HELMERICH & PAYNE, INC.

HELMERICH & PAYNE-TULSA, OKLA.®

ANNUAL REPORT FOR 2015

Helmerich & Payne, Inc.

Helmerich & Payne, Inc. is the holding company for Helmerich & Payne International Drilling Co., a drilling contractor with land and offshore operations in the United States, South America, Africa and the Middle East. Holdings also include commercial real estate properties in the Tulsa, Oklahoma area, and an energy-weighted portfolio of securities valued at approximately $91.5 million as of September 30, 2015.

FINANCIAL HIGHLIGHTS

	Years Ended September 30,		
	2015	**2014**	**2013**
	(in thousands, except per share amounts)		
Operating Revenues	$3,165,441	$3,719,707	$3,387,614
Net Income	422,225	708,719	736,639
Diluted Earnings per Share	3.87	6.46	6.79
Dividends Paid per Share	2.75	2.44	.870
Capital Expenditures	1,133,482	952,892	809,066
Total Assets	7,152,012	6,720,998	6,263,564

Financial & Operating Review

HELMERICH & PAYNE, INC.

	Years Ended September 30,		
	2015	2014	2013
SUMMARY OF CONSOLIDATED STATEMENTS OF INCOME*†			
Operating Revenues	$3,165,441	$3,719,707	$3,387,614
Operating Costs, excluding depreciation	1,704,163	2,009,912	1,852,768
Depreciation**	646,234	523,549	455,623
General and Administrative Expense	134,906	135,139	126,250
Operating Income	675,750	1,054,787	956,661
Interest and Dividend Income	5,834	1,583	1,653
Gain on Sale of Investment Securities	—	45,234	162,121
Interest Expense	15,036	4,654	6,129
Income from Continuing Operations	422,272	708,766	721,453
Net Income	422,225	708,719	736,639
Diluted Earnings Per Common Share:			
Income from Continuing Operations	3.87	6.46	6.65
Net Income	3.87	6.46	6.79

* $000's omitted, except per share data
† All data excludes discontinued operations except net income
** 2015 includes an asset impairment of $39,242 and depreciation of $606,992

SUMMARY FINANCIAL DATA*	2015	2014	2013
Cash†	$ 717,977	$ 360,909	$ 447,868
Working Capital†	1,083,059	765,851	805,443
Investments	104,354	236,644	316,154
Property, Plant, and Equipment, Net†	5,567,235	5,188,544	4,676,103
Total Assets**	7,152,012	6,720,998	6,263,564
Long-term Debt**	492,443	39,502	79,137
Shareholders' Equity	4,897,452	4,890,977	4,443,727
Capital Expenditures	1,133,482	952,892	809,066

* $000's omitted
† Excludes discontinued operations
** 2014 and prior restated due to adoption of ASU 2015-03

Rig Fleet Summary†

	2015	2014	2013
Drilling Rigs—			
U. S. Land—FlexRigs	341	322	286
U. S. Land—Highly Mobile	—	—	—
U. S. Land—Conventional	2	7	16
Offshore Platform	9	9	9
International Land†	38	36	29
Total Rig Fleet	390	374	340
Rig Utilization Percentage—			
U. S. Land—FlexRigs	63	91	87
U. S. Land—Highly Mobile	0	0	0
U. S. Land—Conventional	11	3	2
U. S. Land—All Rigs	62	86	82
Offshore Platform	93	89	89
International Land†	53	76	82

† Excludes discontinued operations

2012	2011	2010	2009	2008	2007	2006	2005
$3,151,802	$2,543,894	$1,875,162	$1,843,740	$1,869,371	$1,502,380	$1,140,219	$ 733.,902
1,750,510	1,432,602	1,071,959	944,780	987,838	788,967	606,945	435,057
387,549	315,468	262,658	227,535	195,343	137,187	93,363	88,483
107,307	91,452	81,479	58,822	56,429	47,401	51,873	41,015
909,599	702,511	451,796	608,875	640,084	586,506	395,341	182,355
1,380	1,951	1,811	2,755	3,524	4,143	9,688	5,772
—	913	—	—	21,994	65,458	19,866	26,969
8,653	17,355	17,158	13,590	18,721	9,591	6,499	12,416
573,609	434,668	286,081	380,546	420,258	415,924	269,852	120,666
581,045	434,186	156,312	353,545	461,738	449,261	293,858	127,606
5.27	3.99	2.66	3.56	3.93	3.95	2.54	1.16
5.34	3.99	1.45	3.31	4.32	4.27	2.77	1.23
$ 96,095	$ 364,246	$ 63,020	$ 96,142	$ 77,549	$ 67,445	$ 32,193	$ 284,460
511,574	537,034	417,888	157,103	274,519	209,766	126,540	378,496
451,144	347,924	320,712	356,404	199,266	223,360	218,309	178,452
4,351,571	3,677,070	3,275,020	3,194,273	2,605,384	2,068,812	1,399,974	897,504
5,719,413	5,003,001	4,264,311	4,159,323	3,587,524	2,884,710	2,134,254	1,662,794
193,737	234,279	359,110	418,467	474,648	444,510	174,640	199,542
3,834,998	3,270,047	2,807,465	2,683,009	2,265,474	1,815,516	1,381,892	1,079,238
1,097,680	694,264	329,572	876,839	697,906	885,583	521,847	78,677
264	221	182	163	146	118	73	50
—	4	11	11	12	12	12	12
18	23	27	27	27	27	28	29
9	9	9	9	9	9	9	11
29	24	28	33	19	16	16	14
320	281	257	243	213	182	138	116
97	99	87	76	100	100	100	100
0	0	0	29	83	93	100	99
14	16	17	39	80	87	95	82
89	86	73	68	96	97	99	94
79	77	80	89	75	65	69	53
77	70	71	70	72	89	95	80

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended September 30, 2015

OR

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

For the transition period from to

Commission file number 1-4221

HELMERICH & PAYNE, INC.

(Exact Name of Registrant as Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	**73-0679879** (I.R.S. Employer Identification No.)
1437 S. Boulder Ave., Suite 1400, Tulsa, Oklahoma (Address of Principal Executive Offices)	**74119-3623** (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
Preferred Stock Purchase Rights	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 ☒ Accelerated filer ☐ Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

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

At March 31, 2015, the aggregate market value of the voting stock held by non-affiliates was approximately $7.1 billion.

Number of shares of common stock outstanding at November 13, 2015: 107,787,205.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's 2016 Proxy Statement for the Annual Meeting of Stockholders to be held on March 2, 2016 are incorporated by reference into Part III of this Form 10-K. The 2016 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.

HELMERICH & PAYNE, INC.
FORM 10-K
YEAR ENDED SEPTEMBER 30, 2015
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PART I

Item 1. BUSINESS

Helmerich & Payne, Inc. (hereafter referred to as the "Company", "we", "us" or "our"), 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 2015, our U.S. Land operations drilled primarily in Oklahoma, California, Texas, Wyoming, Colorado, Louisiana, Mississippi, Pennsylvania, Ohio, Utah, New Mexico, Montana, North Dakota, West Virginia and Nevada. Offshore operations were conducted in the Gulf of Mexico and Equatorial Guinea. Our International Land segment conducted drilling operations in six international locations during fiscal 2015: Ecuador, Colombia, Argentina, Bahrain, United Arab Emirates ("UAE") and Mozambique.

We are also engaged in the ownership, development and operation of commercial real estate and the research and development of rotary steerable technology. Each of the businesses operates independently of the others through wholly-owned subsidiaries. This operating decentralization is balanced by centralized finance and legal organizations.

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.

Our subsidiary, TerraVici Drilling Solutions, Inc. ("TerraVici"), continues to develop patented rotary steerable technology to enhance horizontal and directional drilling operations. TerraVici complements our existing drilling rig technology and allows us to offer directional drilling services to customers. By combining this new technology with our existing capabilities, we expect to improve drilling productivity and reduce total well cost to the customer.

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 2015, we received approximately 59 percent of our consolidated operating revenues from our ten largest contract drilling customers. BHP Billiton, Occidental Oil and Gas Corporation and EOG Resources (respectively, "BHP", "Oxy" and "EOG"), including their affiliates, are our three largest contract drilling customers. We perform drilling services for BHP in U.S. land operations, Oxy on a world-wide basis and EOG in U.S. land operations. Revenues from drilling services performed for BHP, Oxy and EOG in fiscal 2015 accounted for approximately 11 percent, 10 percent and 6 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 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 were 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 design. 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 the past few years our mechanical rigs have been sold or decommissioned as we added new AC drive rigs to our fleet. The decommission of our remaining seven mechanical rigs in fiscal 2011 marked the end of a multi-year evolution in the high-grading of our fleet from mechanical rigs to high-efficiency, high-performance rigs. In fiscal 2015, we also decommissioned 23 of our 37 remaining SCR rigs including six of the eight 3,000 horsepower conventional rigs in our U.S. Land fleet, all six of our FlexRig1 SCR rigs and all 11 of our FlexRig2 SCR rigs.

Since 1998, we have built 229 FlexRig3s, 88 FlexRig4s, and 49 FlexRig5s with 357 of those delivered to the field. Of the total 366 FlexRigs built through September 30, 2015, 186 have been built in the last five years. As of November 12, 2015, an additional six new FlexRigs remained under construction.

The effective use of technology is important to the maintenance of our competitive position within the drilling industry. We expect to continue to refine our existing technology (such as rotary steerable technology, discussed above) and develop new technology in the future. Our research and development expense totaled $16.1 million in fiscal 2015, $15.9 million in fiscal 2014 and $15.2 million in fiscal 2013.

We assemble new FlexRigs at our gulf coast facility near Houston, Texas. We also have 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, for the purpose of overhauling/repairing rig equipment and associated component parts.

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 2016. 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 the beginning of fiscal 2015. This decline in pricing has resulted in lower demand for our drilling services. Specifically, at the close of fiscal 2015, we had 170 contracted rigs, compared to 325 contracted rigs at the same time during the prior year. In addition, and in light of the price of oil and the status of the drilling industry and our rig fleet, we have 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. No additional impairments were identified for any other 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 several hundred other competitors with regional operations. Internationally, we compete directly with various contractors at each location where we operate. We also have numerous competitors in the offshore contract drilling industry that have significant resources.

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 2015, 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.

As of September 30, 2015, we had 137 existing rigs under fixed-term contracts. While the original duration for these current fixed-term contracts are for six-month to seven-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.

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, 2015 and 2014 was $3.1 billion and $5.0 billion, respectively. The decrease in backlog at September 30, 2015 from September 30, 2014, is primarily due to the revenue earned since September 30, 2014 and the expiration and termination of long-term contracts. Approximately 60.7 percent of the total September 30, 2015 backlog is not reasonably expected to be filled in fiscal 2016. A portion of the backlog represents term contracts for new rigs that will be constructed in the future.

The following table sets forth the total backlog by reportable segment as of September 30, 2015 and 2014, and the percentage of the September 30, 2015 backlog not reasonably expected to be filled in fiscal 2016:

Reportable Segment	Total Backlog Revenue 9/30/2015	Total Backlog Revenue 9/30/2014	Percentage Not Reasonably Expected to be Filled in Fiscal 2016
	(in billions)		
U.S. Land	$2.2	$3.8	55.7%
Offshore	0.1	0.1	58.0%
International	0.8	1.1	74.2%
	$3.1	$5.0	

We obtain certain key rig components from a single or limited number of vendors or fabricators. Certain of these vendors or fabricators are thinly capitalized independent companies located on the Texas gulf coast. Therefore, disruptions in rig component deliveries may occur. Further, 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 2015, 2014, and 2013, we had 343, 329 and 302, respectively, of our land rigs available for work in the United States. The total number of rigs at the end of fiscal 2015 increased by a net of 14 rigs from the end of fiscal 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. Our U.S. Land operations contributed approximately 80 percent ($2.5 billion) of our consolidated operating revenues during fiscal 2015, compared with approximately 83 percent ($3.1 billion) of consolidated operating revenues during fiscal 2014 and approximately 82 percent ($2.8 billion) of consolidated operating revenues during fiscal 2013. Rig utilization was approximately 62 percent in fiscal 2015, approximately 86 percent in fiscal 2014 and approximately 82 percent in fiscal 2013. Our fleet of FlexRigs had an average utilization of approximately 63 percent during fiscal 2015, while our conventional rigs had an average utilization of approximately 11 percent. A rig is considered to be utilized when it is operated or being mobilized or demobilized under contract. At the close of fiscal 2015, 145 out of an available 343 land rigs were generating revenue.

Offshore Drilling

Our Offshore operations contributed approximately 8 percent in fiscal year 2015 ($241.0 million) of our consolidated operating revenues compared to approximately 7 percent ($250.8 million) of consolidated operating revenues during fiscal 2014 and 7 percent ($221.9 million) of consolidated operating revenues during fiscal 2013. Rig utilization in fiscal 2015 was approximately 93 percent compared to approximately 89 percent in fiscal 2014 and fiscal 2013. At the end of fiscal 2015 and 2014, we had eight of our nine offshore platform rigs under contract and continued to work under management contracts for four customer-owned rigs. Revenues from drilling services performed for our largest offshore drilling customer totaled approximately 54 percent ($129.6 million) of offshore revenues during fiscal 2015.

International Land Drilling

General

Our International Land operations contributed approximately 12 percent ($386.7 million) of our consolidated operating revenues during fiscal 2015, compared with approximately 10 percent ($355.5 million) of consolidated operating revenues during fiscal 2014 and 11 percent ($366.8 million) of consolidated operating revenues during fiscal 2013. Rig utilization in fiscal 2015 was 53 percent, 76 percent in fiscal 2014 and 82 percent in fiscal 2013. 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 2015, we had 19 rigs in Argentina. Our utilization rate was approximately 56 percent during fiscal 2015, approximately 80 percent during fiscal 2014 and approximately 62 percent during fiscal 2013. Revenues generated by Argentine drilling operations contributed approximately 5 percent in fiscal 2015 ($169.4 million) of our consolidated operating revenues compared to approximately 3 percent ($107.9 million) of our consolidated operating revenues during fiscal 2014 and approximately 2 percent ($73.2 million) of our consolidated operating revenues during fiscal 2013. Revenues from drilling services performed for our two largest customers in Argentina totaled approximately 4 percent of consolidated operating revenues and approximately 30 percent of international operating revenues during fiscal 2015. The Argentine drilling contracts are primarily with large international or national oil companies.

Colombia

At the end of fiscal 2015, we had eight rigs in Colombia. Our utilization rate was approximately 52 percent during fiscal 2015, approximately 63 percent during fiscal 2014 and approximately 82 percent during fiscal 2013. Revenues generated by Colombian drilling operations contributed approximately 2 percent in fiscal 2015 ($74.3 million) of our consolidated operating revenues compared to approximately 2 percent ($85.2 million) of our consolidated operating revenues during fiscal 2014 and approximately 3 percent ($100.1 million) of our consolidated operating revenues during fiscal 2013. Revenues from drilling services performed for our two customers in Colombia totaled approximately 2 percent of consolidated operating revenues and approximately 19 percent of international operating revenues during fiscal 2015. The Colombian drilling contracts are primarily with large international or national oil companies.

Ecuador

At the end of fiscal 2015, we had six rigs in Ecuador. The utilization rate in Ecuador was 34 percent in fiscal 2015, compared to 85 percent in fiscal 2014 and 95 percent in fiscal 2013. Revenues generated by Ecuadorian drilling operations contributed approximately 1 percent in fiscal 2015 ($34.2 million) of our consolidated operating revenues compared to approximately 2 percent in fiscal 2014 and fiscal 2013 of our consolidated operating revenues ($69.2 million and $67.9 million, respectively). Revenues from drilling services performed for our two largest customers in Ecuador totaled approximately 1 percent of consolidated operating revenues and approximately 7 percent of international operating revenues during fiscal 2015. The Ecuadorian drilling contracts are primarily with large international or national oil companies.

Other Locations

In addition to our operations discussed above, at the end of fiscal 2015 we had three rigs in Bahrain and two rigs in the UAE.

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 5,803 employees within the United States (11 of which were part-time employees) and 935 employees in international operations as of September 30, 2015.

AVAILABLE INFORMATION

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

Item 1A. RISK FACTORS

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

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 and continued in 2015. For example, in July of 2014 oil prices exceeded $100 per barrel. Oil prices in recent months have been below $50 per barrel. In response, many of our customers announced significant reductions in their 2015 capital spending budgets. As such, demand for our drilling services significantly declined. 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, 2015, 145 out of an available 343 land rigs were contracted in the U.S. Land segment. After giving effect to new FlexRigs placed into service and additional rig releases since September 30, 2015, as of November 12, 2015, 132 rigs remain contracted in the U.S. Land segment. In the event oil prices remain depressed for a sustained period, or decline further, our U.S. Land, International Land and Offshore segments may experience further, 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;
- 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 new-build rig assembly facility located near the Houston, Texas ship channel, 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. Our customers and other third parties may also dispute, or be unable to meet, their contractual indemnification obligations to us. Accordingly, we may be unable to transfer these risks to our drilling customers and other third parties by contract or indemnification agreements. Incurring a liability for which we are not fully indemnified or insured could have a material adverse effect on our business, financial condition and results of operations.

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

We have insurance coverage for comprehensive general liability, automobile liability, worker's compensation and employer's liability, and certain other specific risks. Insurance is purchased over deductibles to reduce our exposure to catastrophic events. We retain a significant portion of our expected losses under our worker's compensation, general liability and automobile liability programs. The Company self-insures a number of other risks including loss of earnings and business interruption. 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 2016, 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 an inability to pay vendors, including us. The global economic environment in the past has experienced significant deterioration in a relatively short period of time and there can be no assurance that the global economic environment will not quickly deteriorate again due to one or more factors. These conditions could have a material adverse effect on our business, financial condition and results of operations.

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

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

Although many contracts for drilling services are awarded based solely on price, we have been successful in establishing long-term relationships with certain customers which have allowed us to secure drilling work even though we may not have been the lowest bidder for such work. We have continued to attempt to differentiate our services based upon our FlexRigs and our engineering design expertise, operational efficiency, safety and environmental awareness. However, development of new drilling technology by competitors has increased in recent years and future improvements in operational efficiency and safety by our competitors could further negatively affect our ability to differentiate our services. Also, the strategy of differentiation is less effective during low commodity price environments when lower demand for drilling services intensifies price competition and makes it more difficult or impossible to compete on any basis other than price. The oil and natural gas services industry in the United States, for example, has experienced downturns in demand during the last decade, including a significant downturn that started in 2014. During these periods there have been 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 have difficulty sustaining rig utilization and profit margins, 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 2015, we received approximately 59 percent of our consolidated operating revenues from our ten largest contract drilling customers and approximately 27 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 build new, technologically advanced drilling rigs or to improve existing rigs;
- avoid cost overruns inherent in large construction projects resulting from numerous factors such as shortages of equipment, materials and skilled labor, unscheduled delays in delivery of ordered equipment and materials, unanticipated increases in costs of equipment, materials and labor, design and engineering problems, and financial or other difficulties;
- successfully integrate additional drilling rigs;
- effectively manage the growth and increased size of our organization and drilling fleet;
- successfully deploy idle, stacked or additional drilling rigs;
- maintain crews necessary to operate additional drilling rigs; or
- successfully improve our financial condition, results of operations, business or prospects as a result of building new drilling rigs.

If we are not successful in building new rigs and equipment or upgrading our existing rigs and equipment in a timely and cost-effective manner, 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.

Failure to comply with the terms of our plea agreement with the United States Department of Justice may 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. As part of the plea agreement, H&PIDC agreed, during a three-year probationary period, to not commit any further criminal violations and to fulfill the terms of an environmental compliance plan (“ECP”) whose purpose is to develop and implement additional training and safety programs. Our ability to comply with the terms of the plea agreement is dependent, in part, on our successful implementation of the additional training and safety programs set forth in the ECP. While not anticipated, a failure to comply with the terms of the plea agreement, including the ECP, could result in prosecution and other regulatory sanctions, and could otherwise adversely affect our business. 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 2015, approximately 12 percent of our consolidated operating revenues were generated from the international contract drilling business. During fiscal 2015, approximately 72 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.

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, 2015, our contract drilling backlog was approximately $3.1 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 and financial strength.

At September 30, 2015, we had a portfolio of securities with a total fair value of approximately $91.5 million, consisting of Atwood Oceanics, Inc. and Schlumberger, Ltd. These securities are subject to a wide variety of market-related risks that could substantially reduce or increase the fair value of our holdings. The portfolio is recorded at fair value on our balance sheet with changes in unrealized after-tax value reflected in the equity section of our balance sheet. At November 12, 2015, the fair value of the portfolio had increased to approximately $98.7 million.

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. 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 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 or increased demands in the industry. If we are unable to procure certain of such rig components, our ability to construct, maintain or improve drilling rigs could be impaired, which could have a material adverse effect on our business, financial condition and results of operations.

If our principal fabricator, located on the Texas gulf coast, was unable or unwilling to continue fabricating rig components, then we would have to transfer this work to other acceptable fabricators. This transfer could result in delay in the completion of new FlexRigs. Any significant interruption in the fabrication of rig components could have a material adverse impact on our business, financial condition and results of operations.

Certain key rig components 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. Therefore, disruptions in rig component delivery may occur, and such disruptions and terminations 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. We may incur currency devaluations 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 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.

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

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

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

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

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

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

Our business is subject to cybersecurity risks.

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

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, make loans or certain types of investments, sell or otherwise dispose of assets, enter into new lines of business, and merge or consolidate. In addition, our debt agreements also require us to maintain minimum current, funded leverage and interest coverage ratios. 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 2015 fiscal year and that remain unresolved.

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, 2015:

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
WYOMING	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
NEW MEXICO	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
NEW MEXICO	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

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
NEW MEXICO	267	22,000	AC (FlexRig3)	1,500
TEXAS	268	22,000	AC (FlexRig3)	1,500
TEXAS	269	22,000	AC (FlexRig3)	1,500
WYOMING	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
WYOMING	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

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
NEW MEXICO	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
TEXAS	383	22,000	AC (FlexRig3)	1,500
TEXAS	384	22,000	AC (FlexRig3)	1,500

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
NEW MEXICO	415	22,000	AC (FlexRig3)	1,500
NEW MEXICO	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
NORTH DAKOTA	448	22,000	AC (FlexRig3)	1,500

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
NEW MEXICO	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

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
NORTH DAKOTA	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
PENNSYLVANIA	521	25,000	AC (FlexRig5)	1,500
COLORADO	522	25,000	AC (FlexRig5)	1,500
TEXAS	523	25,000	AC (FlexRig5)	1,500
NORTH DAKOTA	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
TEXAS	533	25,000	AC (FlexRig5)	1,500
LOUISIANA	534	25,000	AC (FlexRig5)	1,500
NORTH DAKOTA	535	25,000	AC (FlexRig5)	1,500
NEW MEXICO	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	552	25,000	AC (FlexRig5)	1,500
TEXAS	556	25,000	AC (FlexRig5)	1,500

Location	Rig	Optimum Depth (Feet)	Rig Type	Drawworks: Horsepower
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
TEXAS	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
TEXAS	636	22,000	AC (FlexRig3)	1,500
TEXAS	637	22,000	AC (FlexRig3)	1,500
TEXAS	638	22,000	AC (FlexRig3)	1,500
TEXAS	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
TEXAS	648	22,000	AC (FlexRig3)	1,500
TEXAS	649	22,000	AC (FlexRig3)	1,500

Location	Rig	Optimum Depth (Feet)	Rig Type	Drawworks: Horsepower
TEXAS	650	22,000	AC (FlexRig3)	1,500
TEXAS	651	22,000	AC (FlexRig3)	1,500
TEXAS	652	22,000	AC (FlexRig3)	1,500
TEXAS	653	22,000	AC (FlexRig3)	1,500
TEXAS	659	22,000	AC (FlexRig3)	1,500
CONVENTIONAL RIGS				
TEXAS	139	30,000	SCR	3,000
LOUISIANA	161	30,000	SCR	3,000
OFFSHORE PLATFORM RIGS				
GULF OF MEXICO	100	30,000	Conventional	3,000
GULF OF MEXICO	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
GULF OF MEXICO	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,				
	2011	2012	2013	2014	2015
U.S. Land Rigs					
Number of rigs at end of period	248	282	302	329	343
Average rig utilization rate during period (1)	86%	89%	82%	86%	62%
U.S. Offshore Platform Rigs					
Number of rigs at end of period	9	9	9	9	9
Average rig utilization rate during period (1)	77%	79%	89%	89%	93%

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

The following table sets forth certain information concerning our international drilling rigs as of September 30, 2015:

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

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

	Years ended September 30,				
	2011	2012	2013	2014	2015
Number of rigs at end of period	24	29	29	36	38
Average rig utilization rate during period (1)(2)	70%	77%	82%	76%	53%

(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.

STOCK PORTFOLIO

Information required by this item regarding our stock portfolio may be found on, 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 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.

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 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.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

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, 54	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, 50	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, 53	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
Jeffrey L. Flaherty, 52	Senior Vice President of Operations, Helmerich & Payne International Drilling Co., since August 2014; Senior Vice President, U.S. Land Operations of Helmerich & Payne International Drilling Co. from January 2012 to August 2014; Vice President, U.S. Land Operations of Helmerich & Payne International Drilling Co. from March 2006 to January 2012
John R. Bell, 45	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, 39	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

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 13, 2015, there were 611 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:

	2014		2015	
Quarter	**High**	**Low**	**High**	**Low**
First	$ 84.87	$ 68.87	$98.47	$59.24
Second	108.43	81.34	71.55	54.00
Third	118.02	103.54	79.90	67.60
Fourth	118.95	96.79	70.34	46.16

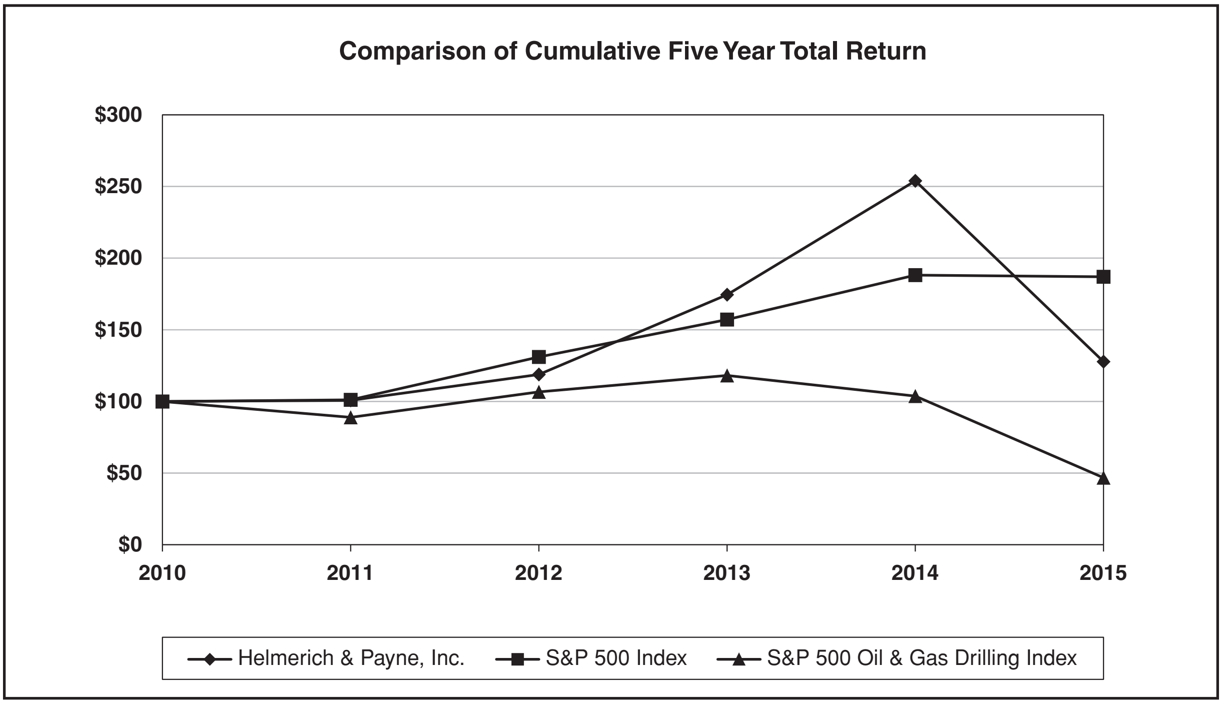
Dividends

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

	Paid per Share		Total Payment	
	Fiscal		Fiscal	
Quarter	**2014**	**2015**	**2014**	**2015**
First	$.5000	$.6875	$53,859,536	$74,822,055
Second	.6250	.6875	67,685,672	74,525,525
Third	.6250	.6875	67,996,052	74,478,918
Fourth	.6875	.6875	74,844,562	74,540,202

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.



Company / Index	Base Period Sep10	INDEXED RETURNS Years Ending Sep11	Sep12	Sep13	Sep14	Sep15
Helmerich & Payne, Inc.	**100**	100.79	118.84	174.52	253.98	127.78
S&P 500 Index	**100**	101.15	131.69	157.17	188.18	187.02
S&P 500 Oil & Gas Drilling Index	**100**	88.93	106.70	118.16	103.77	46.80

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.

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

	2015	2014	2013	2012	2011
	(in thousands except per share amounts)				
Operating revenues	$3,165,441	$3,719,707	$3,387,614	$3,151,802	$2,543,894
Income from continuing operations	422,272	708,766	721,453	573,609	434,668
Income (loss) from discontinued operations	(47)	(47)	15,186	7,436	(482)
Net income	422,225	708,719	736,639	581,045	434,186
Basic earnings per share from continuing operations	3.90	6.54	6.75	5.35	4.06
Basic earnings per share from discontinued operations	—	—	0.14	0.07	—
Basic earnings per share	3.90	6.54	6.89	5.42	4.06
Diluted earnings per share from continuing operations	3.87	6.46	6.65	5.27	3.99
Diluted earnings per share from discontinued operations	—	—	0.14	0.07	—
Diluted earnings per share	3.87	6.46	6.79	5.34	3.99
Total assets* ^	7,152,012	6,720,998	6,263,564	5,719,413	5,003,001
Long-term debt ^	492,443	39,502	79,137	193,737	234,279
Cash dividends declared per common share	2.750	2.625	1.300	0.280	0.260

* *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 390 drilling rigs at September 30, 2015. Our contract drilling segments consist of the U.S. Land segment with 343 rigs, the Offshore segment with nine offshore platform rigs and the International Land segment with 38 rigs at September 30, 2015. During fiscal 2015, we placed into service 30 new FlexRigs and completed another nine new FlexRigs. At the close of fiscal 2015, we had 170 contracted rigs, compared to 325 contracted rigs at the same time during the prior year. Faced with a global oversupply of oil, the short-term outlook for the industry is unfavorable. However, our long-term strategy remains 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 manage the current slowdown and take advantage of opportunities that lie ahead.

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 2015, 2014 and 2013 in the following discussion are referring to fiscal years 2015, 2014 and 2013.

Results of Operations

All per share amounts included in the Results of Operations discussion are stated on a diluted basis. Our net income for 2015 was $422.2 million ($3.87 per share), compared with $708.7 million

($6.46 per share) for 2014 and $736.6 million ($6.79 per share) for 2013. Included in our net income is after-tax gains from the sale of investment securities of $27.8 million ($0.25 per share) in 2014 and $97.9 million ($0.91 per share) in 2013. Net income also includes after-tax gains from the sale of assets of $7.4 million ($0.07 per share) in 2015, $12.7 million ($0.12 per share) in 2014 and $12.2 million ($0.11 per share) in 2013.

Consolidated operating revenues were $3.2 billion in 2015, $3.7 billion in 2014 and $3.4 billion in 2013. As oil prices steeply declined during 2015, 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 75,866 in 2015, compared to 100,638 in 2014 and 88,620 in 2013. Our U.S. land rig utilization was 62 percent in 2015, 86 percent in 2014 and 82 percent in 2013. The average number of U.S. land rigs available was 336 rigs in 2015, 319 rigs in 2014 and 295 rigs in 2013. Revenue in the Offshore segment steadily decreased in 2015 after increasing in 2014 from 2013 while rig utilization for offshore rigs was 93 percent in 2015, compared to 89 percent in 2014 and 2013. The International Land segment has also been affected by the decline in oil prices causing revenue days to decline to 7,474 in 2015 from 8,303 in 2014 and 8,707 in 2013. Rig utilization in our International Land segment was 53 percent in 2015, 76 percent in 2014 and 82 percent in 2013.

In 2014 and 2013, we had $45.2 million and $162.1 million in gains from the sale of investment securities, respectively. Interest and dividend income was $5.8 million, $1.6 million and $1.7 million in 2015, 2014 and 2013, respectively. The increase was primarily the result of Atwood Oceanics, Inc. declaring dividends during 2015.

Direct operating costs in 2015 were $1.7 billion or 54 percent of operating revenues, compared with $2.0 billion or 54 percent of operating revenues in 2014 and $1.9 billion or 55 percent of operating revenues in 2013.

Depreciation expense was $607.0 million in 2015, $523.5 million in 2014 and $455.6 million in 2013. Included in depreciation are abandonments of equipment of $43.6 million in 2015, $23.0 million in 2014 and $9.1 million in 2013. Depreciation expense, exclusive of the abandonments, increased over the three-year period as we placed into service 30 new rigs in 2015, 45 in 2014 and 20 in 2013. Depreciation expense in 2016 is expected to increase from 2015 from new rigs placed into service during 2015 and additional rigs placed into service during 2016. (See Liquidity and Capital Resources.) Abandonments increased over the three-year period primarily due to decommissioning 23 rigs in 2015, nine rigs in 2014 and two rigs in 2013.

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 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. The impairment charge is not expected to have an impact on our liquidity or debt covenants. In 2014 and 2013, no impairment was recorded.

General and administrative expenses totaled $134.9 million in 2015, $135.1 million in 2014 and $126.3 million in 2013. The $8.8 million increase in 2014 from 2013 is primarily due to continued growth in the number of employees in the comparative periods and increases in salaries, bonuses, and stock-based compensation.

Interest expense net of amounts capitalized totaled $15.0 million in 2015, $4.7 million in 2014 and $6.1 million in 2013. Interest expense is primarily attributable to fixed-rate debt outstanding. Interest expense increased in 2015 from 2014 primarily due to the issuance of $500 million unsecured senior notes in March 2015. Interest expense decreased in 2014 from 2013 primarily due to a reduction in outstanding debt balances during the two years. Capitalized interest was $7.0 million, $7.7 million and $8.8 million in 2015, 2014 and 2013, respectively. All of the capitalized interest is attributable to our rig construction program.

The provision for income taxes totaled $243.4 million in 2015, $387.5 million in 2014 and $392.8 million in 2013. The effective income tax rate was 36.6 percent in 2015 compared to 35.4 percent in 2014 and 35.3 percent in 2013. 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 2015, 2014 and 2013, we incurred $16.1 million, $15.9 million and $15.2 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 2016.

Expenses incurred within the country of Venezuela are reported as discontinued operations. Included in 2013 are proceeds from arbitration disputes with third parties not affiliated with the Bolivarian Republic of Venezuela, Petroleos de Venezuela, S.A. ("PDVSA") or PDVSA Petroleo, S.A. ("Petroleo") related to the seizure of our property in Venezuela on June 30, 2010. Proceeds of $15.0 million were received and recorded as discontinued operations in 2013.

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, PDVSA and 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.

The following tables summarize operations by reportable operating segment.

Comparison of the years ended September 30, 2015 and 2014

	2015	2014	% 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. As of November 12, 2015, six announced FlexRigs remained to be delivered.

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. As a result of the new FlexRigs added in fiscal 2015 and additional rigs scheduled for completion in fiscal 2016, we anticipate depreciation expense to continue to increase in fiscal 2016.

At September 30, 2015, 145 out of 343 existing rigs in the U.S. Land segment were generating revenue. Of the 145 rigs generating revenue, 120 were under fixed-term contracts, and 25 were working in the spot market. At November 12, 2015, the number of existing rigs under fixed-term contracts in the segment was 108 and the number of rigs working in the spot market was 24.

Comparison of the years ended September 30, 2015 and 2014

	2015	2014	% Change
	(in thousands, except operating statistics)		
OFFSHORE OPERATIONS			
Operating revenues	$241,043	$250,811	(3.9)%
Direct operating expenses	158,138	158,834	(0.4)
General and administrative expense	3,517	9,858	(64.3)
Depreciation	11,659	12,300	(5.2)
Segment operating income	$ 67,729	$ 69,819	(3.0)
Operating Statistics:			
Revenue days	3,067	2,920	5%
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 $32,868 and $19,007 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.

Comparison of the years ended September 30, 2015 and 2014

	2015	2014	% Change
	(in thousands, except operating statistics)		
INTERNATIONAL LAND OPERATIONS			
Operating revenues	$386,693	$355,532	8.8%
Direct operating expenses	290,752	274,894	5.8
General and administrative expense	3,342	4,289	(22.1)
Depreciation	56,287	39,932	41.0
Asset Impairment charge	39,242	—	100.0
Segment operating income (loss)	$ (2,930)	$ 36,417	(108.0)
Operating Statistics:			
Revenue days	7,474	8,303	(10.0)%
Average rig revenue per day	$ 46,684	$ 37,117	25.8
Average rig expense per day	$ 34,211	$ 27,278	25.4
Average rig margin per day	$ 12,473	$ 9,839	26.8
Number of rigs at end of period	38	36	5.6
Rig utilization	53%	76%	(30.3)

Operating statistics for per day revenue, expense and margin do not include reimbursements of "out-of-pocket" expenses of $37,776 and $47,350 for 2015 and 2014, respectively. Also excluded are the effects of currency revaluation expense.

The International Land segment had an operating loss of $2.9 million for 2015 compared to operating income of $36.4 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 revenue in 2015, the average rig revenue per day increased by $7,065 as compared to 2014. Rigs transferred into the segment during 2015 and 2014 favorably impacted revenue and revenue per day. The average number of active rigs was 20.5 during 2015 compared to 22.7 during 2014.

The average rig expense increase was attributable to expenses incurred on rigs that have become idle and other costs associated with rigs transitioning between locations. The average rig expense was also impacted by approximately $673 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 17 and 23 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 is not expected to have an impact on our liquidity or debt covenants.

Comparison of the years ended September 30, 2014 and 2013

	2014	2013	% Change
	(in thousands, except operating statistics)		
U.S. LAND OPERATIONS			
Operating revenues	$3,099,954	$2,785,449	11.3%
Direct operating expenses	1,576,702	1,424,716	10.7
General and administrative expense	41,573	37,070	12.1
Depreciation	455,934	391,072	16.6
Segment operating income	$1,025,745	$ 932,591	10.0
Operating Statistics:			
Revenue days	100,638	88,620	13.6%
Average rig revenue per day	$ 28,194	$ 28,382	(0.7)
Average rig expense per day	$ 13,058	$ 13,029	0.2
Average rig margin per day	$ 15,136	$ 15,353	(1.4)
Number of rigs at end of period	329	302	8.9
Rig utilization	86%	82%	4.9

Operating statistics for per day revenue, expense and margin do not include reimbursements of "out-of-pocket" expenses of $262,532 and $270,223 for 2014 and 2013, respectively.

Rig utilization in 2013 excludes two FlexRigs completed and ready for delivery at September 30, 2013.

Operating income in the U.S. Land segment increased to $1.0 billion in 2014 from $932.6 million in 2013 primarily due to an increase in revenue days. Included in U.S. land revenues for 2014 and 2013 is approximately $11.7 million and $19.0 million, respectively, from early termination of fixed-term contracts. Excluding early termination related revenue, the average rig revenue per day for 2014 only slightly decreased by $90 to $28,078 from $28,168 in 2013. Direct operating expenses as a percentage of revenue were 51 percent in 2014 and 51 percent in 2013.

Rig utilization increased to 86 percent in 2014 from 82 percent in 2013. The total number of available rigs at September 30, 2014 was 329 compared to 302 rigs at September 30, 2013. The net increase is due to 42 new FlexRigs completed and placed into service, six FlexRigs transferred to the International Land segment and nine older conventional rigs removed from service.

Depreciation includes charges for abandoned equipment of $21.5 million and $8.2 million in 2014 and 2013, respectively. Included in abandonments in 2014 is the decommissioning of nine conventional rigs and spare equipment for drilling rigs. Included in abandonments in 2013 is the decommissioning of two conventional rigs. Excluding the abandonment amounts, depreciation in 2014 increased 13 percent from 2013 due to the increase in available rigs.

Comparison of the years ended September 30, 2014 and 2013

	2014	2013	% Change
	(in thousands, except operating statistics)		
OFFSHORE OPERATIONS			
Operating revenues	$250,811	$221,863	13.0%
Direct operating expenses	158,834	146,184	8.7
General and administrative expense	9,858	8,849	11.4
Depreciation	12,300	13,766	(10.6)
Segment operating income	$ 69,819	$ 53,064	31.6
Operating Statistics:			
Revenue days	2,920	2,920	—%
Average rig revenue per day	$ 63,094	$ 61,069	3.3
Average rig expense per day	$ 37,653	$ 37,654	—
Average rig margin per day	$ 25,441	$ 23,415	8.7
Number of rigs at end of period	9	9	—
Rig utilization	89%	89%	—

Operating statistics for per day revenue, expense and margin do not include reimbursements of "out-of-pocket" expenses of $19,007 and $19,701 for 2014 and 2013, 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 increased in 2014 from 2013 primarily due to our offshore management contracts. Included in 2013 direct operating expenses is a one-time charge of $6.4 million related to an incident in the Gulf of Mexico. At September 30, 2014 and 2013, eight of our nine rigs were working.

Comparison of the years ended September 30, 2014 and 2013

	2014	2013	% Change
	(in thousands, except operating statistics)		
INTERNATIONAL LAND OPERATIONS			
Operating revenues	$355,532	$366,841	(3.1)%
Direct operating expenses	274,894	282,335	(2.6)
General and administrative expense	4,289	3,911	9.7
Depreciation	39,932	36,000	10.9
Segment operating income	$ 36,417	$ 44,595	(18.3)
Operating Statistics:			
Revenue days	8,303	8,707	(4.6)%
Average rig revenue per day	$ 37,117	$ 37,246	(0.3)
Average rig expense per day	$ 27,278	$ 27,589	(1.1)
Average rig margin per day	$ 9,839	$ 9,657	1.9
Number of rigs at end of period	36	29	24.1
Rig utilization	76%	82%	(7.3)

Operating statistics for per day revenue, expense and margin do not include reimbursements of "out-of-pocket" expenses of $47,350 and $42,542 for 2014 and 2013, respectively. Also excluded are the effects of currency revaluation expense.

The International Land segment had operating income of $36.4 million for 2014 compared to $44.6 million for 2013. Included in International land revenues in 2013 is approximately $5.3 million related to early termination fees.

Excluding the $5.3 million early termination revenues in 2013, segment operating income in 2014 decreased from 2013 with revenue days decreasing 4.6 percent and rig utilization decreasing to 76 percent in 2014 from 82 percent in 2013. The total number of available rigs increased to 36 at September 30, 2014 from 29 at September 30, 2013.

During 2014, the total number of available rigs increased by seven due to one new 3,000 horsepower AC drive rig added to the fleet and six FlexRigs transferred from the U.S. Land segment. At the close of 2014 and 2013, we had 23 and 22 rigs working, respectively.

LIQUIDITY AND CAPITAL RESOURCES

Our capital spending was $1.1 billion in 2015, $952.9 million in 2014 and $809.1 million in 2013. Net cash provided from operating activities was $1.4 billion in 2015, $1.1 billion in 2014 and $997.2 million in 2013. Our 2016 capital spending is currently estimated to be between $300 million and $400 million, depending primarily on drilling market conditions. This estimate includes contracted new builds, capital maintenance requirements, tubulars and other special projects.

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 purchased $45.6 million of short-term investments classified as trading securities. 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 2015, had a fair value of $91.5 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 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. During 2013, we had cash proceeds from the sale of investment securities of $232.2 million including $214.1 from the sale of marketable equity available-for-sale securities and $18.1 million from the sale of three limited partnerships.

Our proceeds from asset sales totaled $22.5 million in 2015, $30.8 million in 2014 and $28.0 million in 2013. Income from asset sales in 2015 totaled $11.7 million, $19.6 million in 2014 and $18.9 million in 2013. 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 will be held as treasury shares. We had no purchases of common shares in fiscal 2014 and 2013.

During 2015, we paid dividends of $2.75 per share, or a total of $298.4 million. We paid $2.438 per share or $264.4 million in 2014 and $0.87 per share or $93.1 million in 2013. Adjusting for stock splits accordingly, we have increased the effective annual dividend per share every year for over 40 years.

We have $40 million of senior unsecured fixed-rate notes outstanding at September 30, 2015 that mature July 2016. Interest on the notes is paid semi-annually based on an annual rate of 6.10 percent. A final annual principal repayment of $40 million is due July 2016. We have complied with our financial covenants which require us to maintain a funded leverage ratio of less than 55 percent and an interest coverage ratio (as defined) of not less than 2.50 to 1.00.

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, were 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 each year, commencing on September 15, 2015. 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.

We have a $300 million unsecured revolving credit facility that will mature May 25, 2017. The credit facility has $100 million available to use for letters of credit. The majority of 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 .35 percent per annum. Based on our debt to total capitalization on September 30, 2015, the spread over LIBOR and commitment fees would be 1.125 percent and .15 percent, respectively. Financial covenants in the facility require us to maintain a funded leverage ratio (as defined) of less than 50 percent and an interest coverage ratio (as defined) of not less than 3.00 to 1.00. 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. As of September 30, 2015, there were no borrowings, but there were three letters of credit outstanding in the amount of $48.2 million. At September 30, 2015, we had $251.8 million available to borrow under our $300 million unsecured credit facility. Subsequent to September 30, 2015, we reduced our outstanding letters of credit by $7.9 million, which increased available borrowing capacity to $259.7 million.

At September 30, 2015, we had two letters of credit outstanding, totaling $12 million that were issued to support international operations. These letters of credit were issued separately from the $300 million credit facility so they do not reduce the available borrowing capacity discussed in the previous paragraph.

The applicable agreements for all unsecured debt described in Note 3 to the Consolidated Financial Statements 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, 2015, we were in compliance with all debt covenants.

At September 30, 2015, we had 137 existing rigs with fixed term contracts with original term durations ranging from six months to seven years, with some expiring in fiscal 2016. 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 construction program, for fiscal 2016 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 4.1 at September 30, 2015 and 2.5 at September 30, 2014. The long-term debt to total capitalization ratio, including the current portion of long-term debt, was ten percent at September 30, 2015 compared to two percent at September 30, 2014.

STOCK PORTFOLIO HELD

September 30, 2015	Number of Shares	Cost Basis	Market Value
	(in thousands, except share amounts)		
Atwood Oceanics, Inc.	4,000,000	$60,749	$59,240
Schlumberger, Ltd.	467,500	3,713	32,243
Total		$64,462	$91,483

Material Commitments

We have no off balance sheet arrangements other than operating leases discussed below. Our contractual obligations as of September 30, 2015, are summarized in the table below in thousands:

	Payments due by year						
Contractual Obligations	Total	2016	2017	2018	2019	2020	After 2020
Long-term debt and estimated interest (a)	$762,346	$ 65,690	$23,250	$23,250	$23,250	$23,250	$603,656
Operating leases (b)	38,635	7,803	6,246	4,304	4,236	3,711	12,335
Purchase obligations (b)	81,090	81,090	—	—	—	—	—
Total contractual obligations	$882,071	$154,583	$29,496	$27,554	$27,486	$26,961	$615,991

(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 2015, we contributed $2.2 million to the pension plan. Contributions may be made in fiscal 2016 to fund unexpected distributions in lieu of liquidating pension assets. Future contributions beyond fiscal 2016 are difficult to estimate due to multiple variables involved.

At September 30, 2015, we had $22.3 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.

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 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 rigs fair value was estimated using discounted future cash flows.

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.

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 4.27 percent from 4.32 percent as of September 30, 2015 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 approximately $1.4 million in 2016 from 2015.

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, 2015, unrecognized compensation cost related to unvested restricted stock was $21.2 million. The cost is expected to be recognized over a weighted-average period of 2.2 years.

Revenue Recognition Contract drilling revenues are comprised of daywork drilling contracts for which the related revenues and expenses are recognized as services are performed and collection is reasonably assured. For certain contracts, we receive payments contractually designated for the mobilization of rigs and other drilling equipment. Mobilization payments received, and direct costs incurred for the mobilization, are deferred and recognized over the term of the related drilling contract. Costs incurred to relocate rigs and other drilling equipment to areas in which a contract has not been secured are expensed as incurred. Reimbursements received for out-of-pocket expenses are recorded as both revenues and direct costs. For contracts that are terminated prior to the specified term, early termination payments received by us are recognized as revenues when all contractual requirements are met.

NEW ACCOUNTING STANDARDS

In April 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2015-03 "*Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs*". ASU No. 2015-03 amends the FASB Accounting Standards Codifications ("ASC") to require that debt issuance cost be presented in the balance sheet as a direct deduction from the carrying amount of the related liability. Prior to the amendment, debt issuance costs were reported in the balance sheet as an asset. The amended guidance is effective for financial statements issued for fiscal years beginning after December 15, 2015, however, we elected to early adopt effective January 1, 2015. The election requires retrospective application and represents a change in accounting principle. The ASU provides that debt issuance costs are similar to debt discounts and in effect reduce the proceeds of borrowing, thereby increasing the effective interest rate. As a result of the adoption, the September 30, 2014 Consolidated Balance Sheet has been restated as shown in Note 1 of the Consolidated Financial Statements.

In April 2014, FASB issued ASU No. 2014-08, *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity*. The amendments in ASU 2014-08 change the criteria for reporting discontinued operations while enhancing disclosures in this area. Under the new guidance, only disposals representing a strategic shift in operations should be presented as discontinued operations. Those strategic shifts should have a major effect on the organization's operations and financial results. In addition, the new guidance requires expanded disclosures about discontinued operations that will provide financial statement users with more information about the assets, liabilities, income, and expenses of discontinued operations. The pronouncement is effective for fiscal years beginning on or after December 15, 2014 and interim periods within those years. The adoption of this pronouncement is not expected to have a material impact on our financial statements.

In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers*, which supersedes virtually all existing revenue recognition guidance. The new standard requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. This update also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts, including significant judgments and changes in judgments and assets recognized from costs incurred to obtain or fulfill a contract. The provisions of ASU 2014-09 are effective for interim and annual periods beginning after December 15, 2017, and we have the option of using either a full retrospective or a modified retrospective approach when adopting this new standard.

We are currently evaluating the alternative transition methods and 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 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.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Foreign Currency Exchange Rate Risk Our contracts for work in foreign countries generally provide for payment in U.S. dollars. However, in Argentina we are paid in Argentine pesos. The Argentine branch of one of our second-tier subsidiaries then remits U.S. dollars to its U.S. parent by converting the Argentine pesos into U.S. dollars through the Argentine Foreign Exchange Market and repatriating the U.S. dollars. In the future, other contracts or applicable law may require payments to be made in foreign currencies. As such, there can be no assurance that we will not experience in Argentina or elsewhere a devaluation of foreign currency, foreign exchange restrictions or other difficulties repatriating U.S. dollars even if we are able to negotiate the contract provisions designed to mitigate such risks. In the event of future payments in foreign currencies and an inability to timely exchange foreign currencies for U.S. dollars, we may incur currency devaluation losses which could have a material adverse impact on our business, financial condition and results of operations. A hypothetical 10% decrease in the value of our Argentine pesos relative to the U.S. dollar as of September 30, 2015 would result in a $2.5 million decrease in the fair value of our monetary assets and liabilities denominated in Argentine pesos.

We are not operating in any country that is currently considered highly inflationary, 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. Estimates from other published sources may indicate that Argentina is a highly inflationary country. 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.

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, 2015 has fixed-rate interest obligations, there is no current risk due to interest rate fluctuation.

The following tables provide information as of September 30, 2015 and 2014 about our interest rate risk sensitive instruments:

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								

INTEREST RATE RISK AS OF SEPTEMBER 30, 2014 (dollars in thousands)

	2015	2016	2017	2018	2019	After 2019	Total	Fair Value 9/30/14
Fixed-Rate Debt	$40,000	$40,000	$—	$—	$—	$—	$80,000	$84,328
Average Interest Rate	6.1%	6.1%	—%	—%	—%	—%	6.1%	
Variable Rate Debt	$ —	$ —	$—	$—	$—	$—	$ —	$ —
Average Interest Rate								

Equity Price Risk On September 30, 2015, we had a portfolio of securities with a total fair value of $91.5 million. The total fair value of the portfolio of securities was $222.3 million at September 30, 2014. A hypothetical 10% decrease in the market prices for all securities in our portfolio as of September 30, 2015 would decrease the fair value of our available-for-sale securities by $9.2 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. At November 12, 2015, the total fair value of the remaining securities had increased to approximately $98.7 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.

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, 2015 and 2014, and the related consolidated statements of income, comprehensive income, shareholders' equity and cash flows for each of the three years in the period ended September 30, 2015. 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, 2015 and 2014, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2015, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Helmerich & Payne, Inc.'s internal control over financial reporting as of September 30, 2015, 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 25, 2015 expressed an unqualified opinion thereon.

/s/Ernst & Young LLP

Tulsa, Oklahoma
November 25, 2015

Consolidated Statements of Income

HELMERICH & PAYNE, INC.

	Years Ended September 30,		
	2015	2014	2013
	(in thousands, except per share amounts)		
Operating revenues			
Drilling—U.S. Land	$2,523,518	$3,099,954	$2,785,449
Drilling—Offshore	241,043	250,811	221,863
Drilling—International Land	386,693	355,532	366,841
Other	14,187	13,410	13,461
	3,165,441	3,719,707	3,387,614
Operating costs and expenses			
Operating costs, excluding depreciation	1,704,163	2,009,912	1,852,768
Depreciation	606,992	523,549	455,623
Asset impairment charge	39,242	—	—
Research and development	16,104	15,905	15,235
General and administrative	134,906	135,139	126,250
Income from asset sales	(11,716)	(19,585)	(18,923)
	2,489,691	2,664,920	2,430,953
Operating income from continuing operations	**675,750**	**1,054,787**	**956,661**
Other income (expense)			
Interest and dividend income	5,834	1,583	1,653
Interest expense	(15,036)	(4,654)	(6,129)
Gain on sale of investment securities	—	45,234	162,121
Other	(901)	(636)	(9)
	(10,103)	41,527	157,636
Income from continuing operations before income taxes	665,647	1,096,314	1,114,297
Income tax provision	243,375	387,548	392,844
Income from continuing operations	422,272	708,766	721,453
Income (loss) from discontinued operations before income taxes	(124)	2,758	14,701
Income tax provision (benefit)	(77)	2,805	(485)
Income (loss) from discontinued operations	(47)	(47)	15,186
NET INCOME	**$ 422,225**	**$ 708,719**	**$ 736,639**
Basic earnings per common share:			
Income from continuing operations	$ 3.90	$ 6.54	$ 6.75
Income from discontinued operations	$ —	$ —	$ 0.14
Net income	$ 3.90	$ 6.54	$ 6.89
Diluted earnings per common share:			
Income from continuing operations	$ 3.87	$ 6.46	$ 6.65
Income from discontinued operations	$ —	$ —	$ 0.14
Net income	$ 3.87	$ 6.46	$ 6.79
Weighted average shares outstanding (in thousands):			
Basic	107,754	107,800	106,286
Diluted	108,570	109,141	107,879

The accompanying notes are an integral part of these statements.

Consolidated Statements of Comprehensive Income

HELMERICH & PAYNE, INC.

	Years Ended September 30,		
	2015	2014	2013
		(in thousands)	
Net income	$422,225	$708,719	$736,639
Other comprehensive income, net of income taxes:			
Unrealized appreciation (depreciation) on securities, net of income taxes of ($50.6) million at September 30, 2015, ($15.5) million at September 30, 2014 and $34.2 million at September 30, 2013	(80,217)	(19,006)	46,853
Reclassification of realized gains in net income, net of income taxes of ($17.5) million at September 30, 2014 and ($60.8) million at September 30, 2013	—	(27,737)	(92,543)
Minimum pension liability adjustments, net of income taxes of ($2.5) million at September 30, 2015, ($1.5) million at September 30, 2014 and $6.6 million at September 30, 2013	(4,286)	(2,661)	11,413
Other comprehensive loss	(84,503)	(49,404)	(34,277)
Comprehensive income	$337,722	$659,315	$702,362

The accompanying notes are an integral part of these statements.

Consolidated Balance Sheets

HELMERICH & PAYNE, INC.

	September 30, 2015	September 30, 2014 (as adjusted)
	(in thousands)	
Assets		
CURRENT ASSETS:		
Cash and cash equivalents	$ 717,977	$ 360,909
Short-term investments	45,543	—
Accounts receivable, less reserve of $6,181 in 2015 and $4,597 in 2014	449,344	705,214
Inventories	128,729	106,241
Deferred income taxes	17,200	16,519
Prepaid expenses and other	72,117	80,912
Current assets of discontinued operations	8,097	7,206
Total current assets	1,439,007	1,277,001
INVESTMENTS	104,354	236,644
PROPERTY, PLANT AND EQUIPMENT, at cost:		
Contract drilling equipment	7,985,052	7,191,281
Construction in progress	95,518	288,877
Real estate properties	65,466	64,812
Other	457,614	354,853
	8,603,650	7,899,823
Less-Accumulated depreciation	3,036,415	2,711,279
Net property, plant and equipment	5,567,235	5,188,544
NONCURRENT ASSETS:		
Other assets	41,416	18,809
TOTAL ASSETS	$7,152,012	$6,720,998

The accompanying notes are an integral part of these statements.

Consolidated Balance Sheets (Continued)

HELMERICH & PAYNE, INC.

	September 30, 2015	September 30, 2014 (as adjusted)
	(in thousands, except share data and per share amounts)	
Liabilities and Shareholders' Equity		
CURRENT LIABILITIES:		
Accounts payable	$ 110,704	$ 182,031
Accrued liabilities	198,053	282,278
Long-term debt due within one year	39,094	39,635
Current liabilities of discontinued operations	3,377	3,217
Total current liabilities	351,228	507,161
NONCURRENT LIABILITIES:		
Long-term debt	492,443	39,502
Deferred income taxes	1,295,065	1,215,259
Other	111,104	64,110
Noncurrent liabilities of discontinued operations	4,720	3,989
Total noncurrent liabilities	1,903,332	1,322,860
SHAREHOLDERS' EQUITY:		
Common stock, $.10 par value, 160,000,000 shares authorized, 110,987,546 and 110,508,605 shares issued as of September 30, 2015 and 2014, respectively, and 107,767,915 and 108,232,284 shares outstanding as of September 30, 2015 and 2014, respectively	11,099	11,051
Preferred stock, no par value, 1,000,000 shares authorized, no shares issued	—	—
Additional paid-in capital	420,141	383,972
Retained earnings	4,649,952	4,525,797
Accumulated other comprehensive income (loss)	(1,377)	83,126
	5,079,815	5,003,946
Less treasury stock, 3,219,631 shares in 2015 and 2,276,321 shares in 2014, at cost	182,363	112,969
Total shareholders' equity	4,897,452	4,890,977
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$7,152,012	$6,720,998

The accompanying notes are an integral part of these statements.

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, 2012	107,599	10,760	236,240	3,505,295	166,807	1,901	(84,104)	3,834,998
Comprehensive Income:								
Net income				736,639				736,639
Other comprehensive loss					(34,277)			(34,277)
Dividends declared ($1.30 per share)				(139,271)				(139,271)
Exercise of stock options	1,057	106	21,746			162	(8,535)	13,317
Tax benefit of stock-based awards			10,727					10,727
Stock issued for vested restricted stock, net of shares withheld for employee taxes	83	8	(3,226)			(41)	1,541	(1,677)
Stock-based compensation			23,271					23,271
Balance, September 30, 2013	108,739	10,874	288,758	4,102,663	132,530	2,022	(91,098)	4,443,727
Comprehensive Income:								
Net income				708,719				708,719
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	110,509	11,051	383,972	4,525,797	83,126	2,276	(112,969)	4,890,977
Comprehensive Income:								
Net income				422,225				422,225
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	110,987	$11,099	$420,141	$4,649,952	$ (1,377)	3,220	$(182,363)	$4,897,452

The accompanying notes are an integral part of these statements.

Consolidated Statements of Cash Flows

HELMERICH & PAYNE, INC.

	Years Ended September 30,		
	2015	2014	2013
	(in thousands)		
OPERATING ACTIVITIES:			
Net income	$ 422,225	$ 708,719	$ 736,639
Adjustment for (income) loss from discontinued operations	47	47	(15,186)
Income from continuing operations	422,272	708,766	721,453
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	606,992	523,549	455,623
Asset impairment charge	39,242	—	—
Amortization of debt issuance costs	749	400	409
Provision for (recovery of) bad debt	6,034	(200)	3,875
Stock-based compensation	25,195	26,703	23,271
Pension settlement charge	2,873	1,376	—
Gain on sale of investment securities	—	(45,234)	(162,121)
Income from asset sales	(11,716)	(19,585)	(18,923)
Deferred income tax expense	131,580	27,124	29,557
Other	(368)	2	2,490
Change in assets and liabilities:			
Accounts receivable	249,873	(83,594)	(4,806)
Inventories	(22,488)	(17,375)	(12,289)
Prepaid expenses and other	(13,812)	(6,687)	5,321
Accounts payable	(34,150)	(21,082)	(52,076)
Accrued liabilities	(22,901)	35,845	24,259
Deferred income taxes	598	(784)	(1,673)
Other noncurrent liabilities	38,818	(10,650)	(17,371)
Net cash provided by operating activities from continuing operations	1,418,791	1,118,574	996,999
Net cash provided by (used in) operating activities from discontinued operations	(47)	(47)	186
Net cash provided by operating activities	1,418,744	1,118,527	997,185
INVESTING ACTIVITIES:			
Capital expenditures	(1,133,482)	(952,892)	(809,066)
Purchase of short-term investments	(45,607)	—	—
Proceeds from asset sales	22,501	30,770	28,026
Proceeds from sale of investments	—	49,205	232,221
Net cash used in investing activities from continuing operations	(1,156,588)	(872,917)	(548,819)
Net cash provided by investing activities from discontinued operations	—	—	15,000
Net cash used in investing activities	(1,156,588)	(872,917)	(533,819)
FINANCING ACTIVITIES:			
Payments on long-term debt	(40,000)	(115,000)	(40,000)
Proceeds from senior notes, net of discount	497,125	—	—
Debt issuance costs	(5,474)	—	—
Proceeds on short-term debt	1,002	—	—
Payments on short-term debt	(1,002)	—	—
Repurchase of common stock	(59,654)	—	—
Dividends paid	(298,367)	(264,386)	(93,053)
Exercise of stock options, net of tax withholding	2,650	23,250	13,317
Tax withholdings related to net share settlements of restricted stock	(5,140)	(3,049)	(1,677)
Excess tax benefit from stock-based compensation	3,772	26,616	9,820
Net cash provided by (used in) financing activities	94,912	(332,569)	(111,593)
Net increase (decrease) in cash and cash equivalents	357,068	(86,959)	351,773
Cash and cash equivalents, beginning of period	360,909	447,868	96,095
Cash and cash equivalents, end of period	$ 717,977	$ 360,909	$ 447,868

The accompanying notes are an integral part of these statements.

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. Fiscal years of our foreign operations end on August 31 to facilitate reporting of consolidated results. There were no significant intervening events that materially affected the financial statements.

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 year. 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 are aggregate foreign currency remeasurement and a transaction gain of $2.8 million in fiscal 2015, a transaction loss of $0.8 million in fiscal 2014 and a transaction gain of $0.7 million in fiscal 2013.

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 April 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2015-03 "*Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs*". ASU No. 2015-03 amends the FASB Accounting Standards Codifications ("ASC") to require that debt issuance cost be presented in the balance sheet as a direct deduction from the carrying amount of the related liability. Prior to the amendment, debt issuance costs were reported in the balance sheet as an asset. The amended guidance is effective for financial statements issued for fiscal years beginning after December 15, 2015, however, we elected to early adopt effective January 1, 2015. The election requires retrospective application and represents a change in accounting principle. The ASU provides that debt issuance costs are similar to debt discounts and in

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

effect reduce the proceeds of borrowing. As a result of the adoption, the September 30, 2014 Consolidated Balance Sheet has been restated as follows:

	September 30, 2014		
	Previously Reported	Effect of Accounting Principle Adoption	Adjusted
		(in thousands)	
Consolidated Balance Sheet			
Prepaid expenses and other	$ 81,277	$(365)	$ 80,912
Total current assets	1,277,366	(365)	1,277,001
Other assets	19,307	(498)	18,809
Total assets	6,721,861	(863)	6,720,998
Long-term debt due within one year less unamortized discount and debt issuance costs	40,000	(365)	39,635
Total current liabilities	507,526	(365)	507,161
Long-term debt less unamortized discount and debt issuance costs	40,000	(498)	39,502
Total noncurrent liabilities	1,323,358	(498)	1,322,860
Total liabilities and shareholders' equity	6,721,861	(863)	6,720,998

Amortization of debt discount and debt issuance costs has been reclassified in the accompanying Consolidated Statements of Cash Flow for September 30, 2014 and 2013 to conform to current year presentation. The amortization was previously included as a change in assets.

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 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 $32.0 million and $30.2 million at September 30, 2015 and 2014, 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, 2015, $2.0 million is from the initial capitalization of the captive company and management has elected to restrict an additional $30.0 million. The restricted amounts are primarily invested in short-term money market securities.

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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

	September 30,	
	2015	2014
	(in thousands)	
Prepaid expenses and other	$29,998	$28,244
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 cost (moving average or actual) 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 Income includes abandonments of $43.6 million, $23.0 million and $9.1 million for fiscal 2015, 2014 and 2013, respectively. During fiscal 2015 and 2014, we decommissioned 23 and nine idle 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 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 2015, 2014 and 2013 was $7.0 million, $7.7 million and $8.8 million, respectively.

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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. 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 this year, domestic and international oil prices have declined significantly. This decline in pricing has resulted in lower demand for our drilling services. As a result, we have 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.

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 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. No additional impairments were identified for any other rigs in our domestic, international or offshore fleets.

SELF-INSURANCE ACCRUALS

We have accrued a liability for estimated worker's compensation and other casualty claims incurred.

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

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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 2015, 2014 and 2013 were $302.2 million, $328.9 million and $332.5 million, respectively. 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.

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 Income. Our rent revenues are as follows:

	Years Ended September 30,		
	2015	2014	2013
	(in thousands)		
Minimum rents	$9,608	$9,400	$9,009
Overage and percentage rents	$1,030	$1,090	$1,384

At September 30, 2015, minimum future rental income to be received on noncancelable operating leases was as follows:

Fiscal Year	Amount (in thousands)
2016	$ 7,395
2017	6,116
2018	4,440
2019	3,238
2020	2,391
Thereafter	3,985
Total	$27,565

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

At September 30, 2015 and 2014, the cost and accumulated depreciation for real estate properties were as follows:

	September 30,	
	2015	2014
	(in thousands)	
Real estate properties	$ 65,466	$ 64,812
Accumulated depreciation	(43,326)	(42,754)
	$ 22,140	$ 22,058

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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 Income.

EARNINGS PER SHARE

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

STOCK-BASED COMPENSATION

We record compensation expense associated with stock options in accordance with ASC 718, *Compensation—Stock Compensation*. 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 share-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 Income.

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.

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

NEW ACCOUNTING STANDARDS

In April 2014, FASB issued ASU No. 2014-08, *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity*. The amendments in ASU 2014-08 change the criteria for reporting discontinued operations while enhancing disclosures in this area. Under the new guidance, only disposals representing a strategic shift in operations should be presented as discontinued operations. Those strategic shifts should have a major effect on the organization's operations and financial results. In addition, the new guidance requires expanded disclosures about discontinued operations that will provide financial statement users with more information about the assets, liabilities, income, and expenses of discontinued operations. The pronouncement is effective for fiscal years beginning on or after December 15, 2014 and interim periods within those years. The adoption of this pronouncement is not expected to have a material impact on our financial statements.

In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers*, which supersedes virtually all existing revenue recognition guidance. The new standard requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. This update also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts, including significant judgments and changes in judgments and assets recognized from costs incurred to obtain or fulfill a contract. The provisions of ASU 2014-09 are effective for interim and annual periods beginning after December 15, 2017, and we have the option of using either a full retrospective or a modified retrospective approach when adopting this new standard. We are currently evaluating the alternative transition methods and 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 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.

NOTE 2 DISCONTINUED OPERATIONS

Current assets of discontinued operations consist of restricted cash to meet remaining current obligations with 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. Included in fiscal 2013 are proceeds from arbitration, as more fully described in Note 13.

NOTE 3 DEBT

At September 30, 2015 and 2014, we had $500 million and $40 million, respectively, in unsecured long-term debt outstanding at rates and maturities shown in the following table:

	Principal		Unamortized Discount and Debt Issuance Costs	
	September 30, 2015	September 30, 2014	September 30, 2015	September 30, 2014
	(in thousands)			
Unsecured senior notes issued July 21, 2009:				
Due July 21, 2015	$ —	$40,000	$ —	$(141)
Due July 21, 2016	40,000	40,000	(498)	(141)
Unsecured revolving credit facility issued May 25, 2012	—	—	—	(581)
Unsecured senior notes issued March 19, 2015:				
Due March 19, 2025	500,000	—	(7,965)	—
	540,000	80,000	(8,463)	(863)
Less long-term debt due within one year	40,000	40,000	(906)	(365)
Long-term debt	$500,000	$40,000	$(7,557)	$(498)

We have $40 million senior unsecured fixed-rate notes outstanding at September 30, 2015 that mature July 2016. Interest on the notes is paid semi-annually based on an annual rate of 6.10 percent. A final annual principal repayment of $40 million is due July 2016. We have complied with our financial covenants which require us to maintain a funded leverage ratio of less than 55 percent and an interest coverage ratio (as defined) of not less than 2.50 to 1.00.

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, 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 each year, commencing on September 15, 2015. 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.

We have a $300 million unsecured revolving credit facility that will mature May 25, 2017. The credit facility has $100 million available to use for letters of credit. The majority of 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 .35 percent per annum. Based on our debt to total capitalization on September 30, 2015, the spread over LIBOR and commitment fees would be 1.125 percent and .15 percent, respectively. Financial covenants in the facility require us to maintain a funded leverage ratio (as defined) of less than 50 percent and an interest coverage ratio (as defined) of not less than 3.00 to 1.00. 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. As of September 30, 2015, there were no borrowings, but there were

NOTE 3 DEBT (Continued)

three letters of credit outstanding in the amount of $48.2 million. At September 30, 2015, we had $251.8 million available to borrow under our $300 million unsecured credit facility. Subsequent to September 30, 2015, we reduced our outstanding letters of credit by $7.9 million, which increased available borrowing capacity to $259.7.

At September 30, 2015, we had two letters of credit outstanding, totaling $12 million that were issued to support international operations. These letters of credit were issued separately from the $300 million credit facility so they do not reduce the available borrowing capacity discussed in the previous paragraph.

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, 2015, we were in compliance with all debt covenants.

At September 30, 2015, aggregate maturities of long-term debt are as follows (in thousands):

Years ending September 30,	
2016	$ 40,000
2017	—
2018	—
2019	—
2020	—
Thereafter	$500,000
	$540,000

NOTE 4 INCOME TAXES

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

	Years Ended September 30,		
	2015	2014	2013
		(in thousands)	
Current:			
Federal	$ 84,229	$323,386	$315,820
Foreign	16,685	15,841	14,551
State	10,881	21,197	32,916
	111,795	360,424	363,287
Deferred:			
Federal	159,686	28,183	35,530
Foreign	(28,456)	(3,265)	(1,409)
State	350	2,206	(4,564)
	131,580	27,124	29,557
Total provision	$243,375	$387,548	$392,844

NOTE 4 INCOME TAXES (Continued)

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

	Years Ended September 30,		
	2015	2014	2013
		(in thousands)	
Domestic	$676,146	$1,061,006	$1,071,435
Foreign	(10,499)	35,308	42,862
	$665,647	$1,096,314	$1,114,297

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.

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

	September 30,	
	2015	2014
	(in thousands)	
Deferred tax liabilities:		
Property, plant and equipment	$1,334,611	$1,187,774
Available-for-sale securities	33,187	83,787
Other	3,928	67
Total deferred tax liabilities	1,371,726	1,271,628
Deferred tax assets:		
Pension reserves	3,405	1,370
Self-insurance reserves	14,318	10,311
Net operating loss and foreign tax credit carryforwards	56,287	48,285
Financial accruals	63,560	52,289
Other	12,049	8,332
Total deferred tax assets	149,619	120,587
Valuation allowance	55,758	47,699
Net deferred tax assets	93,861	72,888
Net deferred tax liabilities	$1,277,865	$1,198,740

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

As of September 30, 2015, we had state and foreign net operating loss carryforwards for income tax purposes of $6.2 million and $20.7 million, respectively, and foreign tax credit carryforwards of approximately $59.4 million (of which $48.6 million is reflected as a deferred tax asset in our Consolidated Financial Statements prior to consideration of our valuation allowance) which will expire

NOTE 4 INCOME TAXES (Continued)

in fiscal 2016 through 2025. The valuation allowance is primarily attributable to state and foreign net operating loss carryforwards of $0.5 million and $6.6 million, respectively, and foreign tax credit carryforwards of $48.6 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,		
	2015	2014	2013
U.S. Federal income tax rate	35.0%	35.0%	35.0%
Effect of foreign taxes	(2.1)	1.2	1.1
State income taxes, net of federal tax benefit	0.8	1.4	1.5
U.S. domestic production activities	(1.2)	(2.6)	(2.1)
Other impact of foreign operations	3.5	0.6	(0.5)
Other	0.6	(0.2)	0.3
Effective income tax rate	36.6%	35.4%	35.3%

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, 2015 was also impacted by a December 2014 tax law change which resulted in a reduction of the fiscal 2014 Internal Revenue Code Section 199 deduction for domestic production activities. In addition, the effective tax rate for the twelve months ended September 30, 2015 was impacted by a reduction in the deferred state income tax rate.

We recognize accrued interest related to unrecognized tax benefits in interest expense, and penalties in other expense in the Consolidated Statements of Income. As of September 30, 2015 and 2014, we had accrued interest and penalties of $11.1 million and $6.4 million, respectively.

A reconciliation of the change in our gross unrecognized tax benefits for the fiscal year ended September 30, 2015 and 2014 is as follows:

	September 30,	
	2015	2014
	(in thousands)	
Unrecognized tax benefits at October 1,	$10,747	$ 8,129
Gross decreases—tax positions in prior periods	(706)	(4)
Gross increases—tax positions in prior periods	3,278	4,293
Gross decreases—current period effect of tax positions	(821)	(836)
Gross increases—current period effect of tax positions	—	4
Expiration of statute of limitations for assessments	(956)	(533)
Settlements	(331)	(306)
Unrecognized tax benefits at September 30,	$11,211	$10,747

As of September 30, 2015 and September 30, 2014, our liability for unrecognized tax benefits includes $2.9 million, for each year, of unrecognized tax benefits related to discontinued operations

NOTE 4 INCOME TAXES (Continued)

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 results of operations or financial position. We provided for uncertain tax positions of $6.7 million, including interest and penalties, during the twelve months ended September 30, 2015 related to the previous disclosure of a possible increase in the reserve for uncertain tax positions of approximately $8.4 million to $11.0 million due to international tax matters.

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 2011 through 2014, with exception of certain state jurisdictions currently under audit. Audits in foreign jurisdictions are generally complete through fiscal 2002.

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 determination of our taxable income for the fiscal year end 2015 tax provision. The implementation of the regulations did not have a significant impact on the overall tax provision.

NOTE 5 SHAREHOLDERS' EQUITY

On September 30, 2015, we had 107,767,915 outstanding preferred stock purchase rights ("Rights") pursuant to the terms of the Rights Agreement dated January 8, 1996, as amended by Amendment No. 1 dated December 8, 2005. As adjusted for the two-for-one stock splits in fiscal 1998 and fiscal 2006, and as long as the Rights are not separately transferable, one-half Right attaches to each share of our common stock. Under the terms of the Rights Agreement each Right entitles the holder thereof to purchase one full unit consisting of one one-thousandth of a share of Series A Junior Participating Preferred Stock ("Preferred Stock"), without par value, at a price of $250 per unit. The exercise price and the number of units of Preferred Stock issuable on exercise of the Rights are subject to adjustment in certain cases to prevent dilution. The Rights will be attached to the common stock certificates and are not exercisable or transferable apart from the common stock, until ten business days after a person acquires 15 percent or more of the outstanding common stock or ten business days following the commencement of a tender offer or exchange offer that would result in a person owning 15 percent or more of the outstanding common stock. In that event, each holder of a Right (other than the acquiring person) shall have the right to receive, upon exercise of the Right, common stock of the Company having a value equal to two times the exercise price of the Right. In the event we are acquired in a merger or certain other business combination transactions (including one in which we are the surviving corporation), or more than 50 percent of our assets or earning power is sold or transferred, each holder of a Right shall have the right to receive, upon exercise of the Right, common stock of the acquiring company having a value equal to two times the exercise price of the Right. The Rights are

NOTE 5 SHAREHOLDERS' EQUITY (Continued)

redeemable under certain circumstances at $0.01 per Right and will expire, unless earlier redeemed, on January 31, 2016.

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 2013 and fiscal 2014.

ACCUMULATED OTHER COMPREHENSIVE INCOME

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

	September 30, 2015	September 30, 2014	September 30, 2013
	(in thousands)		
Pre-tax amounts:			
Unrealized appreciation on securities	$ 27,021	$157,838	$237,214
Unrealized actuarial loss	(30,144)	(23,405)	(19,210)
	$ (3,123)	$134,433	$218,004
After-tax amounts:			
Unrealized appreciation on securities	$ 17,201	$ 97,418	$144,161
Unrealized actuarial loss	(18,578)	(14,292)	(11,631)
	$ (1,377)	$ 83,126	$132,530

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, 2015:

	Unrealized Appreciation (Depreciation) on Available-for-sale Securities	Defined Benefit Pension Plan	Total
	(in thousands)		
Balance September 30, 2014	$ 97,418	$(14,292)	$ 83,126
Other comprehensive loss before reclassifications	(80,217)	—	(80,217)
Amounts reclassified from accumulated other comprehensive loss	—	(4,286)	(4,286)
Net current-period other comprehensive loss	(80,217)	(4,286)	(84,503)
Balance September 30, 2015	$ 17,201	$(18,578)	$ (1,377)

NOTE 5 SHAREHOLDERS' EQUITY (Continued)

The following provides detail about accumulated other comprehensive income (loss) components which were reclassified to the Consolidated Statement of Income during the years ended September 30, 2015 and 2014:

Details about Accumulated Other Comprehensive Income (Loss) Components	Amount Reclassified from Accumulated Other Comprehensive Income (Loss) 2015	2014	Affected line item in the Consolidated Statement of Income
	(in thousands)		
Unrealized gains on available-for-sale securities	$ —	$(45,234)	Gain on sale of investment securities
	—	17,497	Income tax provision
	$ —	$(27,737)	Net of tax
Defined Benefit Pension Items	$(6,738)	$ (4,196)	General and administrative
Amortization of net actuarial loss	2,452	1,535	Income tax provision
	$(4,286)	$ (2,661)	Net of tax
Total reclassifications for the period	$(4,286)	$(30,398)	

NOTE 6 STOCK-BASED COMPENSATION

On March 2, 2011, the 2010 Long-Term Incentive Plan (the "2010 Plan") was approved by our stockholders. The 2010 Plan, among other things, authorizes the Human Resources Committee of the Board of Directors to grant nonqualified stock options, restricted stock awards and stock appreciation rights 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. We have the right to satisfy option exercises from treasury shares and from authorized but unissued shares. There were 419,585 nonqualified stock options and 275,250 shares of restricted stock awards granted under the 2010 Plan during fiscal 2015. Awards outstanding in the 2005 Long-Term Incentive Plan (the "2005 Plan") and one prior equity plan remain subject to the terms and conditions of those plans.

A summary of compensation cost for stock-based payment arrangements recognized in general and administrative expense in fiscal 2015, 2014 and 2013 is as follows:

	September 30, 2015	2014	2013
	(in thousands)		
Compensation expense			
Stock options	$ 8,846	$11,268	$11,512
Restricted stock	16,349	15,435	11,759
	$25,195	$26,703	$23,271

NOTE 6 STOCK-BASED COMPENSATION (Continued)

Benefits of tax deductions in excess of recognized compensation cost of $3.8 million, $26.6 million and $9.8 million are reported as a financing cash flow in the Consolidated Statements of Cash Flows for fiscal 2015, 2014 and 2013, 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.

	2015	2014	2013
Risk-free interest rate	1.7%	1.6%	0.7%
Expected stock volatility	36.9%	52.6%	53.9%
Dividend yield	3.9%	3.1%	1.1%
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 $16.39, $29.44 and $23.80 per share for fiscal 2015, 2014 and 2013, respectively.

NOTE 6 STOCK-BASED COMPENSATION (Continued)

The following summary reflects the stock option activity for our common stock and related information for fiscal 2015, 2014 and 2013 (shares in thousands):

	2015		2014		2013	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at October 1,	2,629	$43.46	3,991	$34.12	4,690	$29.56
Granted	420	68.83	261	79.67	365	54.18
Exercised	(255)	28.46	(1,613)	26.08	(1,057)	20.68
Forfeited/Expired	(18)	66.78	(10)	68.82	(7)	52.32
Outstanding on September 30,	2,776	$48.51	2,629	$43.46	3,991	$34.12
Exercisable on September 30,	2,014	$41.62	1,884	$35.93	3,063	$28.48
Shares available to grant	2,515		3,432		4,116	

The following table summarizes information about stock options at September 30, 2015 (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	1,198	2.5	$30.13	1,197	$30.13
$47.29 to $59.76	911	6.3	$54.85	650	$54.25
$68.83 to $79.67	667	8.8	$72.85	167	$74.83
$21.065 to $79.67	2,776	5.3	$48.51	2,014	$41.62

At September 30, 2015, the weighted-average remaining life of exercisable stock options was 4.2 years and the aggregate intrinsic value was $20.5 million with a weighted-average exercise price of $41.62 per share.

The number of options vested or expected to vest at September 30, 2015 was 2,768,897 with an aggregate intrinsic value of $20.5 million and a weighted-average exercise price of $48.46 per share.

As of September 30, 2015, the unrecognized compensation cost related to the stock options was $5.3 million. That cost is expected to be recognized over a weighted-average period of 2.4 years.

The total intrinsic value of options exercised during fiscal 2015, 2014 and 2013 was $10.7 million, $100.9 million and $40.4 million, respectively.

The grant date fair value of shares vested during fiscal 2015, 2014 and 2013 was $8.1 million, $8.8 million and $9.3 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, 2015, there was $21.2 million of total unrecognized compensation

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 2.2 years.

A summary of the status of our restricted stock awards as of September 30, 2015, and of changes in restricted stock outstanding during the fiscal years ended September 30, 2015, 2014 and 2013, is as follows (shares in thousands):

	2015		2014		2013	
	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,	634	$64.03	576	$55.17	430	$52.52
Granted	275	68.83	230	79.67	307	54.18
Vested (1)	(214)	60.80	(157)	54.08	(155)	45.88
Forfeited	(27)	64.45	(15)	67.92	(6)	54.67
Outstanding on September 30	668	$67.03	634	$64.03	576	$55.17

(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.

NOTE 7 EARNINGS PER SHARE (Continued)

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

	September 30,		
	2015	2014	2013
		(in thousands)	
Numerator:			
Income from continuing operations	$422,272	$708,766	$721,453
Income (loss) from discontinued operations	(47)	(47)	15,186
Net income	422,225	708,719	736,639
Adjustment for basic earnings per share			
Earnings allocated to unvested shareholders	(2,174)	(4,145)	(3,842)
Numerator for basic earnings per share:			
From continuing operations	420,098	704,621	717,611
From discontinued operations	(47)	(47)	15,186
	420,051	704,574	732,797
Adjustment for diluted earnings per share:			
Effect of reallocating undistributed earnings of unvested shareholders	6	30	46
Numerator for diluted earnings per share:			
From continuing operations	420,104	704,651	717,657
From discontinued operations	(47)	(47)	15,186
	$420,057	$704,604	$732,843
Denominator:			
Denominator for basic earnings per share—weighted-average shares	107,754	107,800	106,286
Effect of dilutive shares from stock options and restricted stock	816	1,341	1,593
Denominator for diluted earnings per share—adjusted weighted-average shares	108,570	109,141	107,879
Basic earnings per common share:			
Income from continuing operations	$ 3.90	$ 6.54	$ 6.75
Income from discontinued operations	—	—	0.14
Net income	$ 3.90	$ 6.54	$ 6.89
Diluted earnings per common share:			
Income from continuing operations	$ 3.87	$ 6.46	$ 6.65
Income from discontinued operations	—	—	0.14
Net income	$ 3.87	$ 6.46	$ 6.79

NOTE 7 EARNINGS PER SHARE (Continued)

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:

	2015	2014	2013
	(in thousands, except per share amounts)		
Shares excluded from calculation of diluted earnings per share	667	215	743
Weighted-average price per share	$72.85	$79.67	$57.27

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, 2015	$64,462	$ 28,530	$1,509	$ 91,483
September 30, 2014	$64,462	$157,838	$ —	$222,300

On an on-going basis, we evaluate the marketable equity securities to determine if a 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. Considering the factors outlined above including the limited time that the related security was in an unrealized loss position, impairment was not considered other-than-temporary as of September 30, 2015.

During 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. During the year ended September 30, 2013, marketable equity available-for-sale securities with a fair value at the date of sale of $214.1 million were sold. The gross realized gain on such sales of available-for-sale securities totaled $153.4 million. All of the gains from available-for-sale securities are included in gain from sale of investment securities in the Consolidated Statements of Income.

During fiscal 2013, we sold our shares in three limited partnerships that were primarily invested in international equities and carried at a cost of $9.4 million, realizing a gain of $8.8 million that is included in gain from sale of investment securities in the Consolidated Statements of Income. We no longer have any investments in limited partnerships.

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 $12.9 million and $14.3 million at September 30, 2015 and 2014, 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 Income. 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, 2015 and 2014.

ASC 820 defines fair value as "the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date." ASC 820 establishes a fair value hierarchy to prioritize the inputs used in valuation techniques into three levels as follows:

- Level 1—Observable inputs that reflect quoted prices in active markets for identical assets or liabilities in active markets.
- Level 2—Inputs other than Level 1 that are observable, either directly or indirectly, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities.
- Level 3—Valuations based on inputs that are unobservable and not corroborated by market data.

At September 30, 2015, our financial assets utilizing Level 1 inputs include cash equivalents, equity securities with active markets, U.S. Treasury securities and 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 we have elected to classify as restricted that is included in current assets of discontinued operations and limited to remaining liabilities of discontinued operations. For these items, quoted current market prices are readily available.

At September 30, 2015, 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.

Currently, we do not have any financial instruments utilizing Level 3 inputs.

NOTE 8 FINANCIAL INSTRUMENTS AND FAIR VALUE MEASUREMENT (Continued)

The following table summarizes our assets measured at fair value on a recurring basis presented in our Consolidated Balance Sheets as of September 30, 2015:

	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)			
Short-term investments:				
Certificate of deposit	$ 2,101	$ —	$ 2,101	$—
Corporate debt securities	27,139	—	27,139	—
U.S. government and federal agency securities	16,303	4,823	11,480	—
Total short-term investments	45,543	4,823	40,720	—
Cash and cash equivalents	717,977	717,977	—	—
Investments	91,483	91,483	—	—
Other current assets	38,095	37,845	250	—
Other assets	2,000	2,000	—	—
Total assets measured at fair value	$895,098	$854,128	$40,970	$—

The following information presents the supplemental fair value information about long-term fixed-rate debt at September 30, 2015 and September 30, 2014.

	September 30, 2015	September 30, 2014 (as adjusted)
	(in millions)	
Carrying value of long-term fixed-rate debt	$531.5	$79.1
Fair value of long-term fixed-rate debt	$553.5	$84.3

The fair value at September 30, 2015 for the $40 million fixed-rate debt was estimated using discounted cash flows at rates reflecting current interest rates at similar maturities plus a credit spread which was estimated using the outstanding market information on debt instruments with a similar credit profile to us. The debt was valued using a Level 2 input.

The fair value for the $500 million fixed-rate debt was based on broker quotes at September 30, 2015. The notes are classified within Level 2 as they are not actively traded in markets.

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.

NOTE 9 EMPLOYEE BENEFIT PLANS (Continued)

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, 2015 and a statement of the funded status as of September 30, 2015 and 2014:

	2015	2014
	(in thousands)	
Accumulated Benefit Obligation	$107,417	$111,108
Changes in projected benefit obligations		
Projected benefit obligation at beginning of year	$111,108	$102,680
Interest cost	4,584	4,763
Actuarial loss	2,741	10,787
Benefits paid	(11,016)	(7,122)
Projected benefit obligation at end of year	$107,417	$111,108
Change in plan assets		
Fair value of plan assets at beginning of year	$108,157	$ 96,818
Actual return on plan assets	(1,324)	11,132
Employer contribution	2,243	7,329
Benefits paid	(11,016)	(7,122)
Fair value of plan assets at end of year	$ 98,060	$108,157
Funded status of the plan at end of year	$ (9,357)	$ (2,951)

The amounts recognized in the Consolidated Balance Sheets at September 30, 2015 and 2014 are as follows (in thousands):

Accrued liabilities	$ (44)	$ (62)
Noncurrent liabilities—other	(9,313)	(2,889)
Net amount recognized	$ (9,357)	$ (2,951)

The amounts recognized in Accumulated Other Comprehensive Income at September 30, 2015 and 2014, and not yet reflected in net periodic benefit cost, are as follows (in thousands):

Net actuarial loss	$(30,144)	$(23,405)

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 $2.0 million.

NOTE 9 EMPLOYEE BENEFIT PLANS (Continued)

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

	Years Ended September 30,		
	2015	2014	2013
Discount rate for net periodic benefit costs	4.32%	4.80%	4.06%
Discount rate for year-end obligations	4.27%	4.32%	4.80%
Expected return on plan assets	6.26%	6.61%	7.06%

The mortality table issued by the Society of Actuaries in October 2015 was used for the September 30, 2015 pension calculation. The new mortality information reflects improved life expectancies and projected mortality improvements.

We contributed $2.2 million to the Pension Plan in fiscal 2015 to fund distributions in lieu of liquidating pension assets. In fiscal 2016, we do not expect minimum contributions required by law to be needed. However, we may make contributions in fiscal 2016 if needed to fund unexpected distributions.

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

	Years Ended September 30,		
	2015	2014	2013
	(in thousands)		
Interest cost	$ 4,584	$ 4,763	$ 4,339
Expected return on plan assets	(6,855)	(6,789)	(6,099)
Amortization of prior service cost	—	—	1
Recognized net actuarial loss	1,308	873	2,372
Settlement	2,873	1,376	—
Net pension expense (benefit)	$ 1,910	$ 223	$ 613

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,						
2016	2017	2018	2019	2020	2021 - 2025	Total
$5,855	$5,547	$6,441	$6,560	$7,879	$33,540	$65,822

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 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

NOTE 9 EMPLOYEE BENEFIT PLANS (Continued)

determining the appropriate asset mix, our financial strength and ability to fund potential shortfalls are considered. Plan assets are invested in portfolios of diversified public-market equity securities and fixed income securities. The Plan does not directly hold securities of the Company.

The expected long-term rate of return on Plan assets is based on historical and projected rates of return for current and planned asset classes in the Plan's investment portfolio after analyzing historical experience and future expectations of the return and volatility of various asset classes.

The target allocation for 2016 and the asset allocation for the Pension Plan at the end of fiscal 2015 and 2014, by asset category, follows:

Asset Category	Target Allocation 2016	Percentage of Plan Assets At September 30, 2015	2014
U.S. equities	55%	59%	61%
International equities	13	13	12
Fixed income	27	23	25
Real estate and other	5	5	2
Total	100%	100%	100%

PLAN ASSETS

The fair value of Plan assets at September 30, 2015 and 2014, summarized by level within the fair value hierarchy described in Note 8, are as follows:

	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

NOTE 9 EMPLOYEE BENEFIT PLANS (Continued)

	Fair Value as of September 30, 2014			
	Total	Level 1	Level 2	Level 3
	(in thousands)			
Short-term investments	$ 2,250	$ 2,250	$—	$ —
Mutual funds:				
Domestic stock funds	55,054	55,054	—	—
Bond funds	24,722	24,722	—	—
International stock funds	8,731	8,731	—	—
Total mutual funds	88,507	88,507	—	—
Domestic common stock	15,733	15,733	—	—
Foreign equity stock	1,366	1,366	—	—
Oil and gas properties	301	—	—	301
Total	$108,157	$107,856	$—	$301

The 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 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 Plan's Level 3 assets for the years ended September 30, 2015 and 2014:

	Oil and Gas Properties	
	Years Ended September 30,	
	2015	2014
	(in thousands)	
Balance, beginning of year	$301	$287
Unrealized gains (losses) relating to property still held at the reporting date	86	14
Balance, end of year	$387	$301

DEFINED CONTRIBUTION PLAN

Substantially all employees on the United States payroll may elect to participate in the 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 $24.8 million, $32.3 million and $28.3 million in fiscal 2015, 2014 and 2013, respectively.

NOTE 10 SUPPLEMENTAL BALANCE SHEET INFORMATION

The following reflects the activity in our reserve for bad debt for 2015, 2014 and 2013:

	September 30,		
	2015	2014	2013
	(in thousands)		
Reserve for bad debt:			
Balance at October 1,	$ 4,597	$4,795	$ 942
Provision for (recovery of) bad debt	6,034	(200)	3,875
Write-off of bad debt	(4,450)	2	(22)
Balance at September 30,	$ 6,181	$4,597	$4,795

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

	September 30,	
	2015	2014 (as adjusted)
	(in thousands)	
Prepaid expenses and other current assets:		
Restricted cash	$ 29,998	$ 28,244
Prepaid insurance	6,572	13,316
Deferred mobilization	11,899	20,133
Prepaid income taxes	7,320	—
Prepaid value added tax	1,063	434
Other	15,265	18,785
Total prepaid expenses and other current assets	$ 72,117	$ 80,912
Accrued liabilities:		
Accrued operating costs	$ 28,022	$ 91,408
Payroll and employee benefits	35,938	88,128
Taxes payable, other than income tax	38,992	42,538
Accrued income taxes	—	10,611
Deferred mobilization	18,230	18,103
Self-insurance liabilities	10,796	8,118
Deferred income	42,627	3,144
Other	23,448	20,228
Total accrued liabilities	$198,053	$282,278
Noncurrent liabilities—Other:		
Pension and other non-qualified retirement plans	$ 28,430	$ 25,305
Self-insurance liabilities	20,846	13,476
Deferred mobilization	39,469	3,818
Uncertain tax positions including interest and penalties	17,724	13,239
Other	4,635	8,272
Total noncurrent liabilities—other	$111,104	$ 64,110

NOTE 11 SUPPLEMENTAL CASH FLOW INFORMATION

	Years Ended September 30,		
	2015	2014	2013
		(in thousands)	
Cash payments:			
Interest paid, net of amounts capitalized	$ 11,663	$ 5,374	$ 6,991
Income taxes paid	$131,128	$317,599	$363,326

Capital expenditures on the Consolidated Statements of Cash Flows for the years ended September 30, 2015, 2014 and 2013 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,		
	2015	2014	2013
		(in thousands)	
Capital expenditures incurred	$1,035,278	$1,047,176	$791,741
Additions incurred prior year but paid for in current year	123,548	29,264	46,589
Additions incurred but not paid for as of the end of the year	(25,344)	(123,548)	(29,264)
Capital expenditures per Consolidated Statements of Cash Flows	$1,133,482	$ 952,892	$809,066

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 and price volatility are generally more important for determining a customer's future spending levels.

NOTE 12 RISK FACTORS (Continued)

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.

We are not operating in any country that is currently considered highly inflationary, 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 subsidiaries use the U.S. dollar as the functional currency and local currency monetary assets are remeasured into

NOTE 12 RISK FACTORS (Continued)

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

During fiscal 2015, we announced agreements to build and operate six new FlexRigs in the U.S. As of November 12, 2015, six new FlexRigs with customer commitments remained under construction. During construction, rig construction cost is included in construction in progress and then transferred to contract drilling equipment when the rig is placed in the field for service. Equipment, parts and supplies are ordered in advance to promote efficient construction progress. At September 30, 2015, we had purchase orders outstanding of approximately $81.1 million for the purchase of drilling equipment.

LEASES

At September 30, 2015, we were leasing approximately 215,600 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, 2015 are as follows:

Fiscal Year	Amount (in thousands)
2016	$ 7,803
2017	6,246
2018	4,304
2019	4,236
2020	3,711
Thereafter	12,335
Total	$38,635

Total rent expense was $13.6 million, $12.1 million and $9.9 million for fiscal 2015, 2014 and 2013, respectively.

NOTE 13 COMMITMENTS AND CONTINGENCIES (Continued)

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. None of these legal actions are expected to have a material adverse effect on our financial condition, cash flows or results of operations.

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.

In the third quarter of fiscal 2013 and in the fourth fiscal quarter of 2012, we settled arbitration disputes with third parties not affiliated with the Venezuelan government, PDVSA or Petroleo related to the seizure of our property in Venezuela. Proceeds of $15.0 million and $7.5 million were received and recorded in discontinued operations in fiscal 2013 and 2012, respectively.

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. Although we presently believe that the outcome of our discussions will not have a material adverse effect on the Company, we cannot estimate the amount of any potential loss, nor can we provide any assurances as to the timing or eventual outcome of these discussions.

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

NOTE 14 SEGMENT INFORMATION (Continued)

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.

NOTE 14 SEGMENT INFORMATION (Continued)

Summarized financial information of our reportable segments for continuing operations for each of the years ended September 30, 2015, 2014 and 2013 is shown in the following table:

(in thousands)	External Sales	Inter-Segment	Total Sales	Segment Operating Income (Loss)	Depreciation	Total Assets (as adjusted)	Additions to Long-Lived Assets
2015							
Contract Drilling							
U.S. Land	$2,523,518	$ —	$2,523,518	$ 698,375	$519,950	$5,430,533	$ 949,978
Offshore	241,043	—	241,043	67,729	11,659	117,684	16,100
International Land	386,693	—	386,693	(2,930)	56,287	583,064	41,682
	3,151,254	—	3,151,254	763,174	587,896	6,131,281	1,007,760
Other	14,187	880	15,067	(10,911)	19,096	1,012,634	27,518
	3,165,441	880	3,166,321	752,263	606,992	7,143,915	1,035,278
Eliminations	—	(880)	(880)	—	—	—	—
Total	$3,165,441	$ —	$3,165,441	$ 752,263	$606,992	$7,143,915	$1,035,278
2014							
Contract Drilling							
U.S. Land	$3,099,954	$ —	$3,099,954	$1,025,745	$455,934	$5,259,947	$ 930,263
Offshore	250,811	—	250,811	69,819	12,300	137,101	4,372
International Land	355,532	—	355,532	36,417	39,932	589,968	85,424
	3,706,297	—	3,706,297	1,131,981	508,166	5,987,016	1,020,059
Other	13,410	867	14,277	(9,068)	15,383	726,776	27,117
	3,719,707	867	3,720,574	1,122,913	523,549	6,713,792	1,047,176
Eliminations	—	(867)	(867)	—	—	—	—
Total	$3,719,707	$ —	$3,719,707	$1,122,913	$523,549	$6,713,792	$1,047,176
2013							
Contract Drilling							
U.S. Land	$2,785,449	$ —	$2,785,449	$ 932,591	$391,072	$4,742,381	$ 726,206
Offshore	221,863	—	221,863	53,064	13,766	149,128	4,470
International Land	366,841	—	366,841	44,595	36,000	486,914	51,193
	3,374,153	—	3,374,153	1,030,250	440,838	5,378,423	781,869
Other	13,461	858	14,319	(8,602)	14,785	881,436	9,872
	3,387,614	858	3,388,472	1,021,648	455,623	6,259,859	791,741
Eliminations	—	(858)	(858)	—	—	—	—
Total	$3,387,614	$ —	$3,387,614	$1,021,648	$455,623	$6,259,859	$ 791,741

NOTE 14 SEGMENT INFORMATION (Continued)

The following table reconciles segment operating income to income from continuing operations before income taxes as reported on the Consolidated Statements of Income:

	Years Ended September 30,		
	2015	2014	2013
		(in thousands)	
Segment operating income	$752,263	$1,122,913	$1,021,648
Income from asset sales	11,716	19,585	18,923
Corporate general and administrative costs and corporate depreciation	(88,229)	(87,711)	(83,910)
Operating income	675,750	1,054,787	956,661
Other income (expense)			
Interest and dividend income	5,834	1,583	1,653
Interest expense	(15,036)	(4,654)	(6,129)
Gain on sale of investment securities	—	45,234	162,121
Other	(901)	(636)	(9)
Total unallocated amounts	(10,103)	41,527	157,636
Income from continuing operations before income taxes	$665,647	$1,096,314	$1,114,297

The following table presents revenues from external customers and long-lived assets by country based on the location of service provided:

	Years Ended September 30,		
	2015	2014	2013
		(in thousands)	
Revenues			
United States	$2,750,043	$3,338,365	$3,011,760
Argentina	169,359	107,945	73,208
Colombia	74,339	85,176	100,052
Ecuador	34,211	69,195	67,890
Other Foreign	137,489	119,026	134,704
Total	$3,165,441	$3,719,707	$3,387,614
Long-Lived Assets			
United States	$5,149,315	$4,753,844	$4,345,950
Argentina	213,938	144,823	83,149
Colombia	103,316	107,112	81,315
Ecuador	29,142	70,742	63,894
Other Foreign	71,524	112,023	101,795
Total	$5,567,235	$5,188,544	$4,676,103

Long-lived assets are comprised of property, plant and equipment.

NOTE 14 SEGMENT INFORMATION (Continued)

Revenues from one customer accounted for approximately 10.6 percent, 7.3 percent and 10.8 percent of total operating revenues during the years ended September 30, 2015, 2014 and 2013, respectively. Revenues from another customer accounted for approximately 9.8 percent, 10.7 percent and 9.5 percent of total operating revenues during the years ended September 30, 2015, 2014 and 2013, respectively. Collectively, the receivables from these customers were approximately $116.9 million and $121.4 million at September 30, 2015 and 2014, respectively.

NOTE 15 GUARANTOR AND NON-GUARANTOR FINANCIAL INFORMATION

In March 2015, Helmerich & Payne International Drilling Co. (“the issuer”), a 100 percent owned subsidiary of Helmerich & Payne, Inc. (“parent”, “the guarantor”), issued senior unsecured notes with an aggregate principal amount of $500.0 million. The notes are fully and unconditionally guaranteed by the parent. No subsidiaries of the parent currently guarantee the notes, subject to certain provisions that if any subsidiary guarantees certain other debt of the issuer or parent, then such subsidiary will provide a guarantee of the obligation under the notes.

In connection with the notes, we are providing the following condensed consolidating financial information in accordance with the Securities and Exchange Commission disclosure requirements. Each entity in the consolidating financial information follows the same accounting policies as described in the consolidated financial statements. Condensed consolidating financial information for the issuer, Helmerich & Payne International Drilling Co. and parent, guarantor, Helmerich & Payne, Inc. is shown in the tables below.

NOTE 15 GUARANTOR AND NON-GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF INCOME (in thousands)

	Year Ended September 30, 2015				
	Guarantor/ Parent	Issuer Subsidiary	Non-Guarantor Subsidiaries	Eliminations	Total Consolidated
Operating revenue	$ —	$2,735,864	$429,652	$ (75)	$3,165,441
Operating costs and other	10,875	2,037,464	444,456	(3,104)	2,489,691
Operating income (loss) from continuing operations	(10,875)	698,400	(14,804)	3,029	675,750
Other income, net	(91)	7,522	531	(3,029)	4,933
Interest expense	(159)	(8,955)	(5,922)	—	(15,036)
Equity in net income (loss) of subsidiaries	429,140	(11,207)	—	(417,933)	—
Income (loss) from continuing operations before income taxes	418,015	685,760	(20,195)	(417,933)	665,647
Income tax provision	(4,210)	258,660	(11,075)	—	243,375
Income (loss) from continuing operations	422,225	427,100	(9,120)	(417,933)	422,272
Loss from discontinued operations before income taxes	—	—	(124)	—	(124)
Income tax provision	—	—	(77)	—	(77)
Loss from discontinued operations	—	—	(47)	—	(47)
Net income (loss)	$422,225	$ 427,100	$ (9,167)	$(417,933)	$ 422,225

CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME (in thousands)

	Year Ended September 30, 2015				
	Guarantor/ Parent	Issuer Subsidiary	Non-Guarantor Subsidiaries	Eliminations	Total Consolidated
Net income (loss)	$422,225	$427,100	$(9,167)	$(417,933)	$422,225
Other comprehensive loss, net of income taxes:					
Unrealized depreciation on securities, net	—	(80,217)	—	—	(80,217)
Minimum pension liability adjustments, net	(666)	(3,620)	—	—	(4,286)
Other comprehensive loss	(666)	(83,837)	—	—	(84,503)
Comprehensive income	$421,559	$343,263	$(9,167)	$(417,933)	$337,722

NOTE 15 GUARANTOR AND NON-GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF INCOME
(in thousands)

	Year Ended September 30, 2014				
	Guarantor/ Parent	Issuer Subsidiary	Non-Guarantor Subsidiaries	Eliminations	Total Consolidated
Operating revenue	$ —	$3,325,039	$394,820	$ (152)	$3,719,707
Operating costs and other	10,763	2,291,775	366,682	(4,300)	2,664,920
Operating income (loss) from continuing operations	(10,763)	1,033,264	28,138	4,148	1,054,787
Other income, net	57	48,108	2,164	(4,148)	46,181
Interest expense	(42)	(3,049)	(1,563)	—	(4,654)
Equity in net income of subsidiaries	715,157	4,668	—	(719,825)	—
Income from continuing operations before income taxes	704,409	1,082,991	28,739	(719,825)	1,096,314
Income tax provision	(4,310)	370,723	21,135	—	387,548
Income from continuing operations	708,719	712,268	7,604	(719,825)	708,766
Income from discontinued operations before income taxes	—	—	2,758	—	2,758
Income tax provision	—	—	2,805	—	2,805
Loss from discontinued operations	—	—	(47)	—	(47)
Net income	$708,719	$ 712,268	$ 7,557	$(719,825)	$ 708,719

CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME
(in thousands)

	Year Ended September 30, 2014				
	Guarantor/ Parent	Issuer Subsidiary	Non-Guarantor Subsidiaries	Eliminations	Total Consolidated
Net income	$708,719	$712,268	$7,557	$(719,825)	$708,719
Other comprehensive loss, net of income taxes:					
Unrealized depreciation on securities, net	—	(19,006)	—	—	(19,006)
Reclassification of realized gains in net income, net	—	(27,737)	—	—	(27,737)
Minimum pension liability adjustments, net	(213)	(2,448)	—	—	(2,661)
Other comprehensive loss	(213)	(49,191)	—	—	(49,404)
Comprehensive income	$708,506	$663,077	$7,557	$(719,825)	$659,315

NOTE 15 GUARANTOR AND NON-GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF INCOME
(in thousands)

	Year Ended September 30, 2013				
	Guarantor/ Parent	Issuer Subsidiary	Non-Guarantor Subsidiaries	Eliminations	Total Consolidated
Operating revenue	$ —	$2,998,299	$389,382	$ (67)	$3,387,614
Operating costs and other	12,775	2,063,737	355,751	(1,310)	2,430,953
Operating income (loss) from continuing operations	(12,775)	934,562	33,631	1,243	956,661
Other income, net	20	164,170	863	(1,288)	163,765
Interest expense	(83)	(4,776)	(1,315)	45	(6,129)
Equity in net income of subsidiaries	745,105	33,360	—	(778,465)	—
Income from continuing operations before income taxes	732,267	1,127,316	33,179	(778,465)	1,114,297
Income tax provision	(4,372)	383,881	13,335	—	392,844
Income from continuing operations	736,639	743,435	19,844	(778,465)	721,453
Income from discontinued operations before income taxes	—	—	14,701	—	14,701
Income tax provision	—	—	(485)	—	(485)
Loss from discontinued operations	—	—	15,186	—	15,186
Net income	$736,639	$ 743,435	$ 35,030	$(778,465)	$ 736,639

CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME
(in thousands)

	Year Ended September 30, 2013				
	Guarantor/ Parent	Issuer Subsidiary	Non-Guarantor Subsidiaries	Eliminations	Total Consolidated
Net income	$736,639	$743,435	$35,030	$(778,465)	$736,639
Other comprehensive income (loss), net of income taxes:					
Unrealized appreciation on securities, net	—	46,853	—	—	46,853
Reclassification of realized gains in net income, net	—	(92,543)	—	—	(92,543)
Minimum pension liability adjustments, net	2,663	8,750	—	—	11,413
Other comprehensive income (loss)	2,663	(36,940)	—	—	(34,277)
Comprehensive income	$739,302	$706,495	$35,030	$(778,465)	$702,362

NOTE 15 GUARANTOR AND NON-GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING BALANCE SHEETS
(in thousands)

	September 30, 2015				
	Guarantor/ Parent	Issuer Subsidiary	Non-Guarantor Subsidiaries	Eliminations	Total Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ (838)	$ 693,273	$ 34,096	$ (8,554)	$ 717,977
Short-term investments	—	45,543	—	—	45,543
Accounts receivable, net of reserve	152	374,383	80,484	(5,675)	449,344
Inventories	—	88,010	40,719	—	128,729
Deferred income taxes	2,834	19,154	—	(4,788)	17,200
Prepaid expenses and other	20,018	6,713	48,100	(2,714)	72,117
Current assets of discontinued operations	—	—	8,097	—	8,097
Total current assets	22,166	1,227,076	211,496	(21,731)	1,439,007
Investments	12,871	91,483	—	—	104,354
Property, plant and equipment, net	55,902	5,063,705	447,628	—	5,567,235
Intercompany	15,875	1,192,634	229,626	(1,438,135)	—
Other assets	8,387	1,389	39,793	(8,153)	41,416
Investment in subsidiaries	5,625,360	227,910	—	(5,853,270)	—
Total assets	$5,740,561	$7,804,197	$928,543	$(7,321,289)	$7,152,012
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 80,673	$ 20,404	$ 9,632	$ (5)	$ 110,704
Accrued liabilities	10,688	151,607	46,542	(10,784)	198,053
Long-term debt due within one year	—	39,094	—	—	39,094
Current liabilities of discontinued operations	—	—	3,377	—	3,377
Total current liabilities	91,361	211,105	59,551	(10,789)	351,228
Noncurrent liabilities:					
Long-term debt	—	492,443	—	—	492,443
Deferred income taxes	—	1,275,427	32,579	(12,941)	1,295,065
Intercompany	733,008	185,493	525,788	(1,444,289)	—
Other	18,740	31,560	60,804	—	111,104
Noncurrent liabilities of discontinued operations	—	—	4,720	—	4,720
Total noncurrent liabilities	751,748	1,984,923	623,891	(1,457,230)	1,903,332
Shareholders' equity:					
Common stock	11,099	100	—	(100)	11,099
Additional paid-in capital	420,141	45,824	349	(46,173)	420,141
Retained earnings	4,649,952	5,558,389	244,752	(5,803,141)	4,649,952
Accumulated other comprehensive income (loss)	(1,377)	3,856	—	(3,856)	(1,377)
Treasury stock, at cost	(182,363)	—	—	—	(182,363)
Total shareholders' equity	4,897,452	5,608,169	245,101	(5,853,270)	4,897,452
Total liabilities and shareholders' equity	$5,740,561	$7,804,197	$928,543	$(7,321,289)	$7,152,012

NOTE 15 GUARANTOR AND NON-GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING BALANCE SHEETS (Continued)
(in thousands)

	September 30, 2014, as adjusted				
	Guarantor/ Parent	Issuer Subsidiary	Non-Guarantor Subsidiaries	Eliminations	Total Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ (2,050)	$ 329,655	$ 36,932	$ (3,628)	$ 360,909
Accounts receivable, net of reserve	(31)	623,274	98,913	(16,942)	705,214
Inventories	—	67,113	37,358	1,770	106,241
Deferred income taxes	5,372	19,499	—	(8,352)	16,519
Prepaid expenses and other	8,863	15,013	56,982	54	80,912
Current assets of discontinued operations	—	—	7,206	—	7,206
Total current assets	12,154	1,054,554	237,391	(27,098)	1,277,001
Investments	14,344	222,300	—	—	236,644
Property, plant and equipment, net	42,027	4,681,294	465,223	—	5,188,544
Intercompany	14,855	782,626	196,641	(994,122)	—
Other assets	8,110	1,197	16,123	(6,621)	18,809
Investment in subsidiaries	5,276,750	235,355	—	(5,512,105)	—
Total assets	$5,368,240	$6,977,326	$915,378	$(6,539,946)	$6,720,998
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 80,562	$ 80,488	$ 20,988	$ (7)	$ 182,031
Accrued liabilities	31,960	212,896	43,560	(6,138)	282,278
Long-term debt due within one year	—	39,635	—	—	39,635
Current liabilities of discontinued operations	—	—	3,217	—	3,217
Total current liabilities	112,522	333,019	67,765	(6,145)	507,161
Noncurrent liabilities:					
Long-term debt	—	39,502	—	—	39,502
Deferred income taxes	—	1,182,192	47,640	(14,573)	1,215,259
Intercompany	346,545	141,066	519,512	(1,007,123)	—
Other	18,196	19,948	25,966	—	64,110
Noncurrent liabilities of discontinued operations	—	—	3,989	—	3,989
Total noncurrent liabilities	364,741	1,382,708	597,107	(1,021,696)	1,322,860
Shareholders' equity:					
Common stock	11,051	100	—	(100)	11,051
Additional paid-in capital	383,972	42,516	319	(42,835)	383,972
Retained earnings	4,525,797	5,131,289	250,187	(5,381,476)	4,525,797
Accumulated other comprehensive income	83,126	87,694	—	(87,694)	83,126
Treasury stock, at cost	(112,969)	—	—	—	(112,969)
Total shareholders' equity	4,890,977	5,261,599	250,506	(5,512,105)	4,890,977
Total liabilities and shareholders' equity	$5,368,240	$6,977,326	$915,378	$(6,539,946)	$6,720,998

NOTE 15 GUARANTOR AND NON-GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS (in thousands)

	September 30, 2015				
	Guarantor/ Parent	Issuer Subsidiary	Non-Guarantor Subsidiaries	Eliminations	Total Consolidated
Net cash provided by operating activities	$ 3,623	$ 1,379,707	$ 40,340	$(4,926)	$ 1,418,744
INVESTING ACTIVITIES:					
Capital expenditures	(24,818)	(1,064,288)	(44,376)	—	(1,133,482)
Purchase of short-term investments	—	(45,607)	—	—	(45,607)
Intercompany transfers	24,818	(24,818)	—	—	—
Proceeds from asset sales	1	21,329	1,171	—	22,501
Net cash provided by (used in) investing activities	1	(1,113,384)	(43,205)	—	(1,156,588)
FINANCING ACTIVITIES:					
Payments on long-term debt	—	(40,000)	—	—	(40,000)
Proceeds from senior notes, net of discount	—	497,125	—	—	497,125
Debt issuance costs	—	(5,474)	—	—	(5,474)
Proceeds on short-term debt		—	1,002		1,002
Payments on short-term debt		—	(1,002)		(1,002)
Intercompany transfers	358,021	(358,021)	—	—	—
Repurchase of common stock	(59,654)	—	—	—	(59,654)
Dividends paid	(298,367)	—	—	—	(298,367)
Exercise of stock options, net of tax withholding	2,650	—	—	—	2,650
Tax withholdings related to net share settlements of restricted stock	(5,140)	—	—	—	(5,140)
Excess tax benefit from stock-based compensation	78	3,665	29	—	3,772
Net cash provided by (used in) financing activities	(2,412)	97,295	29	—	94,912
Net increase (decrease) in cash and cash equivalents	1,212	363,618	(2,836)	(4,926)	357,068
Cash and cash equivalents, beginning of period	(2,050)	329,655	36,932	(3,628)	360,909
Cash and cash equivalents, end of period	$ (838)	$ 693,273	$ 34,096	$(8,554)	$ 717,977

NOTE 15 GUARANTOR AND NON-GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS (Continued)
(in thousands)

	September 30, 2014				
	Guarantor/ Parent	Issuer Subsidiary	Non-Guarantor Subsidiaries	Eliminations	Total Consolidated
Net cash provided by (used in) operating activities	$ (21,094)	$1,050,609	$ 94,196	$(5,184)	$1,118,527
INVESTING ACTIVITIES:					
Capital expenditures	(17,786)	(840,341)	(94,765)	—	(952,892)
Intercompany transfers	17,786	(17,786)	—	—	—
Proceeds from asset sales	2	27,401	3,367	—	30,770
Proceeds from sale of investments	—	49,205	—	—	49,205
Net cash provided by (used in) investing activities	2	(781,521)	(91,398)	—	(872,917)
FINANCING ACTIVITIES:					
Payments on long-term debt	—	(115,000)	—	—	(115,000)
Intercompany transfers	264,386	(264,386)	—	—	—
Dividends paid	(264,386)	—	—	—	(264,386)
Exercise of stock options, net of tax withholding	23,250	—	—	—	23,250
Tax withholdings related to net share settlements of restricted stock	(3,049)	—	—	—	(3,049)
Excess tax benefit from stock-based compensation	(957)	27,357	216	—	26,616
Net cash provided by (used in) financing activities	19,244	(352,029)	216	—	(332,569)
Net increase (decrease) in cash and cash equivalents	(1,848)	(82,941)	3,014	(5,184)	(86,959)
Cash and cash equivalents, beginning of period	(202)	412,596	33,918	1,556	447,868
Cash and cash equivalents, end of period	$ (2,050)	$ 329,655	$ 36,932	$(3,628)	$ 360,909

NOTE 15 GUARANTOR AND NON-GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS (Continued)
(in thousands)

	September 30, 2013				
	Guarantor/ Parent	Issuer Subsidiary	Non-Guarantor Subsidiaries	Eliminations	Total Consolidated
Net cash provided by operating activities	$ 3,066	$ 973,850	$ 17,708	$ 2,561	$ 997,185
INVESTING ACTIVITIES:					
Capital expenditures	(6,828)	(752,642)	(49,596)	—	(809,066)
Intercompany transfers	6,828	(6,828)	—	—	—
Proceeds from asset sales	3,235	21,694	3,097	—	28,026
Proceeds from sale of investments	—	232,221	—	—	232,221
Net cash provided by (used in) investing activities	3,235	(505,555)	(46,499)	—	(548,819)
Net cash provided by investing activities by discontinued operations	—	—	15,000	—	15,000
Net cash provided by (used in) investing activities	3,235	(505,555)	(31,499)	2561	(533,819)
FINANCING ACTIVITIES:					
Payments on long-term debt	—	(40,000)	—	—	(40,000)
Intercompany transfers	93,053	(93,053)	—	—	—
Dividends paid	(93,053)	—	—	—	(93,053)
Intercompany notes	(16,500)	—	16,500	—	—
Exercise of stock options, net of tax withholding	13,317	—	—	—	13,317
Tax withholdings related to net share settlements of restricted stock	(1,677)	—	—	—	(1,677)
Excess tax benefit from stock-based compensation	(563)	10,280	103	—	9,820
Net cash provided by (used in) financing activities	(5,423)	(122,773)	16,603	—	(111,593)
Net increase in cash and cash equivalents	878	345,522	2,812	2,561	351,773
Cash and cash equivalents, beginning of period	(1,080)	67,074	31,106	(1,005)	96,095
Cash and cash equivalents, end of period	$ (202)	$ 412,596	$ 33,918	$ 1,556	$ 447,868

NOTE 16 SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

	(in thousands, except per share amounts)			
2015	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Operating revenues	$1,056,585	$883,052	$659,694	$566,110
Operating income (loss)	331,819	227,172	132,780	(16,021)
Income (loss) from continuing operations	203,057	149,536	90,887	(21,208)
Net income (loss)	203,042	149,537	90,860	(21,214)
Basic earnings per common share:				
Income (loss) from continuing operations	1.87	1.38	0.84	(0.20)
Net income (loss)	1.87	1.38	0.84	(0.20)
Diluted earnings per common share:				
Income (loss) from continuing operations	1.85	1.37	0.83	(0.20)
Net income	1.85	1.37	0.83	(0.20)

2014	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Operating revenues	$889,152	$893,430	$952,087	$985,038
Operating income	264,031	255,342	271,912	263,502
Income from continuing operations	173,182	174,589	192,290	168,705
Net income	173,182	174,570	192,279	168,688
Basic earnings per common share:				
Income from continuing operations	1.61	1.61	1.77	1.55
Net income	1.61	1.61	1.77	1.55
Diluted earnings per common share:				
Income from continuing operations	1.59	1.59	1.75	1.53
Net income	1.59	1.59	1.75	1.53

The sum of earnings per share for the four quarters may not equal the total earnings per share for the year due to changes in the average number of common shares outstanding.

In the first quarter of fiscal 2015, net income includes an after-tax gain from the sale of assets of $2.5 million, $0.02 per share on a diluted basis.

In the second quarter of fiscal 2015, net income includes an after-tax gain from the sale of assets of $1.9 million, $0.02 per share on a diluted basis and an after-tax abandonment charge, primarily related to the decommission of 17 SCR powered FlexRigs, of approximately $7.5 million, $0.05 per share on a diluted basis.

In the third quarter of fiscal 2015, net income includes an after-tax gain from the sale of assets of $1.3 million, $0.01 per share on a diluted basis.

In the fourth quarter of fiscal 2015, net income includes an after-tax gain from the sale of assets of $1.7 million, $0.02 per share on a diluted basis.

In the fourth quarter of fiscal 2015, net income includes an after-tax impairment charge of approximately $24.9 million, $0.23 per share on a diluted basis and an after-tax abandonment charge primarily due to the decommission of six SCR powered land rigs and other used drilling equipment of approximately $19.1 million, $0.18 per share on a diluted basis.

NOTE 16 SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED) (Continued)

In the first quarter of fiscal 2014, net income includes an after-tax gain from the sale of assets of $3.7 million, $0.03 per share on a diluted basis.

In the second quarter of fiscal 2014, net income includes an after-tax gain from the sale of assets of $2.7 million, $0.02 per share on a diluted basis, and an after-tax gain from the sale of investment securities of $12.9 million, $0.12 per share on a diluted basis.

In the third quarter of fiscal 2014, net income includes an after-tax gain from the sale of assets of $1.4 million, $0.01 per share on a diluted basis, and an after-tax gain from the sale of investment securities of $14.9 million, $0.13 per share on a diluted basis.

In the fourth quarter of fiscal 2014, net income includes an after-tax gain from the sale of assets of $5.0 million, $0.05 per share on a diluted basis.

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

None.

Item 9A. CONTROLS AND PROCEDURES

a) Evaluation of Disclosure Controls and Procedures.

As of the end of the period covered by this Form 10-K, our management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) or 15d-15(e) under the Securities Exchange Act of 1934, as amended) as of September 30, 2015. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that:

- our disclosure controls and procedures are effective at ensuring that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms; and
- our disclosure controls and procedures operate such that important information flows to appropriate collection and disclosure points in a timely manner and are effective to ensure that such information is accumulated and communicated to our management, and made known to our Chief Executive Officer and Chief Financial Officer, particularly during the period when this Form 10-K was prepared, as appropriate to allow timely decision regarding the required disclosure.

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

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) or 15d-15(f) under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Our internal control over financial reporting includes those policies and procedures that:

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

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

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

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

Management, with the participation of our Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the effectiveness of internal control over financial reporting based on criteria established in the *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. This evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation. Although there are inherent limitations in the effectiveness of any system of internal control over financial reporting, based on this evaluation, management has concluded that our internal control over financial reporting was effective as of September 30, 2015.

The independent registered public accounting firm that audited our financial statements, Ernst & Young LLP, has issued an attestation report on our internal control over financial reporting. This report appears below at the end of this Item 9A of Form 10-K.

c) Changes in Internal Control Over Financial Reporting.

There were no changes in our internal control over financial reporting during our fourth fiscal quarter of 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

* * *

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of
Helmerich & Payne, Inc.

We have audited Helmerich & Payne, Inc.'s internal control over financial reporting as of September 30, 2015, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the "COSO criteria"). Helmerich & Payne, Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, Helmerich & Payne, Inc. maintained, in all material respects, effective internal control over financial reporting as of September 30, 2015, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Helmerich & Payne, Inc. as of September 30, 2015 and 2014, and the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2015, and our report dated November 25, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
November 25, 2015

Item 9B. OTHER INFORMATION

None.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item is incorporated herein by reference to the material under the captions "Proposal 1—Election of Directors," "Corporate Governance" and "Section 16(a) Beneficial Ownership Reporting Compliance" in our definitive Proxy Statement for the Annual Meeting of Stockholders to be held March 2, 2016, to be filed with the SEC not later than 120 days after September 30, 2015. Information required under this item with respect to executive officers under Item 401 of Regulation S-K appears under "Executive Officers of the Company" in Part I of this Form 10-K.

We have adopted a Code of Ethics for Principal Executive Officer and Senior Financial Officers. The text of this code is located on our website under "Corporate Governance." Our Internet address is www.hpinc.com. We intend to disclose any amendments to or waivers from this code on our website.

Item 11. EXECUTIVE COMPENSATION

The information required by this item regarding executive compensation, as well as director compensation and compensation committee interlocks and insider participation is incorporated herein by reference to the material beginning with the caption "Executive Compensation Discussion and Analysis" and ending with the caption "Potential Payments Upon Change-in-Control", as well as under the captions "Director Compensation in Fiscal 2015" and "Corporate Governance—Compensation Committee Interlocks and Insider Participation" in our definitive Proxy Statement for the Annual Meeting of Stockholders to be held March 2, 2016, to be filed with the SEC not later than 120 days after September 30, 2015.

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

The information required by this item is incorporated herein by reference to the material under the captions "Summary of All Existing Equity Compensation Plans," "Security Ownership of Certain Beneficial Owners" and "Security Ownership of Management" in our definitive Proxy Statement for the Annual Meeting of Stockholders to be held March 2, 2016, to be filed with the SEC not later than 120 days after September 30, 2015.

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

The information required by this item is incorporated herein by reference to the material under the captions "Corporate Governance—Transactions With Related Persons, Promoters and Certain Control Persons" and "Corporate Governance—Director Independence" in our definitive Proxy Statement for the Annual Meeting of Stockholders to be held March 2, 2016, to be filed with the SEC not later than 120 days after September 30, 2015.

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item is incorporated herein by reference to the material under the caption "Proposal 2—Ratification of Appointment of Independent Auditors—Audit Fees" in our definitive Proxy Statement for the Annual Meeting of Stockholders to be held March 2, 2016, to be filed with the SEC not later than 120 days after September 30, 2015.

PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

1. *Financial Statements*: Our consolidated financial statements, together with the notes thereto and the report of Ernst & Young LLP dated November 25, 2015, are listed below and included in Item 8—"Financial Statements and Supplementary Data" of this Form 10-K.

2. *Financial Statement Schedules*: All schedules are omitted because they are not applicable or required or because the required information is contained in the financial statements or included in the notes thereto.

3. *Exhibits*. The following documents are included as exhibits to this Form 10-K. Exhibits incorporated by reference are duly noted as such.

3.1 Amended and Restated Certificate of Incorporation of Helmerich & Payne, Inc. is incorporated herein by reference to Exhibit 3.1 of the Company's Form 8-K filed on March 14, 2012, SEC File No. 001-04221.

3.2 Amended and Restated By-laws of Helmerich & Payne, Inc. are incorporated herein by reference to Exhibit 3.1 of the Company's Form 8-K/A filed on June 9, 2014, SEC File No. 001-04221.

4.1 Rights Agreement dated as of January 8, 1996, between the Company and The Liberty National Bank and Trust Company of Oklahoma City, N.A. is incorporated herein by reference to Exhibit 1 of the Company's Form 8-K filed on January 18, 1996, SEC File No. 001-04221.

4.2 Amendment to Rights Agreement dated December 8, 2005, between the Company and UMB Bank, N.A. is incorporated herein by reference to Exhibit 4 of the Company's Form 8-K filed on December 12, 2005, SEC File No. 001-04221.

4.3 Base Indenture, dated March 19, 2015, by and between Helmerich & Payne International Drilling Co., Helmerich & Payne, Inc. and Wells Fargo Bank, National Association is incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on March 19, 2015, SEC File No. 001-04221.

4.4 First Supplemental Indenture, dated March 19, 2015, by and between Helmerich & Payne International Drilling Co., Helmerich & Payne, Inc. and Wells Fargo Bank, National Association is incorporated herein by reference to Exhibit 4.2 of the Company's Form 8-K filed on March 19, 2015, SEC File No. 001-04221.

4.5 Form of Note (included in Exhibit 4.4 above).

*10.1 Helmerich & Payne, Inc. 2000 Stock Incentive Plan is incorporated herein by reference to Appendix "A" of the Company's Proxy Statement on Schedule 14A filed on January 26, 2001.

*10.2 2012-1 Amendment to Helmerich & Payne, Inc. 2000 Stock Incentive Plan is incorporated herein by reference to Exhibit 10.5 of the Company's Quarterly Report on Form 10-Q to the Securities and Exchange Commission for the quarter ended March 31, 2012, SEC File No. 001-04221.

*10.3 Form of Agreements for Helmerich & Payne, Inc. 2000 Stock Incentive Plan being (i) Restricted Stock Award Agreement, (ii) Incentive Stock Option Agreement and (iii) Nonqualified Stock Option Agreement are incorporated by reference to Exhibit 99.2 to the Company's Registration Statement No. 333-63124 on Form S-8 dated June 15, 2001.

*10.4 Form of Director Nonqualified Stock Option Agreement for the Helmerich & Payne, Inc. 2000 Stock Incentive Plan is incorporated herein by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q to the Securities and Exchange Commission for the quarter ended June 30, 2002, SEC File No. 001-04221.

*10.5 Form of Change of Control Agreement for Helmerich & Payne, Inc. is incorporated herein by reference to Exhibits 10.2 and 10.3 of the Company's Quarterly Report on Form 10-Q to the Securities and Exchange Commission for the quarter ended June 30, 2002, SEC File No. 001-04221.

10.6 Note Purchase Agreement dated as of June 15, 2009, among Helmerich & Payne International Drilling Co., Helmerich & Payne, Inc. and various Note purchasers is incorporated by reference to Exhibit 10.1 of the Company's Form 8-K filed on July 21, 2009, SEC File No. 001-04221.

10.7 Credit Agreement dated May 25, 2012, among Helmerich & Payne International Drilling Co., Helmerich & Payne, Inc. and Wells Fargo Bank, National Association is incorporated by reference to Exhibit 10.1 of the Company's Form 8-K filed on May 31, 2012, SEC File No. 001-04221.

10.8 Purchase Agreement, dated March 12, 2015, among Helmerich & Payne International Drilling Co., Helmerich & Payne, Inc., Goldman, Sachs & Co. and Wells Fargo Securities, LLC is incorporated herein by reference to Exhibit 10.1 of the Company's Form 8-K filed on March 13, 2015, SEC File No. 001-04221.

10.9 Registration Rights Agreement, dated March 19, 2015, by and between Helmerich & Payne International Drilling Co., Helmerich & Payne, Inc., Goldman, Sachs & Co. and Wells Fargo Securities, LLC is incorporated herein by reference to Exhibit 4.4 of the Company's Form 8-K filed on March 19, 2015, SEC File No. 001-04221.

10.10 Office Lease dated May 30, 2003, between K/B Fund IV and Helmerich & Payne, Inc. is incorporated herein by reference to Exhibit 10.18 of the Company's Annual Report on Form 10-K to the Securities and Exchange Commission for fiscal 2003, SEC File No. 001-04221.

10.11 First Amendment to Lease between ASP, Inc. and Helmerich & Payne, Inc. is incorporated herein by reference to Exhibit 10.1 of the Company's Form 8-K filed on May 29, 2008, SEC File No. 001-04221.

10.12 Second Amendment to Office Lease dated December 13, 2011, between ASP, Inc. and Helmerich & Payne, Inc. is incorporated herein by reference to Exhibit 10.1 of Form 8-K filed by the Company on December 14, 2011, SEC File No. 001-04221.

10.13 Third Amendment to Office Lease dated September 5, 2012, between ASP, Inc. and Helmerich & Payne, Inc. (with form of Fourth Amendment to Office Lease attached thereto as Exhibit "B") is incorporated herein by reference to Exhibit 10.12 of the Company's Annual Report on Form 10-K to the Securities and Exchange Commission for fiscal 2012, SEC File No. 001-04221.

10.14 Fifth Amendment to Office Lease dated December 21, 2012, between ASP, Inc. and Helmerich & Payne, Inc. is incorporated herein by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q to the Securities and Exchange Commission for the quarter ended December 31, 2012, SEC File No. 001-04221.

10.15 Sixth Amendment to Office Lease dated April 24, 2013, between ASP, Inc. and Helmerich & Payne, Inc. is incorporated herein by reference to Exhibit 10.1 of Form 8-K filed by the Company on April 26, 2013, SEC File No. 001-04221.

10.16 Seventh Amendment to Office Lease dated September 16, 2013, between ASP, Inc. and Helmerich & Payne, Inc. is incorporated herein by reference to Exhibit 10.1 of Form 8-K filed by the Company on September 17, 2013, SEC File No. 001-04221.

10.17 Eighth Amendment to Office Lease dated March 24, 2014, between ASP, Inc. and Helmerich & Payne, Inc. is incorporated herein by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q to the Securities and Exchange Commission for the quarter ended March 31, 2014, SEC File No. 001-04221.

10.18 Ninth Amendment to Office Lease dated June 16, 2014, between ASP, Inc. and Helmerich & Payne, Inc. is incorporated herein by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q to the Securities and Exchange Commission for the quarter ended June 30, 2014, SEC File No. 001-04221.

10.19 Tenth Amendment to Office Lease dated November 26, 2014, between ASP, Inc. and Helmerich & Payne, Inc. is incorporated herein by reference to Exhibit 10.5 of the Company's Quarterly Report on Form 10-Q to the Securities and Exchange Commission for the quarter ended December 31, 2014, SEC File No. 001-04221.

10.20 Eleventh Amendment to Office Lease dated February 18, 2015, and Twelfth Amendment to Office Lease dated June 30, 2015, both between Helmerich & Payne, Inc. and ASP, Inc., are incorporated herein by reference to Exhibits 10.1 and 10.2 of the Company's Quarterly Report on Form 10-Q to the Securities and Exchange Commission for the quarter ended June 30, 2015, SEC File No. 001-04221.

10.21 Thirteenth Amendment to Office Lease dated October 9, 2015, between ASP, Inc. and Helmerich & Payne, Inc.

*10.22 Helmerich & Payne, Inc. Annual Bonus Plan for Executive Officers is incorporated herein by reference to Exhibit 10.7 of the Company's Quarterly Report on Form 10-Q to the Securities and Exchange Commission for the quarter ended March 31, 2015, SEC File No. 001-04221.

*10.23 Helmerich & Payne, Inc. 2005 Long-Term Incentive Plan is incorporated herein by reference to Appendix "A" to the Company's Proxy Statement on Schedule 14A filed January 26, 2006.

*10.24 2012-1 Amendment to Helmerich & Payne, Inc. 2005 Long-Term Incentive Plan is incorporated herein by reference to Exhibit 10.6 of the Company's Quarterly Report on Form 10-Q to the Securities and Exchange Commission for the quarter ended March 31, 2012, SEC File No. 001-04221.

*10.25 Form of Agreements for Helmerich & Payne, Inc. 2005 Long-Term Incentive Plan applicable to certain executives: (i) Nonqualified Stock Option Agreement, (ii) Incentive Stock Option Agreement, and (iii) Restricted Stock Award Agreement are incorporated herein by reference to Exhibit 10.2 of the Company's Form 8-K filed on December 7, 2009, SEC File No. 001-04221.

*10.26 Form of Agreements for the Helmerich & Payne, Inc. 2005 Long-Term Incentive Plan applicable to participants other than certain executives: Nonqualified Stock Option Agreement, Incentive Stock Option Agreement, and Restricted Stock Award Agreement are incorporated herein by reference to Exhibit 10.3 of the Company's Form 8-K filed on December 7, 2009, SEC File No. 001-04221.

*10.27 Form of Amendment to Nonqualified Stock Option Agreements and Amendment to Restricted Stock Award Agreements for the Helmerich & Payne, Inc. 2005 Long-Term Incentive Plan applicable to certain executive officers are incorporated herein by reference to Exhibit 10.4 of the Company's Form 8-K filed on December 7, 2009, SEC File No. 001-04221.

*10.28 Form of Amendment to Nonqualified Stock Option Agreements and Amendment to Restricted Stock Award Agreements for the Helmerich & Payne, Inc. 2005 Long-Term Incentive Plan applicable to participants other than certain executive officers are incorporated herein by reference to Exhibit 10.5 of the Company's Form 8-K filed on December 7, 2009, SEC File No. 001-04221.

*10.29 Helmerich & Payne, Inc. 2010 Long-Term Incentive Plan is incorporated herein by reference to Appendix "A" of the Company's Proxy Statement on Schedule 14A filed on January 26, 2011.

*10.30 Form of Agreements for Helmerich & Payne, Inc. 2010 Long-Term Incentive Plan applicable to certain executives: (i) Nonqualified Stock Option Award Agreement is incorporated herein by reference to Exhibit 10.1 of the Company's Form 8-K filed on March 14, 2012, SEC File No. 001-04221, and (ii) Restricted Stock Award Agreement is incorporated herein by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q to the Securities and Exchange Commission for the quarter ended December 31, 2013, SEC File No. 001-04221.

*10.31 Form of Agreements for the Helmerich & Payne, Inc. 2010 Long-Term Incentive Plan applicable to participants other than certain executives: (i) Nonqualified Stock Option Award Agreement is incorporated herein by reference to Exhibit 10.2 of the Company's Form 8-K filed on March 14, 2012, SEC File No. 001-04221, and (ii) Restricted Stock Award Agreement is incorporated herein by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q to the Securities and Exchange Commission for the quarter ended December 31, 2013, SEC File No. 001-04221.

*10.32 Form of Agreements for the Helmerich & Payne, Inc. 2010 Long-Term Incentive Plan applicable to Directors: (i) Nonqualified Stock Option Award Agreement and (ii) Restricted Stock Award Agreement are incorporated by reference to Exhibit 10.3 of the Company's Form 8-K filed on March 14, 2012, SEC File No. 001-04221.

10.33 Fabrication Contract between Helmerich & Payne International Drilling Co. and Southeast Texas Industries, Inc. is incorporated herein by reference to Exhibit 10.1 of the Company's Form 8-K filed on December 7, 2006, SEC File No. 001-04221.

10.34 Contract dated July 18, 2007, between Helmerich & Payne International Drilling Co. and Southeast Texas Industrial Services, Inc. is incorporated herein by reference to Exhibit 10.1 of the Company's Form 8-K filed on July 18, 2007, SEC File No. 001-04221.

10.35 Amendment to Contract dated August 8, 2008, between Helmerich & Payne International Drilling Co. and Southeast Texas Industries, Inc. is incorporated herein by reference to Exhibit 10.33 of the Company's Annual Report on Form 10-K to the Securities and Exchange Commission for fiscal 2008, SEC File No. 001-04221.

10.36 Amendment to Contract dated August 8, 2008, between Helmerich & Payne International Drilling Co. and Southeast Texas Industrial Services, Inc. is incorporated herein by reference to Exhibit 10.34 of the Company's Annual Report on Form 10-K to the Securities and Exchange Commission for fiscal 2008, SEC File No. 001-04221.

10.37 Second Amendment to Contract dated March 26, 2010, and Third Amendment to Contract dated August 4, 2011, both between Helmerich & Payne International Drilling Co. and Southeast Texas Industries, Inc., are incorporated herein by reference to Exhibits 10.24 and 10.26, respectively, of the Company's Annual Report on Form 10-K to the Securities and Exchange Commission for fiscal 2011, SEC File No. 001-04221.

10.38 Second Amendment to Contract dated March 26, 2010, and Third Amendment to Contract dated August 4, 2011, both between Helmerich & Payne International Drilling Co. and Southeast Texas Industrial Services, Inc., are incorporated herein by reference to Exhibits 10.25 and 10.27, respectively, of the Company's Annual Report on Form 10-K to the Securities and Exchange Commission for fiscal 2011, SEC File No. 001-04221.

10.39 Fourth Amendment to Contract dated January 11, 2013, and Fifth Amendment to Contract dated November 21, 2014, both between Helmerich & Payne International Drilling Co. and Southeast Texas Industries, Inc., are incorporated herein by reference to Exhibits 10.1 and 10.3, respectively, of the Company's Quarterly Report on Form 10-Q to the Securities and Exchange Commission for the quarter ended December 31, 2014, SEC File No. 001-04221.

10.40 Fourth Amendment to Contract dated January 11, 2013, and Fifth Amendment to Contract dated November 21, 2014, both between Helmerich & Payne International Drilling Co. and Southeast Texas Industrial Services, Inc., are incorporated herein by reference to Exhibits 10.2 and 10.4, respectively, of the Company's Quarterly Report on Form 10-Q to the Securities and Exchange Commission for the quarter ended December 31, 2014, SEC File No. 001-04221.

*10.41 Supplemental Retirement Income Plan for Salaried Employees of Helmerich & Payne, Inc. is incorporated herein by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q to the Securities and Exchange Commission for the quarter ended December 31, 2008, SEC File No. 001-04221.

*10.42 Supplemental Savings Plan for Salaried Employees of Helmerich & Payne, Inc. is incorporated herein by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q to the Securities and Exchange Commission for the quarter ended December 31, 2008, SEC File No. 001-04221.

*10.43 Helmerich & Payne, Inc. Director Deferred Compensation Plan is incorporated herein by reference to Exhibit 10.3 of the Company's Quarterly Report on Form 10-Q to the Securities and Exchange Commission for the quarter ended December 31, 2008, SEC File No. 001-04221.

*10.44 Advisory Services Agreement dated March 5, 2014 between Helmerich & Payne, Inc. and Hans C. Helmerich is incorporated herein by reference to Exhibit 10.1 of the Company's Form 8-K filed on March 7, 2014, SEC File No. 001-04221.

*10.45 Advisory Services Agreement effective March 4, 2015 between Helmerich & Payne, Inc. and Steven R. Mackey is incorporated herein by reference to Exhibit 10.7 of the Company's Quarterly Report on Form 10-Q to the Securities and Exchange Commission for the quarter ended March 31, 2015, SEC File No. 001-04221.

12.1 Helmerich & Payne, Inc.'s Statement Regarding Computation of Ratio of Earnings to Fixed Charges.

21. List of Subsidiaries of the Company.

23.1 Consent of Independent Registered Public Accounting Firm.

31.1 Certification of Chief Executive Officer pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of Chief Financial Officer pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32. Certification of Chief Executive Officer and Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

99.1 Plea Agreement dated October 30, 2013 between Helmerich & Payne International Drilling Co. and the United States Department of Justice, United States Attorney's Office for the Eastern District of Louisiana is incorporated herein by reference to Exhibit 99.1 of the Company's Form 8-K filed on November 8, 2013, SEC File No. 001-04221.

101. Financial statements from this Form 10-K formatted in XBRL: (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Balance Sheets, (iv) the Consolidated Statements of Shareholders' Equity, (v) the Consolidated Statements of Cash Flows and (vi) the Notes to Consolidated Financial Statements.

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* Management or Compensatory Plan or Arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Company has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized:

HELMERICH & PAYNE, INC.

By: /s/ JOHN W. LINDSAY

John W. Lindsay,
President and Chief Executive Officer

Date: November 25, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Company and in the capacities and on the dates indicated:

Signature	Title	Date
/s/ JOHN W. LINDSAY John W. Lindsay	Director, President and Chief Executive Officer (Principal Executive Officer)	November 25, 2015
/s/ JUAN PABLO TARDIO Juan Pablo Tardio	Vice President and Chief Financial Officer (Principal Financial Officer)	November 25, 2015
/s/ GORDON K. HELM Gordon K. Helm	Vice President and Controller (Principal Accounting Officer)	November 25, 2015
/s/ HANS HELMERICH Hans Helmerich	Director and Chairman of the Board	November 25, 2015
/s/ WILLIAM L. ARMSTRONG William L. Armstrong	Director	November 25, 2015
/s/ RANDY A. FOUTCH Randy A. Foutch	Director	November 25, 2015
/s/ PAULA MARSHALL Paula Marshall	Director	November 25, 2015

Signature	Title	Date
/s/ THOMAS A. PETRIE Thomas A. Petrie	Director	November 25, 2015
/s/ DONALD F. ROBILLARD, JR. Donald F. Robillard, Jr.	Director	November 25, 2015
/s/ FRANCIS ROONEY Francis Rooney	Director	November 25, 2015
/s/ EDWARD B. RUST, JR. Edward B. Rust, Jr.	Director	November 25, 2015
/s/ JOHN D. ZEGLIS John D. Zeglis	Director	November 25, 2015

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Directors

Hans Helmerich
Chairman of the Board
Tulsa, Oklahoma

William L. Armstrong**(***)
President
Colorado Christian University
Lakewood, Colorado

Randy A. Foutch*(***)
Chairman and Chief Executive Officer
Laredo Petroleum, Inc.
Tulsa, Oklahoma

John W. Lindsay
President and Chief Executive Officer
Tulsa, Oklahoma

Paula Marshall**(***)
President and Chief Executive Officer
The Bama Companies, Inc.
Tulsa, Oklahoma

Thomas A. Petrie**(***)
Chairman
Petrie Partners, LLC
Denver, Colorado

Donald F. Robillard, Jr.*(***)
Chief Financial Officer
Hunt Consolidated, Inc.
Dallas, Texas

Hon. Francis Rooney*(***)
Chief Executive Officer
Rooney Holdings, Inc.
Former U.S. Ambassador to the Holy See, 2005-2008
Tulsa, Oklahoma

Edward B. Rust, Jr.*(***)
Chairman
State Farm Mutual Automobile Insurance Company
Bloomington, Illinois

John D. Zeglis**(***)
Chairman and Chief Executive Officer, Retired
AT&T Wireless Services, Inc.
Basking Ridge, New Jersey

Officers

John W. Lindsay
President and Chief Executive Officer

Juan Pablo Tardio
Vice President and Chief Financial Officer

Robert L. Stauder
Senior Vice President and Chief Engineer
Helmerich & Payne International Drilling Co. (subsidiary)

Jeffrey L. Flaherty
Senior Vice President, Operations
Helmerich & Payne International Drilling Co. (subsidiary)

John R. Bell
Vice President, Corporate Services

Gordon K. Helm
Vice President and Controller

Cara M. Hair
Vice President, General Counsel and Chief Compliance Officer

Jonathan M. Cinocca
Corporate Secretary

Stockholders' Meeting
The annual meeting of stockholders will be held on March 2, 2016. We will mail to most stockholders a Notice of Internet Availability of Proxy Materials ("Notice") detailing how to access proxy materials, vote and obtain, if desired, a paper copy of the proxy materials. Stockholders who have requested paper copies of proxy materials or previously elected to receive proxy materials electronically will not receive the Notice and will receive proxy materials in the format requested. The Notice and the proxy materials are first being made available to our stockholders on or about January 19, 2016.

Stock Exchange Listing
Helmerich & Payne, Inc. Common Stock is traded on the New York Stock Exchange with the ticker symbol "HP." The newspaper abbreviation most commonly used for financial reporting is "HelmP." Options on the Company's stock are also traded on the New York Stock Exchange.

Stock Transfer Agent and Registrar
As of November 13, 2015, there were 611 record holders of Helmerich & Payne, Inc. Common Stock as listed by the transfer agent's records.

Our transfer agent is responsible for our stockholder records, issuance of stock certificates, and distribution of our dividends and the IRS Form 1099. Your requests, as stockholders, concerning these matters are most efficiently answered by corresponding directly with the transfer agent at the following address:

Computershare Trust Company, N.A.
Investor Services
P.O. Box 43078
Providence, RI 02940-3078
Telephone: (800) 884-4225
(781) 575-4706

Available Information
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 the Company's website as soon as reasonably practicable after the Company electronically files such materials with, or furnishes it to, the SEC. Also located on the investor relations section of the Company's website are certain corporate governance documents, including the following: the Company's Amended and Restated Certificate of Incorporation and Amended and Restated By-Laws, the charters of the committees of the Board of Directors; the Company's Corporate Governance Guidelines and Code of Business Conduct and Ethics; the Code of Ethics for Principal Executive Officer and Senior Financial Officers; the Related Person Transaction Policy; the Foreign Corrupt Practices Act Compliance Policy; certain Audit Committee Practices and a description of the means by which employees and other interested persons may communicate certain concerns to the Company's Board of Directors, including the communication of such concerns confidentially and anonymously via the Company's ethics hotline at 1-800-205-4913. Annual reports, quarterly reports, current reports, amendments to those reports, earnings releases, financial statements and the various corporate governance documents are also available free of charge upon written request.

Direct Inquiries To:
Investor Relations
Helmerich & Payne, Inc.
1437 South Boulder Avenue
Tulsa, Oklahoma 74119
Telephone: (918) 742-5531
Internet Address: http://www.hpinc.com

* Member, Audit Committee

** Member, Human Resources Committee

*** Member, Nominating and Corporate Governance Committee

HELMERICH & PAYNE, INC.
1437 SOUTH BOULDER AVENUE
TULSA, OKLAHOMA 74119

ANNUAL REPORT FOR 2015