000,000 shares authorized, no shares issued		
Additional paid-in capital	448,452	420,141
Retained earnings	4,289,807	4,648,346
Accumulated other comprehensive loss	(204)	(1,377)
	4,749,195	5,078,209
Less treasury stock, 3,322,423 shares in 2016 and 3,219,631 shares in 2015, at cost	(188,270)	(182,363)
Total shareholders' equity	4,560,925	4,895,846
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 6,832,019	$ 7,147,242

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 Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock		Total
	Shares	Amount				Shares	Amount	
	(in thousands, except per share amounts)							
Balance, September 30, 2013, as adjusted	108,739	$ 10,874	$ 288,758	$ 4,105,011	$ 132,530	2,022	$ (91,098)	$ 4,446,075
Comprehensive Income:								
Net income				706,563				706,563
Other comprehensive loss					(49,404)			(49,404)
Dividends declared ($2.625 per share)				(285,585)				(285,585)
Exercise of stock options	1,613	161	41,911			216	(18,822)	23,250
Tax benefit of stock-based awards			26,616					26,616
Stock issued for vested restricted stock, net of shares withheld for employee taxes	157	16	(16)			38	(3,049)	(3,049)
Stock-based compensation			26,703					26,703
Balance, September 30, 2014, as adjusted	110,509	11,051	383,972	4,525,989	83,126	2,276	(112,969)	4,891,169
Comprehensive Income:								
Net income				420,427				420,427
Other comprehensive loss					(84,503)			(84,503)
Dividends declared ($2.75 per share)				(298,070)				(298,070)
Exercise of stock options	255	26	7,223			64	(4,599)	2,650
Tax benefit of stock-based awards			3,772					3,772
Stock issued for vested restricted stock, net of shares withheld for employee taxes	223	22	(21)			70	(5,141)	(5,140)
Repurchase of common stock						810	(59,654)	(59,654)
Stock-based compensation			25,195					25,195
Balance, September 30, 2015, as adjusted	110,987	11,099	420,141	4,648,346	(1,377)	3,220	(182,363)	4,895,846
Comprehensive Income:								
Net loss				(56,828)				(56,828)
Other comprehensive income					1,173			1,173
Dividends declared ($2.775 per share)				(301,711)				(301,711)
Exercise of stock options	220	22	6,937			99	(5,919)	1,040
Tax benefit of stock-based awards			934					934
Stock issued for vested restricted stock, net of shares withheld for employee taxes	193	19	(3,943)			3	12	(3,912)
Stock-based compensation			24,383					24,383
Balance, September 30, 2016	111,400	$ 11,140	$ 448,452	$ 4,289,807	$ (204)	3,322	$ (188,270)	$ 4,560,925

The accompanying notes are an integral part of these statements.

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Consolidated Statements of Cash Flows

HELMERICH & PAYNE, INC.

	Years Ended September 30, 2016	2015 (as adjusted)	2014 (as adjusted)
	(in thousands)		
OPERATING ACTIVITIES:			
Net income (loss)	$ (56,828)	$ 420,427	$ 706,563
Adjustment for loss from discontinued operations	3,838	47	47
Income (loss) from continuing operations	(52,990)	420,474	706,610
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation	598,587	608,039	523,984
Asset impairment charge	6,250	39,242	
Amortization of debt issuance costs	1,168	749	400
Provision for (recovery of) bad debt	(2,013)	6,034	(200)
Stock-based compensation	24,383	25,195	26,703
Pension settlement charge	4,964	2,873	1,376
(Gain) loss on investment securities	25,989		(45,234)
Income from asset sales	(9,896)	(11,834)	(19,083)
Deferred income tax expense	60,088	131,431	26,132
Other	151	(368)	1
Change in assets and liabilities:			
Accounts receivable	72,792	259,024	(70,458)
Inventories	1,944	(23,052)	(16,623)
Prepaid expenses and other	(2,460)	(4,457)	(12,862)
Accounts payable	(10,907)	(38,983)	(16,104)
Accrued liabilities	49,562	(24,756)	35,378
Deferred income taxes	2,769	688	(749)
Other noncurrent liabilities	(16,831)	38,322	(10,142)
Net cash provided by operating activities from continuing operations	753,550	1,428,621	1,129,129
Net cash provided by (used in) operating activities from discontinued operations	47	(47)	(47)
Net cash provided by operating activities	753,597	1,428,574	1,129,082
INVESTING ACTIVITIES:			
Capital expenditures	(257,169)	(1,131,445)	(951,536)
Purchase of short-term investments	(57,276)	(45,607)	
Proceeds from sale of short-term investments	58,381		
Proceeds from asset sales	21,845	22,643	30,176
Proceeds from sale of investments			49,205
Net cash used in investing activities	(234,219)	(1,154,409)	(872,155)
FINANCING ACTIVITIES:			
Payments on long-term debt	(40,000)	(40,000)	(115,000)
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	(300,152)	(298,367)	(264,386)
Exercise of stock options, net of tax withholding	1,040	2,650	23,250
Tax withholdings related to net share settlements of restricted stock	(3,912)	(5,140)	(3,049)
Excess tax benefit from stock-based compensation	934	3,772	26,616
Net cash provided by (used in) financing activities	(343,201)	94,912	(332,569)

Net increase (decrease) in cash and cash equivalents	176,177	369,077	(75,642)
Cash and cash equivalents, beginning of period	729,384	360,307	435,949
Cash and cash equivalents, end of period	$ 905,561	$ 729,384	$ 360,307

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. Prior to October 1, 2015, for financial reporting purposes, fiscal years of our foreign operations ended on August 31 to facilitate reporting of consolidated results, resulting in a one-month reporting lag when compared to the remainder of the Company.

Starting October 1, 2015, the reporting year-end of these foreign operations was changed from August 31 to September 30. The previously existing one-month reporting lag was eliminated as it is no longer required to achieve a timely consolidation due to our investments in technology, ERP systems and personnel to enhance our financial statement close process. We believe this change is preferable because the financial information of all operating segments is now reported based on the same period-end, which improves overall financial reporting to investors by providing the most current information available. In accordance with Accounting Standards Codification ("ASC") 810-10-50-2, "*A Change in the Difference Between Parent and Subsidiary Fiscal Year-Ends*," the elimination of this previously existing reporting lag is considered a voluntary change in accounting principle in accordance with ASC 250-10-50 "*Change in Accounting Principle*." Voluntary changes in accounting principles are to be reported through retrospective application of the new principle to all prior financial statement periods presented. Accordingly, our financial statements for periods prior to fiscal 2016 have been changed to reflect the period-specific effects of applying this accounting principle. This change resulted in a cumulative effect of an accounting change of $2.3 million, net of income tax effect, to retained earnings as of October 1, 2013. Net loss from continuing operations for fiscal 2016 would have been approximately $1.4 million higher absent the accounting change.

The impact of this change in accounting principle to eliminate the one-month lag for foreign subsidiaries is summarized below for significant items. Other accounts were minimally impacted.

	As Reported	Adjustments	After Voluntary Change in Accounting Principle
	Year Ended September 30, 2015 (in thousands)		
Operating revenues	$ 3,165,441	$ (3,739)	$ 3,161,702
Operating costs, excluding depreciation	1,704,163	(687)	1,703,476
Net income	422,225	(1,798)	420,427
Diluted earnings per common share	3.87	(0.02)	3.85

	Year Ended September 30, 2014 (in thousands)		
Operating revenues	$ 3,719,707	$ (3,739)	$ 3,715,968
Operating costs, excluding depreciation	2,009,912	(3,197)	2,006,715
Net income	708,719	(2,156)	706,563
Diluted earnings per common share	6.46	(0.02)	6.44

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

	September 30, 2015		
	(in thousands)		
Total assets	$ 7,152,012	$ (4,770)	$ 7,147,242
Total liabilities	2,254,560	(3,164)	2,251,396
Total shareholders' equity	4,897,452	(1,606)	4,895,846

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 2. 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. Foreign currency gains and losses from remeasurement of foreign currency financial statements and foreign currency translations into U.S. dollars are included in direct operating costs. Included in direct operating costs is an aggregate foreign currency loss of $9.3 million in fiscal 2016, a transaction gain of $1.6 million in fiscal 2015 and a transaction loss of $0.4 million in fiscal 2014.

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 November 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2015-17, *Income Taxes (Topic 740), Balance Sheet Classification of Deferred Taxes* requiring all deferred tax assets and liabilities be classified as noncurrent on the balance sheet instead of separating deferred taxes into current and noncurrent amounts. The guidance is effective for financial statements issued for annual periods beginning after December 15, 2016, however, we elected to early adopt effective October 1, 2015 prospectively. As a result of the adoption, we will no longer have deferred income taxes as a current asset in our Consolidated Balance Sheet. Prior year balances were not retrospectively adjusted.

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 primarily 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

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

for funding payroll and accounts payable. As a result of our cash management system, checks issued, but not presented to the banks for payment, may create negative book cash balances.

RESTRICTED CASH AND CASH EQUIVALENTS

We had restricted cash and cash equivalents of $29.6 million and $32.0 million at September 30, 2016 and 2015, respectively. The cash is restricted for the purpose of potential insurance claims in our wholly-owned captive insurance company. Of the total at September 30, 2016, $2.0 million is from the initial capitalization of the captive company and management has elected to restrict an additional $27.6 million. 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,	
	2016	2015
	(in thousands)	
Prepaid expenses and other	$ 27,631	$ 29,998
Other assets	$ 2,000	$ 2,000

INVENTORIES AND SUPPLIES

Inventories and supplies are primarily replacement parts and supplies held for use in our drilling operations. Inventories and supplies 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 $39.3 million, $43.6 million and $23.0 million for fiscal 2016, 2015 and 2014, respectively. During fiscal 2016, we abandoned used drilling equipment removed from service. During 2015 and 2014, we decommissioned 23 idle rigs and 9 rigs, respectively. 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 at any subsequent material modification and, depending on the lease terms, are classified as either capital

Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

leases or operating leases as appropriate under ASC 840, *Leases*. We do not have significant capital leases.

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 2016, 2015 and 2014 was $2.8 million, $7.0 million and $7.7 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 to adjust the carrying value down to the estimated fair value of the asset. The fair value of drilling rigs is determined based upon an income approach using estimated discounted future cash flows or a market approach, if available. 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. This decline in pricing resulted in lower demand for our drilling services. As a result, we performed an impairment evaluation of all our long-lived drilling assets in accordance with ASC 360, *Property, Plant, and Equipment*. In order to estimate our future undiscounted cash flows from the use and eventual disposal, we developed probability weighted cash flow projections for our rig fleets. 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 in rig and rig related equipment classified as held for sale to their estimated fair values, based on expected sales prices. 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. During fiscal 2016, we began actively marketing the equipment. We believe the equipment will be disposed of in under a year. No additional impairments were identified for any other rigs or rig related equipment in our domestic, international or offshore fleets.

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

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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 have been classified as held for sale at September 30, 2016. We plan to sell these assets in their current condition and it is probable the sale will occur within one year.

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 2016, 2015 and 2014 were $125.9 million, $302.2 million and $326.7 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 from early terminated contracts are recognized when all contractual requirements have been met. Early termination revenue for fiscal 2016, 2015 and 2014 was approximately $219.0 million, $222.3 million and $11.7 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:

	Years Ended September 30,		
	2016	2015	2014
	(in thousands)		
Minimum rents	$ 9,196	$ 9,608	$ 9,400
Overage and percentage rents	$ 1,211	$ 1,030	$ 1,090

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

At September 30, 2016, minimum future rental income to be received on noncancelable operating leases was as follows:

Fiscal Year	**Amount (in thousands)**
2016	$ 7,763
2017	6,076
2018	4,594
2019	4,007
2020	2,379
Thereafter	4,642
Total	$ 29,461

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

At September 30, 2016 and 2015, the cost and accumulated depreciation for real estate properties were as follows:

	September 30,	
	2016	**2015**
	(in thousands)	
Real estate properties	$ 62,929	$ 65,466
Accumulated depreciation	(40,777)	(43,326)
	$ 22,152	$ 22,140

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 4. 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.

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.

Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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 certain 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

In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers*, which supersedes virtually all existing revenue recognition guidance. In May 2016, accounting guidance was issued to clarify the not yet effective revenue recognition guidance issued in May 2014. This additional guidance does not change the core principle of the revenue recognition guidance issued by the FASB in May 2014. Rather, it provides clarification of accounting for collections of sales taxes as well as recognition of revenue (i) associated with contract modifications, (ii) for noncash consideration, and (iii) based on the collectability of the consideration from the customer. The ASU provides for full retrospective, modified retrospective, or use of the cumulative effect method during the period of adoption. We have not yet determined which adoption method we will employ. In July 2015, the FASB extended the effective date of this standard to interim and annual periods beginning on or after December 15, 2017. We are currently evaluating the potential effects of the adoption of this update on our consolidated financial statements.

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

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

those annual periods, with early adoption permitted. We 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. 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. Early adoption is permitted. We are currently evaluating the potential impact of adopting this guidance 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 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.

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 2 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 3 DEBT

At September 30, 2016 and 2015, 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, 2016	September 30, 2015	September 30, 2016	September 30, 2015
	(in thousands)			
Unsecured senior notes issued July 21, 2009:				
Due July 21, 2016	$	$ 40,000	$	$ (498)
Unsecured senior notes issued March 19, 2015:				
Due March 19, 2025	500,000	500,000	(8,153)	(7,965)
	500,000	540,000	(8,153)	(8,463)
Less long-term debt due within one year		40,000		(906)
Long-term debt	$ 500,000	$ 500,000	$ (8,153)	$ (7,557)

We had $40 million of senior unsecured fixed-rate notes outstanding that matured in July 2016. The final annual principal repayment of $40 million along with interest was paid with cash on hand in July 2016.

On March 19, 2015, we issued $500 million of 4.65 percent 10-year unsecured senior notes. The net proceeds, after discount and issuance cost, have been or will be used for general corporate purposes, including capital expenditures associated with our rig construction program. 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.

On July 13, 2016, we terminated our previous $300 million unsecured revolving credit facility with no borrowings, and its $40.3 million of letters of credit were transferred to a new $300 million unsecured revolving credit facility which will mature on July 13, 2021. The new 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

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 3 DEBT (Continued)

.15 percent to .30 percent per annum. Based on our debt to total capitalization on September 30, 2016, 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, 2016, there were no borrowings, but there were three letters of credit outstanding in the amount of $38.8 million. At September 30, 2016, we had $261.2 available to borrow under our $300 million unsecured credit facility. Subsequent to September 30, 2016, another letter of credit was issued for $1.5 million lowering the amount available to borrow to $259.7 million.

In addition to the letters of credit mentioned in the preceding paragraph, at September 30, 2016, we had two letters of credit outstanding, totaling $12 million that were issued to support international operations. These additional letters of credit were issued separately from the $300 million credit facility discussed in the preceding paragraph and do not reduce the available borrowing capacity of that facility.

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, 2016, we were in compliance with all debt covenants.

At September 30, 2016, aggregate maturities of long-term debt are as follows (in thousands):

Years ending September 30,		
2017	$	
2018		
2019		
2020		
2021		
Thereafter	$	500,000
	$	500,000

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 4 INCOME TAXES

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

	Years Ended September 30, 2016	2015 (as adjusted)	2014 (as adjusted)
		(in thousands)	
Current:			
Federal	$ (86,010)	$ 84,229	$ 323,386
Foreign	9,987	14,864	17,333
State	(3,742)	10,881	21,197
	(79,765)	109,974	361,916
Deferred:			
Federal	58,136	165,491	28,183
Foreign	408	(34,410)	(4,257)
State	1,544	350	2,206
	60,088	131,431	26,132
Total provision	$ (19,677)	$ 241,405	$ 388,048

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

	Years Ended September 30, 2016	2015 (as adjusted)	2014 (as adjusted)
		(in thousands)	
Domestic	$ (49,636)	$ 675,425	$ 1,061,019
Foreign	(23,031)	(13,546)	33,639
	$ (72,667)	$ 661,879	$ 1,094,658

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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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 4 INCOME TAXES (Continued)

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

	September 30, 2016	September 30, 2015
	(in thousands)	
Deferred tax liabilities:		
Property, plant and equipment	$ 1,411,139	$ 1,335,680
Available-for-sale securities	25,470	33,187
Other	2,326	3,929
Total deferred tax liabilities	1,438,935	1,372,796
Deferred tax assets:		
Pension reserves	8,330	3,405
Self-insurance reserves	15,282	14,317
Net operating loss and foreign tax credit carryforwards	71,778	56,494
Financial accruals	67,594	63,558
Other	4,952	12,283
Total deferred tax assets	167,936	150,057
Valuation allowance	(71,457)	(55,971)
Net deferred tax assets	96,479	94,086
Net deferred tax liabilities	$ 1,342,456	$ 1,278,710

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

As of September 30, 2016, we had state and foreign net operating loss carryforwards for income tax purposes of $11.6 million and $94.0 million, respectively, and foreign tax credit carryforwards of approximately $50.3 million (of which $39.3 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 2017 through 2024. The valuation allowance is primarily attributable to state and foreign net operating loss carryforwards of $1.0 million and $31.1 million, respectively, and foreign tax credit carryforwards of $39.3 million which more likely than not will not be utilized.

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

	Years Ended September 30, 2016	2015	2014
U.S. Federal income tax rate	35.0%	35.0%	35.0%
Effect of foreign taxes	(13.8)	(3.2)	1.3
State income taxes, net of federal tax benefit	3.2	0.8	1.4
U.S. domestic production activities	(10.4)	(1.2)	(2.6)
Other impact of foreign operations	14.7	4.5	0.6
Other	(1.6)	0.6	(0.2)

Effective income tax rate	27.1%	36.5%	35.5%

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 4 INCOME TAXES (Continued)

Effective tax rates differ from the U.S. federal statutory rate of 35.0 percent primarily due to state and foreign income taxes and the tax benefit from the Internal Revenue Code Section 199 deduction for domestic production activities. The effective tax rate for the twelve months ended September 30, 2016 was significantly impacted by reduced earnings before taxes, in conjunction with a December 2015 tax law change which resulted in a reduction of the fiscal 2015 Internal Revenue Code Section 199 deduction for domestic production activities.

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, 2016 and 2015, we had accrued interest and penalties of $6.8 million and $11.1 million, respectively.

A reconciliation of the change in our gross unrecognized tax benefits for the fiscal years ended September 30, 2016 and 2015 is as follows:

	September 30,	
	2016	2015
	(in thousands)	
Unrecognized tax benefits at October 1,	$ 11,211	$ 10,747
Gross decreases tax positions in prior periods		(706)
Gross increases tax positions in prior periods		3,278
Gross decreases current period effect of tax positions	(1,173)	(821)
Gross increases current period effect of tax positions	969	
Expiration of statute of limitations for assessments	(679)	(956)
Settlements	(777)	(331)
Unrecognized tax benefits at September 30,	$ 9,551	$ 11,211

As of September 30, 2016 and September 30, 2015, our liability for unrecognized tax benefits includes $3.8 million and $2.9 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 2012 through 2015, with exception of certain state jurisdictions currently under audit. Audits in foreign jurisdictions are generally complete through fiscal 2003.

On September 13, 2013, the IRS issued final regulations providing guidance on the treatment of amounts paid to acquire, produce or improve tangible property and proposed regulations providing guidance on the dispositions of such property. The implementation date for these regulations is tax years beginning on or after January 1, 2014. The estimated effect of the regulations have been included in the fiscal year end 2015 and 2016 tax provision. The implementation of the regulations did not have a significant impact on the overall tax provision.

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 5 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 2016 and 2014.

ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

	September 30,		
	2016	**2015**	**2014**
		(in thousands)	
Pre-tax amounts:			
Unrealized appreciation on securities	$ 33,051	$ 27,021	$ 157,838
Unrealized actuarial loss	(34,112)	(30,144)	(23,405)
	$ (1,061)	$ (3,123)	$ 134,433
After-tax amounts:			
Unrealized appreciation on securities	$ 20,899	$ 17,201	$ 97,418
Unrealized actuarial loss	(21,103)	(18,578)	(14,292)
	$ (204)	$ (1,377)	$ 83,126

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, 2016:

	Unrealized Appreciation (Depreciation) on Available-for-sale Securities	**Defined Benefit Pension Plan**	**Total**
		(in thousands)	
Balance September 30, 2015	$ 17,201	$ (18,578)	$ (1,377)
Other comprehensive income before reclassifications	2,772		2,772
Amounts reclassified from accumulated other comprehensive income (loss)	926	(2,525)	(1,599)
Net current-period other comprehensive Income (loss)	3,698	(2,525)	1,173
Balance September 30, 2016	$ 20,899	$ (21,103)	$ (204)

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 5 SHAREHOLDERS' EQUITY (Continued)

The following provides detail about accumulated other comprehensive income (loss) components which were reclassified to the Consolidated Statement of Operations during the years ended September 30, 2016 and 2015:

Details about Accumulated Other Comprehensive Income (Loss) Components	Amount Reclassified from Accumulated Other Comprehensive Income (Loss) 2016	2015	Affected line item in the Consolidated Statement of Operations
	(in thousands)		
Other-than-temporary impairment of available-for-sale securities	$ 1,509	$	Gain (loss) on investment securities
	(583)		Income tax provision
	$ 926	$	Net of tax
Defined Benefit Pension Items	$ (3,968)	$ (6,738)	General and administrative
Amortization of net actuarial loss	1,443	2,452	Income tax provision
	$ (2,525)	$ (4,286)	Net of tax
Total reclassifications for the period	$ (1,599)	$ (4,286)	

NOTE 6 STOCK-BASED COMPENSATION

On March 2, 2016, the Helmerich & Payne, Inc. 2016 Omnibus Incentive Plan (the "2016 Plan") was approved by our stockholders. The 2016 Plan, among other things, authorizes the Human Resources Committee of the Board to grant non-qualified stock options and restricted stock awards to selected employees and to non-employee Directors. Restricted stock may be granted for no consideration other than prior and future services. The purchase price per share for stock options may not be less than market price of the underlying stock on the date of grant. Stock options expire 10 years after the grant date. Awards outstanding in the Helmerich & Payne, Inc. 2005 Long-Term Incentive Plan (the "2005 Plan") and the Helmerich & Payne, Inc. 2010 Long-Term Incentive Plan (the "2010 Plan") remain subject to the terms and conditions of those plans. As of November 30, 2015, there were 876,379 non-qualified stock options and 294,575 shares of restricted stock awards granted under the 2010 Plan during fiscal 2016. Effective March 2, 2016, no further common-stock based awards will be made under the 2010 Plan.

A summary of compensation cost for stock-based payment arrangements recognized in general and administrative expense in fiscal 2016, 2015 and 2014 is as follows:

	September 30, 2016	2015	2014
	(in thousands)		
Compensation expense			
Stock options	$ 8,290	$ 8,846	$ 11,268
Restricted stock	16,093	16,349	15,435
	$ 24,383	$ 25,195	$ 26,703

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 6 STOCK-BASED COMPENSATION (Continued)

Benefits of tax deductions in excess of recognized compensation cost of $0.9 million, $3.8 million and $26.6 million are reported as a financing cash flow in the Consolidated Statements of Cash Flows for fiscal 2016, 2015 and 2014, respectively.

STOCK OPTIONS

Vesting requirements for stock options are determined by the Human Resources Committee of our Board of Directors. Options currently outstanding began vesting one year after the grant date with 25 percent of the options vesting for four consecutive years.

We use the Black-Scholes formula to estimate the fair value of stock options granted to employees. The fair value of the options is amortized to compensation expense on a straight-line basis over the requisite service periods of the stock awards, which are generally the vesting periods. The weighted-average fair value calculations for options granted within the fiscal period are based on the following weighted-average assumptions set forth in the table below. Options that were granted in prior periods are based on assumptions prevailing at the date of grant.

	2016	**2015**	**2014**
Risk-free interest rate	1.8%	1.7%	1.6%
Expected stock volatility	37.6%	36.9%	52.6%
Dividend yield	4.6%	3.9%	3.1%
Expected term (in years)	5.5	5.5	5.5

Risk-Free Interest Rate. The risk-free interest rate is based on U.S. Treasury securities for the expected term of the option.

Expected Volatility Rate. Expected volatilities are based on the daily closing price of our stock based upon historical experience over a period which approximates the expected term of the option.

Expected Dividend Yield. The dividend yield is based on our current dividend yield.

Expected Term. The expected term of the options granted represents the period of time that they are expected to be outstanding. We estimate the expected term of options granted based on historical experience with grants and exercises.

Based on these calculations, the weighted-average fair value per option granted to acquire a share of common stock was $13.12, $16.39 and $29.44 per share for fiscal 2016, 2015 and 2014, respectively.

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 6 STOCK-BASED COMPENSATION (Continued)

The following summary reflects the stock option activity for our common stock and related information for fiscal 2016, 2015 and 2014 (shares in thousands):

	2016		2015		2014	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at October 1,	2,776	$ 48.51	2,629	$ 43.46	3,991	$ 34.12
Granted	876	58.25	420	68.83	261	79.67
Exercised	(220)	31.52	(255)	28.46	(1,613)	26.08
Forfeited/Expired	(120)	61.80	(18)	66.78	(10)	68.82
Outstanding on September 30,	3,312	$ 51.74	2,776	$ 48.51	2,629	$ 43.46
Exercisable on September 30,	2,225	$ 46.66	2,014	$ 41.62	1,884	$ 35.93
Shares available to grant	6,600		2,515		3,432	

The following table summarizes information about stock options at September 30, 2016 (shares in thousands):

	Outstanding Stock Options			Exercisable Stock Options	
Range of Exercise Prices	Options	Weighted-Average Remaining Life	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
$21.065 to $38.015	1,000	1.9	$ 30.36	1,000	$ 30.36
$47.29 to $59.76	1,679	7.1	$ 56.50	925	$ 55.41
$68.83 to $79.67	633	7.8	$ 72.89	300	$ 73.94
$21.065 to $79.67	3,312	5.7	$ 51.74	2,225	$ 46.66

At September 30, 2016, the weighted-average remaining life of exercisable stock options was 4.3 years and the aggregate intrinsic value was $47.9 million with a weighted-average exercise price of $46.66 per share.

The number of options vested or expected to vest at September 30, 2016 was 3,284,246 with an aggregate intrinsic value of $54.8 million and a weighted-average exercise price of $51.69 per share.

As of September 30, 2016, the unrecognized compensation cost related to the stock options was $6.6 million. That cost is expected to be recognized over a weighted-average period of 2.7 years.

The total intrinsic value of options exercised during fiscal 2016, 2015 and 2014 was $6.3 million, $10.7 million and $100.9 million, respectively.

The grant date fair value of shares vested during fiscal 2016, 2015 and 2014 was $9.6 million, $8.1 million and $8.8 million, respectively.

RESTRICTED STOCK

Restricted stock awards consist of our common stock and are time-vested over three to six years. We recognize compensation expense on a straight-line basis over the vesting period. The fair value of restricted stock awards under the 2010 Plan is determined based on the closing price of our shares on the grant date. As of September 30, 2016, there was $19.2 million of total unrecognized compensation

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 6 STOCK-BASED COMPENSATION (Continued)

cost related to unvested restricted stock awards. That cost is expected to be recognized over a weighted-average period of 2.1 years.

A summary of the status of our restricted stock awards as of September 30, 2016, and of changes in restricted stock outstanding during the fiscal years ended September 30, 2016, 2015 and 2014, is as follows (shares in thousands):

	2016		2015		2014	
	Shares	Weighted-Average Grant Date Fair Value per Share	Shares	Weighted-Average Grant Date Fair Value per Share	Shares	Weighted-Average Grant Date Fair Value per Share
Outstanding at October 1,	668	$ 67.03	634	$ 64.03	576	$ 55.17
Granted	294	58.25	275	68.83	230	79.67
Vested (1)	(256)	64.75	(214)	60.80	(157)	54.08
Forfeited	(58)	63.65	(27)	64.45	(15)	67.92
Outstanding on September 30,	648	$ 64.24	668	$ 67.03	634	$ 64.03

(1) The number of restricted stock awards vested includes shares that we withheld on behalf of our employees to satisfy the statutory tax withholding requirements.

NOTE 7 EARNINGS PER SHARE

ASC 260, *Earnings per Share*, requires companies to treat unvested share-based payment awards that have non-forfeitable rights to dividend or dividend equivalents as a separate class of securities in calculating earnings per share. We have granted and expect to continue to grant to employees restricted stock grants that contain non-forfeitable rights to dividends. Such grants are considered participating securities under ASC 260. As such, we are required to include these grants in the calculation of our basic earnings per share and calculate basic earnings per share using the two-class method. The two-class method of computing earnings per share is an earnings allocation formula that determines earnings per share for each class of common stock and participating security according to dividends declared (or accumulated) and participation rights in undistributed earnings.

Basic earnings per share is computed utilizing the two-class method and is calculated based on 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.

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 7 EARNINGS PER SHARE (Continued)

The following table sets forth the computation of basic and diluted earnings per share:

	2016	September 30, 2015 (as adjusted)	2014 (as adjusted)
		(in thousands)	
Numerator:			
Income (loss) from continuing operations	$ (52,990)	$ 420,474	$ 706,610
Loss from discontinued operations	(3,838)	(47)	(47)
Net income (loss)	(56,828)	420,427	706,563
Adjustment for basic earnings per share			
Earnings allocated to unvested shareholders	(1,858)	(2,163)	(4,132)
Numerator for basic earnings per share:			
From continuing operations	(54,848)	418,311	702,478
From discontinued operations	(3,838)	(47)	(47)
	(58,686)	418,264	702,431
Adjustment for diluted earnings per share:			
Effect of reallocating undistributed earnings of unvested shareholders		6	30
Numerator for diluted earnings per share:			
From continuing operations	(54,848)	418,317	702,508
From discontinued operations	(3,838)	(47)	(47)
	$ (58,686)	$ 418,270	$ 702,461
Denominator:			
Denominator for basic earnings per share weighted-average shares	107,996	107,754	107,800
Effect of dilutive shares from stock options and restricted stock		816	1,341
Denominator for diluted earnings per share adjusted weighted-average shares	107,996	108,570	109,141
Basic earnings per common share:			
Income (loss) from continuing operations	$ (0.50)	$ 3.88	$ 6.52
Loss from discontinued operations	(0.04)		
Net income (loss)	$ (0.54)	$ 3.88	$ 6.52
Diluted earnings per common share:			
Income (loss) from continuing operations	$ (0.50)	$ 3.85	$ 6.44
Loss from discontinued operations	(0.04)		

Net income (loss)	$ (0.54)	$ 3.85	$ 6.44

We had a net loss for fiscal 2016. Accordingly, our diluted earnings per share calculation for fiscal 2016 was equivalent to our basic earnings per share calculation since diluted earnings per share excluded any assumed exercise of equity awards. These were excluded because they were deemed to be

Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 7 EARNINGS PER SHARE (Continued)

anti-dilutive, meaning their inclusion would have reduced the reported net loss per share in the applicable period.

The following shares attributable to outstanding equity awards were excluded from the calculation of diluted earnings per share because their inclusion would have been anti-dilutive:

	2016	2015	2014
	(in thousands, except per share amounts)		
Shares excluded from calculation of diluted earnings per share	1,788	667	215
Weighted-average price per share	$ 63.73	$ 72.85	$ 79.67

NOTE 8 FINANCIAL INSTRUMENTS AND FAIR VALUE MEASUREMENT

The estimated fair value of our available-for-sale securities is primarily based on market quotes. The following is a summary of available-for-sale securities, which excludes assets held in a Non-qualified Supplemental Savings Plan:

	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(in thousands)			
Equity Securities:				
September 30, 2016	$ 38,473	$ 33,051	$	$ 71,524
September 30, 2015	$ 64,462	$ 28,530	$ 1,509	$ 91,483

On an ongoing basis we evaluate the marketable equity securities to determine if any decline in fair value below cost is other-than-temporary. If a decline in fair value below cost is determined to be other-than-temporary, an impairment charge is recorded and a new cost basis established. We review several factors to determine whether a loss is other-than-temporary. These factors include, but are not limited to, (i) the length of time a security is in an unrealized loss position, (ii) the extent to which fair value is less than cost, (iii) the financial condition and near-term prospects of the issuer and (iv) our intent and ability to hold the security for a period of time sufficient to allow for any anticipated recovery in fair value. The cost of securities used in determining realized gains and losses is based on the average cost basis of the security sold. One of our securities was in an unrealized loss position for under 30 days at September 30, 2015 and then dropped below cost again in December 2015 and continued to be in a loss position through fiscal 2016. The security represents a company that is in the offshore drilling industry which has been severely impacted by the downturn in the energy sector. During the fourth quarter of fiscal 2016, we determined the loss was other-than-temporary. As a result, we recognized a $26.0 million other-than-temporary impairment charge.

During fiscal 2016 and fiscal 2015, we did not sell any marketable equity available-for-sale securities. During fiscal 2014, marketable equity available-for-sale securities with a fair value at the date of sales of $49.2 million were sold. The gross realized gain on such sales of available-for-sale securities totaled $45.2 million. All of the gains from available-for-sale securities are included in gain from sale of investment securities in the Consolidated Statements of Operations.

Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 8 FINANCIAL INSTRUMENTS AND FAIR VALUE MEASUREMENT (Continued)

The assets held in a Non-qualified Supplemental Savings Plan are carried at fair value which totaled $13.4 million and $12.9 million at September 30, 2016 and 2015, respectively. The assets are comprised of mutual funds that are measured using Level 1 inputs.

Short-term investments include securities classified as trading securities. Both realized and unrealized gains and losses on trading securities are included in other income (expense) in the Consolidated Statements of Operations. The securities are recorded at fair value.

The majority of cash equivalents are invested in highly-liquid money-market mutual funds invested primarily in direct or indirect obligations of the U.S. Government. The carrying amount of cash and cash equivalents approximates fair value due to the short maturity of those investments.

The carrying value of other assets, accrued liabilities and other liabilities approximated fair value at September 30, 2016 and 2015.

Fair value is defined as the exchange price that would be received to sell an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants at the measurement date. We use the fair value hierarchy established in ASC 820-10 to measure fair value to prioritize the inputs:

Level 1 Quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity can access at the measurement date.

Level 2 Observable inputs, other than quoted prices included in Level 1, such as quoted prices for similar assets or liabilities in active markets; quoted prices for similar assets and liabilities in markets that are not active; or other inputs that are observable or can be corroborated by observable market data.

Level 3 Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities. This includes pricing models, discounted cash flow methodologies and similar techniques that use significant unobservable inputs.

At September 30, 2016, our financial instruments utilizing Level 1 inputs include cash equivalents, equity securities with active markets, money market funds we have elected to classify as restricted assets that are included in other current assets and other assets. Also included is cash denominated in a foreign currency that we have elected to classify as restricted to be used to settle the remaining liabilities of discontinued operations. For these items, quoted current market prices are readily available.

At September 30, 2016, Level 2 inputs include U.S. Agency issued debt securities and corporate bonds measured using broker quotations that utilize observable market inputs. Also included in level 2 inputs are bank certificate of deposits included in short-term investments or current assets.

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 8 FINANCIAL INSTRUMENTS AND FAIR VALUE MEASUREMENT (Continued)

The following table summarizes our assets measured at fair value presented in our Consolidated Condensed Balance Sheet as of September 30, 2016:

	Total Measured at Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		(in thousands)		
Recurring fair value measurements:				
Short-term investments:				
Certificate of deposit	$ 2,000	$	$ 2,000	$
Corporate debt securities	18,591		18,591	
U.S. government and federal agency securities	23,557	18,074	5,483	
Total short-term investments	44,148	18,074	26,074	
Cash and cash equivalents	905,561	905,561		
Investments	71,524	71,524		
Other current assets	27,631	27,381	250	
Other assets	2,000	2,000		
Total assets measured at fair value	$ 1,050,864	$ 1,024,540	$ 26,324	$
Nonrecurring fair value measurements:				
Assets:				
Assets held for sale (1)	$ 1,106	$	$	$ 1,106

(1) Represents the book value as of September 30, 2016 of decommissioned rigs and rig related equipment written down to their estimated recoverable amounts at September 30, 2016. These assets are included in assets held for sale in our Consolidated Balance Sheet at September 30, 2016.

The following information presents the supplemental fair value information about long-term fixed-rate debt at September 30, 2016 and September 30, 2015.

	September 30, 2016	September 30, 2015
	(in millions)	
Carrying value of long-term fixed-rate debt	$ 491.8	$ 531.5
Fair value of long-term fixed-rate debt	$ 529.6	$ 553.5

The fair value for the $500 million fixed-rate debt was based on broker quotes at September 30, 2016. The notes are classified within Level 2 as they are not actively traded in markets.

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 9 EMPLOYEE BENEFIT PLANS

We maintain a domestic noncontributory defined benefit pension plan covering certain U.S. employees who meet certain age and service requirements. In July 2003, we revised the Helmerich & Payne, Inc. Employee Retirement Plan ("Pension Plan") to close the Pension Plan to new participants effective October 1, 2003, and reduce benefit accruals for current participants through September 30, 2006, at which time benefit accruals were discontinued and the Pension Plan was frozen.

The following table provides a reconciliation of the changes in the pension benefit obligations and fair value of Pension Plan assets over the two-year period ended September 30, 2016 and a statement of the funded status as of September 30, 2016 and 2015:

	2016	2015
	(in thousands)	
Accumulated Benefit Obligation	$ 109,731	$ 107,417
Changes in projected benefit obligations		
Projected benefit obligation at beginning of year	$ 107,417	$ 111,108
Interest cost	4,266	4,584
Actuarial loss	15,051	2,741
Benefits paid	(17,003)	(11,016)
Projected benefit obligation at end of year	$ 109,731	$ 107,417
Change in plan assets		
Fair value of plan assets at beginning of year	$ 98,060	$ 108,157
Actual return on plan assets	9,653	(1,324)
Employer contribution	38	2,243
Benefits paid	(17,003)	(11,016)
Fair value of plan assets at end of year	$ 90,748	$ 98,060
Funded status of the plan at end of year	$ (18,983)	$ (9,357)

The amounts recognized in the Consolidated Balance Sheets at September 30, 2016 and 2015 are as follows (in thousands):

Accrued liabilities	$ (45)	$ (44)
Noncurrent liabilities other	(18,938)	(9,313)
Net amount recognized	$ (18,983)	$ (9,357)

The amounts recognized in Accumulated Other Comprehensive Income at September 30, 2016 and 2015, and not yet reflected in net periodic benefit cost, are as follows (in thousands):

Net actuarial loss	$ (34,112)	$ (30,144)

The amount recognized in Accumulated Other Comprehensive Income and not yet reflected in periodic benefit cost expected to be amortized in next year's periodic benefit cost is a net actuarial loss of $2.3 million.

Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 9 EMPLOYEE BENEFIT PLANS (Continued)

The weighted average assumptions used for the pension calculations were as follows:

	Years Ended September 30,		
	2016	**2015**	**2014**
Discount rate for net periodic benefit costs	4.27%	4.32%	4.80%
Discount rate for year-end obligations	3.64%	4.27%	4.32%
Expected return on plan assets	5.89%	6.26%	6.61%

The mortality table issued by the Society of Actuaries in October 2016 was used for the September 30, 2016 pension calculation. The new mortality information reflects improved life expectancies and projected mortality improvements.

We did not make any contributions to the Pension Plan in fiscal 2016. In fiscal 2017, we do not expect minimum contributions required by law to be needed. However, we may make contributions in fiscal 2017 if needed to fund unexpected distributions in lieu of liquidating pension assets.

Components of the net periodic pension expense (benefit) were as follows:

	Years Ended September 30,		
	2016	**2015**	**2014**
		(in thousands)	
Interest cost	$ 4,266	$ 4,584	$ 4,763
Expected return on plan assets	(5,616)	(6,855)	(6,789)
Recognized net actuarial loss	2,083	1,308	873
Settlement	4,964	2,873	1,376
Net pension expense	$ 5,697	$ 1,910	$ 223

We record settlement expense when benefit payments exceed the total annual service and interest costs.

The following table reflects the expected benefits to be paid from the Pension Plan in each of the next five fiscal years, and in the aggregate for the five years thereafter (in thousands).

Years Ended September 30,						
2017	**2018**	**2019**	**2020**	**2021**	**2022 - 2026**	**Total**
$13,976	$5,859	$6,013	$7,094	$5,674	$33,078	$71,694

Included in the Pension Plan is an unfunded supplemental executive retirement plan.

INVESTMENT STRATEGY AND ASSET ALLOCATION

Our investment policy and strategies are established with a long-term view in mind. The investment strategy is intended to help pay the cost of the Plan while providing adequate security to meet the benefits promised under the Pension Plan. We maintain a diversified asset mix to minimize the risk of a material loss to the portfolio value that might occur from devaluation of any single investment. In determining the appropriate asset mix, our financial strength and ability to fund potential shortfalls are considered. Pension Plan assets are invested in portfolios of diversified

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 9 EMPLOYEE BENEFIT PLANS (Continued)

public-market equity securities and fixed income securities. The Pension Plan does not directly hold securities of the Company.

The expected long-term rate of return on Pension Plan assets is based on historical and projected rates of return for current and planned asset classes in the Pension Plan's investment portfolio after analyzing historical experience and future expectations of the return and volatility of various asset classes. The target allocation for 2017 and the asset allocation for the Pension Plan at the end of fiscal 2016 and 2015, by asset category, follows:

Asset Category	Target Allocation 2017	Percentage of Plan Assets at September 30, 2016	2015
U.S. equities	55%	62%	59%
International equities	13	12	13
Fixed income	27	21	23
Real estate and other	5	5	5
Total	100%	100%	100%

PLAN ASSETS

The fair value of Pension Plan assets at September 30, 2016 and 2015, summarized by level within the fair value hierarchy described in Note 8, are as follows:

	Fair Value as of September 30, 2016			
	Total	Level 1	Level 2	Level 3
	(in thousands)			
Short-term investments	$ 467	$ 467	$	$
Mutual funds:				
Domestic stock funds	36,107	36,107		
Bond funds	22,809	22,809		
International stock funds	11,334	11,334		
Total mutual funds	70,250	70,250		
Domestic common stock	18,305	18,305		
Foreign equity stock	1,549	1,549		
Oil and gas properties	177			177
Total	$ 90,748	$ 90,571	$	$ 177

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 9 EMPLOYEE BENEFIT PLANS (Continued)

	Fair Value as of September 30, 2015			
	Total	Level 1	Level 2	Level 3
	(in thousands)			
Short-term investments	$ 2,248	$ 2,248	$	$
Mutual funds:				
Domestic stock funds	40,072	40,072		
Bond funds	25,344	25,344		
International stock funds	12,644	12,644		
Total mutual funds	78,060	78,060		
Domestic common stock	15,883	15,883		
Foreign equity stock	1,482	1,482		
Oil and gas properties	387			387
Total	$ 98,060	$ 97,673	$	$ 387

The Pension Plan's financial assets utilizing Level 1 inputs are valued based on quoted prices in active markets for identical securities. The Plan has no assets utilizing Level 2. The Pension Plan's assets utilizing Level 3 inputs consist of oil and gas properties. The fair value of oil and gas properties is determined by Wells Fargo Bank, N.A., based upon actual revenue received for the previous twelve-month period and experience with similar assets.

The following table sets forth a summary of changes in the fair value of the Pension Plan's Level 3 assets for the years ended September 30, 2016 and 2015:

	Oil and Gas Properties Years Ended September 30,	
	2016	2015
	(in thousands)	
Balance, beginning of year	$ 387	$ 301
Unrealized gains (losses) relating to property still held at the reporting date	(210)	86
Balance, end of year	$ 177	$ 387

DEFINED CONTRIBUTION PLAN

Substantially all employees on the United States payroll may elect to participate in our 401(k)/Thrift Plan by contributing a portion of their earnings. We contribute an amount equal to 100 percent of the first five percent of the participant's compensation subject to certain limitations. The annual expense incurred for this defined contribution plan was $21.6 million, $24.8 million and $32.3 million in fiscal 2016, 2015 and 2014, respectively.

During fiscal 2016, we determined that employee workforce reductions which started during 2015 and continued into 2016 due to reduced drilling activity resulted in a partial plan termination of the 401(k)/Thrift Plan. All affected participants were fully vested in their accounts. As a result of the partial plan termination status, we recorded additional employer contributions totaling $6.3 million in general and administrative expense.

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 10 SUPPLEMENTAL BALANCE SHEET INFORMATION

The following reflects the activity in our reserve for bad debt for 2016, 2015 and 2014:

	September 30, 2016	September 30, 2015	September 30, 2014
	(in thousands)		
Reserve for bad debt:			
Balance at October 1,	$ 6,181	$ 4,597	$ 4,795
Provision for (recovery of) bad debt	(2,013)	6,034	(200)
Write-off of bad debt	(1,472)	(4,450)	2
Balance at September 30,	$ 2,696	$ 6,181	$ 4,597

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 10 SUPPLEMENTAL BALANCE SHEET INFORMATION (Continued)

Accounts receivable, prepaid expenses and other current assets, accrued liabilities and long-term liabilities at September 30 consist of the following:

	September 30, 2016	September 30, 2015 (as adjusted)
	(in thousands)	
Accounts receivable, net of reserve:		
Trade receivables	$ 286,998	$ 445,948
Insurance recovery receivable	50,200	
Income tax receivable	37,971	
Total accounts receivable, net of reserve	$ 375,169	$ 445,948

	2016	2015 (as adjusted)
Prepaid expenses and other current assets:		
Restricted cash	$ 27,566	$ 28,484
Prepaid insurance	4,354	6,386
Deferred mobilization	9,913	11,697
Prepaid income taxes	26,138	6,867
Prepaid value added tax	1,407	1,055
Other	8,689	9,986
Total prepaid expenses and other current assets	$ 78,067	$ 64,475

	2016	2015 (as adjusted)
Accrued liabilities:		
Accrued operating costs	$ 17,009	$ 34,292
Payroll and employee benefits	43,547	36,101
Taxes payable, other than income tax	31,443	38,571
Accrued income taxes		
Deferred mobilization	17,923	18,230
Self-insurance liabilities	14,801	10,796
Deferred income	34,681	42,769
Litigation and claims	70,535	
Other	4,700	16,798
Total accrued liabilities	$ 234,639	$ 197,557

	2016	2015 (as adjusted)
Noncurrent liabilities Other:		
Pension and other non-qualified retirement plans	$ 39,762	$ 28,423
Self-insurance liabilities	21,651	20,846
Deferred mobilization	24,781	38,492
Uncertain tax positions including interest and penalties	12,502	17,724
Other	4,085	4,635

Total noncurrent liabilities other	$	102,781	$	110,120

Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 11 SUPPLEMENTAL CASH FLOW INFORMATION

	Years Ended September 30,		
	2016	2015	2014
	(in thousands)		
Cash payments:			
Interest paid, net of amounts capitalized	$ 28,011	$ 11,651	$ 5,377
Income taxes paid	$ 15,577	$ 131,128	$ 317,599

Capital expenditures on the Consolidated Statements of Cash Flows for the years ended September 30, 2016, 2015 and 2014 do not include additions which have been incurred but not paid for as of the end of the year. The following table reconciles total capital expenditures incurred to total capital expenditures in the Consolidated Statements of Cash Flows:

	September 30,		
	2016	2015 (as adjusted)	2014 (as adjusted)
	(in thousands)		
Capital expenditures incurred	$ 241,290	$ 1,033,241	$ 1,045,820
Additions incurred prior year but paid for in current year	25,344	123,548	29,264
Additions incurred but not paid for as of the end of the year	(9,465)	(25,344)	(123,548)
Capital expenditures per Consolidated Statements of Cash Flows	$ 257,169	$ 1,131,445	$ 951,536

NOTE 12 RISK FACTORS

CONCENTRATION OF CREDIT

Financial instruments which potentially subject us to concentrations of credit risk consist primarily of temporary cash investments, short-term investments and trade receivables. We place temporary cash investments in the U.S. with established financial institutions and invest in a diversified portfolio of highly rated, short-term money market instruments. Our trade receivables, primarily with established companies in the oil and gas industry, may impact credit risk as customers may be similarly affected by prolonged changes in economic and industry conditions. International sales also present various risks including governmental activities that may limit or disrupt markets and restrict the movement of funds. Most of our international sales, however, are to large international or government-owned national oil companies. We perform ongoing credit evaluations of customers and do not typically require collateral in support for trade receivables. We provide an allowance for doubtful accounts, when necessary, to cover estimated credit losses. Such an allowance is based on management's knowledge of customer accounts.

VOLATILITY OF MARKET

Our operations can be materially affected by oil and gas prices. Oil and natural gas prices have been historically volatile and 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

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 12 RISK FACTORS (Continued)

and price volatility are generally more important for determining a customer's future spending levels. This volatility, along with the difficulty in predicting future prices, 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.

In addition, 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 may cause difficulty 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 a reduction in customer spending and the demand for drilling services. This reduction in spending could have a material adverse effect on our operations.

SELF-INSURANCE

We self-insure a significant portion of expected losses relating to worker's compensation, general liability and automobile liability. Generally, deductibles range from $1 million to $3 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. Estimates are recorded for incurred outstanding liabilities for worker's compensation, general liability claims and claims that are incurred but not reported. Estimates are based on adjusters' estimates, historic 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.

We have a wholly-owned captive insurance company which finances a significant portion of the physical damage risk on company-owned drilling rigs as well as international casualty deductibles.

INTERNATIONAL DRILLING OPERATIONS

International drilling operations may significantly contribute to our revenues and net operating income. There can be no assurance that we will be able to successfully conduct such operations, and a failure to do so may have an adverse effect on our financial position, results of operations, and cash flows. Also, the success of our international operations will be subject to numerous contingencies, some of which are beyond management's control. These contingencies include general and regional economic conditions, fluctuations in currency exchange rates, modified exchange controls, changes in international regulatory requirements and international employment issues, risk of expropriation of real and personal property and the burden of complying with foreign laws. Additionally, in the event that extended labor strikes occur or a country experiences significant political, economic or social instability, we could experience shortages in labor and/or material and supplies necessary to operate some of our drilling rigs, thereby potentially causing an adverse material effect on our business, financial condition and results of operations.

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

Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 12 RISK FACTORS (Continued)

remeasured into U.S. dollars with gains and losses resulting from foreign currency transactions included in current results of operations.

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

NOTE 13 COMMITMENTS AND CONTINGENCIES

PURCHASE OBLIGATIONS

Equipment, parts and supplies are ordered in advance to promote efficient construction and capital improvement progress. At September 30, 2016, we had purchase commitments for equipment, parts and supplies of approximately $44.0 million.

LEASES

At September 30, 2016, we were leasing approximately 219,700 square feet of office space near downtown Tulsa, Oklahoma. We also lease other office space and equipment for use in operations. For operating leases that contain built-in pre-determined rent escalations, rent expense is recognized on a straight-line basis over the life of the lease. Leasehold improvements are capitalized and amortized over the lease term. Future minimum rental payments required under operating leases having initial or remaining non-cancelable lease terms in excess of a year at September 30, 2016 are as follows:

Fiscal Year	**Amount (in thousands)**
2017	$ 8,550
2018	5,680
2019	5,214
2020	4,401
2021	3,049
Thereafter	9,679
Total	$ 36,573

Total rent expense was $13.5 million, $13.6 million and $12.1 million for fiscal 2016, 2015 and 2014, respectively.

CONTINGENCIES

Various legal actions, the majority of which arise in the ordinary course of business, are pending. We maintain insurance against certain business risks subject to certain deductibles. With the exception of the matters discussed below which are independently addressed herein, none of these legal actions are expected to have a material adverse effect on our financial condition, cash flows or results of operations.

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 13 COMMITMENTS AND CONTINGENCIES (Continued)

We are contingently liable to sureties in respect of bonds issued by the sureties in connection with certain commitments entered into by us in the normal course of business. We have agreed to indemnify the sureties for any payments made by them in respect of such bonds.

During the ordinary course of our business, contingencies arise resulting from an existing condition, situation, or set of circumstances involving an uncertainty as to the realization of a possible gain contingency. We account for gain contingencies in accordance with the provisions of ASC 450, *Contingencies*, and, therefore, we do not record gain contingencies and recognize income until realized. The property and equipment of our Venezuelan subsidiary was seized by the Venezuelan government on June 30, 2010. 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. ("PDVSA") and PDVSA Petroleo, S.A. ("Petroleo"). Our subsidiaries seek damages for the taking of their 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. No gain contingencies are recognized in our Consolidated Financial Statements.

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., 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 Helmerich & Payne International Drilling Co.'s offshore platform rigs in the Gulf of Mexico. We have been engaged in discussions with the Inspector General's office of the Department of the Interior regarding the same events that were the subject of the DOJ's investigation. We can provide no assurance as to the timing or eventual outcome of these discussions and are unable to determine the amount of penalty, if any, that may be assessed or the effect of any terms that may be required by an administrative agreement with the DOJ. However, we presently believe that the outcome of our discussions will not have a material adverse effect on us.

On or about April 28, 2015, Joshua Keel ("Keel"), an employee of Helmerich & Payne International Drilling Co. ("HPIDC"), filed a petition in the 152nd Judicial Court for Harris County, Texas (Cause No. 2015-24531) against us, our customer and several subcontractors of our customer. The suit arose from injuries Keel sustained in an accident that occurred while he was working on HPIDC Rig 223 in New Mexico in July of 2014. Keel alleged that the defendants were negligent and negligent *per se*, acted recklessly, intentionally, and/or with an utterly wanton disregard for the rights and safety of the plaintiff and was seeking damages well in excess of $100 million. Pursuant to the terms of the drilling contract between HPIDC and its customer, HPIDC indemnified most of the co-defendants in the lawsuit, subject to certain reservations. On September 14, 2016, the parties in the *Keel* litigation entered into a global settlement agreement, which was approved by the court on October 14, 2016. The total settlement amount of $72 million will be paid by the Company and its insurers on behalf of all defendants pursuant to industry standard contractual indemnification obligations. After taking into account amounts to be paid by the Company's various insurers, $18.8 million was recorded as an operating cost in our U.S. Land segment. At September 30, 2016, we have recorded in our Consolidated Balance Sheet a $72.0 million accrued liability and a $50.2 million accounts receivable from insurance recoveries. The settlement payment is due on or before December 24, 2016.

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 14 SEGMENT INFORMATION

We operate principally in the contract drilling industry. Our contract drilling business includes the following reportable operating segments: U.S. Land, Offshore and International Land. The contract drilling operations consist mainly of contracting Company-owned drilling equipment primarily to large oil and gas exploration companies. To provide information about the different types of business activities in which we operate, we have included Offshore and International Land, along with our U.S. Land reportable operating segment, as separate reportable operating segments. Additionally, each reportable operating segment is a strategic business unit which is managed separately. Our primary international areas of operation include Colombia, Ecuador, Argentina, Bahrain, U.A.E. and other South American and Middle Eastern countries. Other includes additional non-reportable operating segments. Revenues included in Other consist primarily of rental income. Consolidated revenues and expenses reflect the elimination of all material intercompany transactions.

We evaluate segment performance based on income or loss from operations (segment operating income) before income taxes which includes:

- revenues from external and internal customers
- direct operating costs
- depreciation and
- allocated general and administrative costs

but excludes corporate costs for other depreciation, income from asset sales and other corporate income and expense.

General and administrative costs are allocated to the segments based primarily on specific identification and, to the extent that such identification is not practical, on other methods which we believe to be a reasonable reflection of the utilization of services provided.

Segment operating income for all segments is a non-GAAP financial measure of our performance, as it excludes certain general and administrative expenses, corporate depreciation, income from asset sales and other corporate income and expense. We consider segment operating income to be an important supplemental measure of operating performance for presenting trends in our core businesses. We use this measure to facilitate period-to-period comparisons in operating performance of our reportable segments in the aggregate by eliminating items that affect comparability between periods. We believe that segment operating income is useful to investors because it provides a means to evaluate the operating performance of the segments on an ongoing basis using criteria that are used by our internal decision makers. Additionally, it highlights operating trends and aids analytical comparisons. However, segment operating income has limitations and should not be used as an alternative to operating income or loss, a performance measure determined in accordance with GAAP, as it excludes certain costs that may affect our operating performance in future periods.

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 14 SEGMENT INFORMATION (Continued)

Summarized financial information of our reportable segments for continuing operations for each of the years ended September 30, 2016, 2015 and 2014 is shown in the following table:

(in thousands)	External Sales	Inter-Segment	Total Sales	Segment Operating Income (Loss)	Depreciation	Total Assets	Additions to Long-Lived Assets
2016							
Contract Drilling							
U.S. Land	$ 1,242,462	$	$ 1,242,462	$ 74,118	$ 508,237	$ 5,005,299	$ 209,156
Offshore	138,601		138,601	15,659	12,495	105,152	9,694
International Land	229,894		229,894	(14,086)	57,102	487,181	2,364
	1,610,957		1,610,957	75,691	577,834	5,597,632	221,214
Other	13,275	855	14,130	(7,491)	20,753	1,234,323	20,076