UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(MARK ONE)

☑ **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the Fiscal Year Ended December 31, 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 1-7573

PARKER DRILLING COMPANY

(Exact name of registrant as specified in its charter)

Delaware	**73-0618660**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
5 Greenway Plaza, Suite 100, Houston, Texas	**77046**
(Address of principal executive offices)	*(Zip code)*

Registrant's telephone number, including area code:
(281) 406-2000

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

Title of Each Class	Name of Each Exchange on Which Registered:
Common Stock, par value $0.16 \frac{2}{3}$ per share	New York Stock Exchange

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

None

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange 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 website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

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

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

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

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2015 was $395.3 million. At February 19, 2016, there were 123,205,725 shares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of our definitive proxy statement for the Annual Meeting of Shareholders to be held on May 10, 2016 are incorporated by reference in Part III.

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PART I

Item 1. Business

General

Unless otherwise indicated, the terms "Company," "Parker," "we," "us" and "our" refer to Parker Drilling Company together with its subsidiaries and "Parker Drilling" refers solely to the parent, Parker Drilling Company. Parker Drilling was incorporated in the state of Oklahoma in 1954 after having been established in 1934. In March 1976, the state of incorporation of the Company was changed to Delaware. Our principal executive offices are located at 5 Greenway Plaza, Suite 100, Houston, Texas 77046.

We are an international provider of contract drilling and drilling-related services and rental tools. We have operated in over 50 countries since beginning operations in 1934, making us among the most geographically experienced drilling contractors and rental tools providers in the world. We currently have operations in 21 countries. Parker has set numerous world records for deep and extended-reach drilling land rigs and is an industry leader in quality, health, safety and environmental practices.

Our business is comprised of two business lines: (1) Drilling Services and (2) Rental Tools Services. We report our Rental Tools Services business as one reportable segment (Rental Tools) and report our Drilling Services business as two reportable segments: (1) U.S. (Lower 48) Drilling and (2) International & Alaska Drilling. For information regarding our reportable segments and operations by geographic areas for the years ended December 31, 2015, 2014 and 2013, see Note 12 - Reportable Segments in Item 8. Financial Statements and Supplementary Data and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Our Drilling Services Business

In our Drilling Services business, we drill oil and gas wells for customers in both the U.S. and international markets. We provide this service with both Company-owned rigs and customer-owned rigs. We refer to the provision of drilling services with customer owned rigs as our operations and maintenance (O&M) service in which operators own their own drilling rigs but choose Parker Drilling to operate and maintain the rigs for them. The nature and scope of activities involved in drilling an oil and gas well is similar whether it is drilled with a Company-owned rig (as part of a traditional drilling contract) or a customer-owned rig (as part of an O&M contract). In addition, we provide project related services, such as engineering, procurement, project management and commissioning of customer owned drilling facility projects. We have extensive experience and expertise in drilling geologically difficult wells and in managing the logistical and technological challenges of operating in remote, harsh and ecologically sensitive areas.

U.S. (Lower 48) Drilling

Our U.S. (Lower 48) Drilling segment provides drilling services with our Gulf of Mexico (GOM) barge drilling rig fleet and through U.S. (Lower 48) based O&M services. Our GOM barge drilling fleet operates barge rigs that drill for oil and natural gas in shallow waters in and along the inland waterways and coasts of Louisiana, Alabama and Texas. The majority of these wells are drilled in shallow water depths ranging from 6 to 12 feet. Our rigs are all equipped for zero-discharge operations and based on the diversity of our fleet, our rigs are suitable for a variety of drilling programs from inland coastal waters, requiring shallow draft barges, to open water drilling on both state and federal water projects requiring more robust hull depth capabilities. The barge drilling industry in the GOM is characterized by cyclical activity where utilization and dayrates are typically driven by oil and gas prices and our customers' access to project financing. Contract terms tend to be well-to-well or multi-well programs, most commonly ranging from 45 to 150 days.

International & Alaska Drilling

Our International & Alaska Drilling segment provides drilling services, with Company-owned rigs as well as through O&M contracts, and project related services. We strive to deploy our fleet of Parker-owned rigs in markets where we expect to have opportunities to keep the rigs consistently utilized and build a sufficient presence to achieve efficient operating scale. During the year ended December 31, 2015, we had rigs operating in Mexico, Colombia, Guatemala, Kazakhstan, Papua New Guinea, Indonesia, the Kurdistan Region of Iraq, Sakhalin Island, Russia, and Alaska. In addition, we have O&M and ongoing project related services for customer-owned rigs in Abu Dhabi, Sakhalin Island, Russia and Kuwait.

The drilling markets in which this segment operates have one or more of the following characteristics:

- customers that typically are major, independent or national oil and natural gas companies or integrated service providers;

- drilling programs in remote locations with little infrastructure requiring a large inventory of spare parts and other ancillary equipment and self-supported service capabilities;

- complex wells and/or harsh environments (such as high pressures, deep depths, hazardous or geologically challenging conditions and sensitive environments) requiring specialized equipment and considerable experience to drill; and

- drilling and O&M contracts that generally cover periods of one year or more.

Our Rental Tools Services Business

In our Rental Tools Services business, we provide premium rental equipment and services to exploration and production (E&P) companies, drilling contractors and service companies on land and offshore in the United States (U.S.) and select international markets. Tools we provide include standard and heavy-weight drill pipe, all of which are available with standard or high-torque connections, tubing, pressure control equipment, including blow-out preventers (BOPs), drill collars and more. We also provide well construction services, which include tubular running services and downhole tools, and well intervention services, which include whipstock, fishing products and related services, as well as inspection and machine shop support.

Our U.S. rental tools business is headquartered in New Iberia, Louisiana and our international rental tools business is headquartered in Dubai, United Arab Emirates (UAE). We maintain an inventory of rental tools and provide services to our customers on land and offshore from facilities in Louisiana, Texas, Oklahoma, Wyoming, North Dakota and West Virginia, as well as in the Middle East, Latin America, United Kingdom, Europe, and Asia-Pacific regions.

Our largest single market for rental tools is U.S. land drilling, a cyclical market driven primarily by oil and gas prices and our customers' access to project financing. A portion of our U.S. rental tools business is supplying tubular goods and other equipment to offshore GOM customers. Generally, rental tools are used for only a portion of a well drilling program and are requested by the customer when they are needed, requiring us to keep a broad inventory of rental tools in stock. Rental tools are usually rented on a daily or monthly basis.

On April 22, 2013, we completed the acquisition of International Tubular Services Limited (ITS) and related assets (collectively, the ITS Acquisition). On April 17, 2015, we acquired 2M-Tek, a Louisiana-based manufacturer of equipment for tubular running and related well services (the 2M-Tek Acquisition). See Note 2 - Acquisitions in Item 8. Financial Statements and Supplementary Data for further discussion.

Our Business Strategy

We intend to successfully compete in select energy services businesses that benefit our customers' exploration, appraisal and development programs, and in which operational execution is the key measure of success. We will do this by:

- Consistently delivering innovative, reliable, and efficient results that help our customers reduce their operational risks and manage their operating costs; and

- Investing to improve and grow our existing business lines, and to expand the scope of products and services we offer.

Our Core Competencies

We believe our core competencies are the foundation for delivering operational excellence to our customers. Applying and strengthening these core competencies will be a key factor in our success:

Customer Aligned Operational Excellence: Our daily focus is meeting the needs of our customers. We strive to anticipate our customers' challenges and provide innovative, reliable and efficient solutions to help them achieve their business objectives.

Rapid Personnel Development: Motivated, skilled and effective people are critical to the successful execution of our strategy. We strive to attract and retain the best people, to develop depth and strength in key skills, and to provide a safety-and solutions-oriented workforce to our customers.

Selective and Effective Market Entry: We are selective about the services we provide, geographies in which we operate, and customers we serve. We intend to build Parker's business in markets with the best potential for sustained growth, profitability and operating scale. We are strategic, timely and intentional when we enter new markets and when we grow organically or through acquisition or investments in new business ventures.

Enhanced Asset Management and Predictive Maintenance: We believe well-maintained rigs, equipment and rental tools are critical to providing reliable results for our customers. We employ predictive and preventive maintenance programs and training to sustain high levels of effective utilization and to provide reliable operating performance and efficiency.

Standard, Modular and Configurable Processes and Equipment: To address the challenging and harsh environments in which our customers operate, we develop standardized processes and equipment that can be configured to meet each project's distinct technological requirements. Repeatable processes and modular equipment leverage our investments in assets and employees, increase efficiency and reduce disruption.

We believe there are tangible rewards from delivering value to our customers through superior execution of our core competencies. When we deliver innovative, reliable and efficient solutions aligned with our customers' needs, we believe we are well-positioned to earn premium rates, generate follow-on business and create growth opportunities that enhance our financial performance and advance our strategy.

Customers and Scope of Operations

Our customer base consists of major, independent and national oil and natural gas E&P companies and integrated service providers. Each of our segments depends on a limited number of key customers and the loss of any one or more key customers could have a material adverse effect on a segment. In 2015, our largest customer, Exxon Neftegas Limited accounted for approximately 27.9 percent of our total revenues. For information regarding our reportable segments and operations by geographic areas for the years ended December 31, 2015, 2014 and 2013, see Note 12 - Reportable Segments in Item 8. Financial Statements and Supplementary Data and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Competition

We operate in competitive businesses characterized by high capital requirements, rigorous technological challenges, evolving regulatory requirements and challenges in securing and retaining qualified field personnel.

In drilling markets, most contracts are awarded on a competitive bidding basis and operators often consider reliability, efficiency and safety in addition to price. We have been successful in differentiating ourselves from competitors through our drilling performance and safety record, and through providing services that help our customers manage their operating costs and mitigate their operational risks.

In international drilling markets, we compete with a number of international drilling contractors as well as local contractors. Although local drilling contractors often have lower labor and mobilization costs, we are generally able to distinguish ourselves from these companies based on our technical expertise, safety performance, quality of service, and experience. We believe our expertise in operating in challenging environments has been a significant factor in securing contracts. In the GOM barge drilling market, we compete with a small number of contractors. We have the largest number and greatest diversity of rigs available in this market, allowing us to provide equipment and services that are well-matched to customers' requirements. We believe the market for drilling contracts will continue to be competitive with continued focus on reliability, efficiency and safety, in addition to price.

In rental tools markets, we compete with suppliers both larger and smaller than our own business, some of which are components of larger enterprises. We compete against other rental tools companies based on breadth of inventory, the availability and price of product and quality of service. In the U.S. market, our network of locations provides broad and efficient product availability. In international markets, some business is obtained in conjunction with our drilling and O&M projects.

Contracts

Most drilling contracts are awarded based on competitive bidding. The rates specified in drilling contracts vary depending upon the type of rig employed, equipment and services supplied, geographic location, term of the contract, competitive conditions and other variables. Our contracts generally provide for an operating dayrate during drilling operations, with lower rates for periods of equipment downtime, customer stoppage, adverse weather or other conditions, and no payment when certain conditions continue beyond contractually established parameters. When a rig mobilizes to or demobilizes from an operating area, the contract typically provides for a different dayrate or specified fixed payments during mobilization or demobilization. The terms of most of our contracts are based on either a specified period of time or the time required to drill a specified number of wells. The contract term in some instances may be extended by the customer exercising options for an additional time period or for the drilling of additional wells, or by exercising a right of first refusal. Most of our contracts allow termination by the customer prior to the end of the term without penalty under certain circumstances, such as the loss of or major damage to the drilling unit or other events that cause the suspension of drilling operations beyond a specified period of time. See "Certain of our contracts are subject to cancellation by our customers without penalty and with little or no notice." in Item 1A. Risk Factors. Certain contracts require the customer to pay an early termination fee if the customer terminates a contract before the end of the term without cause. Our project services contracts include engineering, procurement, and project management consulting, for which we are compensated through labor rates and cost plus markup basis for non-labor items.

Rental tools contracts are typically on a dayrate basis with rates determined based on type of equipment and competitive conditions. Rental rates generally apply from the time the equipment leaves our facility until it is returned. Rental contracts generally require the customer to pay for lost-in-hole or damaged equipment.

Seasonality

Our rigs in the inland waters of the GOM are subject to severe weather during certain periods of the year, particularly during hurricane season from June through November, which could halt operations for prolonged periods or limit contract opportunities during that period. In addition, mobilization, demobilization, or well-to-well movements of rigs in arctic regions can be affected by seasonal changes in weather or weather so severe the conditions are deemed too unsafe to operate.

Backlog

Backlog is our estimate of the dollar amount of revenues we expect to realize in the future as a result of executing awarded contracts. The Company's backlog of firm orders was approximately $291 million at December 31, 2015 and $674 million at December 31, 2014 and is primarily attributable to the International & Alaska segment of our Drilling Services business. We estimate that, as of December 31, 2015, 68.0 percent of our backlog will be recognized as revenues within one year.

The amount of actual revenues earned and the actual periods during which revenues are earned could be different from amounts disclosed in our backlog calculations due to a lack of predictability of various factors, including unscheduled repairs, maintenance requirements, weather delays, contract terminations or renegotiations, new contracts and other factors. See "Our backlog of contracted revenue may not be fully realized and may reduce significantly in the future, which may have a material adverse effect on our financial position, results of operations or cash flows." in Item 1A. Risk Factors.

Insurance and Indemnification

Substantially all of our operations are subject to hazards that are customary for oil and natural gas drilling operations, including blowouts, reservoir damage, loss of production, loss of well control, lost or stuck drill strings, equipment defects, cratering, oil and natural gas well fires and explosions, natural disasters, pollution, mechanical failure and damage or loss during transportation. Some of our fleet is also subject to hazards inherent in marine operations, either while on-site or during mobilization, such as capsizing, sinking, grounding, collision, damage from severe weather and marine life infestations. These hazards could result in damage to or destruction of drilling equipment, personal injury and property damage, suspension of operations or environmental damage, which could lead to claims by third parties or customers, suspension of operations and contract terminations. We have had accidents in the past due to some of these hazards.

Our contracts provide for varying levels of indemnification between ourselves and our customers. We maintain insurance with respect to personal injuries, damage to or loss of equipment and various other business risks, including well control and subsurface risk. Our insurance policies typically have 12-month policy periods.

Our insurance program provides coverage, to the extent not otherwise paid by the customer under the indemnification provisions of the drilling or rental tool contract, for liability due to well control events and liability arising from third-party claims, including wrongful death and other personal injury claims by our personnel as well as claims brought on behalf of individuals who are not our employees. Generally, our program provides liability coverage up to $350.0 million, with retentions of $1.0 million or less.

Well control events generally include an unintended flow from the well that cannot be contained by using equipment on site (*e.g.,* a BOP), by increasing the weight of drilling fluid or by diverting the fluids safely into production. Our insurance program provides coverage for third-party liability claims relating to sudden and accidental pollution from a well control event up to $350.0 million per occurrence. A separate limit of $10.0 million exists to cover the costs of re-drilling of the well and well control costs under a Contingent Operators Extra Expense policy. For our rig based operations, remediation plans are in place to prevent the spread of pollutants and our insurance program provides coverage for removal, response and remedial actions. We retain the risk for liability not indemnified by the customer below the retention and in excess of our insurance coverage.

Based upon a risk assessment and due to the high cost, high self-insured retention and limited coverage for windstorms in the GOM, we have elected not to purchase windstorm insurance for our barge rigs in the GOM. Although we have retained the risk for physical loss or damage for these rigs arising from a named windstorm, we have procured insurance coverage for removal of a wreck caused by a windstorm.

Our contracts provide for varying levels of indemnification from our customers and may require us to indemnify our customers. Liability with respect to personnel and property is customarily assigned on a “knock-for-knock” basis, which means that we and our customers customarily assume liability for our respective personnel and property regardless of fault. In addition, our customers typically indemnify us for damage to our equipment down-hole, and in some cases our subsea equipment, generally based on replacement cost minus some level of depreciation. However, in certain contracts we may assume liability for damage to our customer’s property and other third-party property on the rig and in other contracts we are not indemnified by our customers for damage to their property and, accordingly, could be liable for any such damage under applicable law.

Our customers typically assume responsibility for and indemnify us from any loss or liability resulting from pollution, including clean-up and removal and third-party damages, arising from operations under the contract and originating below the surface of the land or water, including losses or liability resulting from blowouts or cratering of the well. In some contracts, however, we may have liability for damages resulting from such pollution or contamination caused by our gross negligence or, in some cases, ordinary negligence.

We generally indemnify the customer for legal and financial consequences of spills of industrial waste, lubricants, solvents and other contaminants (other than drilling fluid) on the surface of the land or water originating from our rigs or equipment. We typically require our customers to retain liability for spills of drilling fluid (sometimes called “mud”) which circulates down-hole to the drill bit, lubricates the bit and washes debris back to the surface. Drilling fluid often contains a mixture of synthetics, the exact composition of which is prescribed by the customer based on the particular geology of the well being drilled.

The above description of our insurance program and the indemnification provisions typically found in our contracts is only a summary as of the date hereof and is general in nature. Our insurance program and the terms of our drilling and rental tool contracts may change in the future. In addition, the indemnification provisions of our contracts may be subject to differing interpretations, and enforcement of those provisions may be limited by public policy and other considerations.

If any of the aforementioned operating hazards results in substantial liability and our insurance and contractual indemnification provisions are unavailable or insufficient, our financial condition, operating results or cash flows may be materially adversely affected.

Employees

The following table sets forth the composition of our employee base:

	December 31,	
	2015	**2014**
U.S. (Lower 48) Drilling	160	546
International & Alaska Drilling	1,286	1,571
Rental Tools	942	1,110
Corporate	179	216
Total employees	2,567	3,443

Environmental Considerations

Our operations are subject to numerous U.S. federal, state, and local laws and regulations, as well as the laws and regulations of other jurisdictions in which we operate, pertaining to the environment or otherwise relating to environmental protection. Numerous governmental agencies, such as the U.S. Environmental Protection Agency (EPA), issue regulations to implement and enforce laws pertaining to the environment, which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties or may result in injunctive relief for failure to comply. These laws and regulations may require the acquisition of a permit before drilling commences; restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities; limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically sensitive and other protected areas; require remedial action to clean up pollution from former operations; and impose substantial liabilities for pollution resulting from our operations. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly compliance could adversely affect our operations and financial position, as well as those of similarly situated entities operating in the same markets. While our management believes that we comply with current applicable environmental laws and regulations, there is no assurance that compliance can be maintained in the future.

As an owner or operator of both onshore and offshore facilities, including mobile offshore drilling rigs in or near waters of the United States, we may be liable for the costs of clean up and damages arising out of a pollution incident to the extent set forth in federal statutes such as the Federal Water Pollution Control Act (commonly known as the Clean Water Act (CWA)), as amended by the Oil Pollution Act of 1990 (OPA); the Clean Air Act (CAA); the Outer Continental Shelf Lands Act (OCSLA); the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA); the Resource Conservation and Recovery Act (RCRA); the Emergency Planning and Community Right to Know Act (EPCRA); and the Hazardous Materials Transportation Act (HMTA) as well as comparable state laws. In addition, we may also be subject to civil claims arising out of any such incident.

The OPA and related regulations impose a variety of regulations on “responsible parties” related to the prevention of spills of oil or other hazardous substances and liability for damages resulting from such spills. “Responsible parties” include the owner or operator of a vessel, pipeline or onshore facility, or the lessee or permittee of the area in which an offshore facility is located. The OPA assigns liability for oil removal costs and a variety of public and private damages to each responsible party. The OPA also requires some facilities to demonstrate proof of financial responsibility and to prepare an oil spill response plan. Failure to comply with ongoing requirements or inadequate cooperation in a spill may subject a responsible party to civil or criminal enforcement actions.

The OCSLA authorizes regulations relating to safety and environmental protection applicable to lessees and permittees operating on the Outer Continental Shelf. Specific design and operational standards may apply to Outer Continental Shelf vessels, rigs, platforms, vehicles and structures. The Bureau of Safety and Environmental Enforcement (BSEE) regulates the design and operation of well control and other equipment at offshore production sites, implementation of safety and environmental management systems, and mandatory third-party compliance audits, among other requirements. Violations of environmentally related lease conditions or regulations issued pursuant to the OCSLA can result in substantial civil and criminal penalties as well as potential court injunctions curtailing operations and the cancellation of leases. Such enforcement liabilities, delay or restriction of activities can result from either governmental or citizen prosecution.

Our operations are also governed by laws and regulations related to workplace safety and worker health, primarily the Occupational Safety and Health Act and regulations promulgated thereunder. In addition, various other governmental and quasi-governmental agencies require us to obtain certain miscellaneous permits, licenses and certificates with respect to our operations. The kind of permits, licenses and certificates required by our operations depend upon a number of factors. We believe we have the necessary permits, licenses and certificates that are material to the conduct of our existing business.

CERCLA (also known as "Superfund") and comparable state laws impose potential liability without regard to fault or the legality of the activity, on certain classes of persons who are considered to be responsible for the release of "hazardous substances" into the environment. While CERCLA exempts crude oil from the definition of hazardous substances for purposes of the statute, our operations may involve the use or handling of other materials that may be classified as hazardous substances. CERCLA assigns strict liability to a broad class of potentially responsible parties for all response and remediation costs, as well as natural resource damages. In addition, persons responsible for release of hazardous substances under CERCLA may be subject to joint and several liability for the cost of cleaning up the hazardous substances released into the environment and for damages to natural resources.

RCRA and comparable state laws regulate the management and disposal of solid and hazardous wastes. Current RCRA regulations specifically exclude from the definition of hazardous waste "drilling fluids, produced waters, and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy." However, these wastes and other wastes may be otherwise regulated by EPA or state agencies. Moreover, ordinary industrial wastes, such as paint wastes, spent solvents, laboratory wastes, and used oils, may be regulated as hazardous waste. Although the costs of managing solid and hazardous wastes may be significant, we do not expect to experience more burdensome costs than competitor companies involved in similar drilling operations.

The CAA and similar state laws and regulations restrict the emission of air pollutants and may also impose various monitoring and reporting requirements. In addition, those laws may require us to obtain permits for the construction, modification, or operation of certain projects or facilities and the utilization of specific equipment or technologies to control emissions. For example, the EPA has adopted regulations known as "RICE MACT" that require the use of "maximum achievable control technology" to reduce formaldehyde and other emissions from certain stationary reciprocating internal combustion engines, which can include portable engines used to power drilling rigs.

Some scientific studies have suggested that emissions of certain gases including carbon dioxide and methane, commonly referred to as "greenhouse gases" (GHGs), may be contributing to the warming of the atmosphere resulting in climate change. There are a variety of legislative and regulatory developments, proposals, requirements, and initiatives that have been introduced in the U.S. and international regions in which we operate that are intended to address concerns that emissions of GHGs are contributing to climate change and these may increase costs of compliance for our drilling services or our customer's operations. Among these developments, the Kyoto Protocol to the 1992 United Nations Framework Convention on Climate Change (UNFCC) established a set of emission targets for GHGs that became binding on all those countries that had ratified it. The Kyoto Protocol was followed by the Paris Agreement of the 2015 UNFCC, which will be open for signing on April 22, 2016 and, under the agreement, ratifying countries may set more ambitious GHG emission targets.

Because our business depends on the level of activity in the oil and natural gas industry, existing or future laws, regulations, treaties or international agreements related to GHGs and climate change, including incentives to conserve energy or use alternative energy sources, could have a negative impact on our business if such laws, regulations, treaties or international agreements reduce the worldwide demand for oil and natural gas or otherwise result in reduced economic activity generally. In addition, such laws, regulations, treaties or international agreements could result in increased compliance costs or additional operating restrictions, which may have a negative impact on our business. In addition to potential impacts on our business directly or indirectly resulting from climate-change legislation or regulations, our business also could be negatively affected by climate-change related physical changes or changes in weather patterns. An increase in severe weather patterns could result in damages to or loss of our rigs, impact our ability to conduct our operations and result in a disruption of our customers' operations.

Executive Officers

Officers are elected each year by the board of directors following the annual shareholders' meeting for a term of one year or until the election and qualification of their successors. The current executive officers of the Company and their ages, positions with the Company and business experience are presented below:

- *Gary G. Rich, 57,* joined the Company in October 2012 as the president and chief executive officer. Mr. Rich also serves as Chairman of the Company's board of directors. He is an industry veteran with over 30 years of global technical, commercial and operations experience. Mr. Rich came to Parker Drilling after a 25-year career with Baker Hughes Incorporated. Mr. Rich served as vice president of global sales for Baker Hughes from August 2011 to October 2012, and prior to that role, he served as president of that company's European operations from April 2009 to August 2011. Previously, Mr. Rich was president of Hughes Christensen Company (HCC), a division of Baker Hughes primarily focused on the production and distribution of drilling bits for the petroleum industry.

- *Christopher T. Weber, 43,* joined the Company in May 2013 as the senior vice president and chief financial officer. Prior to joining the Company, Mr. Weber served as the vice president and treasurer of Ensco plc., a public offshore drilling company, from 2011 to May 2013. From 2009 to 2011, Mr. Weber served as vice president, operations for Pride International, Inc., prior to which he served as director, corporate planning and development from 2006 to 2009.

- *Jon-Al Duplantier, 48,* is the senior vice president, chief administrative officer, general counsel, and secretary of the Company, a position held since 2013. Mr. Duplantier has over 20 years' experience in the oil and gas industry. Mr. Duplantier joined the Company in 2009 as vice president and general counsel. From 1995 to 2009, Mr. Duplantier served in several legal and business roles at ConocoPhillips, including senior counsel – Exploration and Production, vice president and general counsel – Conoco Phillips Indonesia, and vice president and general counsel – Dubai Petroleum Company. Prior to joining ConocoPhillips, he served as a patent attorney for DuPont from 1992 to 1995.

- *David R. Farmer, 54,* was appointed the senior vice president, Europe, Middle East, and Asia (EMEA) in early 2014. He joined the Company in 2011 as vice president of operations. Mr. Farmer has over 20 years' experience in the upstream oilfield services business working in executive, engineering, operational, marketing, account management, planning, and general management roles in Europe, the Middle East, North America and South America. From 1991 to 2011, Mr. Farmer served in various positions at Schlumberger, including vice president and global account director – Schlumberger Ltd. The Netherlands, vice president and general manager – Schlumberger Oilfield Service Qatar, and global marketing manager – Schlumberger Drilling & Measurement Division, Houston, Texas. Most recently, Mr. Farmer was responsible for Demand Planning management and the development of long term tactical resource plans for Schlumberger's Drilling & Measurement division.

- *Philip L. Agnew, 47,* has served as the Company's senior vice president and chief technical officer since 2013. He joined the Company in December 2010 as vice president of technical services. Mr. Agnew has more than 20 years' experience in design, construction and project management. From 2003 to 2010, Mr. Agnew held the position of President at Aker MH, Inc., a business unit of Aker Solutions AS. From 1998 to 2003, Mr. Agnew served as Project Manager and then vice president – Project Development at Signal International (previously Friede Goldman Offshore; TDI-Halter LP; Texas Drydock, Inc.). Prior to his career at Signal International, Mr. Agnew served a variety of leadership roles at Schlumberger Sedco Forex International Resources, Interface Consulting International, Inc., and Brown & Root, Inc.

Other Parker Drilling Company Officers

- *Leslie K. Nagy, 41,* was appointed principal accounting officer and controller on April 1, 2014. Mrs. Nagy served as director of finance and assistant controller of the Company from December 2012 through March 2014, as assistant controller of the Company from May 2011 to December 2012, and as manager of external reporting and general accounting of the Company from August 2010 to May 2011. Prior to joining Parker Drilling, Mrs. Nagy worked for Ernst & Young LLP from 1997 to 2010.

- *Philip A. Schlom, 51,* was named vice president, global compliance and internal audit, effective December 2014. He joined the Company in 2009 as principal accounting officer and controller. From 2008 to 2009, he held the position of vice president and corporate controller for Shared Technologies Inc. From 1997 to 2008, Mr. Schlom held several senior financial positions at Flowserve Corporation, a leading manufacturer of pumps, valves and seals for the energy sector. From 1988 through 1997, Mr. Schlom worked at the public accounting firm PricewaterhouseCoopers LLP.

- *David W. Tucker, 60,* treasurer, joined the Company in 1978 as a financial analyst and served in various financial and accounting positions before being named chief financial officer of our formerly wholly-owned subsidiary, Hercules Offshore Corporation, in February 1998. Mr. Tucker was named treasurer of the Company in 1999.

Available Information

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports are made available free of charge on our website at http://www.parkerdrilling.com as soon as reasonably practicable after we electronically file such material with, or furnish such material to, the Securities and Exchange Commission (SEC). The public may read and copy any materials we have filed with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. Additionally, our reports, proxy and information statements and our other SEC filings are available on an Internet website maintained by the SEC at http://www.sec.gov.

Item 1A. Risk Factors

Our businesses involve a high degree of risk. You should consider carefully the risks and uncertainties described below and the other information included in this Form 10-K, including Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data. While these are the risks and uncertainties we believe are most important for you to consider, you should know that they are not the only risks or uncertainties facing us or which may adversely affect our business. If any of the following risks or uncertainties actually occurs, our business, financial condition or results of operations could be adversely affected.

Oil and natural gas prices have declined substantially and are expected to remain depressed for the foreseeable future. Sustained depressed prices of oil and natural gas will adversely affect our financial condition, results of operations and cash flows.

Oil and natural gas prices and market expectations regarding potential changes in these prices are volatile and are likely to continue to be volatile in the future. Increases or decreases in oil and natural gas prices and expectations of future prices could have an impact on our customers' long-term exploration and development activities, which in turn could materially affect our business and financial performance. Furthermore, higher oil and gas prices do not necessarily result immediately in increased drilling activity because our customers' expectations of future oil and natural gas prices typically drive demand for our drilling services. The oil and natural gas industry has historically experienced periodic downturns, which have been characterized by diminished demand for oilfield services and downward pressure on the prices we charge. A prolonged downturn in the oil and natural gas industry could result in a further reduction in demand for oilfield services and could continue to adversely affect our financial condition, results of operations and cash flows. Oil prices have declined by approximately 70 percent since mid-2014, with WTI crude oil prices trading slightly above $30 per barrel during the 2016 first quarter, in contrast to prices in excess of $100 per barrel in July 2014. Oil and natural gas prices and demand for our services also depend upon numerous factors which are beyond our control, including:

- the demand for oil and natural gas;
- the cost of exploring for, producing and delivering oil and natural gas;
- expectations regarding future energy prices;
- advances in exploration, development and production technology;
- the ability of the Organization of Petroleum Exporting Countries (OPEC) to set and maintain production levels and prices;
- the level of production by non-OPEC countries;
- the adoption or repeal of laws and government regulations, both in the United States and other countries;
- the imposition or lifting of economic sanctions against certain regions, persons and other entities;
- the number of ongoing and recently completed rig construction projects which may create overcapacity;
- local and worldwide military, political and economic events, including events in the oil producing regions of Africa, the Middle East, Russia, Central Asia, Southeast Asia and Latin America;
- weather conditions;
- expansion or contraction of worldwide economic activity, which affects levels of consumer and industrial demand;
- the rate of discovery of new oil and natural gas

reserves;

- domestic and foreign tax policies;

- acts of terrorism in the United States or elsewhere;

- the development and use of alternative energy sources; and

- the policies of various governments regarding exploration and development of their oil and natural gas reserves.

Demand for the majority of our services is substantially dependent on the levels of expenditures by the oil and natural gas industry. A substantial or an extended decline in oil and natural gas prices could result in lower expenditures by the oil and natural gas industry, which could have a material adverse effect on our financial condition, results of operations and cash flows.

Demand for the majority of our services depends substantially on the level of expenditures for the exploration, development and production of oil or natural gas reserves by the major, independent and national oil and natural gas E&P companies and large integrated service companies that comprise our customer base. These expenditures are generally dependent on the industry's view of future oil and natural gas prices and are sensitive to the industry's view of future economic growth and the resulting impact on demand for oil and natural gas. Declines in oil and natural gas prices have and may continue to result in project modifications, delays or cancellations, general business disruptions, and delays in payment of, or nonpayment of, amounts that are owed to us, any of which could continue to have a material adverse effect on our financial condition, results of operations and cash flows. Historically, when drilling activity and spending decline, utilization and dayrates also decline and drilling may be reduced or discontinued, resulting in an oversupply of drilling rigs. The recent decrease in oil prices has in turn caused a significant decline in the demand for drilling services. The rig utilization rate of our International & Alaska Drilling segment has fallen from 72 percent for the year ended December 31, 2014 to 59 percent as for the year ended December 31, 2015. Similarly, the rig utilization rate of our U.S. (Lower 48) Drilling segment has declined from 72 percent for the year ended December 31, 2014 to 15 percent for the year ended December 31, 2015. Furthermore, operators have implemented significant declines in capital spending in their budgets, including the cancellation or deferral of existing programs, and are expected to continue to operate under reduced budgets for the foreseeable future.

A slowdown in economic activity may result in lower demand for our drilling and drilling related services and rental tools business, and could have a material adverse effect on our business.

A slowdown in economic activity in the United States or abroad could lead to uncertainty in corporate credit availability and capital market access and could reduce worldwide demand for energy and result in lower crude oil and natural gas prices. For example, weakening economic growth in large emerging and developing markets, such as China, and other issues have contributed to increased economic uncertainty and diminished expectations for the global economy. Concerns about global economic conditions have had a significant adverse impact on domestic and international financial markets and commodity prices, including oil and natural gas. Our business depends to a significant extent on the level of international onshore drilling activity and GOM inland and offshore drilling activity for oil and natural gas. Depressed oil and natural gas prices from lower demand as a result of slow or negative economic growth would reduce the level of exploration, development and production activity, all of which could cause our revenues and margins to decline, decrease dayrates and utilization of our rigs and use of our rental tools and limit our future growth prospects. Any significant decrease in dayrates or utilization of our rigs or use of our rental tools could materially reduce our revenues and profitability. In addition, current and potential customers who depend on financing for their drilling projects may be forced to curtail or delay projects and may also experience an inability to pay suppliers and service providers, including us. Likewise, economic conditions in the United States or abroad could impact our vendors' and suppliers' ability to meet obligations to provide materials and services in general. All of these factors could have a material adverse effect on our business and financial results.

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

As of December 31, 2015, we had:

- $585.0 million of long-term debt;

- $36.8 million of operating lease commitments; and

- $12.5 million of standby letters of credit.

Our ability to meet our debt service obligations depends on our ability to generate positive cash flows from operations. We have in the past, and may in the future, incur negative cash flows from one or more segments of our operating activities. Our future cash flows from operating activities will be influenced by the demand for our drilling services, the utilization of our rigs, the dayrates that we receive for our rigs, demand for our rental tools, oil and gas prices, general economic conditions and financial, business and other factors affecting our operations, many of which are beyond our control.

If we are unable to service our debt obligations, we may have to take one or more of the following actions:

- delay spending on capital projects, including maintenance projects and the acquisition or construction of additional rigs, rental tools and other assets;

- sell equity or assets; and

- restructure or refinance our debt.

Additional indebtedness or equity financing may not be available to us in the future for the refinancing or repayment of existing indebtedness, or if available, such additional indebtedness or equity financing may not be available on a timely basis, or on terms acceptable to us and within the limitations specified in our then existing debt instruments. In addition, in the event we decide to sell assets, we can provide no assurance as to the timing of any asset sales or the proceeds that could be realized from any such asset sale. Our ability to generate sufficient cash flow from operating activities to pay the principal of and interest on our indebtedness is subject to certain market conditions and other factors which are beyond our control.

Increases in the level of our debt and restrictions in the covenants contained in the instruments governing our debt could have important consequences to you. For example, they could:

- result in a reduction of our credit rating, which would make it more difficult for us to obtain additional financing on acceptable terms;

- require us to dedicate a substantial portion of our cash flows from operating activities to the repayment of our debt and the interest associated with our debt;

- limit our operating flexibility due to financial and other restrictive covenants, including restrictions on incurring additional debt and creating liens on our properties;

- place us at a competitive disadvantage compared with our competitors that have relatively less debt; and

- make us more vulnerable to downturns in our business.

Our current operations and future growth may require significant additional capital, and the amount of our indebtedness could impair our ability to fund our capital requirements.

Our business requires substantial capital. We may require additional capital in the event of growth opportunities, unanticipated maintenance requirements or significant departures from our current business plan.

Additional financing may not be available on a timely basis or on terms acceptable to us and within the limitations contained in our Second Amended and Restated Credit Agreement (as amended, the 2015 Secured Credit Agreement) and the indentures governing our outstanding 7.50% Senior Notes due 2020 (7.50% Notes) and 6.75% Senior Notes due 2022 (6.75% Notes, and collectively with the 7.50% Notes, the Senior Notes). Failure to obtain additional financing, should the need for it develop, could impair our ability to fund capital expenditure requirements and meet debt service requirements and could have an adverse effect on our business.

Our 2015 Secured Credit Agreement and the indentures for our Senior Notes impose significant operating and financial restrictions, which may prevent us in the future from obtaining financing or capitalizing on business opportunities.

The 2015 Secured Credit Agreement, the amendments thereto, and the indentures governing our Senior Notes impose significant operating and financial restrictions on us. These restrictions limit our ability to:

- make investments and other restricted payments, including dividends;

- incur additional indebtedness;

- create liens;

- engage in sale leaseback transactions;

- repurchase our common stock or Senior Notes;

- sell our assets or consolidate or merge with or into other companies; and

- engage in transactions with affiliates.

These limitations are subject to a number of important qualifications and exceptions. Our 2015 Secured Credit Agreement also requires us to maintain ratios for consolidated leverage, asset coverage, consolidated interest coverage, and consolidated senior secured leverage. These covenants may adversely affect our ability to finance our future operations and capital needs and to pursue available business opportunities.

As conditions in the oil and gas industry continue to decline, we have engaged in preliminary discussions with our lenders regarding certain covenants and restrictions in the 2015 Secured Credit Agreement. If we become unable to comply with certain of the financial covenants in the 2015 Secured Credit Agreement, we will seek to amend such provisions to remain in compliance. At the same time, our banks may seek to reduce our available credit or impose additional restrictions on our use of funds. If we are unable to negotiate acceptable amendments to the 2015 Secured Credit Agreement, we may breach one or more of these covenants. A breach of any of these existing or potential covenants could result in a default with respect to the related indebtedness.

If a default were to occur, the lenders under our 2015 Secured Credit Agreement and the holders of our Senior Notes could elect to declare the indebtedness, if any outstanding at that time, together with accrued interest, immediately due and payable. If the repayment of the indebtedness were to be accelerated after any applicable notice or grace periods, we may not have sufficient funds to repay the indebtedness.

Our backlog of contracted revenues may not be fully realized and may reduce significantly in the future, which may have a material adverse effect on our financial position, results of operations or cash flows.

Our expected revenues under existing contracts ("contracted revenues") may not be fully realized due to a number of factors, including rig or equipment downtime or suspension of operations. Several factors could cause downtime or a suspension of operations, many of which are beyond our control, including:

- breakdowns of our equipment or the equipment of others necessary for continuation of operations;
- work stoppages, including labor strikes;
- shortages of material and skilled labor;
- severe weather or harsh operating conditions;
- the occurrence or threat of epidemic or pandemic diseases or any government response to such occurrence or threat;
- the early termination of contracts; and
- force majeure events.

Liquidity issues could lead our customers to go into bankruptcy or could encourage our customers to seek to repudiate, cancel or renegotiate our contracts for various reasons. Some of our contracts permit early termination of the contract by the customer for convenience (without cause), generally exercisable upon advance notice to us and in some cases without making an early termination payment to us. There can be no assurances that our customers will be able or willing to fulfill their contractual commitments to us.

The recent decline in oil prices, the perceived risk of a low oil prices for an extended period, and the resulting downward pressure on utilization is causing and may continue to cause some customers to consider early termination of select contracts despite having to pay early termination fees in some cases. In addition, customers may request to re-negotiate the terms of existing contracts. Furthermore, as our existing contracts roll off, we may be unable to secure replacement contracts for our rigs, equipment or services. We have been in discussions with some of our customers regarding these issues. Therefore, revenues recorded in future periods could differ materially from our current contracted revenues, which could have a material adverse effect on our financial position, results of operations or cash flows.

Certain of our contracts are subject to cancellation by our customers without penalty and with little or no notice.

In periods of rapid market downturn similar to the current environment, our customers may not be able to honor the terms of existing contracts, may terminate contracts even where there may be onerous termination fees, or may seek to renegotiate contract dayrates and terms in light of depressed market conditions. Certain of our contracts are subject to cancellation by our customers without penalty and with relatively little or no notice. The recent decline in oil prices, the perceived risk of a further decline in oil prices, and the resulting downward pressure on utilization has caused and may continue to cause some customers to terminate contracts without cause. When drilling market conditions are depressed, a customer may no longer need a rig or rental tools that is currently under contract or may be able to obtain comparable equipment at lower dayrates. Further, due to government actions, a customer may no longer be able to operate in, or it may not be economical to operate in, certain regions. As a result, customers may leverage their termination rights in an effort to renegotiate contract terms.

Our customers may also seek to terminate contracts for cause, such as the loss of or a major damage to the drilling unit or other events that cause the suspension of drilling operations beyond a specified period of time. If we experience operational problems or if our equipment fails to function properly and cannot be repaired promptly, our customers will not be able to engage in drilling operations and may have the right to terminate the contracts. If equipment is not timely delivered to a customer or does not pass acceptance testing, a customer may in certain circumstances have the right to terminate the contract. The payment of a termination fee may not fully compensate us for the loss of the contract. Early termination of a contract may result in a rig or other equipment being idle for an extended period of time. The likelihood that a customer may seek to terminate a contract is increased during periods of market weakness. The cancellation or renegotiation of a number of our contracts could materially reduce our revenues and profitability.

We rely on a small number of customers and the loss of a significant customer could adversely affect us.

A substantial percentage of our revenues are generated from a relatively small number of customers and the loss of a significant customer could adversely affect us. In 2015, our largest customer, Exxon Neftegas Limited accounted for approximately

27.9 percent of our total revenues. Our consolidated results of operations could be adversely affected if any of our significant customers terminate their contracts with us, fail to renew our existing contracts or refuse to award new contracts to us.

The contract drilling and the rental tools businesses are highly competitive and cyclical, with intense price competition.

The contract drilling and rental tools markets are highly competitive and many of our competitors in both the contract drilling and rental tools businesses may possess greater financial resources than we do. Some of our competitors also are incorporated in countries that may provide them with significant tax advantages that are not available to us as a U.S. company and which may impair our ability to compete with them for many projects.

Contract drilling companies compete primarily on a regional basis, and competition may vary significantly from region to region at any particular time. Many drilling and workover rigs can be moved from one region to another in response to changes in levels of activity, provided market conditions warrant, which may result in an oversupply of rigs in an area. Many competitors construct rigs during periods of high energy prices and, consequently, the number of rigs available in some of the markets in which we operate can exceed the demand for rigs for extended periods of time, resulting in intense price competition. Most drilling contracts are awarded on the basis of competitive bids, which also results in price competition. Historically, the drilling service industry has been highly cyclical, with periods of high demand, limited equipment supply and high dayrates often followed by periods of low demand, excess equipment supply and low dayrates. Periods of low demand and excess equipment supply intensify the competition in the industry and often result in equipment being idle for long periods of time. During periods of decreased demand we typically experience significant reductions in dayrates and utilization. The Company, or its competition, may move rigs or other equipment from one geographic location to another location; the cost of which may be substantial. If we experience further reductions in dayrates or if we cannot keep our equipment utilized, our financial performance will be adversely impacted. Prolonged periods of low utilization and dayrates could result in the recognition of impairment charges on certain of our rigs if future cash flow estimates, based upon information available to management at the time, indicate that the carrying value of these rigs may not be recoverable.

Rig upgrade, refurbishment and construction projects are subject to risks and uncertainties, including delays and cost overruns, which could have an adverse impact on our results of operations and cash flows.

We regularly make significant expenditures in connection with upgrading and refurbishing our rig fleet. These activities include planned upgrades to maintain quality standards, routine maintenance and repairs, changes made at the request of customers, and changes made to comply with environmental or other regulations. Rig upgrade, refurbishment and construction projects are subject to the risks of delay or cost overruns inherent in any large construction project, including the following:

- shortages of equipment or skilled labor;
- unforeseen engineering problems;
- unanticipated change orders;
- work stoppages;
- adverse weather conditions;
- unexpectedly long delivery times for manufactured rig components;
- unanticipated repairs to correct defects in construction not covered by warranty;
- failure or delay of third-party equipment vendors or service providers;
- unforeseen increases in the cost of equipment, labor or raw materials, particularly steel;
- disputes with customers, shipyards or suppliers;
- latent damages or deterioration to hull, equipment and machinery in excess of engineering estimates and assumptions;
- financial or other difficulties with current customers at shipyards and suppliers;
- loss of revenue associated with downtime to remedy malfunctioning equipment not covered by

warranty;

- unanticipated cost increases;
- loss of revenue and payments of liquidated damages for downtime to perform repairs associated with defects, unanticipated equipment refurbishment and delays in commencement of operations; and
- lack of ability to obtain the required permits or approvals, including import/export documentation.

Any one of the above risks could adversely affect our financial condition and results of operations. Delays in the delivery of rigs being constructed or undergoing upgrade, refurbishment or repair may, in many cases, delay commencement of a drilling contract resulting in a loss of revenue to us, and may also cause our customer to renegotiate the drilling contract for the rig or terminate or shorten the term of the contract under applicable late delivery clauses, if any. If one of these contracts is terminated, we may not be able to secure a replacement contract on as favorable terms, if at all. Additionally, actual expenditures for required upgrades or to refurbish or construct rigs could exceed our planned capital expenditures, impairing our ability to service our debt obligations.

Our international operations are subject to governmental regulation and other risks.

We derive a significant portion of our revenues from our international operations. In 2015, we derived approximately 67 percent of our revenues from operations in countries other than the United States. Our international operations are subject to the following risks, among others:

- political, social and economic instability, war, terrorism and civil disturbances;
- economic sanctions imposed by the U.S. government against other countries, groups, or individuals, or economic sanctions imposed by other governments against the U.S. or businesses incorporated in the U.S.;
- limitations on insurance coverage, such as war risk coverage, in certain areas;
- expropriation, confiscatory taxation and nationalization of our assets;
- foreign laws and governmental regulation, including inconsistencies and unexpected changes in laws or regulatory requirements, and changes in interpretations or enforcement of existing laws or regulations;
- increases in governmental royalties;
- import-export quotas or trade barriers;
- hiring and retaining skilled and experienced workers, some of whom are represented by foreign labor unions;
- work stoppages;
- damage to our equipment or violence directed at our employees, including kidnapping;
- piracy of vessels transporting our people or equipment;
- unfavorable changes in foreign monetary and tax policies;
- solicitation by government officials for improper payments or other forms of corruption;
- foreign currency fluctuations and restrictions on currency repatriation;
- repudiation, nullification, modification or renegotiation of contracts; and
- other forms of governmental regulation and economic conditions that are beyond our control.

We currently have operations in 21 countries. Our operations are subject to interruption, suspension and possible expropriation due to terrorism, war, civil disturbances, political and capital instability and similar events, and we have previously suffered loss of revenues and damage to equipment due to political violence. Civil and political disturbances in international locations may affect our operations. We may not be able to obtain insurance policies covering risks associated with these types of events, especially political violence coverage, and such policies may only be available with premiums that are not commercially reasonable.

Our international operations are subject to the laws and regulations of a number of countries with political, regulatory and judicial systems and regimes that may differ significantly from those in the U.S. Our ability to compete in international contract drilling and rental tool markets may be adversely affected by foreign governmental regulations and/or policies that favor the awarding of contracts to contractors in which nationals of those foreign countries have substantial ownership interests or by regulations requiring foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. Furthermore, our foreign subsidiaries may face governmentally imposed restrictions or fees from time to time on the transfer of funds to us.

In addition, tax and other laws and regulations in some foreign countries are not always interpreted consistently among local, regional and national authorities, which can result in disputes between us and governing authorities. The ultimate outcome of these disputes is never certain, and it is possible that the outcomes could have an adverse effect on our financial performance.

A portion of the workers we employ in our international operations are members of labor unions or otherwise subject to collective bargaining. We may not be able to hire and retain a sufficient number of skilled and experienced workers for wages and other benefits that we believe are commercially reasonable.

We may experience currency exchange losses where revenues are received or expenses are paid in nonconvertible currencies or where we do not take protective measures against exposure to a foreign currency. We may also incur losses as a result of an inability to collect revenues because of a shortage of convertible currency available to the country of operation, controls over currency exchange or controls over the repatriation of income or capital. Given the international scope of our operations, we are exposed to risks of currency fluctuation and restrictions on currency repatriation. We attempt to limit the risks of currency fluctuation and restrictions on currency repatriation where possible by obtaining contracts payable in U.S. dollars or freely convertible foreign currency. In addition, some parties with which we do business could require that all or a portion of our revenues be paid in local currencies. Foreign currency fluctuations, therefore, could have a material adverse effect upon our results of operations and financial condition.

The shipment of goods, services and technology across international borders subjects us to extensive trade laws and regulations. Our import activities are governed by the unique customs laws and regulations in each of the countries where we operate. Moreover, many countries, including the U.S., control the export and re-export of certain goods, services and technology and impose related export recordkeeping and reporting obligations. Governments may also impose economic sanctions against certain countries, persons and other entities that may restrict or prohibit transactions involving such countries, persons and entities. The laws and regulations concerning import activity, export recordkeeping and reporting, export control and economic sanctions are complex and constantly changing. These laws and regulations can cause delays in shipments and unscheduled operational downtime. Moreover, any failure to comply with applicable legal and regulatory trading obligations could result in criminal and civil penalties and sanctions, such as fines, imprisonment, debarment from governmental contracts, seizure of shipments and loss of import and export privileges.

Failure to comply with anti-corruption laws, such as the U.S. Foreign Corrupt Practices Act and the U.K. Bribery Act 2010, could result in fines, criminal penalties, negative commercial consequences and an adverse effect on our business.

The U.S. Foreign Corrupt Practices Act (FCPA), the U.K. Bribery Act 2010 and similar anti-corruption laws in other jurisdictions generally prohibit companies and their intermediaries from making improper payments or providing improper benefits for the purpose of obtaining or retaining business. Our policies mandate compliance with these anti-corruption laws. However, we operate in many parts of the world that experience corruption. If we are found to be liable for violations of these laws either due to our own acts or our omissions or due to the acts or omissions of others (including our joint ventures partners, our agents or other third party representatives), we could suffer from commercial, civil and criminal penalties or other sanctions, which could have a material adverse effect on our business, financial condition and results of operations.

Failure to attract and retain skilled and experienced personnel could affect our operations.

We require skilled, trained and experienced personnel to provide our customers with the highest quality technical services and support for our drilling operations. We compete with other oilfield services businesses and other employers to attract and retain qualified personnel with the technical skills and experience we require. Competition for skilled labor and other labor required for our operations intensifies as the number of rigs activated or added to worldwide fleets or under construction increases, creating upward pressure on wages. In periods of high utilization, we have found it more difficult to find and retain qualified individuals. A shortage in the available labor pool of skilled workers or other general inflationary pressures or changes in applicable laws and regulations could make it more difficult for us to attract and retain personnel and could require us to enhance our wage and benefits packages. Increases in our operating costs could adversely affect our business and financial results. Moreover, the shortages of qualified personnel or the inability to obtain and retain qualified personnel could negatively affect the quality, safety and timeliness of our operations.

We are not fully insured against all risks associated with our business.

We ordinarily maintain insurance against certain losses and liabilities arising from our operations. However, we do not insure against all operational risks in the course of our business. Due to the high cost, high self-insured retention and limited coverage insurance for windstorms in the GOM we have elected not to purchase windstorm insurance for our inland barges in the GOM. Although we have retained the risk for physical loss or damage for these rigs arising from a named windstorm we have procured insurance coverage for removal of a wreck caused by a windstorm. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on our business activities, financial position and results of operations.

We are subject to hazards customary for drilling operations, which could adversely affect our financial performance if we are not adequately indemnified or insured.

Substantially all of our operations are subject to hazards that are customary for oil and natural gas drilling operations, including blowouts, reservoir damage, loss of production, loss of well control, lost or stuck drill strings, equipment defects, cratering, oil and natural gas well fires and explosions, natural disasters, pollution, mechanical failure and damage or loss during transportation. Some of our fleet is also subject to hazards inherent in marine operations, either while on-site or during mobilization, such as capsizing, sinking, grounding, collision, damage from severe weather and marine life infestations. These hazards could result in damage to or destruction of drilling equipment, personal injury and property damage, suspension of operations or environmental damage, which could lead to claims by third parties or customers, suspension of operations and contract terminations. We have had accidents in the past due to some of these hazards. We may not be able to insure against these risks or to obtain indemnification to adequately protect us against liability from all of the consequences of the hazards and risks described above. The occurrence of an event not fully insured against or for which we are not indemnified, or the failure of a customer or insurer to meet its indemnification or insurance obligations, could result in substantial losses. In addition, insurance may not continue to be available to cover any or all of these risks. For example, pollution, reservoir damage and environmental risks generally are not fully insurable. Even if such insurance is available, insurance premiums or other costs may rise significantly in the future, making the cost of such insurance prohibitive. For a description of our indemnification obligations and insurance, see Item 1. Business — Insurance and Indemnification.

Certain areas in and near the GOM are subject to hurricanes and other extreme weather conditions. When operating in and near the GOM, our drilling rigs and rental tools may be located in areas that could cause them to be susceptible to damage or total loss by these storms. In addition, damage caused by high winds and turbulent seas to our rigs, our shore bases and our corporate infrastructure could potentially cause us to curtail operations for significant periods of time until the effects of the damages can be repaired. In addition, our rigs in arctic regions can be affected by seasonal weather so severe, conditions are deemed too unsafe for operations.

Government regulations may reduce our business opportunities and increase our operating costs.

Government regulations control and often limit access to potential markets and impose extensive requirements concerning employee privacy and safety, environmental protection, pollution control and remediation of environmental contamination. Environmental regulations, including species protections, prohibit access to some locations and make others less economical, increase equipment and personnel costs, and often impose liability without regard to negligence or fault. In addition, governmental regulations, such as those related to climate change, may discourage our customers' activities, reducing demand for our products and services. We may be liable for damages resulting from pollution of offshore waters and, under United States regulations, must establish financial responsibility in order to drill offshore. See Item 1. Business — Environmental Considerations.

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

Some 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. Legislative and regulatory measures to address concerns that emissions of GHGs are contributing to climate change are in various phases of discussions or implementation at the international, national, regional and state levels.

Because our business depends on the level of activity in the oil and natural gas industry, existing or future laws, regulations, treaties or international agreements related to GHGs and climate change, including incentives to conserve energy or use alternative energy sources, could have a negative impact on our business if such laws, regulations, treaties or international agreements reduce the worldwide demand for oil and natural gas or otherwise result in reduced economic activity generally. In addition, such laws, regulations, treaties or international agreements could result in increased compliance costs or additional operating restrictions, which may have a negative impact on our business. In addition to potential impacts on our business directly or indirectly resulting from climate-change legislation or regulations, our business also could be negatively affected by climate-change related physical changes or changes in weather patterns. An increase in severe weather patterns could result in damages to or loss of our rigs, impact our ability to conduct our operations and/or result in a disruption of our customers' operations.

We are regularly involved in litigation, some of which may be material.

We are regularly involved in litigation, claims and disputes incidental to our business, which at times may involve claims for significant monetary amounts, some of which would not be covered by insurance. We undertake all reasonable steps to defend ourselves in such lawsuits. Nevertheless, we cannot predict the ultimate outcome of such lawsuits and any resolution which is adverse to us could have a material adverse effect on our financial condition. See Note 13 - Commitments and Contingencies in Item 8. Financial Statements and Supplementary Data for a discussion of the material legal proceedings affecting us.

A catastrophic event could occur, materially impacting our liquidity, results of operations, and financial condition.

Our services are performed in harsh environments, and the work we perform can be dangerous. Catastrophic events such as a well blowout, fire, or explosion can occur, resulting in property damage, personal injury, death, pollution, and environmental damage. Typically, we are indemnified by our customers for injuries and property damage resulting from these types of events (except for injury to our employees and subcontractors and property damage to ours and our subcontractors' equipment). However, we could be exposed to significant loss if adequate indemnity provisions or insurance are not in place, if indemnity provisions are unenforceable or otherwise invalid, or if our customers are unable or unwilling to satisfy any indemnity obligations.

Increased regulation of hydraulic fracturing could result in reductions or delays in drilling and completing new oil and natural gas wells, which could adversely impact the demand for rental tools.

Hydraulic fracturing is a process sometimes used in the completion of oil and natural gas wells whereby water, other liquids, sand and chemicals are injected under pressure into subsurface formations to stimulate natural gas and, to a lesser extent, oil production. Various governmental entities (within and outside the United States) are in the process of studying, restricting, regulating, or preparing to regulate hydraulic fracturing, directly and indirectly. For example, many state governments now require the disclosure of chemicals used in the fracturing process. The U.S. EPA has taken the position that hydraulic fracturing operations involving the use of diesel fuel in fracturing fluids are subject to permitting requirements under the Safe Drinking Water Act; has adopted air emissions standards that apply to well completion activities; has proposed new standards for wastewater discharges associated with hydraulic fracturing; and has conducted a study on the impacts of hydraulic fracturing on groundwater. Further, in March 2015, the Bureau of Land Management issued a final rule to regulate hydraulic fracturing on public and Indian land; however, enforcement of the rule has been delayed pending a decision in a legal challenge in the U.S. District Court of Wyoming. In addition, some jurisdictions have imposed an express or de facto ban on hydraulic fracturing. For example, New York issued a statewide ban on hydraulic fracturing in June 2015. We do not directly engage in hydraulic fracturing activities. However, these and other developments could cause operational delays or increased costs in exploration and production, which could adversely affect the demand for our rental tools.

A cybersecurity incident could negatively impact our business and our relationships with customers.

If our systems for protecting against cybersecurity risks prove not to be sufficient, we could be adversely affected by, among other things, loss or damage of intellectual property, proprietary information, or customer data, having our business operations interrupted, and increased costs to prevent, respond to, or mitigate cybersecurity attacks. These risks could have a material adverse effect on our business, consolidated results of operations, and consolidated financial condition.

Our acquisitions, dispositions, and investments may not result in the realization of savings, the creation of efficiencies, the generation of cash or income, or the reduction of risk, which may have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

We continually seek opportunities to maximize efficiency and value through various transactions, including purchases or sales of assets, businesses, investments, or joint ventures. These transactions are intended to result in the realization of savings, the creation of efficiencies, the offering of new products or services, the generation of cash or income, or the reduction of risk. Acquisition transactions may be financed by additional borrowings or by the issuance of our common stock. These transactions may also affect our consolidated results of operations.

These transactions also involve risks, and we cannot ensure that:

- any acquisitions would result in an increase in income or earnings per share;
- any acquisitions would be successfully integrated into our operations and internal controls;
- the due diligence prior to an acquisition would uncover situations that could result in financial or legal exposure, or that we will appropriately quantify the exposure from known risks;
- any disposition would not result in decreased earnings, revenues, or cash flow;
- use of cash for acquisitions would not adversely affect our cash available for capital expenditures and other uses;
- any dispositions, investments, acquisitions, or integrations would not divert management resources; or
- any dispositions, investments, acquisitions, or integrations would not have a material adverse effect on our results of operations or financial condition.

The market price of our common stock has fluctuated significantly.

The market price of our common stock may continue to fluctuate in response to various factors and events, most of which are beyond our control, including the following:

- the other risk factors described in this Form 10-K, including changes in oil and natural gas prices;
- a shortfall in rig utilization, operating revenues or net income from that expected by securities analysts and investors;
- changes in securities analysts' estimates of the financial performance of us or our competitors or the financial performance of companies in the oilfield service industry generally;
- changes in actual or market expectations with respect to the amounts of exploration and development spending by oil and natural gas companies;

- general conditions in the economy and in energy-related industries;
- general conditions in the securities markets;

- political instability, terrorism or war; and
- the outcome of pending and future legal proceedings, investigations, tax assessments and other claims.

DISCLOSURE NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Form 10-K contains statements that are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the Securities Act), and Section 21E of the Securities Exchange Act of 1934, as amended, (the Exchange Act). All statements contained in this Form 10-K, other than statements of historical facts, are forward-looking statements for purposes of these provisions, including any statements regarding:

- stability or volatility of prices and demand for oil and natural gas;
- levels of oil and natural gas exploration and production activities;
- demand for contract drilling and drilling-related services and demand for rental tools and related services;
- our future operating results and profitability;
- our future rig utilization, dayrates and rental tools activity;
- entering into new, or extending existing, drilling or rental contracts and our expectations concerning when operations will commence under such contracts;
- entry into new markets or potential exit from existing markets;
- growth through acquisitions of companies or assets;
- organic growth of our operations;
- construction or upgrades of rigs and expectations regarding when these rigs will commence operations;
- capital expenditures for acquisition of rental tools, rigs, construction of new rigs or major upgrades to existing rigs;
- entering into joint venture agreements;
- our future liquidity;
- the sale or potential sale of assets or references to assets held for sale;
- availability and sources of funds to refinance our debt and expectations of when debt will be reduced;
- the outcome of pending or future legal proceedings, investigations, tax assessments and other claims;
- the availability of insurance coverage for pending or future claims;
- the enforceability of contractual indemnification in relation to pending or future claims; and
- compliance with covenants under our debt agreements.

In some cases, you can identify these statements by forward-looking words such as "anticipate," "believe," "could," "estimate," "expect," "intend," "outlook," "may," "should," "will" and "would" or similar words. Forward-looking statements are based on certain assumptions and analyses we make in light of our experience and perception of historical trends, current conditions, expected future developments and other factors we believe are relevant. Although we believe that our assumptions are reasonable based on information currently available, those assumptions are subject to significant risks and uncertainties, many of which are outside of our control. The following factors, as well as any other cautionary language included in this Form 10-K, provide examples of risks, uncertainties and events that may cause our actual results to differ materially from the expectations we describe in our forward-looking statements:

- fluctuations in the market prices of oil and natural gas, including the inability or unwillingness of our customers to fund drilling programs in low price cycles;
- worldwide economic and business conditions that adversely affect market conditions and/or the cost of doing business, including potential currency devaluations or collapses;
- our inability to access the credit markets;
- U.S. credit market volatility resulting from a restrictive regulatory environment imposed upon lenders due to their over exposure to the energy industry;
- the U.S. economy and the demand for oil and natural gas;
- low U.S. oil and natural gas prices that could adversely affect our U.S. drilling, barge rig and U.S. rental tools businesses;
- worldwide demand for oil;
- imposition of trade restrictions, including additional economic sanctions and export/re export controls affecting our business operations in Russia;
- unanticipated operating hazards and uninsured risks;

- political instability, terrorism or war;
- governmental regulations, including changes in accounting rules or tax laws that adversely affect the cost of doing business or our ability to remit funds to the U.S.;
- changes in the tax laws that would allow double taxation on foreign sourced income;
- the outcome of investigations into possible violations of laws;
- adverse environmental events;
- adverse weather conditions;
- global health concerns;
- changes in the concentration of customer and supplier relationships;
- ability of our customers and suppliers to obtain financing for their operations;
- ability of our customers to fund drilling plans;
- unexpected cost increases for new construction and upgrade and refurbishment projects;
- delays in obtaining components for capital projects and in ongoing operational maintenance and equipment certifications;
- shortages of skilled labor;
- unanticipated cancellation of contracts by customers or operators;
- breakdown of equipment;
- other operational problems including delays in start-up or commissioning of rigs;
- changes in competition;
- any failure to realize expected benefits from acquisitions;
- the effect of litigation and contingencies; and
- other similar factors, some of which are discussed in documents referred to or incorporated by reference into this Form 10-K and our other reports and filings with the SEC.

Each forward-looking statement speaks only as of the date of this Form 10-K, and we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. You should be aware that the occurrence of the events described in these risk factors and elsewhere in this Form 10-K could have a material adverse effect on our business, results of operations, financial condition and cash flows.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

We lease corporate headquarters office space in Houston, Texas and own our U.S. rental tools headquarters office in New Iberia, Louisiana. We lease regional headquarters space in Dubai, UAE related to our international rental tools business and Eastern Hemisphere drilling operations. Additionally, we own and/or lease office space and operating facilities in various other locations, domestically and internationally, including facilities where we hold inventories of rental tools and locations in close proximity to where we provide services to our customers. Additionally, we own and/or lease facilities necessary for administrative and operational support functions.

Land and Barge Rigs

The table below shows the locations and drilling depth ratings of our rigs as of December 31, 2015:

Name	Type[(1)]	Year entered into service/ upgraded	Drilling depth rating (in feet)	Location
International & Alaska Drilling				
Eastern Hemisphere				
Rig 231	L	1981/1997	13,000	Indonesia
Rig 253	L	1982/1996	15,000	Indonesia
Rig 226	HH	1989/2010	18,000	Papua New Guinea
Rig 107	L	1983/2009	15,000	Kazakhstan
Rig 216	L	2001/2009	25,000	Kazakhstan
Rig 249	L	2000/2009	25,000	Kazakhstan
Rig 257	B	1999/2010	30,000	Kazakhstan
Rig 258	L	2001/2009	25,000	Kazakhstan
Rig 247	L	1981/2008	18,000	Iraq, Kurdistan Region
Rig 269	L	2008	21,000	Iraq, Kurdistan Region
Rig 265	L	2007	20,000	Iraq, Kurdistan Region
Rig 264	L	2007	20,000	Tunisia
Rig 270	L	2011	21,000	Russia
Latin America				
Rig 271	L	1982/2009	30,000	Colombia
Rig 266	L	2008	20,000	Guatemala
Rig 122	L	1980/2008	18,000	Mexico
Rig 165	L	1978/2007	30,000	Mexico
Rig 221	L	1982/2007	30,000	Mexico
Rig 256	L	1978/2007	25,000	Mexico
Rig 267	L	2008	20,000	Mexico
Alaska				
Rig 272	L	2013	18,000	Alaska
Rig 273	L	2012	18,000	Alaska
U.S. (Lower 48) Drilling				
Rig 8	B	1978/2007	14,000	GOM
Rig 12	B	1979/2006	18,000	GOM
Rig 15	B	1978/2007	15,000	GOM
Rig 20	B	1981/2007	13,000	GOM
Rig 21	B	1979/2012	14,000	GOM
Rig 30	B	2014	18,000	GOM
Rig 50	B	1981/2006	20,000	GOM
Rig 51	B	1981/2008	20,000	GOM
Rig 54	B	1980/2006	25,000	GOM
Rig 55	B	1981/2014	25,000	GOM
Rig 72	B	1982/2005	30,000	GOM
Rig 76	B	1977/2009	30,000	GOM
Rig 77	B	2006/2006	30,000	GOM

(1) Type is defined as: L — land rig; B — barge rig; HH — heli-hoist land rig.

The table above excludes the following four rigs currently not available for service: Rig 225 and Rig 252, located in Indonesia, and Rig 121 and Rig 268, located in Colombia.

Item 3. Legal Proceedings

For information on Legal Proceedings, see Note 13 - Commitments and Contingencies in Item 8. Financial Statements and Supplementary Data, which information is incorporated herein by reference.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Parker Drilling Company’s common stock is listed for trading on the New York Stock Exchange under the symbol “PKD.” The following table sets forth the high and low sales prices per share of our common stock, as reported on the New York Stock Exchange composite tape, for the periods indicated:

	2015		2014	
Quarter	High	Low	High	Low
First	$ 3.74	$ 2.51	$ 8.67	$ 6.85
Second	$ 4.55	$ 3.25	$ 7.39	$ 5.88
Third	$ 3.43	$ 2.34	$ 7.03	$ 4.89
Fourth	$ 3.64	$ 1.75	$ 5.17	$ 2.58

Most of our stockholders maintain their shares as beneficial owners in “street name” accounts and are not, individually, stockholders of record. As of February 19, 2016, there were 1,565 holders of record of our shares and we had an estimated 17,724 beneficial owners.

Our 2015 Secured Credit Agreement and the indentures for the Senior Notes restrict the payment of dividends. In the past we have not paid dividends on our common stock and we have no present intention to pay dividends on our common stock in the foreseeable future.

Issuer Purchases of Equity Securities

The Company currently has no active share repurchase programs.

Item 6. Selected Financial Data

The following table presents selected historical consolidated financial data derived from the audited financial statements of Parker Drilling Company for each of the five years in the period ended December 31, 2015. The following financial data 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.

	Year Ended December 31,				
	2015	2014	2013 (1)	2012	2011 (2)
Dollars in Thousands, Except Per Share Amounts					
Income Statement Data					
Total revenues	$ 712,183	$ 968,684	$ 874,172	$ 677,761	$ 686,234
Total operating income (loss)	(17,338)	120,220	101,872	107,273	(41,837)
Net income (loss)	(94,284)	24,461	27,179	37,098	(50,645)
Net income (loss) attributable to controlling interest	(95,073)	23,451	27,015	37,313	(50,451)
Basic earnings per share:					
Net income (loss)	$ (0.77)	$ 0.20	$ 0.23	$ 0.32	$ (0.43)
Net income (loss) attributable to controlling interest	$ (0.78)	$ 0.19	$ 0.23	$ 0.32	$ (0.43)
Diluted earnings per share:					
Net income (loss)	$ (0.77)	$ 0.20	$ 0.22	$ 0.31	$ (0.43)
Net income (loss) attributable to controlling interest	$ (0.78)	$ 0.19	$ 0.22	$ 0.31	$ (0.43)
Balance Sheet Data					
Total assets	$ 1,376,904	$ 1,520,659	$ 1,534,756	$ 1,255,733	$ 1,216,246
Total long-term debt including current portion of long-term debt	585,000	615,000	653,781	479,205	482,723
Total equity	568,512	666,214	633,142	590,633	544,050

(1) The 2013 results include $22.5 million of acquisition costs related to the acquisition of ITS on April 22, 2013. See Note 2 — Acquisition of ITS in Item 8. Financial Statements and Supplementary Data for further discussion.

(2) The 2011 results reflect a $170.0 million ($109.1 million, net of taxes of $60.9 million) non-cash pretax impairment charge related to our two arctic-class drilling rigs located in Alaska.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Management's discussion and analysis (MD&A) should be read in conjunction with Item 8. Financial Statements and Supplementary Data.

Executive Overview

The oil and gas industry is highly cyclical. Activity levels are driven by traditional energy industry activity indicators, which include current and expected commodity prices, drilling rig counts, footage drilled, well counts, geologic characteristics of wells that determine drilling rig requirements and capabilities, and our customers' spending levels allocated towards exploratory and development drilling.

Historical market indicators are listed below:

	2015	% Change	2014	% Change	2013
Worldwide Rig Count (1)					
U.S. (land and offshore)	978	(47)%	1,862	6 %	1,761
International (2)	1,167	(13)%	1,337	3 %	1,296
Commodity Prices (annual average) (3)					
Crude Oil (United Kingdom Brent)	$ 53.60	(46)%	$ 99.45	(9)%	$ 108.7
Crude Oil (West Texas Intermediate)	$ 48.78	(48)%	$ 92.93	(5)%	$ 98.02
Natural Gas (Henry Hub)	$ 2.63	(38)%	$ 4.26	14 %	$ 3.73

(1) Estimate of drilling activity as measured by annual average active drilling rigs based on Baker Hughes Incorporated rig count information

(2) Excludes Canadian Rig Count.

(3) Estimate of commodity prices as based on NYMEX front-month composite energy prices.

Overall, the operating environment in 2015 was challenging for the Company and the broader energy services industry. Oil prices have declined significantly since late 2014, resulting in curtailed spending and operations on the part of E&P companies. As a result, E&P companies across most geographic regions have reduced their capital spending, terminated certain drilling contracts, requested pricing concessions and have taken other measures aimed at reducing the capital and operating expenses within their supply chain. This has adversely impacted our rental tools activity and pricing, as well as utilization and pricing of our drilling rigs. See "Oil and natural gas prices have declined substantially and are expected to remain depressed for the foreseeable future. Sustained depressed prices of oil and natural gas will adversely affect our financial condition, results of operations and cash flows" in Item 1A. Risk Factors.

As a result, revenues and gross margins in our Drilling Services and Rental Tools Services businesses were lower in 2015 as compared with 2014.

In our Drilling Services business, which is comprised of the International & Alaska Drilling segment and U.S. (Lower 48) Drilling segment - average utilization was 44 percent in 2015 as compared with 72 percent in 2014. Average utilization in our International & Alaska Drilling segment decreased to 59 percent for the year, from 72 percent for the prior year. At the end of 2015, 12 of our drilling rigs were under contract. Pricing and utilization were adversely impacted in the Eastern Hemisphere and Latin America due to the decline in customer activity. Utilization for our two arctic-class drilling rigs in Alaska remained at 100 percent. Activity for our O&M business remained relatively steady.

Our U.S. (Lower 48) Drilling segment average utilization was 15 percent, down significantly from 2014 utilization of 72 percent. The GOM market has experienced the largest decline in activity relative to our other markets. Customers operating in the shallow water GOM market are typically small, private energy producers which tend to be more cash flow sensitive and have limited access to third party capital as compared with many of our larger customers operating in other geographic markets.

Our Rental Tools Services business average utilization index for our U.S. rental tools tubular goods was 54, compared with 91 in 2014. The U.S. tubular goods index is an indexed value of our tubular goods (drill pipe and related products) on rent relative to our total tubular goods inventory. Although our U.S. revenues declined 37 percent from 2014 levels, our U.S. rental tools business did not decline as much as the average number of rigs drilling for oil and gas in the U.S., which experienced a 47 percent decline. We view this as an indication of our ability to maintain share in both our land and offshore market areas, despite this challenging market environment.

The depressed industry conditions also impacted our international rental tools business as revenues declined 16 percent from 2014. However, our internal initiatives helped increase our gross margin as a percent of revenues in our international rental tools business to 16 percent in 2015 from 15 percent in 2014. Despite a $19.4 million decrease in revenues, our gross margin only declined $1.7 million as we took several steps to enhance the performance of this business by consolidating and closing underperforming locations, hiring or replacing management, reducing headcount, and improving the management of our supply chain.

Although the severity and duration of the current industry downturn is contingent upon many factors beyond our control, we have taken several steps in an effort to preserve and increase cash flow, including lowering our cost base through headcount reductions and lower idle rig costs, reducing capital expenditures and striving to sustain utilization and market share.

We further strengthened our financial position by reducing our total debt by $30 million during the year and enhancing our liquidity and financial flexibility by increasing the revolving credit facility under our 2015 Secured Credit Agreement from $80 million to $200 million (2015 Revolver) and extending its maturity to 2020. Liquidity (cash on the balance sheet plus cash available to us from our 2015 Revolver) was approximately $322 million at year-end 2015 as compared with approximately $178 million at year-end 2014.

Executive Outlook

We believe overall energy market conditions will remain at low levels due to the ongoing imbalance in oil supply and demand. We believe these conditions will continue to cause our customers to curtail spending and activity levels in both the U.S. and international market areas.

We anticipate further declines in demand and pricing for our rental tools, particularly in the U.S. land and offshore GOM drilling markets. In addition, dayrates and utilization for our U.S. barge rigs should remain at low levels, and we anticipate lower dayrates and utilization for our international drilling rigs, as the weak market conditions further impact our international customers. In the near term, we do not anticipate significant changes in our international O&M projects or in our Alaska drilling operations.

Although we do not know the depth or duration of this downcycle, we have taken steps to align resources with the ongoing market downturn by lowering our cost base, sustaining our utilization, and managing our cash and liquidity. We will continue to adjust and adapt to the business environment and market conditions, while remaining opportunistic and positioning the Company for longer-term growth.

Results of Operations

Our business is comprised of two business lines: (1) Drilling Services and (2) Rental Tools Services. We report our Rental Tools Services business as one reportable segment (Rental Tools) and report our Drilling Services business as two reportable segments: (1) U.S. (Lower 48) Drilling and (2) International & Alaska Drilling. We eliminate inter-segment revenues and expenses.

We analyze financial results for each of our reportable segments. The reportable segments presented are consistent with our reportable segments discussed in our consolidated financial statements. See Note 12 - Reportable Segments in Item 8. Financial Statements and Supplementary Data for further discussion. We monitor our reporting segments based on several criteria, including operating gross margin and operating gross margin excluding depreciation and amortization. Operating gross margin excluding depreciation and amortization is computed as revenues less direct operating expenses, and excludes depreciation and amortization expense, where applicable. Operating gross margin percentages are computed as operating gross margin as a percent of revenues. The operating gross margin excluding depreciation and amortization amounts and percentages should not be used as a substitute for those amounts reported under accounting policies generally accepted in the United States (U.S. GAAP), but should be viewed in addition to the Company's reported results prepared in accordance with U.S. GAAP. Management believes this information may provide users of this financial information additional, meaningful comparisons between current results and results of prior periods.

Year Ended December 31, 2015 Compared with Year Ended December 31, 2014

Revenues decreased $256.5 million, or 26.5 percent, to $712.2 million for the year ended December 31, 2015 as compared to revenues of $968.7 million for the year ended December 31, 2014. Operating gross margin decreased 80.7 percent to $29.7 million for the year ended December 31, 2015 as compared to $154.2 million for the year ended December 31, 2014.

The following is an analysis of our operating results for the comparable periods by reportable segment:

	Year Ended December 31,			
	2015		2014	
Dollars in Thousands				
Revenues:				
Drilling Services:				
U.S. (Lower 48) Drilling	$ 30,358	4 %	$ 158,405	16%
International & Alaska Drilling	435,096	61 %	462,513	48%
Total Drilling Services	465,454	65 %	620,918	64%
Rental Tools	246,729	35 %	347,766	36%
Total revenues	712,183	100 %	968,684	100%
Operating gross margin excluding depreciation and amortization:				
Drilling Services:				
U.S. (Lower 48) Drilling	(5,889)	(19)%	68,091	43%
International & Alaska Drilling	109,750	25 %	94,089	20%
Total Drilling Services	103,861	22 %	162,180	26%
Rental Tools	82,032	33 %	137,123	39%
Total operating gross margin excluding depreciation and amortization	185,893	26 %	299,303	31%
Depreciation and amortization	(156,194)		(145,121)	
Total operating gross margin	29,699		154,182	
General and administrative expense	(36,190)		(35,016)	
Provision for reduction in carrying value of certain assets	(12,490)		—	
Gain (loss) on disposition of assets, net	1,643		1,054	
Total operating income (loss)	$ (17,338)		$ 120,220	

Operating gross margin amounts are reconciled to our most comparable U.S. GAAP measure as follows:

Dollars in Thousands	U.S. (Lower 48) Drilling	International & Alaska Drilling	Rental Tools	Total
Year Ended December 31, 2015				
Operating gross margin(1)	$ (28,309)	$ 45,211	$ 12,797	$ 29,699
Depreciation and amortization	22,420	64,539	69,235	156,194
Operating gross margin excluding depreciation and amortization	$ (5,889)	$ 109,750	$ 82,032	$ 185,893
Year Ended December 31, 2014				
Operating gross margin(1)	$ 46,831	$ 34,405	$ 72,946	$ 154,182
Depreciation and amortization	21,260	59,684	64,177	145,121
Operating gross margin excluding depreciation and amortization	$ 68,091	$ 94,089	$ 137,123	$ 299,303

(1) Operating gross margin is calculated as revenues less direct operating expenses, including depreciation and amortization expense.

The following table presents our average utilization rates and rigs available for service for the years ended December 31, 2015 and 2014, respectively:

	December 31,	
	2015	2014
U.S. (Lower 48) Drilling		
Rigs available for service (1)	13.0	12.1
Utilization rate of rigs available for service (2)	15%	72%
International & Alaska Drilling		
Eastern Hemisphere		
Rigs available for service (1)	13.0	13.0
Utilization rate of rigs available for service (2)	66%	77%
Latin America Region		
Rigs available for service (1)	9.0	9.0
Utilization rate of rigs available for service (2)	40%	60%
Alaska		
Rigs available for service (1)	2.0	2.0
Utilization rate of rigs available for service (2)	100%	100%
Total International & Alaska Drilling		
Rigs available for service (1)	24.0	24.0
Utilization rate of rigs available for service (2)	59%	72%

(1) The number of rigs available for service is determined by calculating the number of days each rig was in our fleet and was under contract or available for contract. For example, a rig under contract or available for contract for six months of a year is 0.5 rigs available for service during such year. Our method of computation of rigs available for service may not be comparable to other similarly titled measures of other companies.

(2) Rig utilization rates are based on a weighted average basis assuming total days availability for all rigs available for service. Rigs acquired or disposed of are treated as added to or removed from the rig fleet as of the date of acquisition or disposal. Rigs that are in operation or fully or partially staffed and on a revenue-producing standby status are considered to be utilized. Rigs under contract that generate revenues during moves between locations or during mobilization or demobilization are also considered to be utilized. Our method of computation of rig utilization may not be comparable to other similarly titled measures of other companies.

Drilling Services Business Line

U.S. (Lower 48) Drilling

U.S. (Lower 48) Drilling segment revenues decreased $128.0 million, or 80.8 percent, to $30.4 million for the year ended December 31, 2015, as compared with revenues of $158.4 million for the year ended December 31, 2014. The decrease was primarily due to lower utilization in the offshore GOM, which declined from 72 percent for the year ended December 31, 2014 to 15 percent for the year ended December 31, 2015 and resulted in a $101.0 million decrease in revenue. The decline in utilization for the barge drilling business was due to substantial reductions in drilling activity by operators in the inland waters of the GOM resulting from lower oil prices. The remainder of the decrease was primarily driven by a reduction in average dayrates for the barge drilling business and a decrease in revenues from our O&M contract supporting three platform operations located offshore California. The O&M contract ended during the 2015 fourth quarter.

U.S. (Lower 48) Drilling segment operating gross margin excluding depreciation and amortization decreased $74.0 million, or 108.7 percent, to $5.9 million loss for the year ended December 31, 2015, compared with $68.1 million for the year ended December 31, 2014. This decrease was primarily due to the decline in utilization discussed above.

International & Alaska Drilling

International & Alaska Drilling segment revenues decreased $27.4 million, or 5.9 percent, to $435.1 million for the year ended December 31, 2015, compared with $462.5 million for the year ended December 31, 2014.

The decrease in revenues was primarily due to the following:

- a decrease of $50.7 million, excluding revenues from reimbursable costs ("reimbursable revenues"), resulting from decreased utilization for Parker-owned rigs. Utilization for the segment decreased from 72 percent to 59 percent for the years ended December 31, 2014 and 2015, respectively, primarily resulting from the decline in oil prices which led to reduced customer activity; and

- a decrease of approximately $7.4 million of revenues generated from our project service activities.

The decrease in revenues was partially offset by the following:

- an increase of $12.2 million, excluding reimbursable revenues, related to our O&M activity primarily resulting from the two-rig O&M contract in Abu Dhabi that commenced during the 2015 first quarter partially offset by the completion of an O&M contract in May 2014; and

- an increase in reimbursable revenues of $12.0 million which added to revenues but had a minimal impact on operating margins.

International & Alaska Drilling segment operating gross margin excluding depreciation and amortization increased $15.7 million, or 16.7 percent, to $109.8 million for the year ended December 31, 2015, compared with $94.1 million for the year ended December 31, 2014. The increase in operating gross margin excluding depreciation and amortization was primarily due to the benefit of higher margins earned on our project services activities which contributed $13.4 million to the increase. Margins also benefited from increased O&M activity and lower operating costs in certain locations, which helped offset the impact of lower utilization discussed above.

Rental Tools Services Business Line

Rental Tools segment revenues decreased $101.1 million, or 29.1 percent, to $246.7 million for the year ended December 31, 2015 compared to $347.8 million for the year ended December 31, 2014. The decrease was due to an $81.7 million decrease in our U.S. revenues and a $19.4 million decrease in our international revenues. The decreases were primarily attributable to reduced customer activity and pricing pressures resulting from lower oil prices.

Rental Tools segment operating gross margin excluding depreciation and amortization decreased $55.1 million, or 40.2 percent, to $82.0 million for the year ended December 31, 2015 compared with $137.1 million for the year ended December 31, 2014. The decrease in operating gross margin excluding depreciation and amortization was primarily due to a $53.4 million decrease for our U.S operations and a $1.7 million decrease for our international operations due to the declines in oil prices and customer activity discussed above.

Other Financial Data

General and administrative expense

General and administrative expense increased $1.2 million to $36.2 million for the year ended December 31, 2015, compared with $35.0 million for the year ended December 31, 2014. The increase was primarily driven by expenses associated with the implementation of the second phase of our enterprise resource planning system in 2015 and a benefit for the year ended December 31, 2014 from a $2.75 million reimbursement received from an escrow account related to the ITS Acquisition. Excluding the benefit of the reimbursement from escrow in 2014, general and administrative expenses declined as a result of reductions in personnel and cost control activities.

Provision for reduction in carrying value of certain assets

During the year ended December 31, 2015, we recorded $12.5 million of provisions for reduction in carrying value of assets. During the 2015 fourth quarter management made a decision to exit the Drilling Services business in the Colombia market. As of December 31, 2015 there were three-rigs in the country. One of the rigs is being marketed for operations outside of Colombia, and for the remaining two rigs, components of the rigs that are useable elsewhere in our operations are being re-deployed and the carrying value of the remaining components has been written-off, resulting in a provision for reduction in carrying value of $4.8 million. In addition, during the 2015 fourth quarter, to adjust to the lower level of current and expected activity, we performed a review of certain individual assets within our asset groups and recorded a $4.3 million provision for reduction in carrying value of assets primarily related to drilling equipment in our International and Alaska segment. During the 2015 second and third quarters, the Company wrote-off a combined $3.2 million related to certain international rental tools and drilling rigs that management concluded were no longer marketable and the carrying value of the rigs and equipment was no longer recoverable. During 2014, the provision for reduction in carrying value of certain assets was zero.

Gain on disposition of assets

Net gains recorded on asset dispositions for the years ended December 31, 2015 and 2014 were $1.6 million and $1.1 million, respectively. The net gains for 2015 were primarily due an insurance settlement received in the 2015 first quarter related to previously realized asset losses, partially offset by losses incurred during the 2015 fourth quarter related to equipment retirements.

The net gains for 2014 were primarily the result of long-lived asset sales, including the sale of two rigs located in Kazakhstan during the fourth quarter. Activity in both periods included the result of asset sales. We periodically sell equipment deemed to be excess, obsolete, or not currently required for operations.

Interest income and expense

Interest expense increased $0.9 million to $45.2 million for the year ended December 31, 2015 compared with $44.3 million for the year ended December 31, 2014, despite a decrease in debt related interest expense resulting from a decrease in our total amount of outstanding debt and lower interest rates during 2015. The increase in interest expense is primarily due to a lower amount of capitalized interest during 2015 as compared to 2014 and higher fees on the unused portion of the 2015 Revolver. During 2015, we increased our revolver from $80 million to $200 million, and as a result of this increased availability, we experienced a corresponding increase in fees on the unused portion of the revolver.

Interest income increased $0.1 million to $0.3 million during 2015, compared with interest income of $0.2 million during 2014.

Loss on extinguishment of debt

Loss on extinguishment of debt was zero and $30.2 million for the years ended December 31, 2015 and December 31, 2014, respectively. The loss on extinguishment of debt for 2014 related to the purchase and redemption of our 9.125% Senior Notes, due 2018 (9.125% Notes) during the first six months of 2014.

Other income and expense

Other income and expense was $9.7 million of expense and $2.5 million of income for the years ended December 31, 2015 and December 31, 2014, respectively. During the 2015 fourth quarter we incurred a $4.8 million loss on the sale of our controlling interest in a consolidated joint venture in Egypt and during the 2015 second quarter we incurred a $0.9 million loss on the divestiture of our controlling interest in a consolidated joint venture in Russia. Additionally, net losses related to foreign currency fluctuations increased $2.5 million for the 2015 full year compared to the 2014 full year. Other income in 2014 was primarily related to earnings from our investment in an unconsolidated subsidiary that was acquired as part of the ITS Acquisition as well as settlements of claims against a vendor.

Income tax expense

Income tax expense was $22.3 million on a pre-tax loss of $72.0 million for the year ended December 31, 2015, compared with $24.1 million on pre-tax income of $48.5 million for the year ended December 31, 2014. Our effective tax rate was negative 31.0 percent for the year ended December 31, 2015, compared with 49.6 percent for the year ended December 31, 2014. Income tax expense and our annual effective tax rate are primarily affected by recurring items, such as the relative amounts of income or loss we earn in tax paying and non-tax paying jurisdictions, the statutory tax rates applied in the jurisdictions where the income or losses are earned, and our ability to receive tax benefits for losses incurred. It is also affected by discrete items, such as return-to-accrual adjustments and changes in valuation allowances, and changes in reserves for uncertain tax positions, which may occur in any given year but are not consistent from year to year.

Despite the pre-tax loss for the year ended December 31, 2015, we recognized income tax expense as a result of a change in valuation allowance of $40.6 million primarily on U.S. foreign tax credits of $32.4 million and certain foreign net operating losses of $8.2 million. We established the valuation allowance based on the weight of available evidence, both positive and negative, including results of recent and current operations and our estimates of future taxable income or loss by jurisdiction in which we operate. In order to determine the amount of deferred tax assets or liabilities, as well as the valuation allowances, we must make estimates and assumptions regarding future taxable income, where rigs will be deployed and other business considerations. Changes in these estimates and assumptions, including changes in tax laws and other changes impacting our ability to recognize the underlying deferred tax assets, could require us to adjust the valuation allowances.

We are a U.S. based company that operates internationally through various branches and subsidiaries. Accordingly, our worldwide income tax provision includes the impact of income tax rates and foreign tax laws in the jurisdictions in which our operations are conducted and income is earned. We reported tax benefits for foreign statutory rates different than our U.S. statutory rate of $2.7 million and $3.4 million and tax expense of $16.0 million and $11.2 million for the impact of foreign tax laws in effect for the years ended December 31, 2015 and December 31, 2014, respectively. Differences between the U.S. and foreign tax rates and laws have a significant impact in Colombia, Iraq, Kazakhstan, Mexico, Russia, United Arab Emirates and the United Kingdom.

Certain tax payments to foreign jurisdictions are available as credits to reduce tax expense in the U.S. and other foreign jurisdictions. We reported tax benefits for foreign tax credits of $5.6 million and $3.0 million for the years ended December 31, 2015 and December 31, 2014, respectively, which are driven primarily by our operations in Kazakhstan. See Note 6 - Income Taxes in Item 8. Financial Statements and Supplementary Data for further discussion.

Year Ended December 31, 2014 Compared with Year Ended December 31, 2013

Revenues increased $94.5 million, or 10.8 percent, to $968.7 million for the year ended December 31, 2014 as compared to $874.2 million for the year ended December 31, 2013. Operating gross margin decreased 8.5 percent to $154.2 million for the year ended December 31, 2014 as compared to $168.4 million for the year ended December 31, 2013.

The following is an analysis of our operating results for the comparable periods by reportable segment:

Dollars in Thousands	Year Ended December 31, 2014		Year Ended December 31, 2013	
Revenues:				
Drilling Services:				
U.S. (Lower 48) Drilling	$ 158,405	16%	$ 153,624	18%
International & Alaska Drilling (1)	462,513	48%	410,507	47%
Total Drilling Services	620,918	64%	564,131	65%
Rental Tools	347,766	36%	310,041	35%
Total revenues	968,684	100%	874,172	100%
Operating gross margin excluding depreciation and amortization:				
Drilling Services:				
U.S. (Lower 48) Drilling	68,091	43%	69,415	45%
International & Alaska Drilling (1)	94,089	20%	86,068	21%
Total Drilling Services	162,180	26%	155,483	28%
Rental Tools	137,123	39%	147,017	47%
Total operating gross margin excluding depreciation and amortization	299,303	31%	302,500	35%
Depreciation and amortization	(145,121)		(134,053)	
Total operating gross margin	154,182		168,447	
General and administrative expense	(35,016)		(68,025)	
Provision for reduction in carrying value of certain assets	—		(2,544)	
Gain on disposition of assets, net	1,054		3,994	
Total operating income	$ 120,220		$ 101,872	

(1) 2013 includes the close-out of a construction project and recognition of final percentage of completion revenue. The construction project was canceled in 2011 prior to final completion.

Operating gross margin amounts are reconciled to our most comparable U.S. GAAP measure as follows:

Dollars in Thousands	U.S. (Lower 48) Drilling	International & Alaska Drilling	Rental Tools	Total
Year Ended December 31, 2014				
Operating gross margin(1)	$ 46,831	$ 34,405	$ 72,946	$ 154,182
Depreciation and amortization	21,260	59,684	64,177	145,121
Operating gross margin excluding depreciation and amortization	$ 68,091	$ 94,089	$ 137,123	$ 299,303
Year Ended December 31, 2013				
Operating gross margin(1)	$ 54,203	$ 23,080	$ 91,164	$ 168,447
Depreciation and amortization	15,212	62,988	55,853	134,053
Operating gross margin excluding depreciation and amortization	$ 69,415	$ 86,068	$ 147,017	$ 302,500

(1) Operating gross margin is calculated as revenues less direct operating expenses, including depreciation and amortization expense.

The following table presents our average utilization rates and rigs available for service for the years ended December 31, 2014 and 2013, respectively:

	December 31,	
	2014	2013
U.S. (Lower 48) Drilling		
Rigs available for service (1)	12.1	11.0
Utilization rate of rigs available for service (2)	72%	91%
International & Alaska Drilling		
Eastern Hemisphere		
Rigs available for service (1)	13.0	14.0
Utilization rate of rigs available for service (2)	77%	49%
Latin America Region		
Rigs available for service (1)	9.0	9.5
Utilization rate of rigs available for service (2)	60%	75%
Alaska		
Rigs available for service (1)	2.0	1.9
Utilization rate of rigs available for service (2)	100%	100%
Total International & Alaska Drilling		
Rigs available for service (1)	24.0	25.4
Utilization rate of rigs available for service (2)	72%	63%

(1) The number of rigs available for service is determined by calculating the number of days each rig was in our fleet and was under contract or available for contract. For example, a rig under contract or available for contract for six months of a year is 0.5 rigs available for service during such year. Our method of computation of rigs available for service may not be comparable to other similarly titled measures of other companies.

(2) Rig utilization rates are based on a weighted average basis assuming total days availability for all rigs available for service. Rigs acquired or disposed of are treated as added to or removed from the rig fleet as of the date of acquisition or disposal. Rigs that are in operation or fully or partially staffed and on a revenue-producing standby status are considered to be utilized. Rigs under contract that generate revenues during moves between locations or during mobilization or demobilization are also considered to be utilized. Our method of computation of rig utilization may not be comparable to other similarly titled measures of other companies.

Drilling Services Business Line

U.S. (Lower 48) Drilling

U.S. (Lower 48) Drilling segment revenues increased $4.8 million, or 3.1 percent, to $158.4 million for the year ended December 31, 2014, as compared with revenues of $153.6 million for the year ended December 31, 2013. The increase in revenues was primarily due to an additional $12.1 million from higher average dayrates for the U.S. barge rig fleet, including benefits from the addition to our operating fleet of rigs 55B and 30B in the second and third quarters, respectively, of 2014. Additionally, we generated an increase of $4.5 million from the O&M contract supporting three platform operations located offshore California, which generated higher reimbursable revenues and was operating for the full year ended December 31, 2014, compared with just over ten months in 2013. The segment revenue increase was substantially offset by lower utilization for the U.S. barge rig fleet, which declined from 91 percent for the year ended December 31, 2013 to 72 percent for the year ended December 31, 2014 as a result of lower oil prices late in 2014.

U.S. (Lower 48) Drilling segment operating gross margin excluding depreciation and amortization decreased $1.3 million, or 1.9 percent, to $68.1 million for the year ended December 31, 2014, compared with $69.4 million for the year ended December 31, 2013. This decrease was primarily due to lower utilization of the U.S. barge rig fleet discussed above.

International & Alaska Drilling

International & Alaska Drilling segment revenues increased $52.0 million, or 12.7 percent, to $462.5 million for the year ended December 31, 2014, compared with $410.5 million for the year ended December 31, 2013. The increase in revenues was primarily due to the following:

- an increase in reimbursable revenues of $12.1 million which added to revenues but had a minimal impact on operating margins;

- an increase of $27.7 million, excluding reimbursable revenues, primarily resulting from increased utilization for Parker-owned rigs. Utilization for the segment increased from 63 percent to 72 percent for the years ended December 31, 2013 and 2014, respectively, and included the following activities:

    - successful deployment of two previously idle rigs to the Kurdistan Region of Iraq;

    - a full year of operations in 2014 for our two arctic-class drilling rigs in Alaska, compared with 2013, in which one rig was not operational until February 2013; and

    - increased activity for our Sakhalin Island drilling operations.

    - partially offsetting these increases was a decline in activity in our Latin America region.

- an increase of approximately $16.8 million of revenues generated from our project services activities, primarily due to a new Front End Engineering and Design contract entered into during the fourth quarter of 2013 and increased activity under the vendor services phase of the Berkut platform project. Due to the low mark-up on vendor services, this activity had minimal impact on operating gross margin excluding depreciation and amortization; and

- an increase of $4.0 million, excluding reimbursable revenues, primarily resulting from increased activity for our Sakhalin Island O&M operations, partially offset by the completion of an O&M project in Papua New Guinea in May 2014.

International & Alaska Drilling segment operating gross margin excluding depreciation and amortization increased $8.0 million, or 9.3 percent, to $94.1 million for the year ended December 31, 2014, compared with $86.1 million for the year ended December 31, 2013. The increase in operating gross margin excluding depreciation and amortization was primarily due to both arctic-class rigs being fully operational in our Alaska operations and increased activity and lower operating costs associated with our Sakhalin Island O&M operations, which combined contributed $17.1 million to the increase. This increase was partially offset by the impact of net mobilization costs associated with the deployment of two previously idle rigs to Kurdistan and a decline in activity in our Latin America region, both described above. Additionally, included in the 2013 operating gross margin excluding depreciation and amortization was $4.7 million related to the close-out of a construction project and recognition of final percentage of completion revenue. The construction project was an extended-reach drilling rig construction contract that our customer canceled in 2011 prior to final completion.

Rental Tools Services Business Line

Rental Tools segment revenues increased $37.7 million, or 12.2 percent, to $347.8 million for the year ended December 31, 2014 compared to $310.0 million for the year ended December 31, 2013. The increase was due to a $26.7 million increase in our international revenues and an $11.0 million increase in our U.S. revenues. The increase in international revenues was primarily due to a full year of revenues from International Tubular Services (ITS), acquired in April of 2013, which contributed an increase of $23.4 million of revenues for the year ended December 31, 2014. The increase in U.S. rental tools revenues was due to increased activity in the offshore GOM market and increased activity in the U.S. land drilling market.

Rental Tools segment operating gross margin excluding depreciation and amortization decreased $9.9 million, or 6.7 percent, to $137.1 million for the year ended December 31, 2014 compared with $147.0 million for the year ended December 31, 2013. The decrease was primarily due to an $11.0 million reduction in gross margin excluding depreciation and amortization for our international operations, resulting from lower utilization, increased costs related to relocation of facilities and an increase in the allowance for doubtful accounts. This decline was slightly offset by a $1.1 million increase in gross margin excluding depreciation and amortization for our U.S. operations due to the increase in activity in the offshore GOM and U.S. land drilling markets, despite an increase in competitive conditions that led to lower product pricing for rental tools and related activities in the latter part of 2014.

Other Financial Data

General and administrative expense

General and administrative expense decreased $33.0 million to $35.0 million for the year ended December 31, 2014, compared with $68.0 million for the year ended December 31, 2013. The decrease was due primarily to approximately $22.5 million of costs incurred during 2013 related to the ITS Acquisition that did not recur in 2014. During 2013 we also incurred severance costs related to the departure of our former chief financial officer and our executive chairman, along with higher legal costs for matters related to our deferred prosecution agreement and settlements with the Department of Justice (DOJ) and SEC, neither of which recurred during 2014. General and administrative expense during 2014 also benefited from a $2.75 million reimbursement from an escrow account related to the ITS Acquisition.

Provision for reduction in carrying value of certain assets

During the year ended December 31, 2014, the provision for reduction in carrying value of certain assets was zero. During 2013, the provision for reduction in carrying value of certain assets was $2.5 million which was comprised of non-cash charges recognized for three rigs reclassified from assets held for sale to assets held and used for which carrying values exceeded fair values. Management concluded, based on the facts and circumstances at the time, it was no longer probable that the sales of the rigs would be consummated.

Gain on disposition of assets

Net gains recorded on asset dispositions for the years ended December 31, 2014 and 2013 were $1.1 million and $4.0 million, respectively. The net gains for 2014 were primarily the result of long-lived asset sales, including the sale of two rigs located in Kazakhstan during the fourth quarter. The net gains for 2013 were primarily the result of long-lived asset sales, including the sale of two rigs located in New Zealand, a building located in Tulsa, Oklahoma and a barge rig located in Mexico. We periodically sell equipment deemed to be excess, obsolete, or not currently required for operations.

Interest income and expense

Interest expense decreased $3.6 million to $44.3 million for the year ended December 31, 2014 compared with $47.8 million for the year ended December 31, 2013. This decrease was primarily related to a decrease in debt-related interest expense of $6.2 million resulting from lower interest rates on our outstanding debt balance and a lower total debt balance, offset by an increase in amortization of debt issuance costs of $1.4 million and a decrease in capitalized interest of $1.2 million. Interest income decreased $2.3 million to $0.2 million during 2014, compared with interest income of $2.5 million during 2013 primarily related to interest earned on an IRS refund received during 2013.

Loss on extinguishment of debt

Loss on extinguishment of debt was $30.2 million and $5.2 million for the years ended December 31, 2014 and December 31, 2013, respectively. The loss on extinguishment of debt for 2014 related to the purchase and redemption of the 9.125% Notes during the first six months of 2014. The loss on extinguishment of debt for 2013 is related to the write-off of debt issuance costs resulting from the repayment of a $125 million term loan, which was fully funded by Goldman Sachs Bank USA as Sole Lead Arranger and Administrative Agent (Goldman Term Loan) in July 2013.

Other income and expense

Other income and expense was $2.5 million and $1.5 million of income for the years ended December 31, 2014 and December 31, 2013, respectively. Other income in 2014 was primarily related to earnings from our investment in an unconsolidated subsidiary that was acquired as part of the ITS Acquisition as well as settlements of claims against a vendor. This income was partially offset by losses related to foreign currency fluctuations from our Sakhalin Island operations. Other income in 2013 was primarily related to the recognition of non-refundable deposits from a buyer in connection with the sale of three rigs for which the sales agreement was terminated in the fourth quarter of 2013.

Income tax expense

Income tax expense was $24.1 million on pre-tax income of $48.5 million for the year ended December 31, 2014, compared with income tax expense of $25.6 million on pre-tax income of $52.8 million for the year ended December 31, 2013. Our effective tax rate was 49.6 percent for the year ended December 31, 2014, compared with 48.5 percent for the year ended December 31, 2013. Income tax expense and our annual effective tax rate are primarily affected by recurring items, such as the relative amounts of income or loss we earn in domestic and foreign jurisdictions, the statutory tax rates applied in the jurisdictions where the income or losses are earned, and our ability to receive tax benefits for losses incurred. It is also affected by discrete items, such as return-to-accrual adjustments and changes in valuation allowances, and changes in reserves for uncertain tax positions, which may occur in any given year but are not consistent from year to year.

We are a U.S. based company that operates internationally through various branches and subsidiaries. Accordingly, our worldwide income tax provision includes the impact of income tax rates and foreign tax laws in the jurisdictions in which our operations are conducted and income is earned. We reported tax benefits for foreign statutory rates different than our U.S. statutory rate of $3.4 million and $8.9 million and tax expense of $11.2 million and $12.5 million for the impact of foreign tax laws in effect for the years ended December 31, 2014 and December 31, 2013, respectively. Differences between the U.S. and foreign tax rates and laws have a significant impact in Colombia, Iraq, Kazakhstan, Mexico, Russia, United Arab Emirates and the United Kingdom.

Certain tax payments to foreign jurisdictions are available as credits to reduce tax expense in the U.S. and other foreign jurisdictions. We reported tax benefits for foreign tax credits of $3.0 million and $1.5 million for the years ended December 31, 2014 and December 31, 2013, respectively, which are driven primarily by our operations in Kazakhstan. See Note 6 - Income Taxes in Item 8. Financial Statements and Supplementary Data for further discussion.

Liquidity and Capital Resources

We periodically evaluate our liquidity requirements, capital needs and availability of resources in view of expansion plans, debt service requirements, and other operational cash needs. To meet our short- and long-term liquidity requirements, including payment of operating expenses and repaying debt, we rely primarily on cash from operations. We also have access to cash through the 2015 Revolver, subject to our compliance with the covenants contained in the 2015 Secured Credit Agreement. We expect that these sources of liquidity will be sufficient to provide us the ability to fund our operations, provide the working capital necessary to support our strategy, and fund planned capital expenditures. When determined necessary we may seek to raise additional capital in the future. We do not pay dividends to our shareholders.

Liquidity

The following table provides a summary of our total liquidity:

Dollars in thousands		December 31, 2015
Cash and cash equivalents on hand [1]	$	134,294
Availability under 2015 Revolver [2], [3]		187,473
Total liquidity	$	321,767

(1) As of December 31, 2015, approximately $44.1 million of the $134.3 million of cash and equivalents was held by our foreign subsidiaries.

(2) Availability under the 2015 Revolver included $200 million undrawn portion of our 2015 Revolver less $12.5 million of letters of credit outstanding.

(3) In order to access the 2015 Revolver, we must be in compliance with the covenants contained in the 2015 Secured Credit Agreement.

The earnings of foreign subsidiaries as of December 31, 2015 were reinvested to fund our international operations. If in the future we decide to repatriate earnings to the United States, the Company may be required to pay taxes on these amounts based on applicable United States tax law, which would reduce the liquidity of the Company at that time.

We do not have any unconsolidated special-purpose entities, off-balance sheet financing arrangements or guarantees of third-party financial obligations. As of December 31, 2015, we have no energy, commodity, or foreign currency derivative contracts.

Cash Flow Activity

As of December 31, 2015, we had cash and cash equivalents of $134.3 million, an increase of $25.8 million from cash and cash equivalents of $108.5 million at December 31, 2014. The following table provides a summary of our cash flow activity for the last three years:

Dollars in thousands		2015		2014		2013
Operating Activities		162,122	$	202,467	$	161,497
Investing Activities		(101,243)		(173,575)		(265,418)
Financing Activities		(35,041)		(69,125)		164,724
Net change in cash and cash equivalents	$	25,838	$	(40,233)	$	60,803

Operating Activities

Cash flows provided by operating activities were $162.1 million, $202.5 million, and $161.5 million for the years ended December 31, 2015, 2014, and 2013, respectively. Cash flows provided by operating activities in each year were largely impacted by our earnings and changes in working capital. Changes in working capital were a source of cash of $80.7 million for the year ended December 31, 2015 and a use of cash of $17.1 million and $34.0 million for the years ended December 31, 2014 and 2013, respectively. Cash generated from working capital in 2015 is primarily due to increased collections on accounts receivable partially offset by payments to third parties. Uses of working capital in 2014 and 2013 primarily related to increases in receivables, inventory, and accounts payable related to the ITS Acquisition. In addition to the impact of earnings and working capital changes cash flows provided by operating activities in each year were impacted by non-cash charges such as depreciation expense, gains on asset sales, deferred tax benefit, stock compensation expense, debt extinguishment and amortization of debt issuance costs.

Over the past few years we have reinvested a substantial portion of our operating cash flows to enhance our fleet of drilling rigs and our rental tools equipment inventory. It is our long term intention to utilize our operating cash flows to fund maintenance and growth of our rental tool assets and drilling rigs; however, given the decline in demand in the current oil and natural gas services market, our short-term focus is to preserve liquidity by managing our costs and capital expenditures.

Investing Activities

Cash flows used in investing activities were $101.2 million for the years ended December 31, 2015, compared with $173.6 million and $265.4 million for the years ended December 31, 2014 and 2013, respectively. Our primary use of cash during 2015 was $88.2 million for capital expenditures, primarily for tubular and other products for our Rental Tools Services business and rig-related enhancements and maintenance. In addition, during 2015 we had a use of cash of $10.4 million, net of cash acquired, for the 2M-Tek Acquisition and $3.4 million related to the purchase of the remaining noncontrolling interest in ITS Arabia Limited.

Cash flows used in investing activities in 2014 primarily included capital expenditures of $179.5 million primarily for tubular and other products for our Rental Tools Services business, purchase of barge rig 30B, and rig-related enhancements and maintenance.

Cash flows used in investing activities in 2013 primarily included $118.0 million for the ITS Acquisition, net of cash acquired, and $155.6 million for capital expenditures. Capital expenditures in 2013 were primarily for tubular and other products for our Rental Tools Services business, rig-related enhancements and maintenance and costs related to our new enterprise resource planning system.

Capital expenditures for 2016 are estimated to be approximately $50.0 million and will primarily be directed to our Rental Tools segment inventory and maintenance capital on our rigs. Any discretionary spending will be evaluated based upon adequate return requirements and available liquidity.

Financing Activities

Cash flows used in financing activities were $35.0 million and $69.1 million for the years ended for December 31, 2015 and 2014, respectively. Cash provided by financing activities was $164.7 million for the year ended December 31, 2013. Cash flows used in financing activities in 2015 primarily related to the repayment of the $30.0 million borrowing on our 2015 Revolver in the first quarter of 2015.

Cash flows used in financing activities for 2014 primarily related to the repayment of $425.0 million of our 9.125% Senior Notes due 2018 (9.125% Notes), payment of $26.2 million of related tender and consent premiums, and payment of debt issuance costs of $7.6 million. Cash provided by financing activities included proceeds of $360.0 million from the issuance of our 6.75% Senior Notes due 2022 (6.75% Notes) and reborrowing of a $40.0 million Term Loan under our Amended and Restated Senior Secured Credit Agreement (2012 Secured Credit Agreement).

Cash flows provided by financing activities for 2013 primarily related to the $125 million Goldman Term Loan issued during the 2013 second quarter in connection with the ITS Acquisition and the $225.0 million 7.50% Senior Notes due 2020 (7.50% Notes) issued during the 2013 third quarter. Cash used in financing activities included pay-off of the Goldman Term Loan in the 2013 third quarter, principal payments made under our Term Loan and payments of debt issuance costs.

Long-Term Debt Summary

Our principal amount of long-term debt, including current portion, was $585.0 million as of December 31, 2015, which consisted of:

- $360.0 million aggregate principal amount of 6.75% Notes; and
- $225.0 million aggregate principal amount of 7.50% Notes.

6.75% Senior Notes, due July 2022

On January 22, 2014, we issued $360.0 million aggregate principal amount of the 6.75% Notes pursuant to an Indenture between the Company and The Bank of New York Mellon Trust Company, N.A., as trustee. Net proceeds from the 6.75% Notes offering plus a $40.0 million Term Loan draw under the 2012 Secured Credit Agreement and cash on hand were utilized to purchase $416.2 million aggregate principal amount of our outstanding 9.125% Notes pursuant to a tender and consent solicitation offer commenced on January 7, 2014. See further discussion of the tender and consent solicitation offer below entitled "9.125% Senior Notes, due April 2018".

The 6.75% Notes are general unsecured obligations of the Company and rank equal in right of payment with all of our existing and future senior unsecured indebtedness. The 6.75% Notes are jointly and severally guaranteed by all of our subsidiaries that guarantee indebtedness under the Second Amended and Restated Senior Secured Credit Agreement (2015 Secured Credit Agreement) and our 7.50% Notes (collectively with the 6.75% Notes, the Senior Notes). Interest on the 6.75% Notes is payable on January 15 and July 15 of each year, beginning July 15, 2014. Debt issuance costs related to the 6.75% Notes of approximately

$7.6 million ($6.2 million net of amortization as of December 31, 2015) are being amortized over the term of the notes using the effective interest rate method.

At any time prior to January 15, 2017, we may redeem up to 35 percent of the aggregate principal amount of the 6.75% Notes at a redemption price of 106.75 percent of the principal amount, plus accrued and unpaid interest to the redemption date, with the net cash proceeds of certain equity offerings by us. On and after January 15, 2018, we may redeem all or a part of the 6.75% Notes upon appropriate notice, at a redemption price of 103.375 percent of the principal amount, and at redemption prices decreasing each year thereafter to par beginning January 15, 2020. If we experience certain changes in control, we must offer to repurchase the 6.75% Notes at 101.0 percent of the aggregate principal amount, plus accrued and unpaid interest and additional interest, if any, to the date of repurchase.

The Indenture restricts our ability and the ability of certain subsidiaries to: (i) sell assets, (ii) pay dividends or make other distributions on capital stock or redeem or repurchase capital stock or subordinated indebtedness, (iii) make investments, (iv) incur or guarantee additional indebtedness, (v) create or incur liens, (vi) enter into sale and leaseback transactions, (vii) incur dividend or other payment restrictions affecting subsidiaries, (viii) merge or consolidate with other entities, (ix) enter into transactions with affiliates, and (x) engage in certain business activities. Additionally, the Indenture contains certain restrictive covenants designating certain events as Events of Default. These covenants are subject to a number of important exceptions and qualifications.

7.50% Senior Notes, due August 2020

On July 30, 2013, we issued $225.0 million aggregate principal amount of the 7.50% Notes pursuant to an Indenture between the Company and The Bank of New York Mellon Trust Company, N.A., as trustee. Net proceeds from the 7.50% Notes offering were primarily used to repay the $125.0 million aggregate principal amount of the Goldman Term Loan, to repay $45.0 million of Term Loan borrowings and for general corporate purposes.

The 7.50% Notes are general unsecured obligations of the Company and rank equal in right of payment with all of our existing and future senior unsecured indebtedness. The 7.50% Notes are jointly and severally guaranteed by all of our subsidiaries that guarantee indebtedness under the 2015 Secured Credit Agreement and the 6.75% Notes. Interest on the 7.50% Notes is payable on February 1 and August 1 of each year, beginning February 1, 2014. Debt issuance costs related to the 7.50% Notes of approximately $5.6 million ($4.0 million, net of amortization as of December 31, 2015) are being amortized over the term of the notes using the effective interest rate method.

At any time prior to August 1, 2016, we may redeem up to 35 percent of the aggregate principal amount of the 7.50% Notes at a redemption price of 107.50 percent of the principal amount, plus accrued and unpaid interest to the redemption date, with the net cash proceeds of certain equity offerings by us. On and after August 1, 2016, we may redeem all or a part of the 7.50% Notes upon appropriate notice, at a redemption price of 103.750 percent of the principal amount, and at redemption prices decreasing each year thereafter to par beginning August 1, 2018. If we experience certain changes in control, we must offer to repurchase the 7.50% Notes at 101.0 percent of the aggregate principal amount, plus accrued and unpaid interest and additional interest, if any, to the date of repurchase.

The Indenture restricts our ability and the ability of certain subsidiaries to: (i) sell assets, (ii) pay dividends or make other distributions on capital stock or redeem or repurchase capital stock or subordinated indebtedness, (iii) make investments, (iv) incur or guarantee additional indebtedness, (v) create or incur liens, (vi) enter into sale and leaseback transactions, (vii) incur dividend or other payment restrictions affecting subsidiaries, (viii) merge or consolidate with other entities, (ix) enter into transactions with affiliates, and (x) engage in certain business activities. Additionally, the Indenture contains certain restrictive covenants designating certain events as Events of Default. These covenants are subject to a number of important exceptions and qualifications.

9.125% Senior Notes, due April 2018

On January 7, 2014, we commenced a tender and consent solicitation with respect to the 9.125% Notes. The tender offer price was $1,061.98, inclusive of a $30.00 consent payment, for each $1,000 principal amount of 9.125% Notes, plus accrued and unpaid interest. On January 22, 2014, we paid $453.7 million for the tendered 9.125% Notes, comprised of $416.2 million of aggregate principal amount of the 9.125% Notes, $25.8 million of tender and consent premiums and $11.7 million of accrued interest. On April 1, 2014, we redeemed the remaining $8.8 million aggregate principal amount of the outstanding 9.125% Notes for a purchase price of $9.6 million, inclusive of a $0.4 million call premium and $0.4 million interest. During the year ended December 31, 2014, we recorded a loss on extinguishment of debt of approximately $30.2 million, which included the tender and consent premiums of $25.8 million, the call premium of $0.4 million and the write-off of unamortized debt issuance costs of $7.7 million, offset by the write-off of the remaining unamortized debt issuance premium of $3.8 million.

2015 Secured Credit Agreement

On January 26, 2015 we entered into the 2015 Secured Credit Agreement, which amended and restated the 2012 Secured Credit Agreement. The 2015 Secured Credit Agreement is comprised of a $200.0 million revolving credit facility (2015 Revolver) and matures on January 26, 2020. The 2012 Secured Credit Agreement consisted of an $80.0 million revolving credit facility and a $50.0 million term loan (Term Loan). At the closing of the 2015 Secured Credit Agreement, the outstanding balance on the Term Loan was $30 million, and we repaid this balance with a $30.0 million draw on the 2015 Revolver. On June 1, 2015, we executed the first amendment to the 2015 Secured Credit Agreement in order to amend certain provisions of the 2015 Secured Credit Agreement regarding the definition of “Change of Control.” On September 29, 2015, we executed the second amendment to the 2015 Secured Credit Agreement (the “Second Amendment”). Among other things, the Second Amendment: (a) gradually increases the permissible consolidated leverage ratio from a maximum of 4.00:1.00 to 5.75:1.00 through December 31, 2016, which thereafter gradually reduces to 4.00:1.00 by December 31, 2017; (b) reduces the consolidated interest coverage ratio from 2.50:1:00 to 2.25:1.00 for each quarter of 2016, and returning to 2.50:1.00 thereafter; (c) increases the Applicable Rate for certain higher levels of consolidated leverage to a maximum of 4.00 percent per annum for LIBOR rate loans and to 3.00 percent per annum for base rate loans; (d) allows multi-year letters of credit up to an aggregate amount of $5 million; (e) limits payment prior to September 30, 2017 of certain restricted payments and certain prepayments of unsecured senior notes and other specified forms of indebtedness; and (f) removes the option of the Company, subject to the consent of the lenders, to increase the Credit Agreement up to an additional $75 million. We incurred debt issuance costs related to the 2015 Secured Credit Agreement of approximately $2.0 million and had approximately $0.8 million of remaining debt issuance costs for the 2012 Secured Credit agreement. The total debt issuance costs of $2.8 million ($2.4 million, net of amortization as of December 31, 2015) are being amortized over the term of the 2015 Secured Credit Agreement on a straight line basis.

Our obligations under the 2015 Secured Credit Agreement are guaranteed by substantially all of our direct and indirect domestic subsidiaries, other than immaterial subsidiaries and subsidiaries generating revenues primarily outside the United States, each of which has executed guaranty agreements, and are secured by first priority liens on our accounts receivable, specified rigs including barge rigs in the GOM and land rigs in Alaska, certain U.S.-based rental equipment of the Company and its subsidiary guarantors and the equity interests of certain of the Company's subsidiaries. The 2015 Secured Credit Agreement contains customary affirmative and negative covenants, such as limitations on indebtedness, liens, restrictions on entry into certain affiliate transactions and payments (including payment of dividends) and maintenance of certain ratios and coverage tests (including a minimum asset coverage ratio of 1.25:1.00 at each quarter end, a consolidated leverage ratio, as described above, a consolidated interest coverage ratio, as described above, and a maximum senior secured leverage ratio of 1.50:1:00 at each quarter end). We were in compliance with all such covenants as of December 31, 2015.

Our 2015 Revolver is available for general corporate purposes and to support letters of credit. Interest on 2015 Revolver loans accrues at a Base Rate plus an Applicable Rate or LIBOR plus an Applicable Rate. As a result of the Second Amendment, the Applicable Rate ranges from 2.50 percent to 4.00 percent per annum for LIBOR rate loans and from 1.50 percent to 3.00 percent per annum for base rate loans, determined by reference to the consolidated leverage ratio (as defined in the 2015 Secured Credit Agreement). Revolving loans are available subject to a quarterly asset coverage ratio calculation based on the Orderly Liquidation Value of certain specified rigs including barge rigs in the GOM and land rigs in Alaska, and certain U.S.-based rental equipment of the Company and its subsidiary guarantors and a percentage of eligible domestic accounts receivable. The $30.0 million draw at the closing of the 2015 Secured Credit Agreement was repaid in full during the first quarter of 2015 with cash on hand. Letters of credit outstanding against the 2015 Revolver as of December 31, 2015 totaled $12.5 million. There were no amounts drawn on the 2015 Revolver as of December 31, 2015.

As conditions in the oil and gas industry continue to decline, we have engaged in preliminary discussions with our lenders regarding certain covenants and restrictions in the 2015 Secured Credit Agreement. If we become unable to comply with certain of the financial covenants in the 2015 Secured Credit Agreement, we will seek to amend such provisions to remain in compliance.

Summary of Contractual Cash Obligations

The following table summarizes our future contractual cash obligations as of December 31, 2015:

	Total	2016	2017	2018	2019	2020	Beyond 2020
	(Dollars in Thousands)						
Contractual cash obligations:							
Long-term debt — principal	$ 585,000	$ —	$ —	$ —	$ —	$ 225,000	$ 360,000
Long-term debt — interest	254,475	41,175	41,175	41,175	41,175	41,175	48,600
Operating leases(1)	36,773	10,145	7,939	6,131	4,314	3,156	5,088
Purchase commitments(2)	31,359	31,359	—	—	—	—	—
Total contractual obligations	$ 907,607	$ 82,679	$ 49,114	$ 47,306	$ 45,489	$ 269,331	$ 413,688
Commercial commitments:							
Standby letters of credit(3)	$ 12,527	$ 11,877	$ —	$ 650	$ —	$ —	$ —
Total commercial commitments	$ 12,527	$ 11,877	$ —	$ 650	$ —	$ —	$ —

(1) Operating leases consist of lease agreements in excess of one year for office space, equipment, vehicles and personal property.

(2) We had purchase commitments outstanding as of December 31, 2015, related to rental tools and rig upgrade projects.

(3) The available capacity of the 2015 Revolver is $200 million. As of December 31, 2015, $12.5 million of availability had been used to support outstanding letters of credit.

Other Matters

Business Risks

See Item 1A. Risk Factors, for a discussion of risks related to our business.

Critical Accounting Policies

Our discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. On an ongoing basis, we evaluate our estimates, including those related to fair value of assets, bad debt, materials and supplies obsolescence, property and equipment, goodwill, income taxes, workers' compensation and health insurance and contingent liabilities for which settlement is deemed to be probable. We base our estimates 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. While we believe that such estimates are reasonable, actual results could differ from these estimates.

We believe the following are our most critical accounting policies as they can be complex and require significant judgments, assumptions and/or estimates in the preparation of our consolidated financial statements. Other significant accounting policies are summarized in Note 1 in the notes to the consolidated financial statements.

Fair Value Measurements. For purposes of recording fair value adjustments for certain financial and non-financial assets and liabilities, and determining fair value disclosures, we estimate fair value at a price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the principal market for the asset or liability. Our valuation technique requires inputs that we categorize using a three-level hierarchy, from highest to lowest level of observable inputs, as follows: (1) unadjusted quoted prices for identical assets or liabilities in active markets (Level 1), (2) direct or indirect observable inputs, including quoted prices or other market data, for similar assets or liabilities in active markets or identical assets or liabilities in less active markets (Level 2) and (3) unobservable inputs that require significant judgment for which there is little or no market data (Level 3). When multiple input levels are required for a valuation, we categorize the entire fair value measurement according to the lowest level of input that is significant to the measurement even though we may have also utilized significant inputs that are more readily observable.

Impairment of Property, Plant and Equipment. We review the carrying amounts of long-lived assets for potential impairment when events occur or circumstances change that indicate the carrying values of such assets may not be recoverable. For example, evaluations are performed when we experience sustained significant declines in utilization and dayrates, and we do not contemplate recovery in the near future. In addition, we evaluate our assets when we reclassify property and equipment to assets held for sale or as discontinued operations as prescribed by accounting guidance related to accounting for the impairment or disposal of long-lived assets. We determine recoverability by evaluating the undiscounted estimated future net cash flows. When impairment is indicated, we measure the impairment as the amount by which the assets carrying value exceeds its fair value. Management considers a number of factors such as estimated future cash flows, appraisals and current market value analysis in determining fair value. Assets are written down to fair value if the concluded current fair value is below the net carrying value.

Asset impairment evaluations are, by nature, highly subjective. They involve expectations about future cash flows generated by our assets and reflect management's assumptions and judgments regarding future industry conditions and their effect on future utilization levels, dayrates and costs. The use of different estimates and assumptions could result in materially different carrying values of our assets.

Goodwill. We account for all business combinations using the acquisition method of accounting. Under this method, assets and liabilities, including any remaining noncontrolling interests, are recognized at fair value at the date of acquisition. The excess of the purchase price over the fair value of assets acquired, net of liabilities assumed, plus the value of any noncontrolling interests, is recognized as goodwill. We perform our annual goodwill impairment review as of October 1 of each year, and more frequently if negative conditions or other triggering events arise. The quantitative impairment test we perform for goodwill utilizes certain assumptions, including forecasted revenues and costs assumptions.

Intangible Assets. Our intangible assets are related to trade names, customer relationships, and developed technology, which were acquired through acquisition and are generally amortized over a weighted average period of approximately three to six years. We assess the recoverability of the unamortized balance of our intangible assets when indicators of impairment are present based on expected future profitability and undiscounted expected cash flows and their contribution to our overall operations. Should the review indicate that the carrying value is not fully recoverable, the excess of the carrying value over the fair value of the intangible assets would be recognized as an impairment loss.

Accrual for Self-Insurance. Substantially all of our operations are subject to hazards that are customary for oil and natural gas drilling operations, including blowouts, reservoir damage, loss of production, loss of well control, lost or stuck drill strings, equipment defects, cratering, oil and natural gas well fires and explosions, natural disasters, pollution, mechanical failure and damage or loss during transportation. Some of our fleet is also subject to hazards inherent in marine operations, either while on-site or during mobilization, such as capsizing, sinking, grounding, collision, damage from severe weather and marine life infestations. These hazards could result in damage to or destruction of drilling equipment, personal injury and property damage, suspension of operations or environmental damage, which could lead to claims by third parties or customers, suspension of operations and contract terminations. We have had accidents in the past due to some of these hazards.

Our contracts provide for varying levels of indemnification between ourselves and our customers, including with respect to well control and subsurface risks. We seek to obtain indemnification from our customers by contract for certain of these risks. We also maintain insurance for personal injuries, damage to or loss of equipment and other insurance coverage for various business risks. To the extent that we are unable to transfer such risks to customers by contract or indemnification agreements, we seek protection through insurance. However, these insurance or indemnification agreements may not adequately protect us against liability from all of the consequences of the hazards described above. Moreover, our insurance coverage generally provides that we assume a portion of the risk in the form of an insurance coverage deductible.

Based on the risks discussed above, we estimate our liability in excess of insurance coverage and accrue for these amounts in our consolidated financial statements. Accruals related to insurance are based on the facts and circumstances specific to the insurance claims and our past experience with similar claims. The actual outcome of insured claims could differ significantly from the amounts estimated. We accrue actuarially determined amounts in our consolidated balance sheet to cover self-insurance retentions for workers' compensation, employers' liability, general liability, automobile liability and health benefits claims. These accruals use historical data based upon actual claim settlements and reported claims to project future losses. These estimates and accruals have historically been reasonable in light of the actual amount of claims paid.

As the determination of our liability for insurance claims could be material and is subject to significant management judgment and in certain instances is based on actuarially estimated and calculated amounts, management believes that accounting estimates related to insurance accruals are critical.

Accounting for Income Taxes. We are a U.S. company and we operate through our various foreign legal entities and their branches and subsidiaries in numerous countries throughout the world. Consequently, our tax provision is based upon the tax laws and rates in effect in the countries in which our operations are conducted and income is earned. The income tax rates imposed and methods of computing taxable income in these jurisdictions vary. Therefore, as a part of the process of preparing the consolidated financial statements, we are required to estimate the income taxes in each of the jurisdictions in which we operate. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as depreciation, amortization and certain accrued liabilities for tax and accounting purposes. Our effective tax rate for financial statement purposes will continue to fluctuate from year to year as our operations are conducted in different taxing jurisdictions. Current income tax expense represents either liabilities expected to be reflected on our income tax returns for the current year, nonresident withholding taxes or changes in prior year tax estimates which may result from tax audit adjustments. Our deferred tax expense or benefit represents the change in the balance of deferred tax assets or liabilities reported on the consolidated balance sheet. Valuation allowances are established to reduce deferred tax assets when it is more likely than not that some portion or all of the deferred tax assets will not be realized. In order to determine the amount of deferred tax assets or liabilities, as well as the valuation allowances, we must make estimates and assumptions regarding amounts and sources of future taxable income, where rigs will be deployed and other matters. Changes in these estimates and assumptions, as well as changes in tax laws, could require us to adjust the deferred tax assets and liabilities or valuation allowances, including as discussed below.

Our ability to realize the benefit of our deferred tax assets requires that we achieve certain future earnings levels prior to expiration. Evaluations of the realizability of deferred tax assets are, by nature, highly subjective. They involve expectations about future operations and reflect management's assumptions and judgments regarding future industry conditions and their effect on future utilization levels, dayrates and costs. The use of different estimates and assumptions could result in materially different determinations of our ability to realize deferred tax assets. In the event that our earnings performance projections do not indicate that we will be able to benefit from our deferred tax assets, valuation allowances are established following the "more likely than not" criteria. We periodically evaluate our ability to utilize our deferred tax assets and, in accordance with accounting guidance related to accounting for income taxes, will record any resulting adjustments that may be required to deferred income tax expense in the period for which an existing estimate changes.

We do not currently provide for U.S. deferred taxes on unremitted earnings of our foreign subsidiaries as such earnings were reinvested to fund our international operations. If such earnings were to be distributed, we could be subject to U.S. taxes, which may have a material impact on our results of operations and our liquidity. We annually review our position and may elect to change our future tax position.

We apply the accounting standards related to uncertainty in income taxes. This accounting guidance requires that management make estimates and assumptions affecting amounts recorded as liabilities and related disclosures due to the uncertainty as to final resolution of certain tax matters. Because the recognition of liabilities under this interpretation may require periodic adjustments and may not necessarily imply any change in management's assessment of the ultimate outcome of these items, the amount recorded may not accurately reflect actual outcomes.

Revenue Recognition. Contract drilling revenues and expenses, comprised of daywork drilling contracts, call-outs against master service agreements and engineering and related project service contracts, 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; however, 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. Revenues from rental activities are recognized ratably over the rental term which is generally less than six months. Our project related services contracts include engineering, consulting, and project management scopes of work and revenue is typically recognized on a time and materials basis.

Allowance for Doubtful Accounts. The allowance for doubtful accounts is estimated for losses that may occur resulting from disputed amounts and the inability of our customers to pay amounts owed. We estimate the allowance based on historical write-off experience and information about specific customers. We review individually, for collectability, all balances over 90 days past due as well as balances due from any customer with respect to which we have information leading us to believe that a risk exists for potential collection.

Legal and Investigation Matters. As of December 31, 2015, we have accrued an estimate of the probable and estimable costs for the resolution of certain legal and investigation matters. We have not accrued any amounts for other matters for which the liability is not probable and reasonably estimable. Generally, the estimate of probable costs related to these matters is developed in consultation with our legal advisors. The estimates take into consideration factors such as the complexity of the issues, litigation risks and settlement costs. If the actual settlement costs, final judgments, or fines, after appeals, differ from our estimates, our future financial results may be adversely affected.

Recent Accounting Pronouncements

For a discussion of the new accounting pronouncements that have had or are expected to have an effect on our consolidated financial statements, see Note 18 - Recent Accounting Pronouncements in Item 8. Financial Statements and Supplementary Data.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Foreign Currency Exchange Rate Risk

Our international operations expose us to foreign currency exchange rate risk. There are a variety of techniques to minimize the exposure to foreign currency exchange rate risk, including customer contract payment terms and the possible use of foreign currency exchange rate risk derivative instruments. Our primary foreign currency exchange rate risk management strategy involves structuring customer contracts to provide for payment in both U.S. dollars and local currency. The payment portion denominated in local currency is based on anticipated local currency requirements over the contract term. Due to various factors, including customer acceptance, local banking laws, other statutory requirements, local currency convertibility and the impact of inflation on local costs, actual foreign currency exchange rate risk needs may vary from those anticipated in the customer contracts, resulting in partial exposure to foreign exchange risk. Fluctuations in foreign currencies typically have not had a material impact on our overall results. In situations where payments of local currency do not equal local currency requirements, foreign currency exchange rate risk derivative instruments, specifically spot purchases, may be used to mitigate foreign exchange rate currency risk. We do not enter into derivative transactions for speculative purposes. At December 31, 2015, we had no open foreign currency exchange rate risk derivative contracts.

Interest Rate Risk

We are exposed to changes in interest rates through our fixed rate long-term debt. Typically, the fair market value of fixed rate long-term debt will increase as prevailing interest rates decrease and will decrease as prevailing interest rates increase. The fair value of our long-term debt is estimated based on quoted market prices where applicable, or based on the present value of expected cash flows relating to the debt discounted at rates currently available to us for long-term borrowings with similar terms and maturities. The estimated fair value of our $360.0 million principal amount of 6.75% Notes, based on quoted market prices, was $246.6 million at December 31, 2015. The estimated fair value of our $225.0 million principal amount of 7.50% Notes, based on quoted market prices, was $171.0 million at December 31, 2015. A hypothetical 100 basis point increase in interest rates relative to market interest rates at December 31, 2015 would decrease the fair market value of our 6.75% Notes by approximately $22.7 million and decrease the fair market value of our 7.50% Notes by approximately $15.7 million.

Impact of Fluctuating Commodity Prices

We are exposed to the impact of fluctuations in market prices for oil and natural gas affecting spending by E&P companies on drilling programs. Steep, prolonged and unexpected price reductions in oil prices have led to significant reductions in drilling activity for the related commodity. This usually does not result in cancellations of existing contracts for our rigs and rental tools, but rather in fewer opportunities to reengage our equipment when contracted work was completed. At those times, drilling rig and rental tools utilization declined along with associated dayrates and rental rates.

In response to the recent steep and swift decline in market prices for oil, and the continued decline in the U.S. price for natural gas, some E&P companies curtailed U.S. drilling activity and many E&P companies have cut 2016 worldwide spending, terminated certain drilling contracts, requested pricing concessions and taken other measures aimed at reducing the capital and operating expenses within their supply chain. This has adversely impacted our rental tools activity and pricing, as well as utilization and pricing of our drilling rigs. Many E&P companies are expected to reduce their 2016 worldwide spending plans even further.

While our U.S.-based businesses have been significantly impacted, we have also experienced lower pricing and utilization of tools, services and rigs in certain international markets. Although the severity and duration of the current industry downturn is contingent upon many factors beyond our control, we have taken several steps in an effort to generate free cash flow during this period, including lowering our cost base through headcount reductions and lower idle rig costs, and reducing our capital expenditures.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders

Parker Drilling Company:

We have audited Parker Drilling Company's internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Parker Drilling Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Annual Report on Internal Control over Financial Reporting* in Item 9A. Our responsibility is to express an opinion on Parker Drilling 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, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included 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, Parker Drilling Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the COSO.

Parker Drilling Company acquired 2M-Tek during 2015, and management excluded from its assessment of the effectiveness of Parker Drilling Company's internal control over financial reporting as of December 31, 2015, 2M-Tek's internal control over financial reporting. 2M-Tek represents approximately 1.6% of total assets as of December 31, 2015 and less than 1% and 1.6% of revenues and net loss, respectively, included in the consolidated financial statements of Parker Drilling Company as of and for the year ended December 31, 2015. Our audit of internal control over financial reporting of Parker Drilling Company also excluded an evaluation of the internal control over financial reporting of 2M-Tek.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Parker Drilling Company and subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2015, and our report dated February 24, 2016 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
February 24, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders

Parker Drilling Company:

We have audited the accompanying consolidated balance sheets of Parker Drilling Company and subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2015. In connection with our audits of the consolidated financial statements, we also have audited financial statement Schedule II - Valuation and Qualifying Accounts for each of the years in the three-year period ended December 31, 2015. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Parker Drilling Company and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Parker Drilling Company's internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 24, 2016 expressed an unqualified opinion on the effectiveness of Parker Drilling Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 24, 2016

PARKER DRILLING COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF OPERATIONS
(Dollars in Thousands, Except Per Share Data)

	Year Ended December 31,		
	2015	2014	2013
Revenues	$ 712,183	$ 968,684	$ 874,172
Expenses:			
Operating expenses	526,290	669,381	571,672
Depreciation and amortization	156,194	145,121	134,053
	682,484	814,502	705,725
Total operating gross margin	29,699	154,182	168,447
General and administration expense	(36,190)	(35,016)	(68,025)
Provision for reduction in carrying value of certain assets	(12,490)	—	(2,544)
Gain on disposition of assets, net	1,643	1,054	3,994
Total operating income (loss)	(17,338)	120,220	101,872
Other income and (expense):			
Interest expense	(45,155)	(44,265)	(47,820)
Interest income	269	195	2,450
Loss on extinguishment of debt	—	(30,152)	(5,218)
Other	(9,747)	2,539	1,503
Total other expense	(54,633)	(71,683)	(49,085)
Income (loss) before income taxes	(71,971)	48,537	52,787
Income tax expense:			
Current tax expense	19,604	22,567	12,909
Deferred tax expense	2,709	1,509	12,699
Total income tax expense	22,313	24,076	25,608
Net income (loss)	(94,284)	24,461	27,179
Less: Net Income attributable to noncontrolling interest	789	1,010	164
Net income (loss) attributable to controlling interest	$ (95,073)	$ 23,451	$ 27,015
Basic earnings (loss) per share:	$ (0.78)	$ 0.19	$ 0.23
Diluted earnings (loss) per share:	$ (0.78)	$ 0.19	$ 0.22
Number of common shares used in computing earnings per share:			
Basic	122,562,187	121,186,464	119,284,468
Diluted	122,562,187	123,076,648	121,224,550

See accompanying notes to the consolidated financial statements.

PARKER DRILLING COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Dollars in Thousands)

	Year Ended December 31,		
	2015	2014	2013
Comprehensive income (loss):			
Net income (loss)	$ (94,284)	$ 24,461	$ 27,179
Other comprehensive gain (loss), net of tax:			
Currency translation difference on related borrowings	(2,012)	(4,870)	(1,525)
Currency translation difference on foreign currency net investments	405	2,147	3,051
Total other comprehensive gain (loss), net of tax:	(1,607)	(2,723)	1,526
Comprehensive income (loss)	(95,891)	21,738	28,705
Comprehensive (income) loss attributable to noncontrolling interest	4,606	(673)	198
Comprehensive income (loss) attributable to controlling interest	$ (91,285)	$ 21,065	$ 28,903

See accompanying notes to the consolidated financial statements.

PARKER DRILLING COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET
(Dollars in Thousands)

	December 31, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 134,294	$ 108,456
Accounts and Notes Receivable, net of allowance for bad debts of $8,694 in 2015 and $11,188 in 2014	175,105	270,952
Rig materials and supplies	34,937	47,943
Deferred costs	1,367	5,673
Other tax assets	5,192	10,723
Other current assets	15,846	18,556
Total current assets	366,741	462,303
Property, plant and equipment, net of accumulated depreciation of $1,302,380 in 2015 and $1,201,058 in 2014 (Note 5)	805,841	895,940
Goodwill (Note 3)	6,708	—
Intangible assets, net (Note 3)	13,377	4,286
Rig materials and supplies	18,104	6,937
Debt issuance costs	12,626	12,526
Deferred income taxes	139,282	130,165
Other assets	14,225	8,502
Total assets	$ 1,376,904	$ 1,520,659
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Current portion of long-term debt	$ —	$ 10,000
Accounts payable	58,080	78,776
Accrued liabilities	71,623	75,703
Accrued income taxes	6,418	14,186
Total current liabilities	136,121	178,665
Long-term debt	585,000	605,000
Other long-term liabilities	18,617	18,665
Long-term deferred tax liability	68,654	52,115
Commitments and contingencies (Note 13)		
Stockholders' equity:		
Preferred Stock, $1 par value, 1,942,000 shares authorized, no shares outstanding	—	—
Common Stock, $0.16 2/3 par value, authorized 280,000,000 shares, issued and outstanding, 123,206,269 shares (122,045,877 shares in 2014)	20,518	20,325
Capital in excess of par value	669,120	666,769
Accumulated deficit	(119,238)	(24,165)
Accumulated Other Comprehensive Income	(1,888)	(498)
Total controlling interest stockholders' equity	568,512	662,431
Noncontrolling interest	—	3,783
Total equity	568,512	666,214
Total liabilities and stockholders' equity	$ 1,376,904	$ 1,520,659

See accompanying notes to the consolidated financial statements.

PARKER DRILLING COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF CASH FLOWS
(Dollars in Thousands)

	Year Ended December 31,		
	2015	**2014**	**2013**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (94,284)	$ 24,461	$ 27,179
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	156,194	145,121	134,053
Accretion of contingent consideration	826	—	—
Loss on extinguishment of debt	—	30,152	5,218
(Gain) on disposition of assets	(1,643)	(1,054)	(3,994)
Deferred tax expense	2,709	1,509	12,699
Provision for reduction in carrying value of certain assets	12,490	—	2,544
Expenses not requiring cash	5,103	19,331	17,764
Change in assets and liabilities:			
Accounts and notes receivable	103,995	(12,238)	(33,512)
Rig materials and supplies	2,722	(2,878)	1,754
Other current assets	12,548	26,032	(11,715)
Accounts payable and accrued liabilities	(27,425)	27,231	(286)
Accrued income taxes	(7,957)	(7,657)	10,454
Other assets	(3,156)	(47,543)	(661)
Net cash provided by operating activities	162,122	202,467	161,497
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(88,197)	(179,513)	(155,645)
Proceeds from the sale of assets	830	5,938	8,218
Proceeds from insurance settlements	2,500	—	—
Acquisitions, net of cash acquired	(13,806)	—	(117,991)
Divestitures, net of cash paid	(2,570)	—	—
Net cash (used in) investing activities	(101,243)	(173,575)	(265,418)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from issuance of debt	—	400,000	350,000
Repayments of long-term debt	(30,000)	(435,000)	(175,000)
Payments of debt issuance costs	(1,996)	(7,630)	(11,172)
Payments of debt extinguishment costs	—	(26,214)	—
Payment of contingent consideration	(2,000)	—	—
Excess tax benefit (expense) from stock-based compensation	(1,045)	(281)	896
Net cash provided by (used in) financing activities	(35,041)	(69,125)	164,724
Net increase (decrease) in cash and cash equivalents	25,838	(40,233)	60,803
Cash and cash equivalents at beginning of year	108,456	148,689	87,886
Cash and cash equivalents at end of year	$ 134,294	$ 108,456	$ 148,689
Supplemental cash flow information:			
Interest paid	41,393	41,820	42,236
Income taxes paid	26,208	26,694	17,036

See accompanying notes to the consolidated financial statements.

PARKER DRILLING COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY
(Dollars and Shares in Thousands)

	Shares	Common Stock	Treasury Stock	Capital in Excess of Par Value	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Total Controlling Stockholders' Equity	Noncontrolling Interest	Total Stockholders' Equity
Balances, December 31, 2012	118,968	$ 20,053	$ (235)	$ 646,217	$ (74,631)	—	$ 591,404	(771)	$ 590,633
Activity in employees' stock plans	1,523	215	42	805	—	—	1,062	—	1,062
Tax benefit increase from stock based compensation	—	—	—	$ 896	—	—	$ 896	—	$ 896
Amortization of stock-based awards	—	—	—	9,431	—	—	9,431	—	9,431
Purchase of noncontrolling ownership interest	—	—	—	—	—	—	—	2,680	2,680
Distributions to noncontrolling interest	—	—	—	—	—	—	—	(265)	(265)
Comprehensive Income:									
Net income	—	—	—	—	27,015	—	27,015	164	27,179
Other comprehensive income (loss)	—	—	—	—	—	1,888	1,888	(362)	1,526
Balances, December 31, 2013	120,491	$ 20,268	$ (193)	$ 657,349	$ (47,616)	$ 1,888	$ 631,696	$ 1,446	$ 633,142
Activity in employees' stock plans	1,555	227	23	924	—	—	1,174	—	1,174
Tax benefit increase from stock based compensation	—	—	—	(281)	—	—	(281)	—	(281)
Amortization of stock-based awards	—	—	—	9,273	—	—	9,273	—	9,273
Purchase of NCI of joint venture	—	—	—	(496)	—	—	(496)	(13)	(509)
Purchase of noncontrolling ownership interest	—	—	—	—	—	—	—	1,919	1,919
Distributions to noncontrolling interest	—	—	—	—	—	—	—	(242)	(242)
Comprehensive Income:									
Net income	—	—	—	—	23,451	—	23,451	1,010	24,461
Other comprehensive income (loss)	—	—	—	—	—	(2,386)	(2,386)	(337)	(2,723)
Balances, December 31, 2014	122,046	$ 20,495	$ (170)	$ 666,769	$ (24,165)	$ (498)	$ 662,431	$ 3,783	$ 666,214
Activity in employees' stock plans	1,160	193	—	(1,227)	—	—	(1,034)	—	(1,034)
Tax benefit increase from stock based compensation	—	—	—	(1,045)	—	—	(1,045)	—	(1,045)
Amortization of stock-based awards	—	—	—	8,410	—	—	8,410	—	8,410
Disposal of noncontrolling interest related to sale of joint venture	—	—	—	—	—	—	—	(1,392)	(1,392)
Purchase of noncontrolling ownership interest	—	—	—	(3,787)	—	—	(3,787)	(2,963)	(6,750)
Comprehensive Income:									
Net income (loss)	—	—	—	—	(95,073)	—	(95,073)	789	(94,284)
Other comprehensive income (loss)	—	—	—	—	—	(1,390)	(1,390)	(217)	(1,607)
Balances, December 31, 2015	123,206	$ 20,688	$ (170)	$ 669,120	$ (119,238)	$ (1,888)	$ 568,512	$ —	$ 568,512

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1 — Summary of Significant Accounting Policies

Nature of Operations — Our business is comprised of two business lines: (1) Drilling Services and (2) Rental Tools Services. We report our Rental Tools Services business as one reportable segment (Rental Tools) and report our Drilling Services business as two reportable segments: (1) U.S. (Lower 48) Drilling and (2) International & Alaska Drilling.

In our Drilling Services business, we drill oil and gas wells for customers in both the U.S. and international markets. We provide this service with both Company-owned rigs and customer-owned rigs. We refer to the provision of drilling services with customer owned rigs as our operations and maintenance (O&M) service in which operators own their own drilling rigs but choose Parker Drilling to operate and maintain the rigs for them. The nature and scope of activities involved in drilling an oil and gas well is similar whether it is drilled with a Company-owned rig (as part of a traditional drilling contract) or a customer-owned rig (as part of an O&M contract). In addition, we provide project related services, such as engineering, procurement, project management and commissioning of customer owned drilling facility projects. We have extensive experience and expertise in drilling geologically difficult wells and in managing the logistical and technological challenges of operating in remote, harsh and ecologically sensitive areas.

Our U.S. (Lower 48) Drilling segment provides drilling services with our Gulf of Mexico (GOM) barge rig drilling fleet and through U.S. (Lower 48) based O&M services. Our GOM barge drilling fleet operates barge rigs that drill for oil and natural gas in shallow waters in and along the inland waterways and coasts of Louisiana, Alabama and Texas. The majority of these wells are drilled in shallow water depths ranging from 6 to 12 feet. Our International & Alaska Drilling segment provides drilling services, with Company-owned rigs as well as through O&M contracts, and project related services. We strive to deploy our fleet of Parker-owned rigs in markets where we expect to have opportunities to keep the rigs consistently utilized and build a sufficient presence to achieve efficient operating scale.

In our Rental Tools Services business, we provide premium rental equipment and services to exploration and production (E&P) companies, drilling contractors and service companies on land and offshore in the United States (U.S.) and select international markets. Tools we provide include standard and heavy-weight drill pipe, all of which are available with standard or high-torque connections, tubing, pressure control equipment, including blow-out preventers (BOPs), drill collars and more. We also provide well construction services, which include tubular running services and downhole tools, and well intervention services, which include whipstock, fishing products and related services, as well as inspection and machine shop support. Generally, rental tools are used for only a portion of a well drilling program and are requested by the customer when they are needed, requiring us to keep a broad inventory of rental tools in stock. Rental tools are usually rented on a daily or monthly basis.

We have operated in over 50 countries since beginning operations in 1934, making us among the most geographically experienced drilling contractors and rental tools providers in the world. We currently have operations in 21 countries. Parker has set numerous world records for deep and extended-reach drilling land rigs and is an industry leader in quality, health, safety and environmental practices.

Consolidation — The consolidated financial statements include the accounts of the Company and subsidiaries in which we exercise control or have a controlling financial interest, including entities, if any, in which the Company is allocated a majority of the entity's losses or returns, regardless of ownership percentage. If a subsidiary of Parker Drilling has a 50 percent interest in an entity but Parker Drilling's interest in the subsidiary or the entity does not meet the consolidation criteria described above, then that interest is accounted for under the equity method.

Noncontrolling Interest — We apply accounting standards related to noncontrolling interests for ownership interests in our subsidiaries held by parties other than Parker Drilling. We report noncontrolling interest as equity on the consolidated balance sheets and report net income (loss) attributable to controlling interest and to noncontrolling interest separately on the consolidated statements of operations. During the 2015 fourth quarter we incurred a $4.8 million loss on the sale of our controlling interest in a consolidated joint venture in Egypt, which also resulted in the disposal of the related noncontrolling interest of $2.2 million. Also, during the 2015 second quarter we incurred a $0.9 million loss on the divestiture of our controlling interest in a consolidated joint venture in Russia, which also resulted in the disposal of the related noncontrolling interest of $0.8 million. During the fourth quarter of 2015, we also purchased the remaining noncontrolling interest of ITS Arabia Limited for $6.75 million, of which $3.4 million remains payable to the seller at a later date. At the time of purchase, the carrying value of the noncontrolling interest was $3.0 million.

Reclassifications — Certain reclassifications have been made to prior period amounts to conform to the current period presentation. These reclassifications did not materially affect our consolidated financial results.

Revenue Recognition — Drilling revenues and expenses, comprised of daywork drilling contracts, call-outs against master service agreements and engineering and related project service contracts, 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 primary term of the related drilling contract; however, costs incurred to relocate rigs and other drilling equipment to areas in which a contract has not been secured are expensed as incurred. 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. Revenues from rental activities are recognized ratably over the rental term, which is generally less than six months. Our project related services contracts include engineering, consulting, and project management scopes of work and revenue is typically recognized on a time and materials basis.

Reimbursable Revenues — The Company recognizes reimbursements received for out-of-pocket expenses incurred as revenues and accounts for out-of-pocket expenses as direct operating costs. Such amounts totaled $87.8 million, $82.6 million, and $69.7 million during the years ended December 31, 2015, 2014, and 2013, respectively. Additionally, the Company typically receives a nominal handling fee, which is recognized as earned in revenues in our consolidated statement of operations.

Use of Estimates — The preparation of financial statements in accordance with accounting policies generally accepted in the United States (U.S. GAAP) requires management to make estimates and assumptions that affect our reported amounts of assets and liabilities, our disclosure of contingent assets and liabilities at the date of the financial statements, and our revenues and expenses during the periods reported. Estimates are typically used when accounting for certain significant items such as legal or contractual liability accruals, mobilization and deferred mobilization, self-insured medical/dental plans, income taxes and valuation allowance, and other items requiring the use of estimates. Estimates are based on a number of variables which may include third party valuations, historical experience, where applicable, and assumptions that we believe are reasonable under the circumstances. Due to the inherent uncertainty involved with estimates, actual results may differ from management estimates.

Purchase Price Allocation — We allocate the purchase price of an acquired business to its identifiable assets and liabilities in accordance with the acquisition method based on estimated fair values at the transaction date. Transaction and integration costs associated with an acquisition are expensed as incurred. The excess of the purchase price over the amount allocated to the assets and liabilities, if any, is recorded as goodwill. We use all available information to estimate fair values, including quoted market prices, the carrying value of acquired assets, and widely accepted valuation techniques such as discounted cash flows. We typically engage third-party appraisal firms to assist in fair value determination of inventories, identifiable intangible assets, and any other significant assets or liabilities. Judgments made in determining the estimated fair value assigned to each class of assets acquired and liabilities assumed, as well as asset lives, can materially impact our results of operations. See Note 2 - Acquisitions for further discussion.

Goodwill — We account for all business combinations using the acquisition method of accounting. Under this method, assets and liabilities, including any remaining noncontrolling interests, are recognized at fair value at the date of acquisition. The excess of the purchase price over the fair value of assets acquired, net of liabilities assumed, plus the value of any noncontrolling interests, is recognized as goodwill. We perform our annual goodwill impairment review as of October 1 of each year, and more frequently if negative conditions or other triggering events arise. The quantitative impairment test we perform for goodwill utilizes certain assumptions, including forecasted revenue and costs assumptions. See Note 3 - Goodwill and Intangible Assets for further discussion.

Intangible Assets — Our intangible assets are related to trade names, customer relationships, and developed technology, which were acquired through acquisition and are generally amortized over a weighted average period of approximately three to six years. We assess the recoverability of the unamortized balance of our intangible assets when indicators of impairment are present based on expected future profitability and undiscounted expected cash flows and their contribution to our overall operations. Should the review indicate that the carrying value is not fully recoverable, the excess of the carrying value over the fair value of the intangible assets would be recognized as an impairment loss. See Note 3 - Goodwill and Intangible Assets for further discussion.

Cash and Cash Equivalents — For purposes of the consolidated balance sheets and the consolidated statements of cash flows, the Company considers cash equivalents to be highly liquid debt instruments that have a remaining maturity of three months or less at the date of purchase.

Accounts Receivable and Allowance for Bad Debt — Trade accounts receivable are recorded at the invoice amount and typically do not bear interest. The allowance for bad debt is estimated for losses that may occur resulting from disputed amounts and the inability of our customers to pay amounts owed. We estimate the allowance based on historical write-off experience and information about specific customers. We review individually, for collectability, all balances over 90 days past due as well as balances due from any customer with respect to which we have information leading us to believe that a risk exists for potential collection.

Account balances are charged off against the allowance when we believe it is probable the receivable will not be recovered. We do not have any off-balance-sheet credit exposure related to customers.

The components of our accounts and notes receivable, net of allowance for bad debt balance are as follows:

	December 31,	
Dollars in thousands	**2015**	**2014**
Trade	$ 183,299	$ 281,640
Notes receivable	500	500
Allowance for bad debt[1]	(8,694)	(11,188)
Total accounts and notes receivable, net of allowance for bad debt	$ 175,105	$ 270,952

(1) Additional information on the allowance for bad debt for the years ended December 31, 2015, 2014 and 2013 is reported on Schedule II — Valuation and Qualifying Accounts.

Property, Plant and Equipment — Property, plant and equipment is carried at cost. Maintenance and most repair costs are expensed as incurred. The cost of upgrades and replacements is capitalized. The Company capitalizes software developed or obtained for internal use. Accordingly, the cost of third-party software, as well as the cost of third-party and internal personnel that are directly involved in application development activities, are capitalized during the application development phase of new software systems projects. Costs during the preliminary project stage and post-implementation stage of new software systems projects, including data conversion and training costs, are expensed as incurred. We account for depreciation of property, plant and equipment on the straight line method over the estimated useful lives of the assets after provision for salvage value. Depreciation, for tax purposes, utilizes several methods of accelerated depreciation. Depreciable lives for different categories of property, plant and equipment are as follows:

Land drilling equipment	3 to 20 years
Barge drilling equipment	3 to 20 years
Drill pipe, rental tools and other	4 to 15 years
Buildings and improvements	5 to 30 years

Leasehold improvements are depreciated over the shorter of their estimated useful lives or the term of the lease.

Impairment — We evaluate the carrying amounts of long-lived assets for potential impairment when events occur or circumstances change that indicate the carrying values of such assets may not be recoverable. We evaluate recoverability by determining the undiscounted estimated future net cash flows for the respective asset groups identified. If the sum of the estimated undiscounted cashflows is less than the carrying value of the asset group, we measure the impairment as the amount by which the assets' carrying value exceeds its fair value. Management considers a number of factors such as estimated future cash flows from the assets, appraisals and current market value analysis in determining fair value. Assets are written down to fair value if the final estimate of current fair value is below the net carrying value. The assumptions used in the impairment evaluation are inherently uncertain and require management judgment.

Capitalized Interest — Interest from external borrowings is capitalized on major projects until the assets are ready for their intended use. Capitalized interest is added to the cost of the underlying asset and is amortized over the useful lives of the assets in the same manner as the underlying assets. Capitalized interest costs reduce net interest expense in the consolidated statements of operations. During 2015, 2014 and 2013, capitalized interest costs were $0.2 million, $1.2 million and $2.4 million, respectively.

Assets Held for Sale — We classify an asset as held for sale when the facts and circumstances meet the criteria for such classification, including the following: (a) we have committed to a plan to sell the asset, (b) the asset is available for immediate sale, (c) we have initiated actions to complete the sale, including locating a buyer, (d) the sale is expected to be completed within one year, (e) the asset is being actively marketed at a price that is reasonable relative to its fair value, and (f) the plan to sell is unlikely to be subject to significant changes or termination.

Rig Materials and Supplies — Because our international drilling generally occurs in remote locations, making timely outside delivery of spare parts uncertain, a complement of parts and supplies is maintained either at the drilling site or in warehouses close to the operation. During periods of high rig utilization, these parts are generally consumed and replenished within a one-year period. During a period of lower rig utilization in a particular location, the parts, like the related idle rigs, are generally not transferred to other international locations until new contracts are obtained because of the significant transportation costs that would result from such transfers. We classify those parts which are not expected to be utilized in the following year as long-term assets. Additionally, our international rental tools business holds machine shop consumables and steel stock for manufacture in our machine shops and inspection and repair shops. Rig materials and supplies are valued at the lower of cost or market value.

Deferred Costs — We defer costs related to rig mobilization and amortize such costs over the primary term of the related contract. The costs to be amortized within twelve months are classified as current.

Debt Issuance Costs — We typically defer costs associated with issuance of indebtedness, and amortize those costs over the term of the related debt using the effective interest method.

Income Taxes — Income taxes are accounted for under the asset and liability method and have been provided based upon tax laws and rates in effect in the countries in which operations are conducted and income is earned. There is little or no expected relationship between the provision for or benefit from income taxes and income or loss before income taxes as the countries in which we operate have taxation regimes that vary not only with respect to nominal rate, but also in terms of the availability of deductions, credits, and other benefits. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the year in which the temporary differences are expected to be recovered or settled and the effect of changes in tax rates is recognized in income in the period in which the change is enacted. Valuation allowances are established to reduce deferred tax assets when it is more likely than not that some portion or all of the deferred tax assets will not be realized. In order to determine the amount of deferred tax assets or liabilities, as well as the valuation allowances, we must make estimates and assumptions regarding future taxable income, where rigs will be deployed and other matters. Changes in these estimates and assumptions, including changes in tax laws and other changes impacting our ability to recognize the underlying deferred tax assets, could require us to adjust the valuation allowances.

The Company recognizes the effect of income tax positions only if those positions are more likely than not to be sustained. Recognized income tax positions are measured at the largest amount that is greater than 50 percent likely of being realized and changes in recognition or measurement are reflected in the period in which the change in judgment occurs.

Earnings (Loss) Per Share (EPS) — Basic earnings (loss) per share is computed by dividing net income by the weighted average number of common shares outstanding during the period. The effects of dilutive securities, stock options, unvested restricted stock and convertible debt are included in the diluted EPS calculation, when applicable.

Concentrations of Credit Risk — Financial instruments that potentially subject the Company to concentrations of credit risk consist primarily of trade receivables with a variety of national and international oil and natural gas companies. We generally do not require collateral on our trade receivables.

At December 31, 2015 and 2014, we had deposits in domestic banks in excess of federally insured limits of approximately $91.3 million and $59.3 million, respectively. In addition, we had deposits in foreign banks, which were not insured at December 31, 2015 and 2014 of $44.1 million and $54.4 million, respectively.

Our customer base primarily consists of major, independent and national oil and natural gas companies and integrated service providers. We depend on a limited number of significant customers. Our largest customer, Exxon Neftegas Limited constituted 27.9 percent of our revenues for 2015.

Fair Value Measurements — For purposes of recording fair value adjustments for certain financial and non-financial assets and liabilities, and determining fair value disclosures, we estimate fair value at a price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the principal market for the asset or liability. Our valuation technique requires inputs that we categorize using a three-level hierarchy, from highest to lowest level of observable inputs, as follows: (1) unadjusted quoted prices for identical assets or liabilities in active markets (Level 1), (2) direct or indirect observable inputs, including quoted prices or other market data, for similar assets or liabilities in active markets or identical assets or liabilities in less active markets (Level 2) and (3) unobservable inputs that require significant judgment for which there is little or no market data (Level 3). When multiple input levels are required for a valuation, we categorize the entire fair value measurement according to the lowest level of input that is significant to the measurement even though we may have also utilized significant inputs that are more readily observable.

Foreign Currency — In our international rental tool business, for certain subsidiaries and branches outside the U.S., the local currency is the functional currency. The financial statements of these subsidiaries and branches are translated into U.S. dollars as follows: (i) assets and liabilities at month-end exchange rates; (ii) income, expenses and cash flows at monthly average exchange rates or exchange rates in effect on the date of the transaction; and (iii) stockholders' equity at historical exchange rates. For those subsidiaries where the local currency is the functional currency, the resulting translation adjustment is recorded as a component of accumulated other elements of comprehensive income (loss) in the accompanying consolidated balance sheets.

Stock-Based Compensation — Under our long term incentive plan, we are authorized to issue the following: stock options; stock appreciation rights; restricted stock awards; restricted stock units; performance based awards; and other types of awards in cash or stock to key employees, consultants, and directors. We typically grant restricted stock units (RSUs), performance shares units (PSUs), performance cash units (PCUs) and phantom share units.

Our RSUs are service-based awards and compensation expense is recognized ratably over the applicable vesting period, which is typically three years years for employees. RSUs granted to non-management directors typically vest at the end of a one-year vesting period. The grant-date fair value of nonvested RSUs is determined based on the closing trading price of the company's shares on the grant date. Our RSUs are settled in stock upon vesting.

Our PSU, PCU and phantom stock awards are performance based awards containing payout conditions based on our performance against our peers with regard to relative total shareholder return (TSR) and absolute and relative return on capital employed (ROCE). The effects of these conditions are reflected in the grant-date fair value of the award using a simulation-based option pricing approach for valuation.

Typically, PSUs are settled in stock upon vesting and PCUs are settled in cash upon vesting. Phantom stock units represent a grant of hypothetical stock equivalent to shares of stock but are settled in cash upon vesting. PSUs, PCUs and phantom stock units vest fully at the end of a three year performance period. We evaluate the terms of each award to determine whether the award should be accounted for as equity or a liability under the stock compensation rules of U.S. GAAP, and have determined that PSUs should be accounted for as equity, while the PCUs and phantom stock units are accounted for as a liability. Compensation costs for PSUs, PCUs and phantom stock units are recognized ratably over the service period.

Share-based compensation expense is recognized, net of an estimated forfeiture rate, which is based on historical experience and adjusted, if necessary, in subsequent periods based on actual forfeitures. We recognize share-based compensation expense in the same financial statement line item as cash compensation paid to the respective employees. Tax deduction benefits for awards in excess of recognized compensation costs are reported as a financing cash flow.

Legal and Investigation Matters — As of December 31, 2015, we have accrued an estimate of the probable and estimable costs for the resolution of certain legal and investigation matters. We have not accrued any amounts for other matters for which the liability is not probable and reasonably estimable. Generally, the estimate of probable costs related to these matters is developed in consultation with our legal advisors. The estimates take into consideration factors such as the complexity of the issues, litigation risks and settlement costs. If the actual settlement costs, final judgments, or fines, after appeals, differ from our estimates, our future financial results may be adversely affected.

Note 2 — Acquisitions

Acquisition of ITS

On April 22, 2013 we acquired International Tubular Services Limited (ITS) and related assets (the ITS Acquisition) for an initial purchase price of $101 million paid at the closing of the ITS Acquisition. An additional $24 million was deposited into an escrow account, which was payable to the seller or to us in accordance with the ITS Acquisition agreement (the Acquisition Agreement). As of December 31, 2015, the escrow account was closed, with $20.7 million of the cash deposited in escrow released to the seller (or to third parties on behalf of the seller) and $3.3 million released to us ($2.75 million received in 2014 and $0.5 million received in 2015).

Acquisition of 2M-Tek

On April 17, 2015 we acquired 2M-Tek, a Louisiana-based manufacturer of equipment for tubular running and related well services (the 2M-Tek Acquisition) for an initial purchase price of $10.4 million paid at the closing of the acquisition, plus $8.0 million of contingent consideration payable to the seller upon the achievement of certain milestones over the 24-month period following the closing of the 2M-Tek Acquisition. The fair value of the consideration transferred was $17.2 million, which includes the $10.4 million paid at closing plus the estimated fair value of the contingent consideration of $6.8 million. We have recorded the fair value of the liability for contingent consideration in "accrued liabilities" on our consolidated balance sheet. During the fourth quarter of 2015 we paid $2.0 million of the contingent consideration upon the achievement of certain milestones.

We included the operations and related assets acquired and liabilities we assumed in our Rental Tools segment. This acquisition will complement our existing international tubular running services (TRS) business. The acquisition secures our access to a proprietary casing running tool while minimizing the total capital cost of TRS equipment going forward.

Allocation of Consideration Transferred to Net Assets Acquired

The purchase price has been allocated to the fair value of the assets acquired and liabilities assumed. The company used recognized valuation techniques to determine the fair value of the assets and liabilities. The assets acquired and liabilities assumed were recorded at fair value in accordance with U.S. GAAP. Acquisition date fair values represent either Level 2 fair value measurements (current assets and liabilities, property plant and equipment) or Level 3 fair value measurements (intangible assets).

Dollars in thousands		April 17, 2015
Current Assets:		
Cash and Cash Equivalents	$	17
Accounts Receivable, net		1,112
Rig materials and supplies		883
Total current assets		2,012
Property, plant and equipment		477
Goodwill		6,708
Intangible assets		13,470
Total Assets	$	22,667
Current Liabilities:		
Accounts payable and accrued liabilities	$	863
Total current liabilities		863
Deferred tax liability		4,601
Total Liabilities		5,464
Net Assets Acquired		17,203
Total consideration transferred	$	17,203

Pro forma results of operations have not been presented because the effect of the acquisition was not material to our results of operations. Acquisition-related costs for the year ended December 31, 2015 were approximately $0.4 million.

Note 3 - Goodwill and Intangible Assets

We account for all business combinations using the acquisition method of accounting. Under this method, assets and liabilities, including any remaining noncontrolling interests, are recognized at fair value at the date of acquisition. The excess of the purchase price over the fair value of assets acquired, net of liabilities assumed, plus the value of any noncontrolling interests, is recognized as goodwill. We perform our annual goodwill impairment review as of October 1 of each year, and more frequently if negative conditions or other triggering events arise. As a result of our 2015 analysis, we determined that the fair value of the reporting unit exceeded its net book value and therefore, no goodwill impairment was necessary. Should current market conditions worsen or persist for an extended period of time, an impairment of the carrying value of our goodwill could occur.

As part of the 2M-Tek Acquisition we recognized $6.7 million of goodwill and acquired definite-lived intangible assets with an acquisition date fair value of $13.5 million. As part of the ITS Acquisition, we acquired definite-lived intangible assets with an acquisition date fair value of $8.5 million. During the 2015 fourth quarter, we sold our controlling interest in a joint venture in Egypt resulting in the write-off of $0.6 million of intangible assets related to customer relationships and trade name. All of the Company's goodwill and intangible assets are allocated to the Rental Tools segment.

Goodwill

The change in the carrying amount of goodwill for the year ended December 31, 2015 is as follows:

Dollars in thousands		Goodwill
Balance at December 31, 2014	$	—
Acquisition		6,708
Balance at December 31, 2015	$	6,708

Of the total amount of goodwill recognized, zero is expected to be deductible for income tax purposes.

Intangible Assets

Intangible Assets consist of the following:

Dollars in thousands	Estimated Useful Life (Years)	As of December 31, 2015 Gross Carrying Amount	Write-off Due to Sale	Accumulated Amortization	Net Carrying Amount
Amortized intangible assets:					
Developed Technology	6	$ 11,630	$ —	$ (1,454)	10,176
Customer Relationships	3	5,400	(264)	(4,611)	525
Trade Names	5	4,940	(332)	(1,932)	2,676
Total Amortized intangible assets		$ 21,970	$ (596)	$ (7,997)	$ 13,377

Amortization expense was $4.3 million, $2.6 million, and $1.7 million for the year ended December 31, 2015, 2014, and 2013 respectively.

Our remaining intangibles amortization expense for the next five years is presented below:

Dollars in thousands	Expected future intangible amortization expense
2016	$ 3,448
2017	$ 2,801
2018	$ 2,306
2019	$ 2,306
2020	$ 2,030
Beyond 2020	$ 486

Note 4 — Accumulated Other Comprehensive Income

Accumulated other comprehensive income consisted of the following:

Dollars in thousands	Foreign Currency Items
December 31, 2014	$ (498)
Current period other comprehensive income	(1,390)
December 31, 2015	$ (1,888)

As a result of the sale of our controlling interest in a consolidated joint venture in Egypt, $0.5 million was reclassified out of accumulated other comprehensive income and into earnings for the year ended December 31, 2015 related to foreign currency translation losses.

Note 5 — Property, Plant and Equipment

The components of our property, plant and equipment balance are as follows:

	December 31,			
Dollars in Thousands	2015		2014	
Property, Plant and Equipment, at cost:				
Drilling Equipment	$	1,396,748	$	1,383,308
Rental Tools		521,662		494,924
Building, Land and Improvements		53,576		53,024
Other		114,465		95,074
Construction in Progress		21,770		70,668
Total Property, Plant and Equipment at cost		2,108,221		2,096,998
Less: Accumulated Depreciation and Amortization		1,302,380		1,201,058
Property, Plant, and Equipment, Net	$	805,841	$	895,940

Depreciation expense was $151.9 million, $142.5 million and $132.4 million for the years ended December 31, 2015, 2014, and 2013, respectively.

Provision for Reduction in Carrying Value of an Asset

Asset impairment evaluations are, by nature, highly subjective. They involve expectations about future cash flows generated by our assets and reflect management's assumptions and judgments regarding future industry conditions and their effect on future utilization levels, dayrates and costs. The use of different estimates and assumptions could result in materially different carrying values of our assets.

We review the carrying amounts of long-lived assets for potential impairment when events occur or circumstances change that indicate the carrying values of such assets may not be recoverable. During the 2015 third quarter, as a result of the continued decline in oil prices and expected slower recovery, we performed a recoverability test for our respective asset groups. Based on the results of our recoverability test, the current carrying values of our asset groups are fully recoverable through our future estimated cash flows and thus were not subject to impairment at September 30, 2015. The determination of our forecasted cashflows for the respective asset groups included underlying assumptions and estimates with regard to dayrates, utilization, operating costs and capital expenditures associated with each rig based on its expected operating status (i.e. operating, stacked, etc.). During the 2015 fourth quarter, in response to the continuing deterioration of oil prices and market conditions, we updated our recoverability analysis to address significant changes in assumptions for our respective asset groups. Based on the results of our analysis, the respective asset groups were deemed recoverable and were not subject to impairment at December 31, 2015. Should current market conditions worsen or persist for an extended period of time, an impairment of the carrying value of our long-lived assets could occur.

Although no impairment of our asset groups was identified as a result of our 2015 third and fourth quarter analyses, during the year ended December 31, 2015, we recorded $12.5 million of provisions for reduction in carrying value of assets. During the 2015 fourth quarter management made a decision to exit the Drilling Services business in the Colombia market. As of December 31, 2015 there were three-rigs in the country. One of the rigs is being marketed for operations outside of Colombia, and for the remaining two rigs, components of the rigs that are useable elsewhere in our operations are being re-deployed and the carrying value of the remaining components has been written-off, resulting in a provision for reduction in carrying value of $4.8 million. In addition, during the 2015 fourth quarter, to adjust to the lower level of current and expected drilling activity, we performed a review of certain individual assets within our asset groups and recorded a $4.3 million provision for reduction in carrying value of assets primarily related to drilling equipment in our International & Alaska Drilling segment. During the 2015 second and third quarters, the Company wrote-off a combined $3.2 million related to certain international rental tools and drilling rigs that management concluded were no longer marketable and the carrying value of the rigs and equipment was no longer recoverable.

During the 2014 fourth quarter, we performed a recoverability test for our asset groups to determine if the carrying value of such assets was recoverable. Based on the results of our recoverability test, the current carrying values of our asset groups were fully recoverable through our future estimated cash flows. We therefore concluded that the asset groups were not subject to impairment at December 31, 2014.

Disposition of Assets

During the normal course of operations, we periodically sell equipment deemed to be excess, obsolete, or not currently required for operations.

Net gains recorded on asset disposition for the year ended December 31, 2015 were $1.6 million. The net gains for 2015 were primarily the result of a gain from an insurance settlement received during the first quarter of 2015 related to previously realized asset losses. This gain was partially offset by losses incurred during the 2015 fourth quarter related to equipment retirements.

Net gains recorded on assets dispositions for the year ended December 31, 2014 were $1.1 million. The net gains for 2014 were primarily the result of the sale of long lived assets, including the sale of two rigs located in Kazakhstan during the fourth quarter. The sale included the rigs, rig related inventory, property and leasehold improvements. The assets had a carrying value at the time of sale of $3.8 million and were sold for proceeds of $3.5 million, resulting in a net loss of approximately $0.3 million.

Note 6 — Income Taxes

Income (loss) before income taxes is summarized below:

	Year Ended December 31,		
Dollars in thousands	2015	2014	2013
United States	$ (77,368)	$ 37,547	$ 32,136
Foreign	5,397	10,990	20,651
	$ (71,971)	$ 48,537	$ 52,787

Income tax expense (benefit) is summarized as follows:

	Year Ended December 31,		
Dollars in thousands	2015	2014	2013
Current:			
United States:			
Federal	$ 2,485	$ (3,079)	$ (3,658)
State	365	5,335	1,968
Foreign	16,754	20,311	14,599
Deferred:			
United States:			
Federal	(141)	4,703	10,720
State	(4,769)	(379)	2,820
Foreign	7,619	(2,815)	(841)
	$ 22,313	$ 24,076	$ 25,608

Total income tax expense differs from the amount computed by multiplying income before income taxes by the U.S. federal income tax statutory rate. The reasons for this difference are as follows:

	Year Ended December 31,					
	2015		2014		2013	
Dollars in thousands	**Amount**	**% of Pre-Tax Income**	**Amount**	**% of Pre-Tax Income**	**Amount**	**% of Pre-Tax Income**
Computed Expected Tax Expense (Benefit)	$ (25,190)	35.0 %	$ 16,988	35.0 %	$ 18,476	35.0 %
Foreign Taxes	16,043	(22.3)%	11,221	23.1 %	12,470	23.6 %
Tax Effect Different From Statutory Rates	(2,729)	3.8 %	(3,389)	(7.0)%	(8,920)	(16.9)%
State Taxes, net of federal benefit	(4,544)	6.3 %	3,117	6.4 %	4,099	7.8 %
Foreign Tax Credits	(5,566)	7.7 %	(3,043)	(6.3)%	(1,484)	(2.8)%
Change in Valuation Allowance	40,676	(56.5)%	2,800	5.8 %	1,975	3.7 %
Uncertain Tax Positions	(81)	0.1 %	(1,125)	(2.3)%	2,472	4.7 %
Permanent Differences	1,696	(2.4)%	676	1.4 %	4,005	7.6 %
Prior Year Return to Provision Adjustments	1,555	(2.1)%	(2,618)	(5.4)%	(6,268)	(11.9)%
Other	453	(0.6)%	(551)	(1.1)%	(1,217)	(2.3)%
Unremitted Foreign Earnings-Current Year Adjustment	—	— %	—	— %	—	— %
Actual Tax Expense	$ 22,313	(31.0)%	$ 24,076	49.6 %	$ 25,608	48.5 %

The components of the Company's deferred tax assets and liabilities as of December 31, 2015 and 2014 are shown below:

Dollars in thousands	December 31, 2015	December 31, 2014
Deferred tax assets		
Deferred tax assets:		
Federal net operating loss carryforwards	63,607	17,235
State net operating loss carryforwards	5,839	1,130
Other state deferred tax asset, net	3,170	1,658
Foreign Tax Credits	45,751	37,344
FIN 48	1,789	4,870
Foreign tax	27,861	28,656
Asset Impairment	33,723	38,931
Accruals not currently deductible for tax purposes	4,315	7,053
Deferred compensation	3,487	3,210
Other	845	—
Gross long-term deferred tax assets	190,387	140,087
Valuation Allowance	(51,105)	(9,922)
Net deferred tax assets, net of valuation allowance	139,282	130,165
Deferred tax liabilities:		
Deferred tax liabilities:		
Property, Plant and equipment	(59,879)	(43,637)
Foreign tax local	(3,169)	(4,985)
Other state deferred tax liability, net	(5,606)	(3,491)
Other	—	(2)
Gross deferred tax liabilities	(68,654)	(52,115)
Net deferred tax asset	$ 70,628	$ 78,050

As part of the process of preparing the consolidated financial statements, the Company is required to determine its provision for income taxes. This process involves estimating the annual effective tax rate and the nature and measurements of temporary and permanent differences resulting from differing treatment of items for tax and accounting purposes. These differences and the operating loss and tax credit carryforwards result in deferred tax assets and liabilities. In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that all or a portion of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income of appropriate character in each taxing jurisdiction during the periods in which those temporary differences become deductible. Management considers the weight of available evidence, both positive and negative, including the scheduled reversal of deferred tax liabilities (including the impact of available carryback and carryforward periods), projected future taxable income, and tax planning strategies in making this assessment. To the extent the Company believes that it does not meet the test that recovery is more likely than not, it establishes a valuation allowance. To the extent that the Company establishes a valuation allowance or changes this allowance in a period, it adjusts the tax provision or tax benefit in the consolidated statement of operations. We use our judgment in determining provisions or benefits for income taxes, and any valuation allowance recorded against previously established deferred tax assets. We have measured the value of our deferred tax assets for the year ended December 31, 2015 based on the cumulative weight of positive and negative evidence that exists as of the date of the financial statements. Should the cumulative weight of all available positive and negative evidence change in the forecast period, the expectation of realization of deferred tax assets existing as of December 31, 2015 and prospectively may change.

The 2015 results include income tax benefits of $24.7 million for depreciation and amortization relating to our two arctic-class drilling rigs in Alaska. In addition, we increased our valuation allowance by $40.6 million primarily related to U.S. foreign tax credits and certain foreign net operating losses. We established the valuation allowance based on the weight of available evidence, both positive and negative, including results of recent and current operations and our estimates of future taxable income or loss by jurisdiction in which we operate. In order to determine the amount of deferred tax assets or liabilities, as well as the valuation allowances, we must make estimates and assumptions regarding future taxable income, where rigs will be deployed and other business considerations. Changes in these estimates and assumptions, including changes in tax laws and other changes impacting our ability to recognize the underlying deferred tax assets, could require us to adjust the valuation allowances.

The 2014 results include income tax benefits of $2.2 million related to the settlement of our U.S. Federal Internal Revenue Service refund claim for periods 2008-2011 and $25.0 million for depreciation and amortization relating to our two arctic-class drilling rigs in Alaska. In addition, we increased our valuation allowance by $2.8 million primarily related to foreign net operating losses.

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

Dollars in thousands		
Balance at January 1, 2015	$	(8,199)
Additions based on tax positions taken during a prior period		(638)
Reductions based on tax positions taken during a prior period		1,000
Balance at December 31, 2015	$	(7,837)

In many cases, our uncertain tax positions are related to tax years that remain subject to examination by tax authorities. The following describes the open tax years, by major tax jurisdiction, as of December 31, 2015:

Colombia	2011-present
Kazakhstan	2007-present
Mexico	2010-present
Papua New Guinea	2012-present
Russia	2012-present
United States — Federal	2009-present
United Kingdom	2013-present

At December 31, 2015, we had a liability for unrecognized tax benefits of $7.8 million ($3.6 million of which, if recognized, would favorably impact our effective tax rate), on which no payments were made during 2015.

The Company recognized interest and penalties related to uncertain tax positions in income tax expense. As of December 31, 2015 and December 31, 2014 we had approximately $3.4 million and $3.3 million of accrued interest and penalties related to uncertain tax positions, respectively. We recognized an increase of $0.4 million of interest and no penalties on unrecognized tax benefits for the year ended December 31, 2015.

As of December 31, 2015, the Company has permanently reinvested accumulated undistributed earnings of foreign subsidiaries and, therefore, has not recorded a deferred tax liability related to subject earnings. Upon distribution of additional earnings in the form of dividends or otherwise, we could be subject to U.S. income taxes and foreign withholding taxes. It is not practicable to determine precisely the amount of taxes that may be payable on the eventual remittance of these earnings due to many factors, including application of foreign tax credits, levels of accumulated earnings and profits at the time of remittance, and the sources of earnings remitted.

Note 7 — Long-Term Debt

The following table illustrates the Company's current debt portfolio as of December 31, 2015 and December 31, 2014:

	December 31,			
Dollars in thousands		2015		2014
6.75% Senior Notes, due July 2022	$	360,000	$	360,000
7.50% Senior Notes, due August 2020		225,000		225,000
Term Note, due December 2017		—		30,000
Total debt		585,000		615,000
Less current portion (1)		—		10,000
Total long-term debt	$	585,000	$	605,000

(1) Current portion of the Term Loan

6.75% Senior Notes, due July 2022

On January 22, 2014, we issued $360.0 million aggregate principal amount of 6.75% Senior Notes, due July 2022 (6.75% Notes) pursuant to an Indenture between the Company and The Bank of New York Mellon Trust Company, N.A., as trustee. Net proceeds from the 6.75% Notes offering plus a $40.0 million Term Loan draw under the Amended and Restated Senior Secured

Credit Agreement (2012 Secured Credit Agreement) and cash on hand were utilized to purchase $416.2 million aggregate principal amount of our outstanding 9.125% Senior Notes due 2018 (9.125% Notes) pursuant to a tender and consent solicitation offer commenced on January 7, 2014. See further discussion of the tender and consent solicitation offer below entitled "9.125% Senior Notes, due April 2018".

The 6.75% Notes are general unsecured obligations of the Company and rank equal in right of payment with all of our existing and future senior unsecured indebtedness. The 6.75% Notes are jointly and severally guaranteed by all of our subsidiaries that guarantee indebtedness under the Second Amended and Restated Senior Secured Credit Agreement (2015 Secured Credit Agreement) and our 7.50% Senior Notes due 2020 (7.50% Notes, and collectively with the 6.75% Notes, the Senior Notes). Interest on the 6.75% Notes is payable on January 15 and July 15 of each year, beginning July 15, 2014. Debt issuance costs related to the 6.75% Notes of approximately $7.6 million ($6.2 million net of amortization as of December 31, 2015) are being amortized over the term of the notes using the effective interest rate method.

At any time prior to January 15, 2017, we may redeem up to 35 percent of the aggregate principal amount of the 6.75% Notes at a redemption price of 106.75 percent of the principal amount, plus accrued and unpaid interest to the redemption date, with the net cash proceeds of certain equity offerings by us. On and after January 15, 2018, we may redeem all or a part of the 6.75% Notes upon appropriate notice, at a redemption price of 103.375 percent of the principal amount, and at redemption prices decreasing each year thereafter to par beginning January 15, 2020. If we experience certain changes in control, we must offer to repurchase the 6.75% Notes at 101.0 percent of the aggregate principal amount, plus accrued and unpaid interest and additional interest, if any, to the date of repurchase.

The Indenture restricts our ability and the ability of certain subsidiaries to: (i) sell assets, (ii) pay dividends or make other distributions on capital stock or redeem or repurchase capital stock or subordinated indebtedness, (iii) make investments, (iv) incur or guarantee additional indebtedness, (v) create or incur liens, (vi) enter into sale and leaseback transactions, (vii) incur dividend or other payment restrictions affecting subsidiaries, (viii) merge or consolidate with other entities, (ix) enter into transactions with affiliates, and (x) engage in certain business activities. Additionally, the Indenture contains certain restrictive covenants designating certain events as Events of Default. These covenants are subject to a number of important exceptions and qualifications.

7.50% Senior Notes, due August 2020

On July 30, 2013, we issued $225.0 million aggregate principal amount of the 7.50% Notes pursuant to an Indenture between the Company and The Bank of New York Mellon Trust Company, N.A., as trustee. Net proceeds from the 7.50% Notes offering were primarily used to repay the $125.0 million aggregate principal amount of the Goldman Term Loan, to repay $45.0 million of Term Loan borrowings and for general corporate purposes.

The 7.50% Notes are general unsecured obligations of the Company and rank equal in right of payment with all of our existing and future senior unsecured indebtedness. The 7.50% Notes are jointly and severally guaranteed by all of our subsidiaries that guarantee indebtedness under the 2015 Secured Credit Agreement and the 6.75% Notes. Interest on the 7.50% Notes is payable on February 1 and August 1 of each year, beginning February 1, 2014. Debt issuance costs related to the 7.50% Notes of approximately $5.6 million ($4.0 million, net of amortization as of December 31, 2015) are being amortized over the term of the notes using the effective interest rate method.

At any time prior to August 1, 2016, we may redeem up to 35 percent of the aggregate principal amount of the 7.50% Notes at a redemption price of 107.50 percent of the principal amount, plus accrued and unpaid interest to the redemption date, with the net cash proceeds of certain equity offerings by us. On and after August 1, 2016, we may redeem all or a part of the 7.50% Notes upon appropriate notice, at a redemption price of 103.750 percent of the principal amount, and at redemption prices decreasing each year thereafter to par beginning August 1, 2018. If we experience certain changes in control, we must offer to repurchase the 7.50% Notes at 101.0 percent of the aggregate principal amount, plus accrued and unpaid interest and additional interest, if any, to the date of repurchase.

The Indenture restricts our ability and the ability of certain subsidiaries to: (i) sell assets, (ii) pay dividends or make other distributions on capital stock or redeem or repurchase capital stock or subordinated indebtedness, (iii) make investments, (iv) incur or guarantee additional indebtedness, (v) create or incur liens, (vi) enter into sale and leaseback transactions, (vii) incur dividend or other payment restrictions affecting subsidiaries, (viii) merge or consolidate with other entities, (ix) enter into transactions with affiliates, and (x) engage in certain business activities. Additionally, the Indenture contains certain restrictive covenants designating certain events as Events of Default. These covenants are subject to a number of important exceptions and qualifications.

9.125% Senior Notes, due April 2018

On January 7, 2014, we commenced a tender and consent solicitation with respect to the 9.125% Notes. The tender offer price was $1,061.98, inclusive of a $30.00 consent payment, for each $1,000 principal amount of 9.125% Notes, plus accrued and unpaid interest. On January 22, 2014, we paid $453.7 million for the tendered 9.125% Notes, comprised of $416.2 million of aggregate principal amount of the 9.125% Notes, $25.8 million of tender and consent premiums and $11.7 million of accrued interest. On April 1, 2014, we redeemed the remaining $8.8 million aggregate principal amount of the outstanding 9.125% Notes for a purchase price of $9.6 million, inclusive of a $0.4 million call premium and $0.4 million interest. During the year ended December 31, 2014, we recorded a loss on extinguishment of debt of approximately $30.2 million, which included the tender and consent premiums of $25.8 million, the call premium of $0.4 million and the write-off of unamortized debt issuance costs of $7.7 million, offset by the write-off of the remaining unamortized debt issuance premium of $3.8 million.

2015 Secured Credit Agreement

On January 26, 2015 we entered into the 2015 Secured Credit Agreement, which amended and restated the 2012 Secured Credit Agreement. The 2015 Secured Credit Agreement is comprised of a $200.0 million revolving credit facility (2015 Revolver) and matures on January 26, 2020. The 2012 Secured Credit Agreement consisted of an $80.0 million revolving credit facility and a $50.0 million term loan (Term Loan). At the closing of the 2015 Secured Credit Agreement, the outstanding balance on the Term Loan was $30 million, and we repaid this balance with a $30.0 million draw on the 2015 Revolver. On June 1, 2015, we executed the first amendment to the 2015 Secured Credit Agreement in order to amend certain provisions of the 2015 Secured Credit Agreement regarding the definition of “Change of Control.” On September 29, 2015, we executed the second amendment to the 2015 Secured Credit Agreement (the “Second Amendment”). Among other things, the Second Amendment: (a) gradually increases the permissible consolidated leverage ratio from a maximum of 4.00:1.00 to 5.75:1.00 through December 31, 2016, which thereafter gradually reduces to 4.00:1.00 by December 31, 2017; (b) reduces the consolidated interest coverage ratio from 2.50:1:00 to 2.25:1.00 for each quarter of 2016, and returning to 2.50:1.00 thereafter; (c) increases the Applicable Rate for certain higher levels of consolidated leverage to a maximum of 4.00 percent per annum for LIBOR rate loans and to 3.00 percent per annum for base rate loans; (d) allows multi-year letters of credit up to an aggregate amount of $5 million; (e) limits payment prior to September 30, 2017 of certain restricted payments and certain prepayments of unsecured senior notes and other specified forms of indebtedness; and (f) removes the option of the Company, subject to the consent of the lenders, to increase the Credit Agreement up to an additional $75 million. We incurred debt issuance costs related to the 2015 Secured Credit Agreement of approximately $2.0 million and had approximately $0.8 million of remaining debt issuance costs for the 2012 Secured Credit agreement. The total debt issuance costs of $2.8 million ($2.4 million, net of amortization as of December 31, 2015) are being amortized over the term of the 2015 Secured Credit Agreement on a straight line basis.

Our obligations under the 2015 Secured Credit Agreement are guaranteed by substantially all of our direct and indirect domestic subsidiaries, other than immaterial subsidiaries and subsidiaries generating revenues primarily outside the United States, each of which has executed guaranty agreements, and are secured by first priority liens on our accounts receivable, specified rigs including barge rigs in the GOM and land rigs in Alaska, certain U.S.-based rental equipment of the Company and its subsidiary guarantors and the equity interests of certain of the Company's subsidiaries. The 2015 Secured Credit Agreement contains customary affirmative and negative covenants, such as limitations on indebtedness, liens, restrictions on entry into certain affiliate transactions and payments (including payment of dividends) and maintenance of certain ratios and coverage tests (including a minimum asset coverage ratio of 1.25:1.00 at each quarter end, a consolidated leverage ratio, as described above, a consolidated interest coverage ratio, as described above, and a maximum senior secured leverage ratio of 1.50:1:00 at each quarter end). We were in compliance with all such covenants as of December 31, 2015.

Our 2015 Revolver is available for general corporate purposes and to support letters of credit. Interest on 2015 Revolver loans accrues at a Base Rate plus an Applicable Rate or LIBOR plus an Applicable Rate. As a result of the Second Amendment, the Applicable Rate ranges from 2.50 percent to 4.00 percent per annum for LIBOR rate loans and from 1.50 percent to 3.00 percent per annum for base rate loans, determined by reference to the consolidated leverage ratio (as defined in the 2015 Secured Credit Agreement). Revolving loans are available subject to a quarterly asset coverage ratio calculation based on the Orderly Liquidation Value of certain specified rigs including barge rigs in the GOM and land rigs in Alaska, and certain U.S.-based rental equipment of the Company and its subsidiary guarantors and a percentage of eligible domestic accounts receivable. The $30.0 million draw at the closing of the 2015 Secured Credit Agreement was repaid in full during the first quarter of 2015 with cash on hand. Letters of credit outstanding against the 2015 Revolver as of December 31, 2015 totaled $12.5 million. There were no amounts drawn on the 2015 Revolver as of December 31, 2015.

Note 8 — Fair Value of Financial Instruments

Certain of our assets and liabilities are required to be measured at fair value on a recurring basis. For purposes of recording fair value adjustments for certain financial and non-financial assets and liabilities, and determining fair value disclosures, we estimate fair value at a price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the principal market for the asset or liability.

The fair value measurement and disclosure requirements of FASB Accounting Standards Codification Topic No. 820, *Fair Value Measurement and Disclosures* (ASC 820) requires inputs that we categorize using a three-level hierarchy, from highest to lowest level of observable inputs, as follows:

- Level 1 — Unadjusted quoted prices for identical assets or liabilities in active markets;

- Level 2 — Direct or indirect observable inputs, including quoted prices or other market data, for similar assets or liabilities in active markets or identical assets or liabilities in less active markets;

- Level 3 — Unobservable inputs that require significant judgment for which there is little or no market data.

When multiple input levels are required for a valuation, we categorize the entire fair value measurement according to the lowest level of input that is significant to the entire measurement even though we may also have utilized significant inputs that are more readily observable. The amounts reported in our consolidated balance sheets for cash and cash equivalents, accounts receivable, and accounts payable approximate fair value.

Fair value of our debt instruments is determined using Level 2 inputs. Fair values and related carrying values of our debt instruments were as follows for the periods indicated:

	December 31, 2015		December 31, 2014	
Dollars in thousands	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term Debt				
6.75% Notes	$ 360,000	$ 246,600	$ 360,000	$ 270,000
7.50% Notes	225,000	171,000	225,000	180,000
Total	$ 585,000	$ 417,600	$ 585,000	$ 450,000

The assets acquired and liabilities assumed in the 2M-Tek Acquisition were recorded at fair value in accordance with U.S. GAAP. Acquisition date fair values represent either Level 2 fair value measurements (current assets and liabilities, property, plant and equipment) or Level 3 fair value measurements (intangible assets).

Market conditions could cause an instrument to be reclassified from Level 1 to Level 2, or Level 2 to Level 3. There were no transfers between levels of the fair value hierarchy or any changes in the valuation techniques used during the year ended December 31, 2015.

Note 9 — Stock-Based Compensation

Stock Plan

In 2015 and 2014 stock-based compensation awards were granted to employees under the Company's 2010 Long-Term Incentive Plan, as amended and restated in May 2013 (the Stock Plan).

The Stock Plan was approved by the stockholders at the Annual Meeting of Stockholders on May 8, 2013. The Stock Plan authorizes the compensation committee or the board of directors to issue stock options, stock appreciation rights, restricted stock awards, restricted stock units, performance based awards, and other types of awards in cash or stock to key employees, consultants, and directors.

The maximum number of shares that may be delivered pursuant to the awards granted under the Stock Plan is 11,000,000 shares of common stock. As of December 31, 2015 there were 1,311,131 shares remaining available under the Stock Plan.

Stock-Based Awards

Stock-based awards generally vest over three years. Stock-based compensation expense is recognized net of an estimated forfeiture rate, which is based on historical experience and adjusted, if necessary, in subsequent periods based on actual forfeitures. We recognize share-based compensation expense in the same financial statement line item as cash compensation paid to the respective employees. Tax deduction benefits for awards in excess of recognized compensation costs are reported as a financing cash flow.

We currently issue three types of stock-based awards: restricted stock units (RSUs), performance share units (PSUs) and phantom stock units:

- RSUs entitle a grantee to receive a share of common stock on a specified vesting date. RSUs are service-based awards and compensation expense is recognized ratably over the applicable vesting period. The grant-date fair value of nonvested RSUs is determined based on the closing trading price of the company’s shares on the grant date. RSUs are settled in stock upon vesting.

- PSUs are performance-based awards as further described under "Performance-Based Awards" below. Compensation costs for PSUs are recognized ratably over a three year performance period. PSUs vest fully at the end of the three year performance period and are typically settled in stock upon vesting.

- Phantom stock units are performance-based awards and represent the equivalent of one share of Common Stock as of the grant date. Compensation costs for phantom stock units are recognized based on the change in fair value of the awards during the performance period. Phantom stock units vest fully at the end of the three year performance period and are settled in cash or other form of immediately available funds upon vesting.

The following table presents RSUs and PSUs granted, vested and forfeited during 2015 under the Company's Stock Plan:

Nonvested Units	Units	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2015	3,344,813	$ 5.66
Granted	2,996,151	3.08
Vested	(1,463,494)	5.48
Forfeited	(103,062)	5.74
Nonvested at December 31, 2015	4,774,408	$ 4.08

In 2015, 2014, and 2013 we issued 2,996,151 units, 1,541,395 units, and 2,602,973 units, respectively, of RSUs to selected key personnel. On May 9, 2013 Chris Weber was elected Senior Vice President and Chief Financial Officer of the Company. As part of his employment agreement, he was granted 261,438 RSUs. This award was granted outside of the Company's Stock Plan but is subject to substantially the same terms and conditions of other service-based RSUs granted by the Company to its executive officers.

Total stock-based compensation expense recognized relating to RSUs and PSUs for the years ended December 31, 2015, 2014, and 2013 was $8.4 million, $9.3 million, and $9.4 million, respectively, all of which was related to nonvested RSUs and PSUs. The total fair value of the units vested during the years ended December 31, 2015, 2014, and 2013 was $8.0 million, $7.1 million, and $7.4 million, respectively. The fair value of RSUs is determined based on the closing trading price of the Company's stock on the grant date. The per-share weighted-average grant-date fair value of units granted during the years 2015, 2014, and 2013 was $3.08, $6.66, and $4.77, respectively. Stock-based compensation expense is included in our consolidated statements of operations in "General and administration expenses."

Nonvested RSUs at December 31, 2015 totaled 4,774,408 and total unrecognized compensation cost related to unamortized RSUs was $7.6 million as of December 31, 2015. The remaining unrecognized compensation cost related to non-vested RSUs will be amortized over a weighted-average vesting period of approximately 18 months.

Performance-Based Awards

We currently issue two types of performance-based awards: performance cash units (PCUs) and phantom stock units. In prior years, we issued PSUs and PCUs.

PCUs are performance-based awards that contain payout conditions which are based on our performance against our peers with regard to relative return on capital employed (ROCE) over a three-year performance period. PCUs are settled in cash. Each PCU has a nominal value of $100.00. A maximum of 200 percent of the number of PCUs granted may be earned if performance at the maximum level is achieved. PCUs vest to the extent earned at the end of a three year performance period.

Phantom stock units are performance based awards denominated in a number of shares which contain payout conditions based on our performance against our peers with regard to relative total shareholder return (TSR) over a three-year performance period. Phantom stock units are settled in cash or other form of immediately-available funds upon vesting. They represent a grant of hypothetical stock equivalent to shares of stock but the employee receives cash upon vesting. We used a simulation-based option pricing approach to determine the fair value of these awards. A maximum of 250 percent of the number of phantom stock units granted may be earned if performance at the maximum level is achieved. Phantom stock units vest fully at the end of the three year performance period.

PSUs are also performance-based awards that contain payout conditions which are based on our performance against our peers with regard to relative TSR over a three-year performance period. The effects of these conditions are reflected in the grant-date fair value of the award using a simulation-based option pricing approach for valuation. A maximum of 250 percent of the number of PSUs granted may be earned if performance at the maximum level is achieved. PSUs vest to the extent earned at the end of a three year performance period.

We evaluate the terms of each award to determine if the award should be accounted for as equity or a liability under the stock compensation rules of U.S. GAAP. PCUs and phantom stock units are classified as liability awards and PSUs are classified as equity awards.

For performance-based awards with graded vesting conditions, we recognize compensation expense on a straight-line basis over the service period for each separately vesting portion of the award as if the award was, in substance, multiple awards. For market-based awards that vest at the end of the service period, we recognize compensation expense on a straight-line basis through the end of the service period.

The following table presents PCUs granted and forfeited under the Company's Stock Plan:

	Year ended December 31,		
	2015	2014	2013
Granted	17,091	16,574	18,000
Forfeited	—	110	13,358

Compensation expense recognized related to PCUs for the years ended December 31, 2015, 2014, and 2013 was $2.3 million, $1.9 million, and $1.8 million, respectively.

The following table presents phantom stock units granted and forfeited under the Company's Stock Plan:

	Year ended December 31,		
	2015	2014	2013
Granted	541,127	—	—
Forfeited	—	—	—

Compensation expense recognized related to phantom stock units for the year ended December 31, 2015 was $0.4 million, and there was no expense recognized in 2014 or 2013.

Note 10 — Reconciliation of Income and Number of Shares Used to Calculate Basic and Diluted Earnings per Share (EPS)

	For the Year Ended December 31, 2015		
	Income (Numerator)	Shares (Denominator)	Per-Share Amount
Basic EPS	$ (95,073,000)	122,562,187	$ (0.78)
Effect of dilutive securities:			
Stock options and restricted stock		—	$ —
Diluted EPS	$ (95,073,000)	122,562,187	$ (0.78)

	For the Year Ended December 31, 2014		
	Income (Numerator)	Shares (Denominator)	Per-Share Amount
Basic EPS	$ 23,451,000	121,186,464	$ 0.19
Effect of dilutive securities:			
Stock options and restricted stock		1,890,184	$ —
Diluted EPS:	$ 23,451,000	123,076,648	$ 0.19

	For the Year Ended December 31, 2013		
	Income (Numerator)	Shares (Denominator)	Per-Share Amount
Basic EPS	$ 27,015,000	119,284,468	$ 0.23
Effect of dilutive securities:			
Stock options and restricted stock		1,940,082	$ (0.01)
Diluted EPS:	$ 27,015,000	121,224,550	$ 0.22

For the year ended December 31, 2015, all common shares potentially issuable in connection with outstanding restricted stock unit awards have been excluded from the calculation of diluted EPS as the company incurred a loss for that year, and therefore, inclusion of such potential common shares in the calculation would be anti-dilutive.

For the years ended December 31, 2014 and 2013, our computation of diluted EPS includes the dilutive effect of common shares potentially issuable in connection with outstanding RSUs and PSUs.

Note 11 — Employee Benefit Plan

The Company sponsors a defined contribution 401(k) plan (Plan) in which substantially all U.S. employees are eligible to participate. The Company currently matches 100 percent of each participant's pre-tax contributions in an amount not exceeding 4 percent of the participant's compensation and 50 percent of each participant's pre-tax contributions in an amount not exceeding 2 percent of the participant's compensation, up to the maximum amount of contributions allowed by law. The costs of our matching contributions to the Plan were $4.0 million, $4.7 million and $3.6 million in 2015, 2014 and 2013, respectively. Employees become 100 percent vested in the employer match contributions immediately upon participation in the Plan.

Note 12 — Reportable Segments

Our business is comprised of two business lines: (1) Drilling Services and (2) Rental Tools Services. We report our Rental Tools Services business as one reportable segment (Rental Tools) and report our Drilling Services business as two reportable segments: (1) U.S. (Lower 48) Drilling and (2) International & Alaska Drilling. Within the three reportable segments, we have aggregated our U.S. and international rental tools business units under Rental Tools, one business unit under U.S. (Lower 48) Drilling, and our Arctic, Eastern Hemisphere and Latin America business units under International & Alaska Drilling for a total of six business units. The Company has aggregated each of its business units in one of the three reporting segments based on the guidelines of ASC Topic 280, "Segment Reporting" ("ASC Topic 280"). We eliminate inter-segment revenue and expenses. We disclose revenue under the three reportable segments based on the similarity of the use and markets for the groups of products and services within each segment.

Drilling Services Business Line

In our Drilling Services business, we drill oil and gas wells for customers in both the U.S. and international markets. We provide this service with both Company-owned rigs and customer-owned rigs. We refer to the provision of drilling services with customer owned rigs as our operations and maintenance (O&M) service in which operators own their own drilling rigs but choose Parker Drilling to operate and maintain the rigs for them. The nature and scope of activities involved in drilling an oil and gas well is similar whether it is drilled with a Company-owned rig (as part of a traditional drilling contract) or a customer-owned rig (as part of an O&M contract). In addition, we provide project related services, such as engineering, procurement, project management and commissioning of customer owned drilling facility projects. We have extensive experience and expertise in drilling geologically difficult wells and in managing the logistical and technological challenges of operating in remote, harsh and ecologically sensitive areas.

U.S. (Lower 48) Drilling

Our U.S. (Lower 48) Drilling segment provides drilling services with our Gulf of Mexico (GOM) barge drilling rig fleet and through U.S. (Lower 48) based O&M services. Our GOM barge drilling fleet operates barge rigs that drill for oil and natural gas in shallow waters in and along the inland waterways and coasts of Louisiana, Alabama and Texas. The majority of these wells are drilled in shallow water depths ranging from 6 to 12 feet. Our rigs are suitable for a variety of drilling programs from inland coastal waters, requiring shallow draft barges, to open water drilling on both state and federal water projects requiring more robust hull depth capabilities. The barge drilling industry in the GOM is characterized by cyclical activity where utilization and dayrates are typically driven by oil and gas prices and our customers' access to project financing. Contract terms tend to be well-to-well or multi-well programs, most commonly ranging from 45 to 150 days.

International & Alaska Drilling

Our International & Alaska Drilling segment provides drilling services, with Company-owned rigs as well as through O&M contracts, and project-related services. The drilling markets in which this segment operates have one or more of the following characteristics:

- customers that typically are major, independent or national oil and natural gas companies or integrated service providers;
- drilling programs in remote locations with little infrastructure requiring a large inventory of spare parts and other ancillary equipment and self-supported service capabilities;
- complex wells and/or harsh environments (such as high pressures, deep depths, hazardous or geologically challenging conditions and sensitive environments) requiring specialized equipment and considerable experience to drill; and
- drilling and O&M contracts that generally cover periods of one year or more

Our Rental Tools Services Business

Our Rental Tools segment provides premium rental equipment and services to exploration and production (E&P) companies, drilling contractors and service companies on land and offshore in the United States (U.S.) and select international markets. Tools we provide include standard and heavy-weight drill pipe, tubing, pressure control equipment, including blow-out preventers (BOPs), drill collars and more. We also provide well construction services, which include tubular running services and downhole tools, and well intervention services, which include whipstock, fishing products and related services, as well as inspection and machine shop support. Our largest single market for rental tools is U.S. land drilling. Generally, rental tools are used for only a portion of a well drilling program and are usually rented on a daily or monthly basis.

With regard to FASB ASC 280-10-50-41, we respectfully note that the Reportable Segments note to the consolidated financial statements includes tabular disclosure by material geography of revenue, operating gross margins and long-lived assets.

The following table represents the results of operations by reportable segment:

	Year Ended December 31,		
Dollars in thousands	**2015**	**2014**	**2013**
Revenues:			
Drilling Services:			
U.S. (Lower 48) Drilling[1]	$ 30,358	$ 158,405	$ 153,624
International & Alaska Drilling[1]	435,096	462,513	410,507
Total Drilling Services	465,454	620,918	564,131
Rental Tools[1]	246,729	347,766	310,041
Total revenues	712,183	968,684	874,172
Operating income:			
Drilling Services:			
U.S. (Lower 48) Drilling[2]	(28,309)	46,831	54,203
International & Alaska Drilling[2]	45,211	34,405	23,080
Total Drilling Services	16,902	81,236	77,283
Rental Tools[2]	12,797	72,946	91,164
Total operating gross margin	29,699	154,182	168,447
General and administrative expense	(36,190)	(35,016)	(68,025)
Provision for reduction in carrying value of certain assets	(12,490)	—	(2,544)
Gain on disposition of assets, net	1,643	1,054	3,994
Total operating income (loss)	(17,338)	120,220	101,872
Interest expense	(45,155)	(44,265)	(47,820)
Interest income	269	195	2,450
Loss on extinguishment of debt	—	(30,152)	(5,218)
Other income (loss)	(9,747)	2,539	1,503
Income (loss) from continuing operations before income taxes	$ (71,971)	$ 48,537	$ 52,787

(1) Exxon Neftegas Limited (ENL), was our largest customer in each of the years ended December 31, 2015, 2014, and 2013. ENL constituted approximately 27.9 percent, 18.7 percent, and 15.6 percent of our total consolidated revenues in the years ended December 31, 2015, 2014, and 2013, respectively, and approximately 45.6 percent, 39.2 percent, and 33.3 percent of our International & Alaska Drilling segment revenues in the years ended December 31, 2015, 2014, and 2013, respectively.

(2) Operating income is calculated as revenues less direct operating expenses, including depreciation and amortization expense.

The following table represents capital expenditures and depreciation and amortization by reportable segment:

	Year Ended December 31,		
Dollars in thousands	2015	2014	2013
Capital expenditures:			
U.S. (Lower 48) Drilling	$ 2,731	$ 43,120	$ 23,796
International & Alaska Drilling	13,458	26,761	40,822
Rental Tools	67,189	95,340	76,928
Corporate	4,819	14,292	14,099
Total capital expenditures	$ 88,197	$ 179,513	$ 155,645
Depreciation and amortization: (1)			
U.S. (Lower 48) Drilling	$ 22,420	$ 21,260	$ 15,212
International & Alaska Drilling	64,539	59,684	62,988
Rental Tools	69,235	64,177	55,853
Total depreciation and amortization	$ 156,194	$ 145,121	$ 134,053

(1) For presentation purposes, depreciation for corporate assets of $7.5 million, $5.0 million, and $3.5 million for the years then ended December 31, 2015, 2014 and 2013, respectively, has been allocated to the above reportable segments.

The following table represents identifiable assets by reportable segment:

	Year Ended December 31,	
Dollars in Thousands	2015	2014
Identifiable assets:		
U.S. (Lower 48) Drilling	$ 102,121	$ 124,701
International & Alaska Drilling	629,784	764,794
Rental Tools	429,281	444,195
Total identifiable assets	1,161,186	1,333,690
Corporate	215,718	186,969
Total assets	$ 1,376,904	$ 1,520,659

The following table represents selected geographic information:

Dollars in Thousands	Year Ended December 31,		
Revenues by geographic area:	2015	2014	2013
Russia	$ 165,193	$ 154,817	$ 131,037
Other CIS	61,145	59,881	54,296
EMEA & Asia	148,015	183,460	135,499
Latin America	69,989	86,651	101,154
United States	231,779	440,642	425,800
Other(1)	36,062	43,233	26,386
Total revenues	$ 712,183	$ 968,684	$ 874,172
Long-lived assets by geographic area: (2)			
Russia	$ 22,607	$ 25,728	
Other CIS	44,675	49,883	
EMEA & Asia	130,434	145,093	
Latin America	63,919	85,492	
United States(3)	544,206	589,744	
Other	—	—	
Total long-lived assets	$ 805,841	$ 895,940	

(1) This category includes our project services activities, as the revenue generated by our project service activities benefit our various geographic locations.

(2) Long-lived assets consist of property, plant and equipment, net.

(3) The long-lived assets for our project service activities primarily relate to office furniture and fixtures and are located in the United States; therefore, they have been included in the United States line item.

Note 13 — Commitments and Contingencies

The Company has various lease agreements for office space, equipment, vehicles and personal property. These obligations extend through 2025 and are typically non-cancelable. Most leases contain renewal options and certain of the leases contain escalation clauses. Future minimum lease payments at December 31, 2015, under operating leases with non-cancelable terms are as follows:

Dollars in Thousands	Year Ended December 31,
2016	$ 10,145
2017	7,939
2018	6,131
2019	4,314
2020	3,156
Thereafter	5,088
Total	$ 36,773

Total rent expense for all operating leases amounted to $19.2 million, $21.8 million and $19.9 million for 2015, 2014, and 2013, respectively.

Self Insurance

We are self-insured for certain losses relating to workers' compensation, employers' liability, general liability (for onshore liability), protection and indemnity (for offshore liability) and property damage. Our exposure (that is, the retention or deductible) per occurrence is $250,000 for worker's compensation and employer's liability, and $500,000 for general liability, protection and indemnity and maritime employers' liability (Jones Act). In addition, we assume a $400,000 annual aggregate deductible for protection and indemnity and maritime employers' liability claims. The annual aggregate deductible is reduced by every dollar that exceeds the $500,000 per occurrence retention. We also assume a retention for foreign casualty exposures of $100,000 for workers' compensation, employers' liability, and $1,000,000 for general liability losses and a $100,000 deductible for auto liability claims. For all primary insurances mentioned above, the Company has excess coverage for those claims that exceed the retention and annual aggregate deductible. We maintain actuarially-determined accruals in our consolidated balance sheets to cover the self-insurance retentions.

We have self-insured retentions for certain other losses relating to rig, equipment, property, business interruption and political, war, and terrorism risks which vary according to the type of rig and line of coverage. Political risk insurance is procured for international operations. However, this coverage may not adequately protect us against liability from all potential consequences.

As of December 31, 2015 and 2014, our gross self-insurance accruals for workers' compensation, employers' liability, general liability, protection and indemnity and maritime employers' liability totaled $5.5 million and $5.9 million, respectively and the related insurance recoveries/receivables were $2.0 million for both years.

Other Commitments

We have entered into employment agreements with terms of one to two years with certain members of management with automatic one year renewal periods at expiration dates. The agreements provide for, among other things, compensation, benefits and severance payments. The employment agreements also provide for lump sum compensation and benefits in the event of termination within two years following a change in control of the Company.

Contingencies

We are a party to various lawsuits and claims arising out of the ordinary course of business. We estimate the range of our liability related to pending litigation when we believe the amount or range of loss can be estimated. We record our best estimate of a loss when the loss is considered probable. When a liability is probable and there is a range of estimated loss with no best estimate in the range, we record the minimum estimated liability related to the lawsuits or claims. As additional information becomes available, we assess the potential liability related to our pending litigation and claims and revise our estimates. Due to uncertainties related to the resolution of lawsuits and claims, the ultimate outcome may differ significantly from our estimates. In the opinion of management and based on liability accruals provided, our ultimate exposure with respect to these pending lawsuits and claims is not expected to have a material adverse effect on our consolidated financial position or cash flows, although they could have a material adverse effect on our results of operations for a particular reporting period.

Customs Agent and Foreign Corrupt Practices Act (FCPA) Settlement

On April 16, 2013, the Company and the Department of Justice (DOJ) entered into a deferred prosecution agreement (DPA), under which the DOJ deferred for three years prosecuting the Company for criminal violations of the anti-bribery provisions of the FCPA relating to the Company's retention and use of an individual agent in Nigeria with respect to certain customs-related issues, in return for: (i) the Company's acceptance of responsibility for, and agreement not to contest or contradict the truthfulness of, the statement of facts and allegations that have been filed in a United States District Court concurrently with the DPA; (ii) the Company's payment of an approximately $11.76 million fine; (iii) the Company's reaffirming its commitment to compliance with the FCPA and other applicable anti-corruption laws in connection with the Company's operations, and continuing cooperation with domestic and foreign authorities in connection with the matters that are the subject of the DPA; (iv) the Company's commitment to continue to address any identified areas for improvement in the Company's internal controls, policies and procedures relating to compliance with the FCPA and other applicable anti-corruption laws if, and to the extent, not already addressed; and (v) the Company's agreement to report to the DOJ in writing annually during the term of the DPA regarding remediation of the matters that are the subject of the DPA, implementation of any enhanced internal controls, and any evidence of improper payments the Company may have discovered during the term of the agreement. If the Company remains in compliance with the terms of the DPA throughout its effective period, the charge against the Company will be dismissed with prejudice. The Company also settled a related civil complaint filed by the Securities and Exchange Commission (SEC) in a United States District Court. The Company has provided the DOJ annual written reports in connection with the DPA and intends to file our final report with the DOJ on or about April 16, 2016.

Note 14 — Related Party Transactions

Consulting Agreement

On December 31, 2013, Robert L. Parker, Jr., our former Executive Chairman, retired as an employee of the Company. Mr. Parker continued to serve as Chairman of the Company's board of directors until the annual meeting of stockholders held in 2014, at which time Mr. Parker was elected to the board for a three-year term.

In connection with Mr. Parker's retirement, the Company and Mr. Parker entered into a Retirement and Separation Agreement dated as of November 1, 2013 (the "Retirement Agreement"). Under the terms of the Retirement Agreement, in 2014 Mr. Parker received a cash bonus of $411,188, a cash payment of $1,096,687 pursuant to the 2010 Long-Term Incentive Program of the Company's Stock Plan, and a severance payment of $2,488,024. The value of benefits provided by the Company to Mr. Parker in 2014 was $12,876. In 2015, Mr. Parker received a cash payment of $706,082 pursuant to the 2010 Long-Term Incentive Program of the Company's Stock Plan. The value of benefits provided by the Company to Mr. Parker in 2015 was $14,441.

In addition, Mr. Parker was paid $250,000 during 2015 and will be paid $250,000 during 2016 and 2017, respectively, in exchange for his agreement to provide additional support to the Company when needed in matters where his historical and industry knowledge, client relationships and related expertise could be of particular benefit to the Company's interests.

Other Related Party Agreements

During 2015 we purchased the legal rights to certain rental tool software from two employees and a relative of the employees. As part of the purchase, we paid $180,000 to a relative of the employees during 2015 and we are required to make a $90,000 payment to each employee in both January 2016 and 2017.

One of the Company's directors held executive positions at Apache Corporation (Apache), including the positions of President and Chief Corporate Officer, Executive Vice President and Chief Financial Officer and Chief Corporate Officer, prior to retiring from Apache on March 31, 2014. During 2014 and 2013, affiliates of Apache paid affiliates of the Company a total of $34.0 million and $40.8 million, respectively, for performance of drilling services and provision of rental tools.

During 2013, one of the Company's directors served on the board of directors of Gardner Denver, Inc. (GD), until resigning from our board of directors during 2014. During 2013, affiliates of the Company paid affiliates of GD $0.2 million for goods and services provided to the Company.

Note 15 — Supplementary Information

The significant components of "Accrued liabilities" on our consolidated balance sheets as of December 31, 2015 and 2014 are presented below:

	Year Ended December 31,	
Dollars in Thousands	**2015**	**2014**
Accrued liabilities:		
Accrued Payroll & Related Benefits	$ 27,678	$ 32,504
Accrued Interest Expense	18,169	18,171
Accrued Professional Fees & Other	20,326	18,073
Deferred Mobilization Fees	2,649	4,245
Workers' Compensation Liabilities, net	2,801	2,710
Total accrued liabilities	$ 71,623	$ 75,703

Note 16 — Parent, Guarantor, Non-Guarantor Unaudited Consolidating Condensed Financial Statements

Set forth on the following pages are the consolidating condensed financial statements of Parker Drilling. The Company's 2015 Secured Credit Agreement and Senior Notes are fully and unconditionally guaranteed by substantially all of our direct and indirect domestic subsidiaries other than immaterial subsidiaries and subsidiaries generating revenues primarily outside the United States, subject to the following customary release provisions:

- in connection with any sale or other disposition of all or substantially all of the assets of that guarantor (including by way of merger or consolidation) to a person that is not (either before or after giving effect to such transaction) a subsidiary of the Company;

- in connection with any sale of such amount of capital stock as would result in such guarantor no longer being a subsidiary to a person that is not (either before or after giving effect to such transaction) a subsidiary of the Company;

- if the Company designates any restricted subsidiary that is a guarantor as an unrestricted subsidiary;

- if the guarantee by a guarantor of all other indebtedness of the Company or any other guarantor is released, terminated or discharged, except by, or as a result of, payment under such guarantee; or

- upon legal defeasance or covenant defeasance (satisfaction and discharge of the indenture).

There are currently no restrictions on the ability of the restricted subsidiaries to transfer funds to Parker Drilling in the form of cash dividends, loans or advances. Parker Drilling is a holding company with no operations, other than through its subsidiaries. Separate financial statements for each guarantor company are not provided as the company complies with the exception to Rule 3-10(a)(1) of Regulation S-X, set forth in sub-paragraph (f) of such rule. All guarantor subsidiaries are owned 100 percent by the parent company.

We are providing consolidating condensed financial information of the parent, Parker Drilling, the guarantor subsidiaries, and the non-guarantor subsidiaries as of December 31, 2015 and December 31, 2014 and for the years ended December 31, 2015, 2014, and 2013. The consolidating condensed financial statements present investments in both the consolidated and unconsolidated subsidiaries using the equity method of accounting.

Upon the closing of our 2015 Secured Credit Agreement, one of our subsidiaries was released as a guarantor subsidiary and is now classified as a non-guarantor subsidiary. In accordance with the guidance Topic No. 810, *Consolidation* (ASC 810), we have retrospectively updated the unaudited consolidating condensed financial information as of December 31, 2015 and December 31, 2014 and for the years ended December 31, 2015, 2014, and 2013.

PARKER DRILLING COMPANY AND SUBSIDIARIES

CONSOLIDATING CONDENSED STATEMENT OF OPERATIONS
(Dollars in Thousands)
(Unaudited)

	Year ended December 31, 2015				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
Total revenues	$ —	$ 254,182	$ 584,204	$ (126,203)	$ 712,183
Operating expenses	—	143,563	508,930	(126,203)	526,290
Depreciation and amortization	—	95,071	61,123	—	156,194
Total operating gross margin	—	15,548	14,151	—	29,699
General and administration expense [(1)]	(1,279)	(38,643)	3,732	—	(36,190)
Provision for reduction in carrying value of certain assets	—	(2,088)	(10,402)	—	(12,490)
Gain on disposition of assets, net	—	439	1,204	—	1,643
Total operating income (loss)	(1,279)	(24,744)	8,685	—	(17,338)
Other income and (expense):					
Interest expense	(47,659)	(1,035)	(11,579)	15,118	(45,155)
Interest income	1,424	852	13,111	(15,118)	269
Other	—	(200)	(9,547)	—	(9,747)
Equity in net earnings of subsidiaries	(36,631)	—	—	36,631	—
Total other income (expense)	(82,866)	(383)	(8,015)	36,631	(54,633)
Income (loss) before income taxes	(84,145)	(25,127)	670	36,631	(71,971)
Income tax expense (benefit):					
Current	29,643	(22,970)	12,931	—	19,604
Deferred	(18,715)	11,718	9,706	—	2,709
Income tax expense (benefit)	10,928	(11,252)	22,637	—	22,313
Net income (loss)	(95,073)	(13,875)	(21,967)	36,631	(94,284)
Less: Net income attributable to noncontrolling interest	—	—	789	—	789
Net income (loss) attributable to controlling interest	$ (95,073)	$ (13,875)	$ (22,756)	$ 36,631	$ (95,073)

(1) General and administration expenses for field operations are included in operating expenses.

PARKER DRILLING COMPANY AND SUBSIDIARIES

CONSOLIDATING CONDENSED STATEMENT OF OPERATIONS
(Dollars in Thousands)
(Unaudited)

	Year ended December 31, 2014				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
Total revenues	$ —	$ 506,205	$ 640,147	$ (177,668)	$ 968,684
Operating expenses	—	279,396	567,653	(177,668)	669,381
Depreciation and amortization	—	87,248	57,873	—	145,121
Total operating gross margin	—	139,561	14,621	—	154,182
General and administration expense [1]	(302)	(33,035)	(1,679)	—	(35,016)
Gain (loss) on disposition of assets, net	(79)	1,156	(23)	—	1,054
Total operating income (loss)	(381)	107,682	12,919	—	120,220
Other income and (expense):					
Interest expense	(46,527)	(148)	(7,692)	10,102	(44,265)
Interest income	1,478	623	8,196	(10,102)	195
Loss on extinguishment of debt	(30,152)	—	—	—	(30,152)
Other	—	2,810	(271)	—	2,539
Equity in net earnings of subsidiaries	67,399	—	—	(67,399)	—
Total other income (expense)	(7,802)	3,285	233	(67,399)	(71,683)
Income (loss) before income taxes	(8,183)	110,967	13,152	(67,399)	48,537
Income tax expense (benefit):					
Current	(17,702)	24,106	16,163	—	22,567
Deferred	(13,932)	16,949	(1,508)	—	1,509
Income tax expense (benefit)	(31,634)	41,055	14,655	—	24,076
Net income (loss)	23,451	69,912	(1,503)	(67,399)	24,461
Less: Net income attributable to noncontrolling interest	—	—	1,010	—	1,010
Net income (loss) attributable to controlling interest	$ 23,451	$ 69,912	$ (2,513)	$ (67,399)	$ 23,451

(1) General and administration expenses for field operations are included in operating expenses.

PARKER DRILLING COMPANY AND SUBSIDIARIES

CONSOLIDATING CONDENSED STATEMENT OF OPERATIONS
(Dollars in Thousands)
(Unaudited)

	Year ended December 31, 2013				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
Total revenues	$ —	$ 468,073	$ 549,295	$ (143,196)	$ 874,172
Operating expenses	—	252,211	462,657	(143,196)	571,672
Depreciation and amortization	—	77,416	56,637	—	134,053
Total operating gross margin	—	138,446	30,001	—	168,447
General and administration expense (1)	(202)	(67,083)	(740)	—	(68,025)
Provision for reduction in carrying value of certain assets	—	—	(2,544)	—	(2,544)
Gain on disposition of assets, net	—	1,759	2,235	—	3,994
Total operating income (loss)	(202)	73,122	28,952	—	101,872
Other income and (expense):					
Interest expense	(51,439)	(335)	(9,930)	13,884	(47,820)
Interest income	3,824	1,761	10,749	(13,884)	2,450
Loss on extinguishment of debt	(5,218)	—	—	—	(5,218)
Other	52	(143)	1,594	—	1,503
Equity in net earnings of subsidiaries	55,430	—	—	(55,430)	—
Total other income and (expense)	2,649	1,283	2,413	(55,430)	(49,085)
Income (loss) before income taxes	2,447	74,405	31,365	(55,430)	52,787
Income tax expense (benefit):					
Current	(21,431)	18,737	15,603	—	12,909
Deferred	(3,137)	19,454	(3,618)	—	12,699
Total income tax expense (benefit)	(24,568)	38,191	11,985	—	25,608
Net income (loss)	27,015	36,214	19,380	(55,430)	27,179
Less: Net (loss) attributable to noncontrolling interest	—	—	164	—	164
Net income (loss) attributable to controlling interest	$ 27,015	$ 36,214	$ 19,216	$ (55,430)	$ 27,015

(1) General and administration expenses for field operations are included in operating expenses.

PARKER DRILLING COMPANY AND SUBSIDIARIES
CONSOLIDATING CONDENSED STATEMENT OF COMPREHENSIVE INCOME (LOSS)
(Dollars in Thousands)
(Unaudited)

	Year Ended December 31, 2015				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
Comprehensive income:					
Net income (loss)	$ (95,073)	$ (13,875)	$ (21,967)	$ 36,631	$ (94,284)
Other comprehensive gain (loss), net of tax:					
Currency translation difference on related borrowings	—	—	(2,012)	—	$ (2,012)
Currency translation difference on foreign currency net investments	—	—	405	—	$ 405
Total other comprehensive gain (loss), net of tax:	—	—	(1,607)	—	(1,607)
Comprehensive income (loss)	(95,073)	(13,875)	(23,574)	36,631	(95,891)
Comprehensive (income) loss attributable to noncontrolling interest	—	—	4,606	—	4,606
Comprehensive income (loss) attributable to controlling interest	$ (95,073)	$ (13,875)	$ (18,968)	$ 36,631	$ (91,285)

PARKER DRILLING COMPANY AND SUBSIDIARIES
CONSOLIDATING CONDENSED STATEMENT OF COMPREHENSIVE INCOME (LOSS)
(Dollars in Thousands)
(Unaudited)

	Year Ended December 31, 2014				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
Comprehensive income:					
Net income (loss)	$ 23,451	$ 69,912	$ (1,503)	$ (67,399)	$ 24,461
Other comprehensive gain (loss), net of tax:					
Currency translation difference on related borrowings	—	—	(4,870)	—	(4,870)
Currency translation difference on foreign currency net investments	—	—	2,147	—	2,147
Total other comprehensive gain (loss), net of tax:	—	—	(2,723)	—	(2,723)
Comprehensive income (loss)	23,451	69,912	(4,226)	(67,399)	21,738
Comprehensive (income) loss attributable to noncontrolling interest	—	—	(673)	—	(673)
Comprehensive income (loss) attributable to controlling interest	$ 23,451	$ 69,912	$ (4,899)	$ (67,399)	$ 21,065

PARKER DRILLING COMPANY AND SUBSIDIARIES
CONSOLIDATING CONDENSED STATEMENT OF COMPREHENSIVE INCOME (LOSS)
(Dollars in Thousands)
(Unaudited)

	Year ended December 31, 2013				
	Parent	**Guarantor**	**Non-Guarantor**	**Eliminations**	**Consolidated**
Comprehensive income:					
Net income (loss)	$ 27,015	$ 36,214	$ 19,380	$ (55,430)	$ 27,179
Other comprehensive gain (loss), net of tax:					
Currency translation difference on related borrowings	—	—	(1,525)	—	(1,525)
Currency translation difference on foreign currency net investments	—	—	3,051	—	3,051
Total other comprehensive gain (loss), net of tax:	—	—	1,526	—	1,526
Comprehensive income (loss)	27,015	36,214	20,906	(55,430)	28,705
Comprehensive (income) loss attributable to noncontrolling interest	—	—	198	—	198
Comprehensive income (loss) attributable to controlling interest	$ 27,015	$ 36,214	$ 21,104	$ (55,430)	$ 28,903

PARKER DRILLING COMPANY AND SUBSIDIARIES

CONSOLIDATING CONDENSED BALANCE SHEET
(Dollars in Thousands)
(Unaudited)

	December 31, 2015				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 73,985	$ 13,854	$ 46,455	$ —	$ 134,294
Accounts and notes receivable, net	—	42,261	132,844	—	175,105
Rig materials and supplies	—	(4,744)	39,681	—	34,937
Deferred costs	—	—	1,367	—	1,367
Other tax assets	—	457	4,735	—	5,192
Other current assets	—	5,525	10,321	—	15,846
Total current assets	73,985	57,353	235,403	—	366,741
Property, plant and equipment, net	(19)	543,346	262,514	—	805,841
Goodwill	—	6,708	—	—	6,708
Intangible assets, net	—	11,740	1,637	—	13,377
Investment in subsidiaries and intercompany advances	3,057,220	2,770,501	3,319,702	(9,147,423)	—
Other noncurrent assets	(224,584)	312,790	265,995	(169,964)	184,237
Total assets	$ 2,906,602	$ 3,702,438	$ 4,085,251	$ (9,317,387)	$ 1,376,904
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities:					
Current portion of long-term debt	$ —	$ —	$ —	$ —	—
Accounts payable and accrued liabilities	84,456	56,382	295,439	(306,574)	129,703
Accrued income taxes	9,900	2,111	(5,593)	—	6,418
Total current liabilities	94,356	58,493	289,846	(306,574)	136,121
Long-term debt	585,000	—	—	—	585,000
Other long-term liabilities	2,868	7,446	8,303	—	18,617
Long-term deferred tax liability	(29)	69,679	(996)	—	68,654
Intercompany payables	1,656,968	1,401,510	1,864,671	(4,923,149)	—
Total liabilities	2,339,163	1,537,128	2,161,824	(5,229,723)	808,392
Total equity	567,439	2,165,310	1,923,427	(4,087,664)	568,512
Total liabilities and stockholders' equity	$ 2,906,602	$ 3,702,438	$ 4,085,251	$ (9,317,387)	$ 1,376,904

PARKER DRILLING COMPANY AND SUBSIDIARIES

CONSOLIDATING CONDENSED BALANCE SHEET
(Dollars in Thousands)
(Unaudited)

	December 31, 2014				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 36,728	$ 13,546	$ 58,182	$ —	$ 108,456
Accounts and notes receivable, net	(33)	96,100	174,885	—	270,952
Rig materials and supplies	—	(1,473)	49,416	—	47,943
Deferred costs	—	—	5,673	—	5,673
Other tax assets	19,885	(18,273)	9,111	—	10,723
Other current assets	—	7,998	10,558	—	18,556
Total current assets	56,580	97,898	307,825	—	462,303
Property, plant and equipment, net	(19)	589,055	306,904	—	895,940
Intangible assets, net	—	—	4,286	—	4,286
Investment in subsidiaries and intercompany advances	3,060,867	2,441,523	2,464,506	(7,966,896)	—
Other noncurrent assets	(440,918)	496,728	269,882	(167,562)	158,130
Total assets	$ 2,676,510	$ 3,625,204	$ 3,353,403	$ (8,134,458)	$ 1,520,659
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities:					
Current portion of long-term debt	$ 10,000	$ —	$ —	$ —	$ 10,000
Accounts payable and accrued liabilities	77,603	71,645	309,344	(304,113)	154,479
Accrued income taxes	(4,061)	10,109	8,138	—	14,186
Total current liabilities	83,542	81,754	317,482	(304,113)	178,665
Long-term debt	605,000	—	—	—	605,000
Other long-term liabilities	2,867	7,135	8,663	—	18,665
Long-term deferred tax liability	—	56,105	(3,990)	—	52,115
Intercompany payables	1,322,172	1,311,404	1,204,769	(3,838,345)	—
Total liabilities	2,013,581	1,456,398	1,526,924	(4,142,458)	854,445
Total equity	662,929	2,168,806	1,826,479	(3,992,000)	666,214
Total liabilities and stockholders' equity	$ 2,676,510	$ 3,625,204	$ 3,353,403	$ (8,134,458)	$ 1,520,659

PARKER DRILLING COMPANY AND SUBSIDIARIES

CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS
(Dollars in Thousands)
(Unaudited)

	Year Ended December 31, 2015				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
Cash flows from operating activities:					
Net income (loss)	$ (95,073)	$ (13,875)	$ (21,967)	$ 36,631	(94,284)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:					
Depreciation and amortization	—	95,071	61,123	—	156,194
Accretion of contingent consideration	—	826	—	—	826
Gain on disposition of assets	—	(439)	(1,204)	—	(1,643)
Deferred income tax expense	(18,715)	11,718	9,706	—	2,709
Provision for reduction in carrying value of certain assets	—	2,088	10,402	—	12,490
Expenses not requiring cash	6,311	854	(2,062)	—	5,103
Equity in net earnings of subsidiaries	36,631	—	—	(36,631)	—
Change in assets and liabilities:					
Accounts and notes receivable	(33)	61,818	42,210	—	103,995
Rig materials and supplies	—	51	2,671	—	2,722
Other current assets	19,885	(16,257)	8,920	—	12,548
Accounts payable and accrued liabilities	10,228	(21,396)	(16,257)	—	(27,425)
Accrued income taxes	15,368	(9,405)	(13,920)	—	(7,957)
Other assets	(198,955)	186,591	9,208	—	(3,156)
Net cash provided by operating activities	(224,353)	297,645	88,830	—	162,122
Cash flows from investing activities:					
Capital expenditures	—	(58,817)	(29,380)	—	(88,197)
Proceeds from the sale of assets	—	500	330	—	830
Proceeds from insurance settlements	—	—	2,500	—	2,500
Acquisitions, net of cash acquired	(3,375)	(10,431)	—	—	(13,806)
Divestitures, net of cash acquired	—	—	(2,570)	—	(2,570)
Net cash (used in) investing activities	(3,375)	(68,748)	(29,120)	—	(101,243)
Cash flows from financing activities:					
Repayment of long term debt	(30,000)	—	—	—	(30,000)
Payment of debt issuance costs	(1,996)	—	—	—	(1,996)
Payment of contingent consideration	—	(2,000)	—	—	(2,000)
Excess tax benefit from stock-based compensation	(1,045)	—	—	—	(1,045)
Intercompany advances, net	298,026	(226,589)	(71,437)	—	—
Net cash provided by (used in) financing activities	264,985	(228,589)	(71,437)	—	(35,041)
Net change in cash and cash equivalents	37,257	308	(11,727)	—	25,838
Cash and cash equivalents at beginning of year	36,728	13,546	58,182	—	108,456
Cash and cash equivalents at end of year	$ 73,985	$ 13,854	$ 46,455	$ —	$ 134,294

See accompanying notes to unaudited consolidated condensed financial statements.

PARKER DRILLING COMPANY AND SUBSIDIARIES

CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS
(Dollars in Thousands)
(Unaudited)

	Year Ended December 31, 2014				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
Cash flows from operating activities:					
Net income (loss)	$ 23,451	$ 69,912	$ (1,503)	$ (67,399)	24,461
Adjustments to reconcile net income (loss) to net cash provided by operating activities:					
Depreciation and amortization	—	87,248	57,873	—	145,121
Loss on extinguishment of debt	30,152	—	—	—	30,152
Gain on disposition of assets	79	(1,156)	23	—	(1,054)
Deferred income tax expense (benefit)	(13,932)	16,949	(1,508)	—	1,509
Expenses not requiring cash	11,978	(710)	8,063	—	19,331
Equity in net earnings of subsidiaries	(67,399)	—	—	67,399	—
Change in assets and liabilities:					
Accounts and notes receivable	32	11,937	(24,207)	—	(12,238)
Rig materials and supplies	—	2,990	(5,868)	—	(2,878)
Other current assets	34,639	(27,404)	18,797	—	26,032
Accounts payable and accrued liabilities	2,336	(20,492)	45,387	—	27,231
Accrued income taxes	(12,474)	11,107	(6,290)	—	(7,657)
Other assets	799	(32,259)	(16,083)	—	(47,543)
Net cash provided by (used in) operating activities	9,661	118,122	74,684	—	202,467
Cash flows from investing activities:					
Capital expenditures	—	(125,260)	(54,253)	—	(179,513)
Proceeds from the sale of assets	—	2,594	3,344	—	5,938
Net cash (used in) investing activities	—	(122,666)	(50,909)	—	(173,575)
Cash flows from financing activities:					
Proceeds from issuance of debt	400,000	—	—	—	400,000
Repayment of long term debt	(435,000)	—	—	—	(435,000)
Payment of debt issuance costs	(7,630)	—	—	—	(7,630)
Payment of debt extinguishment costs	(26,214)	—	—	—	(26,214)
Excess tax benefit from stock-based compensation	(281)	—	—	—	(281)
Intercompany advances, net	7,495	9,780	(17,275)	—	—
Net cash provided by (used in) financing activities	(61,630)	9,780	(17,275)	—	(69,125)
Net change in cash and cash equivalents	(51,969)	5,236	6,500	—	(40,233)
Cash and cash equivalents at beginning of year	88,697	8,310	51,682	—	148,689
Cash and cash equivalents at end of year	$ 36,728	$ 13,546	$ 58,182	$ —	$ 108,456

See accompanying notes to unaudited consolidated condensed financial statements.

PARKER DRILLING COMPANY AND SUBSIDIARIES
CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS
(Dollars in Thousands)
(Unaudited)

	Year Ended December 31, 2013				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
Cash flows from operating activities:					
Net income (loss)	$ 27,015	$ 36,214	$ 19,380	$ (55,430)	$ 27,179
Adjustments to reconcile net income (loss) to net cash provided by operating activities:					
Depreciation and amortization	—	77,416	56,637	—	134,053
Loss on extinguishment of debt	5,218	—	—	—	5,218
Gain on disposition of assets	—	(1,759)	(2,235)	—	(3,994)
Deferred income tax expense	(3,137)	19,454	(3,618)	—	12,699
Provision for reduction in carrying value of certain assets	—	—	2,544	—	2,544
Expenses not requiring cash	13,173	12	4,579	—	17,764
Equity in net earnings of subsidiaries	(55,430)	—	—	55,430	—
Change in assets and liabilities:					
Accounts and notes receivable	(7)	(12,888)	(20,617)	—	(33,512)
Rig materials and supplies	—	(1,323)	3,077	—	1,754
Other current assets	(8,275)	15,297	(18,737)	—	(11,715)
Accounts payable and accrued liabilities	6,934	(877)	(6,343)	—	(286)
Accrued income taxes	6,617	(1,052)	4,889	—	10,454
Other assets	82,686	(99,494)	16,147	—	(661)
Net cash provided by (used in) operating activities	74,794	31,000	55,703	—	161,497
Cash flows from investing activities:					
Capital expenditures	—	(94,269)	(61,376)	—	(155,645)
Proceeds from the sale of assets	—	3,725	4,493	—	8,218
Acquisitions, net of cash acquired	—	(6,903)	(111,088)	—	(117,991)
Net cash (used in) investing activities	—	(97,447)	(167,971)	—	(265,418)
Cash flows from financing activities:					
Proceeds from debt issuance	350,000	—	—	—	350,000
Repayment of long term debt	(175,000)	—	—	—	(175,000)
Payment of debt issuance costs	(11,172)	—	—	—	(11,172)
Excess tax benefit from stock-based compensation	896	—	—	—	896
Intercompany advances, net	(193,072)	63,734	129,338	—	—
Net cash provided by (used in) financing activities	(28,348)	63,734	129,338	—	164,724
Net change in cash and cash equivalents	46,446	(2,713)	17,070	—	60,803
Cash and cash equivalents at beginning of year	42,251	11,023	34,612	—	87,886
Cash and cash equivalents at end of year	$ 88,697	$ 8,310	$ 51,682	$ —	$ 148,689

See accompanying notes to unaudited consolidated condensed financial statements.

Note 17 — Selected Quarterly Financial Data

	Quarter				
Year 2015 [1]	First	Second	Third	Fourth	Total
	(Dollars in Thousands Except Per Share Amounts) (Unaudited)				
Revenues	$ 204,076	$ 185,941	$ 173,418	$ 148,748	$ 712,183
Operating gross margin	$ 24,267	$ 4,021	$ 4,871	$ (3,460)	$ 29,699
Operating income	$ 15,871	$ (7,944)	$ (4,547)	$ (20,718)	$ (17,338)
Net income (loss) attributable to controlling interest	$ 3,222	$ (14,029)	$ (48,620)	$ (35,646)	$ (95,073)
Basic earnings per share — net income (loss)	$ 0.03	$ (0.11)	$ (0.40)	$ (0.29)	$ (0.78)
Diluted earnings per share — net income (loss)	$ 0.03	$ (0.11)	$ (0.40)	$ (0.29)	$ (0.78)

	Quarter				
Year 2014	First	Second	Third	Fourth	Total
	(Dollars in Thousands Except Per Share Amounts) (Unaudited)				
Revenues	$ 229,225	$ 254,234	$ 242,012	$ 243,213	$ 968,684
Operating gross margin	$ 28,863	$ 43,485	$ 45,066	$ 36,768	$ 154,182
Operating income	$ 19,770	$ 37,497	$ 35,239	$ 27,714	$ 120,220
Net income attributable to controlling interest	$ (12,549)	$ 15,681	$ 12,566	$ 7,753	$ 23,451
Basic earnings per share — net income	$ (0.10)	$ 0.13	$ 0.10	$ 0.06	$ 0.19
Diluted earnings per share — net income	$ (0.10)	$ 0.13	$ 0.10	$ 0.06	$ 0.19

(1) As a result of shares issued during the year, earnings per share for each of the year's four quarters, which are based on weighted average shares outstanding during each quarter, may not equal the annual earnings per share, which is based on the weighted average shares outstanding during the year. Additionally, as a result of rounding to the thousands, revenues, operating gross margin, operating income, and net income (loss) attributable to controlling interest may not equal the 2015 year to date results.

Note 18 — Recent Accounting Pronouncements

In November 2015, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2015-17, Balance Sheet Classification of Deferred Taxes (Topic 740). This update requires businesses to classify deferred tax liabilities and assets on their balance sheets as noncurrent. Early adoption is permitted. Upon adoption, an entity must apply the new guidance either retrospectively to all prior periods presented in the financial statements prospectively for all new information on a going forward-basis. We have early adopted the standard on a retrospective basis which resulted in zero of deferred tax liabilities and $7.5 million of deferred tax assets being re-classified from current to noncurrent on the consolidated balance sheet as of December 31, 2014.

In September 2015, the FASB issued ASU No. 2015-16, Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments. This new standard specifies that the acquirer should recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined, eliminating the current requirement to retrospectively account for these adjustments. Additionally, the full effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts should be recognized in the same period as the adjustments to the provisional amounts. The standard is effective for all entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. We plan to adopt this new standard and do not currently anticipate a material impact on our financial position, results of operations and cash flows.

In July 2015, the FASB issued ASU No. 2015-11, Inventory (Topic 330): Simplifying the Measurement of Inventory, which requires companies to measure inventory at the lower of cost or net realizable value rather than at the lower of cost or market. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. The standard is effective for all entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016. We plan to adopt this new standard and do not currently anticipate a material impact on our financial position, results of operations and cash flows.

In June 2015, the FASB issued ASU No. 2015-10, Technical Corrections and Improvements, which contains amendments that will affect a wide variety of topics in the Codification. The amendments in this Update will apply to all reporting entities within the scope of the affected accounting guidance. Transition guidance varies based on the amendments in the Update. The amendments in the Update that require transition guidance are effective for all entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted, including adoption in an interim period. All other amendments will be effective upon the issuance of this Update. We plan to adopt the standard and are in the process of assessing the impact of the adoption of ASU 2015-10 on our financial position, results of operations and cash flows.

In April 2015, the FASB issued ASU No. 2015-03, Interest - Imputation of Interest (Subtopic 835-30) - Simplifying the Presentation of Debt Issuance Costs, which requires debt issuance costs related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the debt liability rather than as an asset. Final guidance on this standard, issued as ASU 2015-15 in August 2015, includes an SEC staff announcement that the SEC staff will not object to an entity presenting the cost of securing a revolving line of credit as an asset, regardless of whether a balance is outstanding. Early adoption is permitted. Upon adoption, an entity must apply the new guidance retrospectively to all prior periods presented in the financial statements. We plan to adopt the standard on a retrospective basis effective January 1, 2016 and expect it will result in the netting of our deferred financing costs against long-term debt balances on the consolidated balance sheets for the periods presented. There will be no impact to the manner in which deferred financing costs are amortized in our consolidated financial statements.

On May 28, 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers. This ASU supersedes the revenue recognition requirements in Accounting Standards Codification 605 - Revenue Recognition and most industry-specific guidance throughout the Codification. The standard requires that an entity recognizes revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services and should be applied retrospectively to each prior reporting period presented or retrospectively with the cumulative effect of initially applying the ASU recognized at the date of initial application. ASU 2014-09 was initially scheduled to be effective for the first quarter of 2017; however, on April 1, 2015, the FASB proposed to defer the effective date by one year and the proposal was accepted during the second quarter of 2015. ASU 2014-09 is now scheduled to be effective for entities beginning after December 15, 2017. We are in the process of assessing the impact of the adoption of ASU 2014-09 on our financial position, results of operations and cash flows. We have not yet selected a transition method nor have we determined the effect of the standard on our ongoing financial reporting.

Note 19 — Subsequent Events

None.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Management's Evaluation of Disclosure Controls and Procedures

In accordance with Rules 13a-15 and 15d-15 under the Securities Exchange Act of 1934 as amended (the Exchange Act), we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures, were effective as of December 31, 2015 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is (1) accumulated and communicated to our management, including our Chief Executive Officer and our Chief Financial Officer, to allow timely decisions regarding required disclosure and is (2) recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission’s rules and forms.

Management’s Annual Report on Internal Control over Financial Reporting

The Company’s management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. 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 accounting principles generally accepted in the United States. Our internal control over financial reporting includes those policies and procedures that:

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

- provide reasonable assurance transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States,

- provide reasonable assurance that receipts and expenditures of the Company are being made only in accordance with authorization of management and directors of the Company; and

- 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 risk that controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate.

The Company’s management with the participation of the chief executive officer and chief financial officer assessed the effectiveness of our internal control over financial reporting as of December 31, 2015 based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management’s assessment included evaluation of the design and testing of the operational effectiveness of our internal control over financial reporting. Management reviewed the results of its assessment with the audit committee of the board of directors.

Based on that assessment and those criteria, management has concluded that our internal control over financial reporting was effective as of December 31, 2015.

KPMG LLP, our independent registered public accounting firm that audited the consolidated financial statements included in this Annual Report on Form 10-K, has issued a report with respect to our internal control over financial reporting as of December 31, 2015.

Changes in Internal Control Over Financial Reporting

The SEC's rules permit the exclusion of an assessment of the effectiveness of a registrant's disclosure controls and procedures as they relate to its internal controls over financial reporting for an acquired business during the first year following such acquisition, if among other circumstances and factors, there is not adequate time between the acquisition date and the date of assessment. As previously noted in this Form 10-K, we completed the 2M-Tek Acquisition on April 17, 2015. 2M-Tek represents approximately 1.6 percent of our total assets and as of December 31, 2015 and less than 1.0 percent and 1.6 percent of revenues and net loss, respectively, for the year ended December 31, 2015. The 2M-Tek Acquisition did not have a material impact on internal control over financial reporting. Management's assessment and conclusion on the effectiveness of the Company's disclosure controls and procedures as of December 31, 2015 excluded an assessment of the internal control over financial reporting of 2M-

Tek. We are in the process of reviewing 2M-Tek's internal controls and processes and extending to 2M-Tek our Section 404 compliance program under the Sarbanes-Oxley Act of 2002 and the applicable rules and regulations promulgated thereunder. Other than any changes resulting from the 2M-Tek Acquisition discussed above, there have been no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

ITEM 10. Directors, Executive Officers and Corporate Governance

Information with respect to directors can be found under the captions “Item 1 — Election of Directors” and “Board of Directors” in our 2016 Proxy Statement for the Annual Meeting of Stockholders to be held on May 10, 2016. Such information is incorporated herein by reference.

Information with respect to executive officers can be found in Item 1. Business - Executive Officers of this Form 10-K.

Information with respect to our audit committee and audit committee financial expert can be found under the caption “The Audit Committee” of our 2016 Proxy Statement for the Annual Meeting of Stockholders to be held on May 10, 2016 and is incorporated herein by reference.

The information in our 2016 Proxy Statement for the Annual Meeting of Stockholders to be held on May 10, 2016 set forth under the caption “Section 16(a) Beneficial Ownership Reporting Compliance” is incorporated herein by reference.

We have adopted the Parker Drilling Code of Conduct (CC) which includes a code of ethics that is applicable to the chief executive officer, chief financial officer, controller and other senior financial personnel as required by the SEC. The CC includes provisions that will ensure compliance with the code of ethics required by the SEC and with the minimum requirements under the corporate governance listing standards of the NYSE. The CC is publicly available on our website at http://www.parkerdrilling.com. If any waivers of the CC occur that apply to a director, the chief executive officer, the chief financial officer, the controller or senior financial personnel or if the Company materially amends the CC, we will disclose the nature of the waiver or amendment on the website or in a current report on Form 8-K within four business days.

Item 11. Executive Compensation

The information under the captions “Executive Compensation,” “Fees and Benefit Plans for Non-Employee Directors,” “2015 Director Compensation Table,” and “Compensation Committee Report” in our 2016 Proxy Statement for the Annual Meeting of Stockholders to be held on May 10, 2016 is incorporated herein by reference.

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

The information required by this item is hereby incorporated by reference to the information appearing under the captions “Security Ownership of Officers, Directors and Principal Stockholders” and “Equity Compensation Plan Information” in our 2016 Proxy Statement for the Annual Meeting of Stockholders to be held on May 10, 2016.

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

The information required by this item is hereby incorporated by reference to such information appearing under the captions “Certain Relationships and Related Party Transactions” and “Director Independence Determination” in our 2016 Proxy Statement for the Annual Meeting of Stockholders to be held on May 10, 2016.

Item 14. Principal Accounting Fees and Services

The information required by this item is hereby incorporated by reference to the information appearing under the captions “Audit and Non-Audit Fees” and “Policy on Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of Independent Registered Public Accounting Firm” in our 2016 Proxy Statement for the Annual Meeting of the Stockholders to be held on May 10, 2016.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) The following documents are filed as part of this report:

(1) Financial Statements of Parker Drilling Company and subsidiaries which are included in Part II, Item 8:

	Page
Report of Independent Registered Public Accounting Firm	43
Consolidated Statement of Operations for the years ended December 31, 2015, 2014 and 2013	44
Consolidated Statement of Comprehensive Income for the years ended December 31, 2015, 2014 and 2013	45
Consolidated Balance Sheet as of December 31, 2015 and 2014	46
Consolidated Statement of Cash Flows for the years ended December 31, 2015, 2014 and 2013	47
Consolidated Statement of Stockholders' Equity for the years ended December 31, 2015, 2014 and 2013	48
Notes to the Consolidated Financial Statements	49

(2) Financial Statement Schedule:

Schedule II — Valuation and qualifying accounts 92

(3) Exhibits:

Exhibit Number		Description
2.1	—	Sale and Purchase Agreement, dated April 22, 2013, among ITS Tubular Services (Holdings) Limited, as Seller, Ian David Green, John Bruce Cartwright and Graham Douglas Frost, as joint administrators of the Seller, ITS Holdings, Inc. and PD International Holdings C.V., Parker Drilling Offshore Corporation and Parker Drilling Company (Incorporated by reference to Exhibit 10.1 to Parker Drilling Company's Current Report on Form 8-K filed on April 23, 2013).
3.1	—	Restated Certificate of Incorporation of the Company, as amended on May 16, 2007 (incorporated by reference to Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q filed on November 9, 2007).
3.2	—	By-laws of Parker Drilling Company, as amended and restated as of July 31, 2014 (Incorporated by reference to Exhibit 3.1 to Parker Drilling Company's Current Report on Form 8-K filed on August 1, 2014).
4.1	—	Indenture, dated July 30, 2013, between Parker Drilling Company, the subsidiary guarantors from time to time parties hereto, as, collectively, Guarantors, and The Bank of New York Mellon Trust Company, N.A. as Trustee (Incorporated by reference to Exhibit 10.3 to Parker Drilling Company's Current Report on Form 8-K filed on July 25, 2013).
4.2	—	Form of 7.500% Senior Note due 2020 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed on July 31, 2013).
4.3	—	Indenture, dated January 22, 2014, among Parker Drilling Company, the Guarantors and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed on January 28, 2014).
4.4	—	Form of 6.750% Senior Note due 2018 (incorporated by reference to Exhibit 4.3 to the Company's Current Report on Form 8-K filed on January 28, 2014).
10.1	—	Parker Drilling Company Incentive Compensation Plan (as amended and restated effective January 1, 2009) (incorporated by reference to Exhibit 10.4 to the Company's Annual Report on Form 10-K filed on March 1, 2011).*
10.2	—	Parker Drilling Company 2010 Long-Term Incentive Plan (incorporated by reference to Annex A to the Company's Definitive Proxy Statement filed on March 16, 2010).*

10.3	—	Form of Parker Drilling Company Restricted Stock Unit Incentive Agreement under the 2010 LTIP (incorporated by reference to Exhibit 10.18 to the Company’s Annual Report on Form 10-K filed on March 1, 2011).*
10.4	—	Form of Parker Drilling Company Performance Unit Award Incentive Agreement under the 2010 LTIP (incorporated by reference to Exhibit 10.19 to the Company’s Annual Report on Form 10-K filed on March 1, 2011).*
10.5	—	Parker Drilling Company 2010 Long-Term Incentive Plan (as amended and restated effective May 8, 2013) (incorporated by reference to Annex A to the Company’s Definitive Proxy Statement filed on March 28, 2013).*
10.6	—	Form of Parker Drilling Company Restricted Stock Unit Incentive Agreement under the 2010 LTIP (as amended and restated effective May 8, 2013) (incorporated by reference to Exhibit 10.6 to the Company's Annual Report on Form 10-K filed on February 25, 2015).*
10.7	—	Form of Parker Drilling Company Performance Stock Unit Award Incentive Agreement under the 2010 LTIP (as amended and restated effective May 8, 2013) (incorporated by reference to Exhibit 10.7 to the Company's Annual Report on Form 10-K filed on February 25, 2015).*
10.8	—	Form of Parker Drilling Company Performance Cash Unit Award Incentive Agreement under the 2010 LTIP (as amended and restated effective May 8, 2013) (incorporated by reference to Exhibit 10.8 to the Company's Annual Report on Form 10-K filed on February 25, 2015).*
10.9		Form of Parker Drilling Company Phantom Stock Unit Award Incentive Agreement under the 2010 LTIP (as amended and restated effective May 8, 2013).*
10.10	—	Form of Indemnification Agreement entered into between Parker Drilling Company and each director and executive officer of Parker Drilling Company (incorporated by reference to Exhibit 10(g) to the Company’s Annual Report on Form 10-K filed on March 20, 2003).*
10.11	—	Employment Agreement dated December 6, 2010 between Parker Drilling Company and Philip Agnew (incorporated by reference to Exhibit 10.10 to the Company's Annual Report on Form 10-K filed on February 25, 2015).*
10.12	—	Employment Agreement between Mr. Jon-Al Duplantier and Parker Drilling Company, effective March 21, 2011 (incorporated by reference to Exhibit 10.2 to the Company’s Current Report on Form 8-K filed on March 25, 2011).*
10.13	—	Employment Agreement dated August 15, 2011 between Parker Drilling Company and David Farmer (incorporated by reference to Exhibit 10.12 to the Company's Annual Report on Form 10-K filed on February 25, 2015).*
10.14		First Amendment dated August 29, 2011 to Employment Agreement between Parker Drilling Company and Philip Agnew (incorporated by reference to Exhibit 10.13 to the Company's Annual Report on Form 10-K filed on February 25, 2015).*
10.15	—	First Amendment dated August 29, 2011 to Employment Agreement between Mr. Jon-Al Duplantier and Parker Drilling Company, effective March 21, 2011 (incorporated by reference to Exhibit 10.4 to the Company’s Current Report on Form 8-K filed on August 30, 2011).*
10.16	—	Employment Agreement, dated as of September 17, 2012, by and between Parker Drilling Company and Gary Rich (incorporated by reference to Exhibit 10.23 to the Company’s Current Report on Form 8-K filed on September 24, 2012).*
10.17	—	Form of Restricted Stock Unit Incentive Agreement between Parker Drilling Company and Gary Rich (incorporated by reference to Exhibit 10.23 to the Company’s Current Report on Form 8-K filed on September 24, 2012).*

10.18	—	Employment Agreement dated May 3, 2013 between Parker Drilling Company and Christopher Weber (incorporated by reference to Exhibit 10.1 to Parker Drilling Company's Current Report on Form 8-K filed on May 14, 2013).*
10.19	—	Form of Restricted Stock Unit Incentive Agreement between Parker Drilling Company and Christopher Weber (incorporated by reference to Exhibit 10.2 to Parker Drilling Company's Current Report on Form 8-K filed on May 14, 2013).*
10.20	—	Retirement and Separation Agreement, dated November 1, 2013, between Parker Drilling Company and Robert L. Parker, Jr. (incorporated by reference to Exhibit 10.1 to Parker Drilling Company's Current Report on Form 8-K filed on November 4, 2013).*
10.21	—	Second Amended and Restated Credit Agreement, dated January 26, 2015, among Parker Drilling Company, as Borrower, Bank of America, N.A., as Administrative Agent and L/C Issuer, Wells Fargo Bank, National Association, as Syndication Agent, Barclays Bank PLC, as Documentation Agent, and the other lenders and L/C issuers from time to time party thereto (incorporated by reference to Exhibit 10.20 to the Company's Annual Report on Form 10-K filed on February 25, 2015).
10.22		First Amendment to the Second Amended and Restated Credit Agreement, dated June 1, 2015, among Parker Drilling Company, as Borrower, Bank of America, N.A., as Administrative Agent and L/C Issuer, Wells Fargo Bank, National Association, as Syndication Agent, Barclays Bank PLC, as Documentation Agent, and the other lenders and L/C issuers from time to time party thereto (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed on August 6, 2015).
10.23		Second Amendment to the Second Amended and Restated Credit Agreement, dated September 29, 2015, among Parker Drilling Company, as Borrower, Bank of America, N.A., as Administrative Agent and L/C Issuer, Wells Fargo Bank, National Association, as Syndication Agent, Barclays Bank PLC, as Documentation Agent, and the other lenders and L/C issuers from time to time party thereto (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed on November 4, 2015).
12.1	—	Computation of Ratio of Earnings to Fixed Charges.
21	—	Subsidiaries of the Registrant.
23.1	—	Consent of KPMG LLP — Independent Registered Public Accounting Firm.
31.1	—	Gary Rich, President and Chief Executive Officer, Rule 13a-14(a)/15d-14(a) Certification.
31.2	—	Christopher T. Weber, Senior Vice President and Chief Financial Officer, Rule 13a-14(a)/15d-14(a) Certification.
32.1	—	Gary Rich, President and Chief Executive Officer, Section 1350 Certification.
32.2	—	Christopher T. Weber, Senior Vice President and Chief Financial Officer, Section 1350 Certification.
101.INS	—	XBRL Instance Document.
101.SCH	—	XBRL Taxonomy Schema Document.
101.CAL	—	XBRL Calculation Linkbase Document.
101.LAB	—	XBRL Label Linkbase Document.
101.PRE	—	XBRL Presentation Linkbase Document.
101.DEF	—	XBRL Definition Linkbase Document.

* — Management contract, compensatory plan or agreement.

PARKER DRILLING COMPANY AND SUBSIDIARIES

Schedule II—Valuation and Qualifying Accounts

Classifications	Balance at beginning of year	Charged to cost and expenses	Charged to other accounts	Deductions	Balance at end of year
Dollars in Thousands					
Year ended December 31, 2015					
Allowance for bad debt	$ 11,188	$ 341	$ (825)	$ (2,010)	$ 8,694
Allowance for obsolete rig materials and supplies	$ 530	—	$ 236	$ (140)	$ 626
Deferred tax valuation allowance	$ 9,922	$ 40,676	$ 507	$ —	$ 51,105
Year ended December 31, 2014					
Allowance for bad debt	$ 12,853	$ 5,248	$ —	$ (6,913)	$ 11,188
Allowance for obsolete rig materials and supplies	$ 3,445	—	$ 1	$ (2,916)	$ 530
Deferred tax valuation allowance	$ 6,827	$ 2,800	$ 295	$ —	$ 9,922
Year ended December 31, 2013					
Allowance for bad debt	$ 8,117	$ 5,092	$ 5,861	$ (6,217)	$ 12,853
Allowance for obsolete rig materials and supplies	$ 312	$ —	$ 3,586	$ (453)	$ 3,445
Deferred tax valuation allowance	$ 4,805	$ 2,010	$ 12	$ —	$ 6,827

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

PARKER DRILLING COMPANY

By: /s/ Christopher T. Weber
Christopher T. Weber
Senior Vice President and Chief Financial Officer

Date: February 24, 2016

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

Signature	Title	Date
By: /s/ Gary G. Rich Gary G. Rich	Chairman, President, and Chief Executive Officer (Principal Executive Officer)	February 24, 2016
By: /s/ Christopher T. Weber Christopher T. Weber	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 24, 2016
By: /s/ Leslie K. Nagy Leslie K. Nagy	Controller and Principal Accounting Officer (Principal Accounting Officer)	February 24, 2016
By: /s/ Jonathan M. Clarkson Jonathan M. Clarkson	Director	February 24, 2016
By: /s/ George J. Donnelly George J. Donnelly	Director	February 24, 2016
By: /s/ Peter T. Fontana Peter T. Fontana	Director	February 24, 2016
By: /s/ Gary R. King Gary R. King	Director	February 24, 2016
By: /s/ Robert L. Parker Jr. Robert L. Parker Jr.	Director	February 24, 2016
By: /s/ Richard D. Paterson Richard D. Paterson	Director	February 24, 2016
By: /s/ Roger B. Plank Roger B. Plank	Director	February 24, 2016
By: /s/ R. Rudolph Reinfrank R. Rudolph Reinfrank	Director	February 24, 2016
By: /s/ Zaki Selim Zaki Selim	Director	February 24, 2016

INDEX TO EXHIBITS

Exhibit Number		Description
10.9	—	Form of Parker Drilling Company Phantom Stock Unit Award Incentive Agreement under the 2010 LTIP (as amended and restated effective May 8, 2013).*
12.1	—	Computation of Ratio of Earnings to Fixed Charges
21	—	Subsidiaries of the Registrant.
23.1	—	Consent of KPMG LLP — Independent Registered Public Accounting Firm.
31.1	—	Gary G. Rich, President and Chief Executive Officer, Rule 13a-14(a)/15d-14(a) Certification.
31.2	—	Christopher T. Weber, Senior Vice President and Chief Financial Officer, Rule 13a-14(a)/15d-14(a) Certification.
32.1	—	Gary G. Rich, President and Chief Executive Officer, Section 1350 Certification.
32.2	—	Christopher T. Weber, Senior Vice President and Chief Financial Officer, Section 1350 Certification.
101.INS	—	XBRL Instance Document.
101.SCH	—	XBRL Taxonomy Schema Document.
101.CAL	—	XBRL Calculation Linkbase Document.
101.LAB	—	XBRL Label Linkbase Document.
101.PRE	—	XBRL Presentation Linkbase Document.
101.DEF	—	XBRL Definition Linkbase Document.

EXHIBIT 10.9

PARKER DRILLING COMPANY

PHANTOM STOCK UNIT AWARD INCENTIVE AGREEMENT

THIS PHANTOM STOCK UNIT AWARD INCENTIVE AGREEMENT (this "**Agreement**") is made and entered into by and between Parker Drilling Company, a Delaware corporation (the **"Company"**), and **[NAME]**, an individual and employee of the Company (**"Grantee"**), as of the **[DATE]** day of **[MONTH]**, 2015 (the **"Grant Date"**), subject to the terms and conditions of the Parker Drilling Company 2010 Long-Term Incentive Plan, as Amended and Restated, as it may be further amended from time to time thereafter (the **"Plan"**). The Plan is hereby incorporated herein in its entirety by this reference. Capitalized terms not otherwise defined in this Agreement shall have the meaning given to such terms in the Plan.

WHEREAS, Grantee is **[TITLE]** of the Company, and in connection therewith, the Company desires to grant a Performance-Based Stock-Based Award to Grantee, subject to the terms and conditions of this Agreement and the Plan, with a view to increasing Grantee's interest in the Company's success and growth; and

WHEREAS, Grantee desires to be the holder of a Performance-Based Stock-Based Award subject to the terms and conditions of this Agreement and the Plan;

NOW, THEREFORE, in consideration of the premises, mutual covenants and agreements contained herein, and such other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the parties hereto, intending to be legally bound, hereby agree as follows:

1. Grant of Phantom Stock Units. Subject to the terms and conditions of this Agreement and the Plan, the Company hereby grants to Grantee [**NUMBER]** Phantom Stock Units as described herein (the " **Phantom Stock Units**"), which constitutes a Performance-Based Stock based Award under the Plan. Each Phantom Stock Unit shall initially represent the equivalent of one Share as of the Grant Date, with the actual payout value to be determined under the terms and conditions of this Agreement. With respect to the Phantom Stock Units granted under this Agreement, the Committee reserves the right and authority, as exercised in its discretion, to decrease the size of the Incentive Award by a percentage not to exceed twenty percent (20%) at any time before or after the Incentive Award becomes fully vested but prior to actual payment, but subject to Section 6 for Detrimental Conduct. As a holder of Phantom Stock Units, the Grantee has the rights of a general unsecured creditor of the Company unless and until the Phantom Stock Units are vested and paid out to Grantee, as set forth herein.

2. Transfer Restrictions. Grantee shall not sell, assign, transfer, exchange, pledge, encumber, gift, devise, hypothecate or otherwise dispose of (collectively, **"Transfer"**) any Phantom Stock Units granted hereunder. Any purported Transfer of Phantom Stock Units in breach of this Agreement shall be void and ineffective, and shall not operate to Transfer any interest or title to the purported transferee.

3. Vesting of Phantom Stock Units.

(a) *Performance Period*. For purposes of this Agreement, the performance period is the three-year period that begins on January 1, 2015 and ends on December 31, 2017 (the "**Performance Period**"). Subject to the terms and conditions of this Agreement, the Phantom Stock Units shall vest and become payable to Grantee at the end of the Performance Period, provided that (i) Grantee was an Employee continuously throughout the Performance Period (the "**Service Requirement**") and (ii) the Committee has certified in writing that the performance criterion established for the Performance Period as described below (the "**Performance Criterion**") has been achieved. All Phantom Stock Units that do not become vested during or at the end of the Performance Period shall be forfeited.

(b) *Performance Criteria*. There is one Performance Criterion that has been established for the Phantom Stock Units awarded under this Agreement, as described in subsection (c) below. When determining performance, the Committee, in its discretion, may take into account special or non-recurring situations or circumstances with respect to the Company or any other company in the Peer Group for any year during the Performance Period arising from the acquisition or disposition of assets, costs associated with exit or disposal activities or material impairments.

(c) *RTSR*. The Performance Criterion is the Company's Relative Total Shareholder Return (" **RTSR**") as defined in Exhibit A to this Agreement (the " **RTSR Criterion**"). The Company's RTSR is compared to the RTSR of each Peer Group company, as listed on Exhibit A to this Agreement (each a " **Peer Company**" and as a group, the "**Peer Group**"), as of the end of each calendar year within the Performance Period to determine where the Company ranks when compared to the Peer Group. The RTSR Criterion is one-hundred percent (100%) of the total weighting for each Phantom Stock Unit.

(d) *Changes in Peer Group* . When calculating RTSR for the Performance Period for the Company and the Peer Group, (i) the performance of a company in the Peer Group will not be used in calculating the RTSR of that member of the Peer Group if the company is not publicly traded (*i.e.*, has no ticker symbol) at the end of the Performance Period; (ii) the performance of any company in the Peer Group that becomes bankrupt during the Performance Period will be included in the calculation of Peer Group performance even if it has no ticker symbol at the end of the measurement period; (iii) the performance of the surviving entities will be used in the event there is a combination of any of the Peer Group companies during the measurement period; and (iv) no new companies will be added to the Peer Group during the Performance Period (including a company that is not a Peer Group member which acquires a member of the Peer Group). Notwithstanding the foregoing provisions of this subsection (d), the Committee may disregard any of these guidelines when evaluating changes in the membership of the Peer Group during the Performance Period in any particular situation, as it deems reasonable in the exercise of its discretion.

(e) *Ranking of Company as Compared to the Peer Group* . The Committee will rank the Company's performance within the Peer Group as of December 31st of each calendar year within the Performance Period and apply the appropriate weighting and award multiplier from the following table:

	Description	Weighting
12/31/2015	Single Year RTSR (2015)	20%
12/31/2016	Cumulative RTSR (2015-2016)	30%
12/31/2017	Cumulative RTSR (2015-2017)	50%

Ranking	Award Multiplier
1	2.50 MAX
2	2.00
3	1.60
4	1.30
5	1.10
6	1.00 TARGET
7	0.75
8	0.50
9	0.25 ENTRY
10	0.00
11	0.00

4. Termination of Employment. If Grantee's Employment is voluntarily or involuntarily terminated during the Performance Period, then Grantee shall immediately forfeit the outstanding Phantom Stock Units, except as provided below in this Section 4. Upon the forfeiture of any Phantom Stock Units hereunder, the Grantee shall cease to have any rights in connection with such Phantom Stock Units as of the date of forfeiture.

(a) *Termination of Employment*. Except as provided in Section 4(c), if the Grantee's Employment is terminated for any reason, including Retirement, other than due to death or Disability during the Performance Period, any non-vested Phantom Stock Units at the time of such termination shall automatically expire and terminate and no further vesting shall occur after the termination of Employment date. In such event, the Grantee will receive no payment for unvested Phantom Stock Units.

(b) *Disability or Death*. Upon termination of Grantee's Employment as the result of Grantee's Disability (as defined below) or death during the Performance Period, then all of the outstanding Phantom Stock Units shall become 100% vested on such date at the 1.0 multiplier award level. For purposes of this Agreement, "**Disability**" means (i) a disability that entitles the Grantee to benefits under the Company's long-term disability plan, as may be in effect from time to time, as determined by the plan administrator of the long-term disability plan or (ii) a disability whereby the Grantee is unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of not less than 12 months.

(c) *Change in Control*. If there is a Change in Control of the Company (as defined in the Plan) during the Performance Period, then in the event of the Grantee's Involuntary Termination Without Cause (as defined below) within two (2) years following the effective date of the Change in Control and during the same Performance Period, all the outstanding

Phantom Stock Units shall automatically become 100% vested on the Grantee's termination of Employment date at the 1.0 multiplier award level.

(d) For purposes of this Agreement, " **Involuntary Termination Without Cause** " means the Employment of Grantee is involuntarily terminated by the Company (or by any successor to the Company) for any reason, including, without limitation, as the result of a Change in Control, except due to death, Disability, Retirement or Cause; provided, that in the event of a dispute regarding whether Employment was terminated voluntarily or involuntarily, or with or without Cause, such dispute will be resolved by the Committee, in good faith, in the exercise of its discretion.

5. Payment for Phantom Stock Units. Payment for the vested Phantom Stock Units subject to this Agreement shall be made to the Grantee as soon as practicable following the time such Phantom Stock Units become vested in accordance with Section 3 or Section 4 prior to their expiration, but not later than seventy-five (75) days following the date of such vesting event. The number of Phantom Stock Units that vest and are payable hereunder shall be determined by the Committee, in its discretion, in accordance with the Payout Schedule in Section 3.

Any amount paid in respect of the vested Phantom Stock Units shall be payable in U.S. dollars in cash or other form of immediately-available funds. The amount payable to the Grantee pursuant to this Agreement shall be an amount equal to (a) the number of vested Phantom Stock Units, multiplied by (b) the award multiplier for the level of achievement of the Performance Criterion determined in Section 3(d), multiplied by (c) the average closing price per Share for the twenty trading days immediately preceding the vesting date.

Prior to any payments under this Agreement, the Committee shall certify in writing, by resolution or otherwise, the amount to be paid in respect of the Phantom Stock Units as a result of the achievement of the Performance Criterion.

6. Detrimental Conduct. In the event that the Committee should determine, in its sole and absolute discretion, that, during Employment or within two (2) years following Employment termination for any reason, the Grantee engaged in Detrimental Conduct (as defined below), the Committee may, in its sole and absolute discretion, if payment previously has been made to the Grantee pursuant to Section 5 upon vesting of his Phantom Stock Units, direct the Company to send a notice of recapture (a "**Recapture Notice**") to such Grantee. Within ten (10) days after receiving a Recapture Notice from the Company, the Grantee will deliver to the Company a cash payment in an amount equal to the payment to the Grantee at the time when paid to the Grantee, unless the Recapture Notice demands repayment of a lesser sum. All repayments hereunder shall be net of the taxes that were withheld by the Company when the payment was originally made to Grantee following vesting of the Phantom Stock Units pursuant to Section 5. For purposes of this Agreement, a Grantee has committed "**Detrimental Conduct**" if the Grantee (a) violated a confidentiality, non-solicitation, non-competition or similar restrictive covenant between the Company or one of its Affiliates and such Grantee, including violation of a Company policy relating to such matters, or (b) engaged in willful fraud that causes harm to the Company or one of its Affiliates or that is intended to manipulate the performance results of any Incentive Award, including, without limitation, any material breach of fiduciary duty, embezzlement or similar conduct that results in a restatement of the Company's financial statements.

7. Grantee's Representations. Notwithstanding any provision hereof to the contrary, the Grantee hereby agrees and represents that neither Grantee nor the Company shall be obligated hereunder to the extent such obligation constitutes a violation by the Grantee or the Company of any law or regulation of any governmental authority. Any determination in this regard that is made by the Committee, in good faith, shall be final and binding. The rights and obligations of the Company and the Grantee are subject to all applicable laws and regulations.

8. Tax Withholding. To the extent that the receipt of the payment hereunder results in compensation income to Grantee for federal, state or local income tax purposes, Grantee shall deliver to Company at such time the sum that the Company requires to meet its tax withholding obligations under applicable law or regulation, and, if Grantee fails to do so, Company is authorized to withhold from any cash or other remuneration (including any Shares), then or thereafter payable to Grantee, any tax required to be withheld to satisfy such tax withholding requirements before transferring the resulting net funds to Grantee in satisfaction of its obligations under this Agreement.

9. Independent Legal and Tax Advice. The Grantee acknowledges that (a) the Company is not providing any legal or tax advice to Grantee and (b) the Company has advised the Grantee to obtain independent legal and tax advice regarding this Agreement and any payment hereunder.

10. No Rights in Shares. The Grantee shall have no rights as a stockholder in respect of any Shares, unless and until the Grantee becomes the record holder of such Shares on the Company's records.

11. Conflicts with Plan, Correction of Errors, and Grantee's Consent . In the event that any provision of this Agreement conflicts in any way with a provision of the Plan, such provisions shall be reconciled, or such discrepancy shall be resolved, by the Committee in the exercise of its discretion. In the event that, due to administrative error, this Agreement does not accurately reflect the Phantom Stock Units properly granted to the Grantee, the Committee reserves the right to cancel any erroneous document and, if appropriate, to replace the canceled document with a corrected document. All determinations and computations under this Agreement shall be made by the Committee (or its authorized delegate) in its discretion as exercised in good faith.

This Agreement and any award of Phantom Stock Units or payment hereunder are intended to comply with or be exempt from Section 409A of the Internal Revenue Code and shall be interpreted accordingly. Accordingly, Grantee consents to such amendment of this Agreement as the Committee may reasonably make in furtherance of such intention, and the Company shall promptly provide, or make available, to Grantee a copy of any such amendment.

12. Miscellaneous.

(a) *Transferability of Phantom Stock Units* . The Phantom Stock Units are transferable only to the extent permitted under the Plan at the time of transfer (i) by will or by the laws of descent and distribution, or (ii) by a domestic relations order in such form as is acceptable to the Company. No right or benefit hereunder shall in any manner be liable for or subject to any debts, contracts, liabilities, obligations or torts of the Grantee or any permitted transferee thereof.

(b) *Not an Employment Agreement*. This Agreement is not an employment agreement, and no provision of this Agreement shall be construed or interpreted to create any Employment relationship between Grantee and the Company for any time period. The Employment of Grantee with the Company shall be subject to termination to the same extent as if this Agreement did not exist.

(c) *Notices*. Any notice, instruction, authorization, request or demand required hereunder shall be in writing, and shall be delivered either by personal in-hand delivery, by telecopy or similar facsimile means, by certified or registered mail, return receipt requested, or by courier or delivery service, addressed to the Company at its then current main corporate address, and to Grantee at the address indicated on the Company's records, or at such other address and number as a party has last previously designated by written notice given to the other party in the manner hereinabove set forth. Notices shall be deemed given when received, if sent by facsimile means (confirmation of such receipt by confirmed facsimile transmission being deemed receipt of communications sent by facsimile means); and when delivered and receipted for (or upon the date of attempted delivery where delivery is refused), if hand-delivered, sent by courier or delivery service, or sent by certified or registered mail, return receipt requested.

(d) *Amendment, Termination and Waiver*. This Agreement may be amended, modified, terminated or superseded only by written instrument executed by or on behalf of the Grantee and the Company (by action of the Committee or its delegate). Any waiver of the terms or conditions hereof shall be made only by a written instrument executed and delivered by the party waiving compliance. Any waiver granted by the Company shall be effective only if executed and delivered by a duly authorized executive officer of the Company other than Grantee. The failure of any party at any time or times to require performance of any provisions hereof shall in no manner affect the right to enforce the same. No waiver by any party of any term or condition herein, or the breach thereof, in one or more instances shall be deemed to be, or construed as, a further or continuing waiver of any such condition or breach or a waiver of any other condition or the breach of any other term or condition.

(e) *No Guarantee of Tax or Other Consequences*. The Company makes no commitment or guarantee that any tax treatment will apply or be available to the Grantee or any other person. The Grantee has been advised, and provided with ample opportunity, to obtain independent legal and tax advice regarding this Agreement.

(f) *Governing Law and Severability*. This Agreement shall be governed by the laws of the State of Texas without regard to its conflicts of law provisions, except as preempted by controlling federal law. The invalidity of any provision of this Agreement shall not affect any other provision hereof or of the Plan, which shall remain in full force and effect.

(g) *Successors and Assigns*. This Agreement shall bind, be enforceable by, and inure to the benefit of, the Company and Grantee and any permitted successors and assigns under the Plan.

[Signature page follows.]

IN WITNESS WHEREOF, this Agreement is hereby approved and executed as of the date first written above.

Parker Drilling Company

By:______________

Name:______________

Title:______________

Grantee

____

Signature

____

Print Name

Grantee's Address for Notices:

____

____

____

____

EXHIBIT A

Performance Criterion

1 . **RTSR**. RTSR is the Performance Criterion applicable to the Phantom Stock Units and is determined by dividing (1) the sum of (a) the cumulative amount of the dividends of the Company or the Peer Company, as applicable, for the applicable period assuming same-day reinvestment into the corporation's common stock on the ex-dividend date and (b) the share price of such corporation at the end of the applicable period minus the share price at the beginning of the applicable period, by (2) the share price at the beginning of the applicable period. The RTSR for each Peer Company in the Peer Group will be calculated over the applicable period, annualized, and then compared with the identical calculation for the Company. The Company's RTSR is a Performance Criterion that is compared to each Peer Company's RTSR for the applicable period.

2 . **Peer Companies and Peer Group** . Subject to Section 3(d), the following Peer Companies comprise the Peer Group to which the Company's RTSR performance will be compared for the Performance Period:

1. BAS Basic Energy Services, Inc.
2. HP Helmerich & Payne, Inc.
3. HERO.O Hercules Offshore, Inc.
4. KEG Key Energy Services, Inc.
5. NBR Nabors Industries Ltd.
6. PES Pioneer Energy Services Corp.
7. PDS Precision Drilling Corporation
8. SPN Superior Energy Services Inc.
9. PTEN.O Patterson
10. WFT Weatherford

3 . **Alternate Payout Scales** . Should the number of Peer Companies decrease during the Performance Period as described in Section 3(d) of the Agreement, then the Company's performance within the Peer Group may be measured according to one of the following alternate tables, subject to the Committee's discretion:

Company + 9 Peers	
Ranking	**Award Multiplier**
1	2.50 MAX
2	2.00
3	1.60
4	1.25
5	1.00 TARGET
6	0.75
7	0.50
8	0.25 ENTRY
9	0.00
10	0.00

Company + 8 Peers	
Ranking	**Award Multiplier**
1	2.50 MAX
2	1.90
3	1.50
4	1.20
5	1.00 TARGET
6	0 .75
7	0.50
8	0.25 ENTRY
9	0.00

If the Peer Group size changes during the Performance Period all determinations that have already occurred for single year or cumulative period(s) will not be recalculated. However, all determinations after the change in Peer Group size will consider the updated Peer Group for measurement periods not yet completed. By way of example, if the Peer group size is 10 in the first year, 9 in the second year, and 8 in the third year, the calculation would be as follows:

12/31/2015	Single Year RTSR (2015) compared to 10 peers	20%
12/31/2016	Cumulative RTSR (2015-2016) compared to 9 peers for the entire cumulative period	30%
12/31/2017	Cumulative RTSR (2015-2017) compared to 8 peers for the entire cumulative period	50%

EXHIBIT 12.1

Parker Drilling Company
Computation of Ratio of Earnings to Fixed Charges
(Dollars in Thousands)

	Fiscal Year Ended December 31,				
	2015	**2014**	**2013**	**2012**	**2011**
Pretax Income	(71,971)	48,537	52,787	70,977	(65,412)
Fixed Charges	45,380	45,436	50,196	43,782	41,865
Amortization of Capitalized Interest	3,793	3,939	4,058	1,887	1,557
Capitalized Interest	(224)	(1,171)	(2,376)	(10,240)	(19,271)
Earnings before Income Tax & Fixed Charges	(23,022)	96,741	104,665	106,406	(41,261)
Interest Expense	45,155	44,265	47,820	33,542	22,594
Capitalized Interest	224	1,171	2,376	10,240	19,271
Total Fixed Charges	45,379	45,436	50,196	43,782	41,865
Ratio of Earnings to Fixed Charges	(1)	2.1x	2.1x	2.4x	(2)

(1) For the year ended December 31, 2015, earnings were deficient to cover fixed charges by $23.0 million.

(2) For the year ended December 31, 2011, earnings were deficient to cover fixed charges by $41.3 million, which was primarily due to a pre-tax, non-cash charge to earnings of $170.0 million related to the impairment of our two Alaska rigs.

EXHIBIT 21

SUBSIDIARIES OF THE REGISTRANT

The following is a list of significant subsidiaries of the Registrant:

1. Parker North America Operations, Inc. (Nevada)-100% direct subsidiary.
2. Parker Drilling International Holding Company, LLC (Delaware)-100% direct subsidiary.
3. Parker Technology, Inc. (Oklahoma)-100% direct subsidiary.
4. Universal Rig Service LLC (Delaware)-100% direct subsidiary.
5. Parker Drilling Offshore USA, LLC (Oklahoma)-100% indirect subsidiary-owned by Parker Drilling Offshore, LLC (100%).
6. Parker Drilling Company International Limited (Nevada)-100% indirect subsidiary-owned by Parker Drilling Eurasia, Inc. (100%)
7. Parker Drilling Company Eastern Hemisphere, Ltd. Co. (Oklahoma)-100% indirect subsidiary-owned by Parker Drilling Eurasia, Inc. (100%).
8. Parker Drilling Netherlands B.V. (Netherlands)-100% indirect subsidiary-owned by PD Selective Holdings C.V. (100%).
9. Parker Drilling Russia B.V. (Netherlands)-100% indirect subsidiary-owned by Parker Drilling Netherlands B.V. (100%).
10. Parker Drilling Overseas B.V. (Netherlands)-100% indirect subsidiary-owned by Parker Drilling Netherlands B.V. (100%).
11. Parker Central Europe Rig Holdings LLC (Hungary)-100% indirect subsidiary-owned by Parker Drilling (Kazakhstan), LLC (100%).
12. Primorsky Drill Rig Services BV (Netherlands)-100% indirect subsidiary-owned by Parker Drilling Netherlands B.V. (100%).
13. Parker Drilling Management Services, Inc. (Nevada)-100% indirect subsidiary-owned by Parker North America Operations, Inc. (100%).
14. Parker Drilling Arctic Operating, LLC (Delaware)-100% indirect subsidiary-owned by Parker North America Operations, Inc. (100%).
15. International Tubulars FZE (United Emirates)-100% indirect subsidiary-owned by International Tubular Services Limited (100%).
16. Parker Hungary Rig Holding LLC - Switzerland Branch (Switzerland)-100% indirect subsidiary-owned by Parker Hungary Rig Holding LLC (100%).
17. Parker Drilling Alaska Services, Ltd (United Kingdom)-100% indirect subsidiary-owned by Parker Drilling Arctic Operating, LLC (100%).
18. Parker Drilling Overseas B.V. - Abu Dhabi Branch (United Emirates)-100% indirect subsidiary-owned by Parker Drilling Netherlands B.V. (100%).
19. Quail Tools, L.P. (Oklahoma)-100% indirect subsidiary-owned by Parker Tools, LLC (99%) and Quail USA LLC (1%).
20. International Tubular Services De Mexico, S. De R.I. De C.V. (Mexico)-100% indirect subsidiary-owned by International Tubular Services Limited (99%) and ITS Egypt Holdings 2, Ltd (1%).
21. Parker Drilling Eurasia, Inc. (Delaware)-100% indirect subsidiary-owned by Parker Drilling International Holding Co LLC (64.8%) and Parker Drilling Offshore LLC (35.2%).

Note: Certain subsidiaries have been omitted from the list since they would not, even if considered in the aggregate, constitute a significant subsidiary. All subsidiaries are included in the consolidated financial statements.

EXHIBIT 23.1

Consent of Independent Registered Public Accounting Firm

The Board of Directors

Parker Drilling Company:

We consent to the incorporation by reference in the registration statement (No. 333-197977) on Form S-3, in registration statements (Nos. 333-188754, 333-184230, 333-167695) on Form S-8 of Parker Drilling Company of our report dated February 24, 2016, with respect to the consolidated balance sheets of Parker Drilling Company and subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2015, and the effectiveness of internal control over financial reporting as of December 31, 2015, which reports appear in the December 31, 2015 annual report on Form 10-K of Parker Drilling Company.

/s/ KPMG LLP

Houston, Texas

February 24, 2016

EXHIBIT 31.1

PARKER DRILLING COMPANY
RULE 13a-14(a)/15d-14(a) CERTIFICATION

I, Gary G. Rich, certify that:

1. I have reviewed this annual report on Form 10-K for the period ended December 31, 2015, of Parker Drilling Company (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material
respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as
defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

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

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

Date: February 24, 2016

/s/ Gary G. Rich
Gary G. Rich
Chairman, President and Chief Executive Officer

EXHIBIT 31.2

PARKER DRILLING COMPANY
RULE 13a-14(a)/15d-14(a) CERTIFICATION

I, Christopher T. Weber, certify that:

1. I have reviewed this annual report on Form 10-K for the period ended December 31, 2015, of Parker Drilling Company (the registrant);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material
respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as
defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2016

/s/ Christopher T. Weber

Christopher T. Weber
Senior Vice President and Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350

Pursuant to 18 U.S.C. Section 1350, the undersigned officer of Parker Drilling Company (the “Company) hereby certifies, to such officer’s knowledge, that:

1. The Company’s Annual Report on Form 10-K for the year ended December 31, 2015 (the “Report) fully complies with the requirements of section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Dated: February 24, 2016

/s/ Gary G. Rich

Gary G. Rich
Chairman, President and Chief Executive Officer

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure statement.

EXHIBIT 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350

Pursuant to 18 U.S.C. Section 1350, the undersigned officer of Parker Drilling Company (the “Company) hereby certifies, to such officer’s knowledge, that:

1. The Company’s Annual Report on Form 10-K for the year ended December 31, 2015 (the “Report) fully complies with the requirements of section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Dated: February 24, 2016

/s/ Christopher T. Weber

Christopher T. Weber
Senior Vice President and Chief Financial Officer

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure statement.