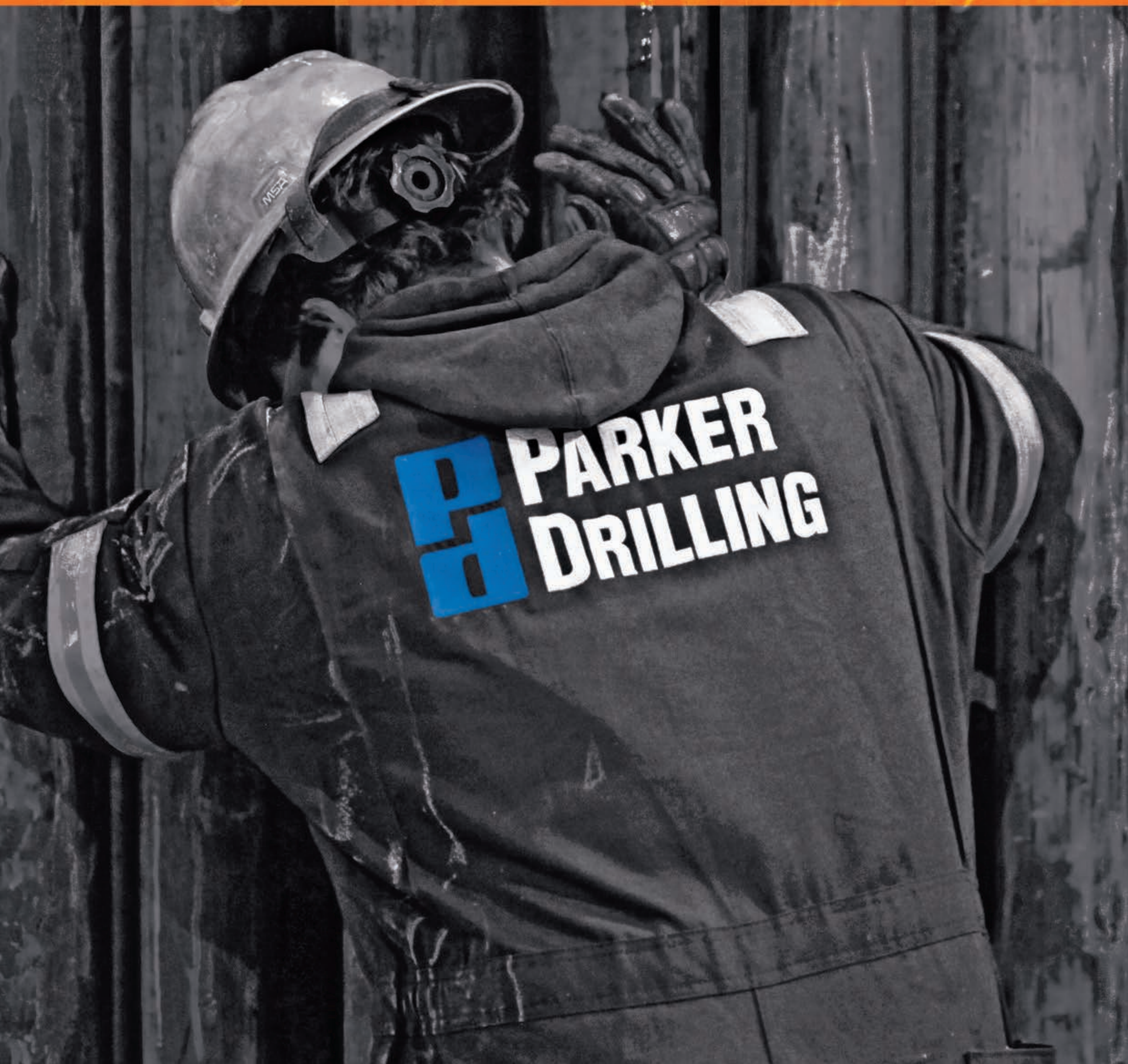
DEEPER EXPECTATIONS.

PARKER DRILLING 2013 ANNUAL REPORT



Financial Highlights

(U.S. dollars in thousands, except per share data)	Year ended December 31, 2013	2012	2011[1]
Revenues	**$ 874,172**	$ 677,761	$ 686,234
Operating income (loss)	**101,872**	107,273	(41,837)
Net income (loss) attributable to controlling interest	**27,015**	37,313	(50,451)
Capital expenditures	**155,645**	191,543	190,399
Total assets	**1,534,756**	1,255,733	1,216,246
Property, plant and equipment, net[2]	**871,356**	793,197	722,774
Total debt	**653,781**	479,205	482,723
Stockholders' equity	**633,142**	590,633	544,050
Per common share data			
Diluted earnings	**0.22**	0.31	(0.43)
Book value	**5.24**	4.97	4.65
Current ratio	**2.5:1**	2.3:1	1.3:1
Return on capital employed (ROCE)[3]	**4.7%**	5.4%	6.7%
Shares of common stock outstanding	**120,491,164**	118,968,396	117,061,203
Employees	**3,395**	2,085	2,317

[1] 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.

[2] The balances for the years ended December 31, 2012 and 2011 have been adjusted to reflect the reclassification to property, plant & equipment of certain assets previously classified as assets held for sale.

[3] ROCE = (Net Income + After-tax Interest Expense) / Average Year (Total Assets – Current Liabilities except Current Debt) based on a 35% tax rate and adjusted for Asset Impairment in 2011. Average Year: average of values at the beginning and end of each year.

TOTAL RIG COUNT*
36

TOTAL RENTAL LOCATIONS*
28

TOTAL O&M CONTRACTS*
4

* As of early 2014

Corporate Profile

Parker Drilling (NYSE: PKD) provides contract drilling and drilling-related services and rental tools to the energy industry. The Company's drilling business serves operators in the inland waters of the U.S. Gulf of Mexico utilizing Parker's barge rig fleet and in select U.S. and international markets and harsh-environment regions utilizing Parker-owned and customer-owned equipment.
The Company's rental tools business supplies premium equipment and well services to operators on land and offshore in the U.S. and international markets. Learn more about the Company at www.parkerdrilling.com.

Parker Goes **Deep.**

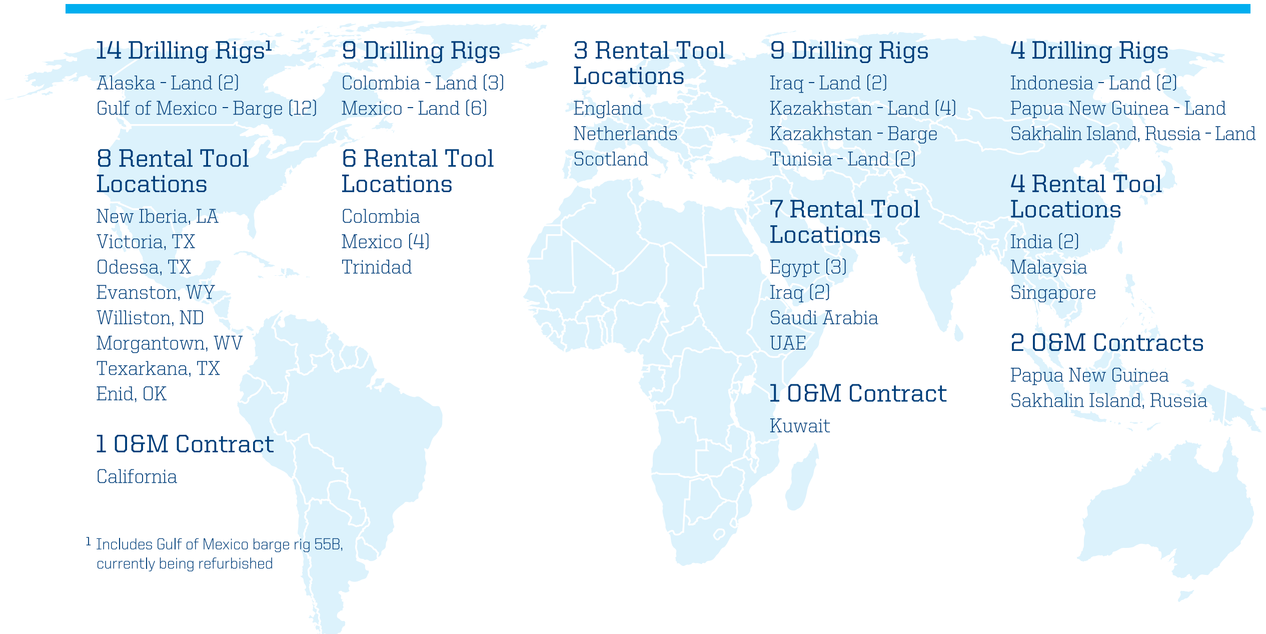
We take on the toughest customer challenges. We drill some of the deepest wells in the world. We bring 80 years of hard-earned experience to every job, every day.

But for all we are and all we've accomplished, we know there is still much work to do. Because progress raises expectations – and when stakeholders expect more of us, we must demand even more of ourselves.

In 2013, the men and women of Parker Drilling proved our collective ability to shape and focus this company for today's world and tomorrow. And while 365 days is just a stepping stone along our journey, we believe this year's results begin to reveal our true potential.

Looking ahead, we'll face each day empowered to raise the bar for innovation, reliability and efficiency in our industry, and to create even greater value for those who invest in us. We'll aim high while staying grounded. And we'll strive to exceed those deeper expectations every step of the way.

Global Presence (as of early 2014)



UNITED STATES

14 Drilling Rigs[1]
Alaska - Land (2)
Gulf of Mexico - Barge (12)

8 Rental Tool Locations
New Iberia, LA
Victoria, TX
Odessa, TX
Evanston, WY
Williston, ND
Morgantown, WV
Texarkana, TX
Enid, OK

1 O&M Contract
California

LATIN AMERICA

9 Drilling Rigs
Colombia - Land (3)
Mexico - Land (6)

6 Rental Tool Locations
Colombia
Mexico (4)
Trinidad

U.K./EUROPE

3 Rental Tool Locations
England
Netherlands
Scotland

CENTRAL ASIA MIDDLE EAST NORTH AFRICA

9 Drilling Rigs
Iraq - Land (2)
Kazakhstan - Land (4)
Kazakhstan - Barge
Tunisia - Land (2)

7 Rental Tool Locations
Egypt (3)
Iraq (2)
Saudi Arabia
UAE

1 O&M Contract
Kuwait

ASIA-PACIFIC

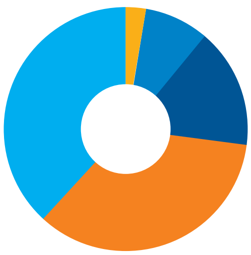
4 Drilling Rigs
Indonesia - Land (2)
Papua New Guinea - Land
Sakhalin Island, Russia - Land

4 Rental Tool Locations
India (2)
Malaysia
Singapore

2 O&M Contracts
Papua New Guinea
Sakhalin Island, Russia

[1] Includes Gulf of Mexico barge rig 55B, currently being refurbished

SEGMENT REVENUES



38% International Drilling
35% Rental Tools
16% U.S. Barge Drilling
8% U.S. Drilling
3% Technical Services

GLOBAL REVENUES

52% Domestic
48% International

Dear Shareholder,

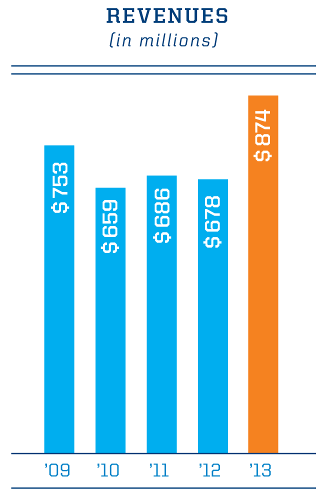
Today, the pursuit of continuous improvement is at the forefront of everyone's mind here at Parker Drilling. We know our mission to deliver innovative, reliable and efficient results and steadily build the confidence of all Parker stakeholders requires us to do things just a little better than we did yesterday. This challenge has us energized and determined to succeed – and I believe our achievements in 2013 are a good indication that we're making real progress on our journey.

Some of this progress was truly transformational, particularly our acquisition of **International Tubular Services Limited (ITS)**, a privately held rental tools and well services company with proven success in strategic international markets. The company's established footprint and range of products and services complement and expand our own portfolio and give us a global pathway to build on the success we've achieved in the U.S. rental tools business through our Quail Tools subsidiary. This is a great opportunity for Parker – one you'll read more about in this report.

We made significant progress in many areas of our business, particularly our international drilling operations and I'm very pleased with the momentum we are gaining. Moving two idle rigs out of Kazakhstan to the Kurdistan Region of Iraq enhances our market position in an area that shows a great deal of promise for Parker. Of our five remaining rigs in Kazakhstan, four are currently under contract and we are actively pursuing additional work for the fifth. Late in the year, we also sold two rigs in New Zealand and one rig in Latin America to eliminate equipment that no longer fits within our strategy. This selective market focus had a strong positive impact on our international rig fleet utilization, which increased to 73 percent for the fourth quarter of 2013, a substantial improvement from 42 percent at the end of the prior year's fourth quarter.

Our barge drilling operations also had another year of strong performance, continuing to build a solid customer base by providing reliable and efficient equipment and crews that consistently deliver results for our customers. Our eleven marketable rigs in the Gulf of Mexico (GOM) barge drilling market represent less than half of the available fleet, yet drilled approximately 60 percent of the wells drilled in the Gulf's inland waters in 2013. The barge drilling operations team also oversaw our work on a new operations and maintenance contract for three drilling platforms off the California coast, where we just completed our first full year of operations for our client.

In 2014, we will introduce barge rig 55B to our GOM fleet to bring additional capabilities to this market. Rig 55B, which is expected to become operational during the second quarter, features advanced equipment and performance enhancements and is already under contract.



We put two Arctic-class drilling rigs to work on the North Slope of Alaska around the beginning of 2013. The two rigs drilled 14 wells in 2013 for our customer and we're seeking ways to apply the knowledge we're gaining from this experience to other areas of our Arctic operations.

On Sakhalin Island, Russia, our focus on reliable performance helped our customer, Exxon Neftegas Ltd. (ENL), set several new extended-reach drilling world records during the year, including a 12,700-meter (nearly eight-mile) well. Just as important, the safety-related efforts of our team on Sakhalin Island resulted in Parker being named **"Drilling Contractor of the Year"** by ENL for 2013. We are proud of these accomplishments and believe they reflect our focus on helping our customers realize optimum returns on their drilling program investments.

Quail Tools
A PARKER COMPANY

Our U.S. rental tools business, **Quail Tools**, navigated weak demand and competitive pricing all year, particularly in the fourth quarter, and continued to strengthen its footprint in the U.S. Gulf of Mexico offshore drilling market. Quail's offshore GOM-related revenues grew approximately 27 percent during the year. In addition, the introduction of a new facility in Enid, Oklahoma will help meet the needs of customers working in the Mississippian Lime shale play and other nearby fields in 2014.

At the end of the year, Robert L. "Bobby" Parker, Jr. retired after a long and notable career. On behalf of the Leadership Team and our employees, who have so much respect and admiration for Bobby, I want to thank him for his many years of dedicated service to this company. I invite you to read more about Bobby's significant contributions to this company and to our industry in a dedicated section of this report.

Year 2013 saw a lot of milestones – but striving for excellence in a complex, changing industry is a never-ending journey. In 2014, we will push to deliver even more results as we generate value for our stakeholders. I look forward to reporting our progress to you in the upcoming year.

Gary G. Rich
President and Chief Executive Officer

Honoring a Visionary Leader

On December 31, 2013, **Robert L. "Bobby" Parker, Jr.** retired as an employee of the company founded by his grandfather, G.C. Parker. Bobby served Parker Drilling for more than 40 years, including 18 years as president and chief executive officer.

During his tenure, Bobby established the company as a respected trailblazer and leader in energy exploration and development. Under his guidance, Parker Drilling was instrumental in creating innovative technologies and operational procedures that advanced the drilling profession and continue to benefit the global oil and gas industry today. He was also a recognized champion of safe operations, environmental stewardship and performance excellence.

Bobby's integrity, genuine passion for the drilling business and customer focus helped fuel decades of success for the company. We are proud to recognize and honor his tremendous vision and leadership.

MEETING EXPECTATIONS. In 2013, we identified four objectives critical to Parker's long-term success. These imperatives cover the range of what we do and how we do it, from performing for our customers to managing an efficient, sustainable business to positioning the company to seize opportunities. We're proud to share our key achievements for the year with you.

OBJECTIVE 1:

Deliver Reliable Results

Every Parker stakeholder wants a company that can be counted on to perform, day to day and year after year. Whether we're working for a customer in the field or honing our analytical capabilities, our ultimate objective is to execute on our strategies, build confidence and produce reliable, sustainable results.

Honored for Collaborative, Record-Setting Partnership

In 2013, Exxon Neftegas, Ltd. (ENL) recognized Parker Drilling's crews on Sakhalin Island, Russia as its Drilling Contractor of the Year. The award was given for our team's commitment to excellence in safety, particularly their proactive efforts to align with ExxonMobil's "Safe Start" initiative created to deal with potential distractions and improve overall safety and environmental performance. By working closely with our customer and sharing the vision that all incidents are preventable, Parker's team helped ENL meet its business needs and objectives – including yet another extended-reach world record well – **with zero recordable injuries or environmental incidents.**

Additional Highlights

- From December 31, 2012 to December 31, 2013, our common stock (NYSE: PKD) price grew from $4.60 to $8.13.
- Our fleet average day-rate for the U.S. barge drilling business was up 14% at the end of 2013 versus the end of 2012.
- International rig fleet utilization increased to 73% for the fourth quarter of 2013, from 42% at the end of the prior year's fourth quarter.


PARKER
DRILLING

- Revenue from rental tools in the U.S. Gulf of Mexico grew by 27% compared to 2012.
- Working under a tight timeline, we mobilized quickly, safely and effectively to provide O&M services for three platforms off the shore of California.
- With our two Arctic-class rigs in Alaska, commissioned near the beginning of 2013, we drilled 14 wells for our customer.
- We continued to build strong business units supported by robust functional areas, an effort that aligns us more closely with customers and positions Parker to best meet their needs.
- A substantial ERP (enterprise resource planning) software implementation in 2013 gave us better visibility into our business operations and enhances our ability to deliver consistent results. Additional 2014 enhancements will benefit supply chain, asset maintenance and project management programs and help optimize our financial and human capital management processes.

OBJECTIVE 2:

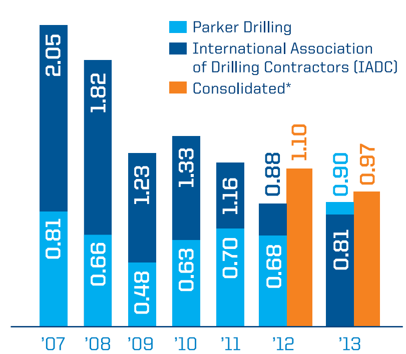
Improve Profitability

Profitability helps fuel company growth and rewards shareholders for their trust and confidence in us. By constantly examining and refining the way we generate income and manage expenses, Parker Drilling continuously strives for more profitable operations.

Additional Highlights

- Global operating revenues grew 29% from $677.8 million in 2012 to $874.2 million in 2013.
- Adjusted EBITDA (excluding non-routine expenses) for 2013 increased to $257.3 million versus $235.1 million in 2012.
- We added three platforms in California, mobilized two rigs to the Kurdistan Region of Iraq, and began preparing an additional barge rig for future work in the inland waters of the Gulf of Mexico.
- Although industry pricing is highly competitive, we continued to pursue a position that greater performance – reducing customers' risks and costs while meeting their business objectives – is well worth premium pricing.

2007 - 2013 TRIR



* Includes Parker Drilling and a full-year rate for ITS, which was acquired by Parker Drilling in April 2013

SAFETY + ENVIRONMENT

Parker Drilling and its employees are committed to upholding the highest standards in safety and environmental stewardship. For ten consecutive years (2003-2012), our Total Recordable Incident Rate (TRIR) was well below the International Association of Drilling Contractors (IADC) rate. In 2013, the Company:

- **Reported zero recordable injuries at 71% of all facilities and 54% of all rigs (compared to 71% and 44%, respectively, for 2012)**
- **Reported seven divisions with zero recordable incidents (Sakhalin, Kazakhstan [excluding SaiPar], Kuwait, PNG, California, Corporate and Technical Services) and one division (Mexico) with only one recordable incident.**

With the Company's ITS acquisition in April 2013, our combined TRIR for 2013 exceeded the IADC rate. Therefore, our 2014 goal is to effect a step change in health, safety and environmental (HSE) performance through reductions in injuries, spills and drops. On January 1, 2014, we rolled out IndustrySafe, an electronic information management tool for incident tracking and reporting, which will drive improved timeliness and completion of corrective actions. In addition, we are providing TapRooT® training and software to Health, Safety and Environment (HSE), Operations, and Maintenance personnel to improve the quality and consistency of incident causal analysis.

Welcoming a New Member to Our Executive Management Team

Industry veteran **Christopher T. "Chris" Weber** joined Parker Drilling as senior vice president and chief financial officer in May 2013. With nearly 20 years in the global drilling, oil and gas, and power industries, Chris brings deep experience in international finance and operations activities, including strategic planning, accounting, treasury, risk management, corporate development, turnaround initiatives and competitor and market analysis.

He most recently served as vice president and treasurer of Ensco plc, one of the world's largest offshore drilling companies, with revenues of $4 billion and global operations spanning six continents. In 2006, Chris joined Pride International, Inc. (acquired by Ensco in 2011) as director of corporate planning and development, eventually becoming vice president and treasurer. Prior to his tenure at Pride/Ensco, he spent five years with The Boston Consulting Group in both Houston and London, England.

He holds an MBA in Finance and Strategic Management from The Wharton School at the University of Pennsylvania, and is a Magna Cum Laude graduate in Economics and English Literature from Vanderbilt University.

OBJECTIVE 3:

Strengthen Our Strategic Position

We believe a conservative balance sheet positions Parker Drilling to perform today and capitalize on future opportunities. Achieving this objective requires lowering our borrowing rates and debt-to-EBITDA multiple, as well as making smart, strategic investments in people and equipment.

Tactical Moves Improve Debt Portfolio

After Parker Drilling purchased ITS in April 2013 (see Objective 4), the company pursued two transactions to reduce our debt level and decrease borrowing costs. In 2013, we issued $225 million of senior notes at 7.50%, due in 2020, with the proceeds used to repay a $45 million term loan and the loan that funded the ITS acquisition. This refinancing helped us secure longer-term, lower-cost funds and stagger the maturity of our debt portfolio. Then, in January 2014, we launched a tender offer for the outstanding $425 million of 9.125% senior notes, due 2018, while also issuing $360 million of 6.75% senior notes due 2022. As a result of these transactions, outstanding debt at January 31, 2014 was $19 million lower than at December 31, 2013 and our annualized interest expense dropped approximately $13 million per year.

OBJECTIVE 4:

Develop Pathways For Growth

Growing our business depends largely on the opportunities we make for ourselves. So we actively assess our markets and our competitors to determine what's next, from new service lines to strategic partnerships. And we're continually investing in the business intelligence, financial planning and strategic insight necessary for smart growth with calculated risks.

Key Acquisition Expands Rental Tools Business

In April 2013, Parker Drilling purchased International Tubular Services Limited (ITS), one of the industry's leading independent international rental tools and well service companies, with a broad footprint and a strong portfolio of products and service capabilities. The acquisition is in line with our strategic goal to offer services and expertise to

(Continued on page 10)


Safe Way

(Continued from page 8)

international energy exploration and production operators and drilling contractors. By expanding our geographic presence and service lines, we are better positioned to benefit from projected international spending growth. The business combination also creates opportunities to increase financial performance by leveraging operating costs and realizing tax benefits. Learn more about ITS at www.its-energyservices.com.

Adding Depth and Industry Expertise to Our Board

In October 2013, Parker Drilling welcomed **Peter C. Wallace** to the company's board of directors. Mr. Wallace brings extensive senior leadership, product and business development, sales and marketing management, and operational experience at multinational companies operating in the oil and gas, power transmission, fluid management and industrial manufacturing sectors. His career includes successful tenures as:

- President and CEO of **Robbins & Myers, Inc.**, an international equipment and systems supplier to the energy and chemicals sectors (2004-2013);
- President and CEO of **IMI Norgren Group**, a world leader in motion and fluid control technologies (2001-2004); and
- President and Chief Operating Officer of **Rexnord Corporation** a designer, manufacturer and service provider of highly engineered mechanical components (1998-2001, plus various management and senior leadership roles throughout 25 years with the company).

Mr. Wallace holds an MBA from the University of Wisconsin and a Bachelor of Science degree in Mechanical Engineering from Cornell University. His proven leadership, along with his broad background in industrial markets and quality assurance, bring a unique and valuable perspective to our board.

Moving Forward. **Always.**

Our job is to help our customers reduce their risks and manage their costs to meet their business objectives. In carrying out that promise, Parker strives to become the most **innovative**, **reliable** and **efficient** company in our industry. And we'll only get there by performing in five critical ways that create value for our customers and stakeholders:

- Investing in people to create the safest, most solution-focused workforce on the planet;
- Entering markets selectively and effectively to build a strategic foundation for growth;
- Aligning operations with customers' needs to minimize their risks and maximize their ROI;
- Enhancing asset management and predictive maintenance to ensure reliable, job-ready equipment; and
- Creating standard, modular and reconfigurable processes to build a more flexible, efficient business.

Because we work in a complex and dynamic industry, we know that success is a journey of continuous improvement. So we greet each day with the challenge of meeting our customers' needs even better than the day before. We look forward to reporting our results to you.

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, 2013

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 $^{2}/_{3}$ 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 Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of 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 ☐ Smaller reporting company ☐
(Do not check if a 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 28, 2013 was $582.6 million. At March 3, 2014, there were 120,557,208 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 1, 2014 are incorporated by reference in Part III.

TABLE OF CONTENTS

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 24 countries, 10 of which we entered through our acquisition in 2013 of International Tubular Services Limited and certain of its affiliates (collectively, ITS) and other related assets (the ITS Acquisition). We own and operate drilling rigs and drilling-related equipment and also perform drilling-related services, referred to as Operations & Maintenance (O&M) work, for customer-owned drilling rigs on a contracted basis. 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 rental tools business supplies premium equipment to operators on land and offshore in the U.S. and select international markets. We have significant knowledge of the equipment needs of our customers and the logistical and product quality requirements of an effective rental tools supplier. We believe we are industry leaders in quality, health, safety and environmental practices.

Our business is currently comprised of five operating segments: Rental Tools, U.S. Barge Drilling, U.S. Drilling, International Drilling, and Technical Services.

Our Rental Tools Business

Our rental tools business provides premium rental tools for land and offshore oil and natural gas drilling and workover and production applications. Tools we provide include drill pipe, heavy-weight drill pipe, tubing, high-torque connections, blow-out preventers (BOPs), drill collars, casing running systems, tools for fishing services and more. Our U.S. rental tools business is headquartered in New Iberia, Louisiana and our international rental tools business is headquartered in Aberdeen, Scotland. We maintain an inventory of rental tools and provide services to our customers from facilities in Louisiana, Texas, Oklahoma, Wyoming, North Dakota and West Virginia, as well as in the Middle East, Latin America, the U.K. and Europe, and the Asia-Pacific regions.

During 2013, our largest single market for rental tools continued to be U.S. land drilling, a cyclical market driven primarily by commodity prices and our customers' access to project financing. The increase in unconventional lateral drilling, often used in shale formations, added to the market demand for rental tools, keeping our U.S. market focus in the regions of primary shale plays. A growing portion of our U.S. rental tools business is supplying tubular goods and other equipment to offshore Gulf of Mexico (GOM) customers.

On April 22, 2013, we completed the ITS Acquisition. ITS provides rental drilling equipment and pressure control systems, fishing services, tubular running services and machine shop support for exploration and production (E&P) companies, drilling contractors and service companies from 21 operating facilities. See Note 2, “Acquisition of ITS,” in Item 8 of this Form 10-K for further discussion.

Our principal customers are major and independent oil and natural gas E&P companies. 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. For 2013, approximately 51.1 percent, 31.3 percent, and 17.6 percent of revenues from our rental tools business were derived from U.S. land, international, and offshore GOM customers, respectively.

Our U.S. Barge Drilling Business

Our U.S. GOM barge drilling rig fleet is the largest marketed barge fleet in the GOM region, with rigs ranging from 1,000 to 3,000 horsepower with drilling depth capabilities ranging from 13,000 to over 30,000 feet. Our rigs drill for oil and natural gas in the shallow waters in and along the inland waterways and coasts of Louisiana, Alabama and Texas. The barge drilling industry in the GOM is characterized by cyclical activity where utilization and dayrates are typically driven by commodity 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.

We continue to make investments in our barge drilling fleet to increase its efficiency and safety performance, and we expect to bring one additional rig to market in 2014. Our rigs are all equipped for zero-discharge operations and are suitable for a variety of drilling programs in inland coastal waters, from along inland waterways requiring shallow draft barges to open water drilling on the continental shelf requiring more robust capabilities.

Our U.S. Drilling Business

Our U.S. Drilling business primarily consists of two new-design arctic-class drilling rigs in Alaska intended to address the challenges presented by the remote location, harsh climate and sensitive environment that characterize the Alaskan North Slope and O&M work in support of ExxonMobil's Santa Ynez Unit offshore platform operations located in the Channel Islands region of California. The arctic-class drilling rigs deliver improved drilling efficiency, operating consistency and safety in this very demanding setting. In early December 2012 we commenced drilling operations with the first rig. The second rig completed client acceptance testing and began drilling in February 2013. The Alaskan North Slope drilling market is a focus of global and regional E&P companies with active programs to develop the area's hydrocarbon resources. In this market, drilling activity, and therefore production, is constrained by the existing limits of the infrastructure in place and the capabilities of existing aged technology. We believe our new-design rigs contribute to expanded drilling capabilities for our customers in this market.

Our International Drilling Business

Our international drilling business includes operations related to Parker-owned and customer-owned rigs. We strive to deploy our fleet of Parker-owned rigs in markets where we expect to have opportunities to keep the rigs at work consistently and build a sufficient presence to achieve efficient operating scale. As of December 31, we had rigs operating in Mexico, Colombia, Kazakhstan, Papua New Guinea, Indonesia, the Kurdistan Region of Iraq and Sakhalin Island, Russia. In addition, we have O&M and ongoing project management activities for customer-owned rigs in Sakhalin Island, Russia, Papua New Guinea, South Korea and Kuwait.

The international drilling markets in which we operate 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 pressure, deep depths, hazardous or geologically challenging conditions, requiring specialized equipment and considerable experience to drill;
- drilling contracts that generally cover periods of one year or more; and
- O&M contracts that are typically in support of multi-year drilling programs.

Our Technical Services Business

Our technical services business provides engineering and related project services during the Front End Engineering Design (FEED), pre-FEED and concept development phases of customer-owned drilling facility projects. During the Engineering, Procurement, Construction and Installation (EPCI) phase, we focus primarily on the drilling systems engineering, procurement, commissioning and installation and we typically provide customer support during construction. Currently, we provide these services on the Berkut platform project for Exxon Neftegas Limited (ENL). Additionally, we have a FEED engagement for an onshore arctic drilling facility project. Because these projects are customer-owned and customer-funded, the Technical Services business does not typically require significant capital and we believe this business helps to position us for future expansion in the drilling O&M business.

Our technical services business is also our engineering expertise center and provides our ongoing businesses with services similar to those provided to our external customers, including engineering design, retrofitting of existing rigs, modification, upgrades and other technology-related improvements.

Our Strategy

We intend to successfully compete in select energy services businesses which 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

There are many factors that will affect our success, but key among them is strengthening our core competencies, which we believe are the foundation for delivering operational excellence to our customers:

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.

Deployment of 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

Our customer base consists of major, independent and national oil and natural gas 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 2013, our largest customer, Exxon Neftegas Limited (ENL) accounted for approximately 15.6 percent of our total revenues.

Competition

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

In the rental tools market we compete with suppliers both larger and smaller than our own business, some of which are components of larger enterprises. Our rental tools business competes against other rental tools companies based on breadth of inventory, the availability and price of product and quality of service. In international land drilling markets, we compete with a number of international drilling contractors as well as local contractors. Most contracts are awarded on a competitive bidding basis and operators often consider reliability and efficiency in addition to price. Although local drilling contractors typically 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 experience operating in challenging environments has been a significant factor in securing contracts and we believe the market for drilling contracts will continue to be highly competitive with continued focus on safety, efficiency and quality.

In the GOM barge drilling market, we are awarded most contracts through a competitive bidding process. We have achieved some success differentiating ourselves from competitors through our drilling performance, upgraded fleet, planned maintenance programs, well-trained and experienced crews and safety record. This strategy has resulted in safer and more efficient operations and we believe these are important factors in contract awards.

Contracts

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, lost-in-hole or damaged equipment.

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. 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, but in the remainder of the contracts the customer has the discretion to terminate the contract without cause prior to the end of the term without penalty.

Technical Services contracts include engineering, consulting, and project management scopes of work and are typically on a time and materials basis.

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.

Insurance and Indemnification

Our operations are subject to hazards inherent in the drilling industry, such as blowouts, reservoir damage, loss of production, loss of well control, lost or stuck drill strings, equipment defects, cratering, fires, explosions, pollution, and damage or loss during transportation. These hazards can cause personal injury or loss of life, severe damage to or destruction of property and equipment and pollution damage, which could lead to claims by third parties or customers, suspension of operations and contract terminations. 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.

Our contracts provide for varying levels of indemnification between ourselves and our customers, including with respect to well control and subsurface risks. We also maintain insurance for personal injuries, damage to or loss of equipment and other insurance coverage for various business risks. Our insurance policies are typically 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. Our insurance program also provides coverage for liability resulting from sudden and accidental pollution events originating from our rigs up to $350.0 million per occurrence. We retain the risk for liability not indemnified by the customer below the retention and in excess of our insurance coverage.

Based upon a Company risk assessment and 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 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 as a result of 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,	
	2013	2012
Rental Tools	1,122	279
U.S. Barge Drilling	444	387
U.S. Drilling	278	144
International Drilling	1,291	1,019
Technical Services and Corporate	260	256
Total employees	3,395	2,085

Environmental Considerations

Our operations are subject to numerous U.S. federal, state, local and foreign laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous foreign and U.S. governmental agencies, such as the U.S. Environmental Protection Agency (EPA), issue regulations to implement and enforce such laws, 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 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); Emergency Planning and Community Right to Know Act (EPCRA); Hazardous Materials Transportation Act (HMTA) and comparable state laws, each as may be amended from time to time. In addition, we may also be subject to applicable state law and other civil claims arising out of any such incident.

The OPA and regulations promulgated pursuant thereto 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 of oil removal costs and a variety of public and private damages to each responsible party.

The OPA liability for a mobile offshore drilling rig is determined by whether the unit is functioning as a vessel or is in place and functioning as an offshore facility. If operating as a vessel, liability limits of $1,000 per gross ton or $854,400, whichever is greater, apply. If functioning as an offshore facility, the mobile offshore drilling rig is considered a "tank vessel" for spills of oil or hazardous substances on or above the water surface, with liability limits of $3,200 per gross ton or $23.5 million, whichever is greater. To the extent damages and removal costs exceed this amount, the mobile offshore drilling rig will be treated as an offshore facility and the offshore lessee will be responsible up to higher liability limits for all removal costs plus $75.0 million. The party must reimburse all removal costs actually incurred by a governmental entity for actual or threatened oil or hazardous substance discharges associated with any Outer Continental Shelf facilities, without regard to the limits described above. A party also cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply.

Few defenses exist to the liability imposed by the OPA. The OPA also imposes ongoing requirements on a responsible party, including proof of financial responsibility, for offshore facilities and vessels in excess of 300 gross tons (to cover at least some costs in a potential spill) and preparation of an oil spill contingency plan for offshore facilities and vessels. The OPA requires owners and operators of offshore facilities that have a worst case oil or hazardous substance spill potential of more than 1,000 barrels to demonstrate financial responsibility in amounts ranging from $10.0 million in specified state waters to $35.0 million in federal Outer Continental Shelf waters, with higher amounts, up to $150.0 million, in certain limited circumstances where the Bureau of Ocean Energy Management (BOEM) believes such a level is justified by the risks posed by the quantity or quality of oil or hazardous substance that is handled by the facility. For "tank vessels," as our offshore drilling rigs are typically classified, the OPA requires owners and operators to demonstrate financial responsibility in the amount of their largest vessel's liability limit, as those limits are described in the preceding paragraph. 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. BSEE has proposed stricter requirements for subsea drilling production equipment and has indicated that there will be an additional, separate rulemaking to govern the design, performance and maintenance of BOPs, but that rule has not yet been published. BSEE has also published a draft statement of policy on safety culture with nine proposed characteristics of a robust safety culture. Finally, together with BOEM, BSEE is drafting new standards governing drilling in the Arctic. BSEE contends that it has the legal authority to extend its regulatory reach to include contractors, like us, in addition to operators. 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 operating U.S. barge drilling rigs are designed to achieve zero-discharge as required by laws, such as the CWA. In addition, in recognition of environmental concerns regarding dredging of inland waters and permitting requirements, we conduct negligible dredging operations, with approximately two-thirds of our offshore drilling contracts involving directional drilling, which minimizes the need for dredging. However, the existence of such laws and regulations (e.g., Section 404 of the CWA, Section 10 of the Rivers and Harbors Act, etc.) has had and will continue to have a restrictive effect on us and our customers.

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 liability without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" 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. Few defenses exist to the liability imposed by CERCLA.

RCRA and comparable state laws regulate the management of wastes. Current RCRA regulations specifically excludes 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 may be regulated by EPA or state agencies as solid waste. 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 similarly situated companies involved in drilling operations in the Gulf Coast market.

The CAA, comparable state laws, and implementing regulations restrict the emission of air pollutants from various sources, and may require us to obtain permits for the construction, modification, or operation of certain projects or facilities and utilize 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.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" (GHGs) and which include carbon dioxide and methane, may be contributing to the warming of the atmosphere resulting in climate change. In response to such studies, the issue of climate change and the effect of GHG emissions, in particular emissions from fossil fuels, are 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 international, national, regional and state levels.

In 2005, the Kyoto Protocol to the 1992 United Nations Framework Convention on Climate Change, which establishes a binding set of emission targets for GHGs, became binding on all those countries that had ratified it. International discussions are currently underway to develop a treaty to replace the Kyoto Protocol after its expiration in 2020. In the United States, federal legislation imposing restrictions on GHGs is under consideration. Proposed legislation has been introduced that would establish an economy-wide cap on emissions of GHGs and would require most sources of GHG emissions to obtain GHG emission "allowances" corresponding to their annual emissions. Legislation has also been considered that would establish taxes tied to GHG emissions. In addition, the EPA is taking steps to regulate GHGs as pollutants under the CAA. To-date, the EPA has issued (i) a "Mandatory Reporting of Greenhouse Gases" final rule, which establishes a new comprehensive scheme requiring operators of stationary sources (including certain oil and natural gas production systems) in the United States emitting more than established annual thresholds of carbon dioxide-equivalent GHGs to inventory and report their GHG emissions annually; (ii) an "Endangerment Finding" final rule, effective January 14, 2010 which states that current and projected concentrations of six key GHGs in the atmosphere, as well as emissions from new motor vehicles and new motor vehicle engines, threaten public health and welfare, which allowed the EPA to finalize motor vehicle GHG standards (the effect of which could reduce demand for motor fuels refined from crude oil); and (iii) a final rule, effective August 2, 2010, to address permitting of GHG emissions from stationary sources under the CAA's Prevention of Significant Deterioration (PSD) and Title V programs. This final rule "tailors" the PSD and Title V programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting.

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.

FINANCIAL INFORMATION ABOUT INDUSTRY SEGMENTS AND GEOGRAPHIC AREAS

We have five operating segments: Rental Tools, U.S. Barge Drilling, U.S. Drilling, International Drilling, and Technical Services. Historically we reported a sixth segment, Construction Contract, for which there was no activity during the nine months ended September 30, 2013 or the year ended December 31, 2012. As a result of the reversal of reserves relating to this segment in the fourth quarter of 2013, this segment has been included in this report. See Item 7. Information about our reportable segments and operations by geographic areas for the years ended December 31, 2013, 2012 and 2011 is set forth in Note 14 included in Item 8 of this report.

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, 55,* joined the Company in October 2012 as the president and chief executive officer. Mr. Rich also serves as a member 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, 41* 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, 46,* is the senior vice president, chief administrative officer, general counsel, and secretary of the Company, a position held since 2013. Mr. Duplantier has over 18 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, 52,* 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, 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, 45,* 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

- *J. Daniel Chapman, 43,* joined the Company in 2009 as chief compliance officer and counsel. Prior to joining the Company, Mr. Chapman was employed by Baker Hughes from 2002 to 2009 where he served in several legal counsel positions including compliance counsel, international trade counsel, division counsel (drilling fluids), and global ethics and compliance director. Prior to 2002, Mr. Chapman was employed as a securities and mergers and acquisitions lawyer with the law firms Freshfields (London) and King & Spalding (Atlanta and Houston).

- *Philip A. Schlom, 49,* joined the Company in 2009 as principal accounting officer and corporate 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.

- *David W. Tucker, 58,* 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

We make available free of charge on our website at *www.parkerdrilling.com* our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports as soon as reasonably practicable after we electronically file such material with, or furnish such material to, the Securities and Exchange Commission (SEC). Additionally, these reports are available on an Internet website maintained by the SEC at *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, 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.

Volatile oil and natural gas prices impact demand for our services. A decrease in demand for crude oil and natural gas or other factors may reduce demand for our services and substantially reduce our profitability or result in losses.

The success of our operations is significantly dependent upon the exploration and development activities of the major, independent and national oil and natural gas companies and large integrated service companies that comprise our customer base. Oil and natural gas prices and market expectations regarding potential changes in these prices can be extremely volatile. 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. Higher commodity prices do not necessarily result immediately in increased drilling activity because our customers' expectations of future commodity prices typically drive demand for our drilling services.

Commodity prices and demand for our services also depends 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 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 countries of Africa, the Middle East, Russia, Central Asia, Southeast Asia and Latin America;
- 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;
- 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.

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. 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 revenue 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.

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.

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.

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, 2013, we had:

- $653.8 million of long-term debt, including $25.0 million of current portion of long-term debt;
- $52.1 million of operating lease commitments; and
- $4.6 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, 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 create 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. Currently, we anticipate that our capital expenditures in 2014 will be between $180 million and $200 million. 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 Amended and Restated Senior Secured Credit Agreement (Secured Credit Agreement) and the indentures governing our outstanding 9.125% Senior Notes due 2018 (9.125% Notes), 7.50% Senior Notes due 2020 (7.50% Notes) and 6.75% Senior Notes due 2022 (6.75% Notes, and collectively with the 9.125% Notes and the 7.50% Notes, 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 Secured Credit Agreement and the indentures for our Senior Notes impose significant operating and financial restrictions, which may prevent us from capitalizing on business opportunities and taking some actions.

The Secured Credit Agreement 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;
- 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 Secured Credit Agreement also requires us to maintain ratios for consolidated leverage, 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. A breach of any of these covenants could result in a default with respect to the related indebtedness. If a default were to occur, the lenders under our Secured Credit Agreement and the holders of our Senior Notes could elect to declare the indebtedness, 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.

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

Certain of our contracts are subject to cancellation by our customers without penalty and with relatively little or no notice. 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 if we experience operational problems. 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. Even 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 revenue 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 2013, our largest customer, Exxon Neftegas Limited accounted for approximately 15.6 percent of our total revenues. 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. 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 have constructed numerous rigs during periods of high energy prices and, consequently, the number of rigs available in some of the markets in which we operate has exceeded 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 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.

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

We derive a significant portion of our revenues from our international operations. In 2013, we derived approximately 48.1 percent of our revenues from operations in countries outside the United States. Our international operations are subject to the following risks, among others:

- political, social and economic instability, war, terrorism and civil disturbances;
- 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 24 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 revenue 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 justifiable.

Our international operations are subject to the laws and regulations of a number of foreign countries with political, regulatory and judicial systems and regimes that may differ significantly from those in the United States. 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.

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 well control, cratering, oil and natural gas well fires and explosions, natural disasters, pollution and mechanical failure. Our offshore operations also are subject to hazards inherent in marine operations, such as capsizing, sinking, grounding, collision and damage from severe weather conditions. Any of these risks could result in damage to or destruction of drilling equipment, personal injury and property damage, suspension of operations or environmental damage. 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, please read 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 and environmental risks, which reduce our business opportunities and increase our operating costs, might become more stringent in the future.

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 Part I, 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.

In 2005, the Kyoto Protocol to the 1992 United Nations Framework Convention on Climate Change, which establishes a binding set of emission targets for GHGs, became binding on the countries that had ratified it. International discussions are underway to develop a treaty to replace the Kyoto Protocol after its expiration in 2020. In the United States, federal legislation imposing restrictions on GHGs is under consideration. In addition, the EPA is taking steps to regulate GHGs as pollutants under the Clean Air Act (the CAA). To date, the EPA has issued (i) a “Mandatory Reporting of Greenhouse Gases” final rule, which establishes a new comprehensive scheme requiring operators of stationary sources (including certain oil and natural gas production systems) in the United States emitting more than established annual thresholds of carbon dioxide-equivalent GHGs to inventory and report their GHG emissions annually; (ii) an “Endangerment Finding” final rule, effective January 14, 2010, which states that current and projected concentrations of six key GHGs in the atmosphere, as well as emissions from new motor vehicles and new motor vehicle engines, threaten public health and welfare, which allowed the EPA to finalize motor vehicle GHG standards (the effect of which could reduce demand for motor fuels refined from crude oil); and (iii) a final rule, effective August 2, 2010, to address permitting of GHG emissions from stationary sources under the CAA’s Prevention of Significant Deterioration (PSD) and Title V programs. This final rule “tailors” the PSD and Title V programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting.

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 15, "Commitments and Contingencies," in Item 8 of this Form 10-K for a discussion of the material legal proceedings affecting us.

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, 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; is developing new standards for wastewater discharges associated with hydraulic fracturing; and is conducting a study on the impacts of hydraulic fracturing on groundwater. The Bureau of Land Management has also proposed regulations for hydraulic fracturing activities that would be unique to federal lands. In addition, some jurisdictions have imposed an express or de facto ban on hydraulic fracturing. 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;
- 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, revenue, 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.

If we fail to integrate or realize the expected benefits from the ITS Acquisition, or if we incur any liabilities as a result of such transaction, our business, results of operations and profitability may be adversely affected.

We may not realize the expected benefits of the ITS Acquisition because the business may not perform financially as expected or because of integration difficulties and other challenges. The success of the ITS Acquisition will depend, in part, on our ability to successfully integrate the acquired business with our existing businesses. The integration process is anticipated to be complex, costly and time-consuming. Complications with the integration could result from the following circumstances, among others: failure to implement our business plan for the combined business; unanticipated issues in integrating and applying our internal control and other systems; failure to retain key customers; failure to retain key employees of ITS; and operating risks inherent in the acquired business. In addition, we may not accomplish the integration smoothly, successfully or within the anticipated costs or timeframe. Furthermore, we may not be able to achieve anticipated cost savings or other synergies or realize growth opportunities that we expect with respect to our operation of ITS' business. Additionally, the ITS Acquisition subjects us to potential liabilities to which we would not otherwise be exposed. In particular, our due diligence process with respect to the ITS Acquisition suggests that its internal controls may have failed to prevent violations of potentially applicable international trade and anti-corruption laws, including those of the United Kingdom. We have investigated such violations and have and will, as appropriate, make any identified violations known to relevant authorities, cooperate with any resulting investigations and take proper remediation measures (including seeking any necessary government authorizations).

If we experience difficulties with the integration process or the anticipated growth opportunities and other potential synergies of the ITS Acquisition, or if we incur any liabilities related to such acquisition, our business, results of operations and profitability may be adversely affected.

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 revenue 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, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or 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 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;
- 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; including the ITS acquisition;
- 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;
- 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;
- our future liquidity;
- 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:

- worldwide economic and business conditions that adversely affect market conditions and/or the cost of doing business including potential country failures and downgrades;
- our inability to access the credit or bond markets;
- U.S credit market volatility resulting from the U.S national debt and potential further downgrades of the U.S. credit rating;
- the U.S. economy and the demand for natural gas;
- low U.S. natural gas prices could adversely affect U.S. drilling and our barge rig and U.S. rental tools businesses;
- worldwide demand for oil;
- 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;
- imposition of unanticipated trade restrictions;
- unanticipated operating hazards and uninsured risks;
- political instability, terrorism or war;
- governmental regulations, including changes in accounting rules or tax laws or ability to remit funds to the U.S., that adversely affect the cost of doing business;
- 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 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. Before you decide to invest in our securities, 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 Aberdeen, Scotland and Dubai, UAE related to our international rental tools business. 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 following table shows, as of December 31, 2013, the locations and drilling depth ratings of our rigs:

Name	Type[(1)]	Year entered into service/ upgraded	Drilling depth rating (in feet)	Location
International				
Europe, Middle East, and Asia				
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	Kurdistan Region of Iraq
Rig 269	L	2008	21,000	Kurdistan Region of Iraq
Rig 264	L	2007	20,000	Tunisia
Rig 265	L	2007	20,000	Tunisia
Rig 270	L	2011	21,000	Russia
Latin America				
Rig 268	L	1978/2009	30,000	Colombia
Rig 271	L	1982/2009	30,000	Colombia
Rig 121	L	1980/2007	18,000	Colombia
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 266	L	2008	20,000	Mexico
Rig 267	L	2008	20,000	Mexico
U.S. Land and Barge 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 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(2)	B	1981/2001	25,000	GOM
Rig 72	B	1982/2005	25,000	GOM
Rig 76	B	1977/2009	30,000	GOM
Rig 77	B	2006/2006	30,000	GOM
Rig 272	L	2013	18,000	Alaska
Rig 273	L	2012	18,000	Alaska

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

2) This rig is currently undergoing major refurbishment to make it available for service in 2014.

The table above excludes five rigs currently not available for service. These rigs are Rig 140, located in Papua New Guinea, Rig 225 and Rig 252, located in Indonesia, and Rig 230 and Rig 236, located in Kazakhstan.

The following table presents our average utilization rates and rigs available for service for the years ended December 31, 2013 and 2012:

	December 31, 2013	December 31, 2012
U.S. Land & Barge Rigs		
U.S. Barge Drilling Rigs		
Rigs available for service (1)	11.0	13.0
Utilization rate of rigs available for service (2)	91%	78%
U.S. Drilling Rigs		
Rigs available for service (1)	1.9	1.1
Utilization rate of rigs available for service (2)	100%	5%
International Land & Barge Rigs		
Europe, Middle East, and Asia Region		
Rigs available for service (1)	14.0	15.5
Utilization rate of rigs available for service (2)	49%	37%
Latin America Region		
Rigs available for service (1)	9.5	10.0
Utilization rate of rigs available for service (2)	75%	67%
Total International Land & Barge Rigs		
Rigs available for service (1)	23.5	25.5
Utilization rate of rigs available for service (2)	60%	49%

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 365 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.

ITEM 3. *LEGAL PROCEEDINGS*

For information on Legal Proceedings, see Note 15, Commitments and Contingencies, in the notes to the consolidated financial statements included in Item 8 of this annual report on Form 10-K, 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:

	2013		2012	
Quarter	**High**	**Low**	**High**	**Low**
First	$ 6.18	$ 4.27	$ 7.62	$ 5.69
Second	$ 5.20	$ 3.75	$ 6.27	$ 4.19
Third	$ 6.42	$ 4.92	$ 4.91	$ 4.00
Fourth	$ 8.50	$ 5.68	$ 4.60	$ 3.61

Most of our stockholders maintain their shares as beneficial owners in "street name" accounts and are not, individually, stockholders of record. As of March 3, 2014, there were 1,601 holders of record of our shares and we had an estimated 20,675 beneficial owners.

Our Secured Credit Agreement and the indentures for the Senior Notes (except the amended indenture for the 9.125% Notes) restrict the payment of dividends. We have not in the past paid dividends on our common stock and 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. When restricted stock awarded by the Company becomes taxable compensation to personnel, shares may be withheld to satisfy the associated withholding tax liabilities. Information on our purchases of equity securities by means of such share withholdings is provided in the table below:

	Issuer Purchases of Equity Securities	
Period	**Total Number of Shares Purchased**	**Average Price Paid Per Share**
October 1-31, 2013	39,811	$ 7.20
November 1-30, 2013	221	$ 7.07
December 1-31, 2013	92,691	$ 8.11
Total	132,723	$ 7.83

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, 2013. The following financial data should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the financial statements and related notes appearing elsewhere in this Form 10-K.

	Year Ended December 31,				
	2013	**2012**	**2011 (1)**	**2010**	**2009**
	(Dollars in Thousands, Except Per Share Amounts)				
Income Statement Data					
Total revenues	$ 874,172	$ 677,761	$ 686,234	$ 659,475	$ 752,910
Total operating income (loss)	101,872	107,273	(41,837)	45,107	39,322
Other expense, net	(49,085)	(36,296)	(23,575)	(33,602)	(29,495)
Income tax expense (benefit)	25,608	33,879	(14,767)	26,213	560
Net income (loss)	27,179	37,098	(50,645)	(14,708)	9,267
Net income (loss) attributable to controlling interest	27,015	37,313	(50,451)	(14,461)	9,267
Basic earnings per share:					
Income (loss) from continuing operations	$ 0.23	$ 0.32	$ (0.43)	$ (0.13)	$ 0.08
Net income (loss)	$ 0.23	$ 0.32	$ (0.43)	$ (0.13)	$ 0.08
Diluted earnings per share:					
Income (loss) from continuing operations	$ 0.22	$ 0.31	$ (0.43)	$ (0.13)	$ 0.08
Net income (loss)	$ 0.22	$ 0.31	$ (0.43)	$ (0.13)	$ 0.08
Balance Sheet Data					
Cash and cash equivalents	$ 148,689	$ 87,886	$ 97,869	$ 51,431	$ 108,803
Property, plant and equipment, net (2)	871,356	793,197	722,774	819,112	716,798
Assets held for sale (2)	—	—	—	—	—
Total assets	1,534,756	1,255,733	1,216,246	1,274,555	1,243,086
Total long-term debt including current portion of long-term debt	653,781	479,205	482,723	472,862	423,831
Total equity	633,142	590,633	544,050	588,066	595,899

1) 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. See Note 4 to the Consolidated Financial Statements in Item 8 of this Form 10-K.

2) The balances for the years ended December 31, 2012, 2011, and 2010 have been adjusted to reflect the reclassification to property, plant & equipment of certain assets previously classified as assets held for sale. During 2013, management concluded, based on the facts and circumstances at the time, it was no longer probable that the sales of five rigs that had been previously reclassified to assets held for sale would be consummated within a reasonable time period.

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

OVERVIEW AND OUTLOOK

Overview

We continued to make progress in 2013, leading to better operating performance and financial results. Our international drilling operations increased average utilization to 73 percent for the 2013 fourth quarter, up from 42 percent for the prior year's fourth quarter. Our GOM barge drilling operations increased average utilization to 89 percent for the 2013 fourth quarter, up from 83 percent for the prior year's fourth quarter, and earned a 14 percent higher average dayrate. Our U.S. rental tools operation continued its growth in the GOM offshore drilling market, recording a 23 percent increase in revenues generated from that market in the 2013 fourth quarter, compared with the same period of 2012. The most challenging market conditions we encountered in 2013 were in the U.S. land drilling market, where a slow, steady decline in drilling activity impacted rental tools utilization and market pricing. In addition, we made a significant addition to the Company's position in the international rental tools market with the April 22 acquisition of ITS.

During 2013 we undertook, progressed or completed several important projects, including:

- We made significant growth investments in our Rental Tools segment. This includes the acquisition of ITS and the purchase of capital equipment to leverage our growing position in the GOM offshore drilling market and to capture growth opportunities for ITS. The integration of ITS into the Company's operations required significant effort during the year and was substantially completed at year-end.
- We improved average utilization of our international drilling rig fleet. Of the fifteen rigs located in the Eastern Hemisphere, only four were under contract at the start of 2013. By year-end, nine of those rigs were under contract; one rig had been added to the fleet under contract for work in Russia; three rigs had been sold; and we were in discussions concerning future work for the remaining idle rigs.
- In early 2013, we commenced operation of Rig 272, the second of our two arctic-class drilling rigs on the Alaskan North Slope. It joined Rig 273, commissioned in December, 2012. Each rig is operating on a long-term contract and is expected to continue to be a solid cash flow contributor.
- In February 2013, we expanded our O&M activities with the addition of a contract to operate three platform rigs offshore California for ExxonMobil. In addition, we continued our involvement in the development of the Exxon Neftegas Limited (ENL) Berkut platform, which will soon move to Sakhalin Island, Russia and join our O&M activities there.
- Late in 2013, we began the overhaul and refurbishment of barge rig 55-B. We believe this rig, when completed, will offer considerable value to operators in our GOM market and significantly contribute to the operating and financial performance of our U.S. barge drilling business. We expect the rig to be ready to work some time during the 2014 second quarter.
- During the year we took steps to sharpen our business focus, selling two international land drilling rigs and one international barge drilling rig, no longer suited to our strategy.
- The Company's implementation of a new enterprise resource planning (ERP) system continued with the start-up of two important modules, human resources and finance, during the year. This Oracle-based system is providing us with new and better tools to plan and manage our business.
- In July 2013, we issued $225.0 million of 7.50% Notes and used the proceeds to refinance the $125.0 million term loan associated with the ITS Acquisition, to repay the term loan portion of our Secured Credit Facility and for future retirement of debt. Subsequently, in January, 2014, we issued $360 million of 6.75% Notes, and used the proceeds along with a $40.0 million draw on our Secured Credit Agreement and cash on hand to repurchase our 9.125% Notes. This transaction resulted in lower debt outstanding, reduced annual interest expense and extended our debt maturity schedule.

Outlook

We are encouraged by industry forecasts calling for expanded drilling activity in the U.S. and international markets. The projected growth, when it occurs, should benefit us broadly. Nevertheless, current market conditions have yet to reflect those forecasts. Based on our recent experience and current markets, we expect revenue and earnings to grow in 2014, with relatively stronger results later in the year as we improve operating performance and leverage the projected market growth.

We expect current conditions impacting our Rental Tools segment to continue in early 2014 before improving later in the year. Sluggish drilling activity in the U.S. land drilling market has led to competitive conditions for rental tools suppliers.

While there has been no significant change recently, we expect market conditions to improve as drilling activity picks up. We expect our expanding participation in the U.S. offshore GOM drilling market will provide a growing contribution to the segment's results. Several international locations which recently completed large contracts are gearing up for expected further work. This will add to an expected increase in work activity from the growing inflow and deployment of capital equipment, purchased in 2013 and now beginning to arrive at our international rental tools locations.

For our U.S. Barge Drilling segment, winter conditions and customer delays during the start of the year have reduced first quarter drilling opportunities in the GOM inland waters. We do not expect these conditions to persist and anticipate an improvement in drilling activity during the year should lead to better utilization and support for our industry-leading dayrates. The addition of Rig 55B to our fleet during the 2014 second quarter should augment the segment's contributions in the latter part of the year.

Our U.S. Drilling segment, is expected to continue to deliver solid operating results and cash flow, with two arctic-class drilling rigs working in Alaska and management of three offshore platforms in California on multi-year contracts.

We have successfully raised the level of utilization for our international rig fleet and expect tender activity and contract renewals to provide ample opportunities to maintain utilization without significant breaks in activity. We expect to continue to provide reliable revenue and earnings contributions to this business through our O&M contracts, as well.

As we strengthen our ability to consistently provide our customers with innovative, reliable and efficient responses to their operational needs, we expect additional opportunities to produce enhanced returns and continued growth.

RESULTS OF OPERATIONS

Year ended December 31, 2013 Compared with Year ended December 31, 2012

Revenues of $874.2 million for the year ended December 31, 2013 increased $196.4 million, or 29.0 percent, from the comparable 2012 period. Operating gross margin, including depreciation and amortization increased 11.1 percent to $168.4 million for the year ended December 31, 2013 as compared to $151.6 million for the year ended December 31, 2012.

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

	Year Ended December 31,			
	2013		2012	
	(Dollars in Thousands)			
Revenues:				
Rental Tools	$ 310,041	35%	$ 246,900	36%
U.S. Barge Drilling	136,855	16%	123,672	18%
U.S. Drilling	66,928	8%	1,387	1%
International Drilling	333,962	38%	291,772	43%
Technical Services	26,386	3%	14,030	2%
Construction Contract (1)	—	—%	—	—%
Total revenues	874,172	100%	677,761	100%
Operating gross margin excluding depreciation and amortization(2):				
Rental Tools gross margin	147,017	47%	158,016	64%
U.S Barge Drilling gross margin	65,595	48%	54,100	44%
U.S. Drilling gross margin	11,901	18%	(8,151)	n/a
International Drilling gross margin	71,078	21%	60,492	21%
Technical Services gross margin	2,181	8%	116	1%
Construction Contract gross margin (1)	4,728	n/a	—	—%
Total operating gross margin excluding depreciation and amortization	302,500	35%	264,573	39%
Depreciation and amortization	(134,053)		(113,017)	
Total operating gross margin	168,447		151,556	
General and administrative expense	(68,025)		(46,257)	
Provision for reduction in carrying value of certain assets	(2,544)		—	
Gain on disposition of assets, net	3,994		1,974	
Total operating income	$ 101,872		$ 107,273	

(1) As of December 31, 2013, the Company has five active operating segments: Rental Tools, U.S. Barge Drilling, U.S. Drilling, International Drilling, and Technical Services. We historically reported a sixth segment, Construction Contract, for which there was no activity for the nine months ended September 30, 2013 or the year ended December 31, 2012. As a result of our reversal of reserves relating to this segment in the fourth quarter of 2013, this segment has been included in this report. See “—Operations —Construction Contract”.

(2) 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 amounts and operating gross margin percentages should not be used as a substitute for those amounts reported under generally accepted accounting principles in the U.S. (U.S. GAAP). However, we monitor our business segments based on several criteria, including operating gross margin. Management believes that this information is useful to our investors because it more accurately reflects cash generated by segment. Such operating gross margin amounts are reconciled to our most comparable U.S. GAAP measure as follows:

	Rental Tools	U.S. Barge Drilling	U.S. Drilling	International Drilling	Technical Services	Construction Contract[2]
	(Dollars in Thousands)					
Year ended December 31, 2013						
Operating gross margin[1]	$ 91,164	$ 51,257	$ (4,484)	$ 23,732	$ 2,050	$ 4,728
Depreciation and amortization	55,853	14,338	16,385	47,346	131	—
Segment operating gross margin excluding depreciation and amortization	$ 147,017	$ 65,595	$ 11,901	$ 71,078	$ 2,181	$ 4,728
Year ended December 31, 2012						
Operating gross margin[1]	$ 113,899	$ 39,608	$ (15,168)	$ 13,138	$ 79	$ —
Depreciation and amortization	44,117	14,492	7,017	47,354	37	—
Segment operating gross margin excluding depreciation and amortization	$ 158,016	$ 54,100	$ (8,151)	$ 60,492	$ 116	$ —

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

(2) The Construction Contract segment does not incur depreciation and amortization.

Operations

Rental Tools

Rental Tools segment revenues increased $63.1 million, or 25.6 percent, to $310.0 million for the year ended December 31, 2013 compared to $246.9 million for the year ended December 31, 2012. The increase is primarily due to the contribution of $88.0 million of revenues from ITS and higher revenues from a growing participation in the expanding U.S. GOM offshore drilling market. The increase in revenues was primarily offset by the impact of the continuing competitive conditions in the U.S. land drilling market due to declines in drilling activity in almost all major basins.

Rental Tools segment operating gross margin excluding depreciation and amortization decreased $11.0 million, or 7.0 percent, to $147.0 million for the year ended December 31, 2013 as compared with $158.0 million for the year ended December 31, 2012. The decrease was primarily due to a reduction in gross margin excluding depreciation and amortization for our U.S. Rental Tools business of $31.5 million, primarily due to the increase in competitive conditions which led to lower product pricing for rental tools and related activities and a decline in rental tool utilization. This decrease was partially offset by the contribution of $20.5 million of gross margin excluding depreciation and amortization attributable to ITS from the date of acquisition.

U.S. Barge Drilling

U.S. Barge Drilling segment revenues increased $13.2 million, or 10.7 percent, to $136.9 million for the year ended December 31, 2013, as compared with revenues of $123.7 million for the year ended December 31, 2012. The increase in revenues was primarily due to an increase in rig fleet utilization and higher average dayrates for the fleet during 2013. Both of these factors reflect a general increase in overall drilling activity in the U.S. GOM inland waters and an increase in our dayrates for multi-well contracts based on our ability to deliver higher levels of performance compared with our competitors.

U.S. Barge Drilling segment operating gross margin excluding depreciation and amortization increased $11.5 million, or 21.2 percent, to $65.6 million for the year ended December 31, 2013, compared with $54.1 million for the year ended December 31, 2012. This increase is primarily a result of improved average dayrates and the continued control of operating costs.

U.S. Drilling

U.S. Drilling segment revenues increased $65.5 million to $66.9 million for the year ended December 31, 2013, compared with $1.4 million for the year ended December 31, 2012. This increase in revenues is primarily due to the commencement of operations by our two arctic-class drilling rigs in Alaska, one in the fourth quarter of 2012 and the other in the first quarter of 2013. Prior to that, during the first three quarters of 2012, both rigs were under construction and not generating revenues. Additionally, in February 2013 we began an O&M contract supporting three platform operations located offshore California.

U.S. Drilling segment operating gross margin excluding depreciation and amortization was $11.9 million for the year ended December 31, 2013 compared with a loss of $8.2 million for the year ended December 31, 2012. The increase in gross margin excluding depreciation and amortization for this segment is mainly due to the contributions from the arctic-class drilling rigs in Alaska and the California O&M contract described above which were not earning revenues or contributing to gross margin during 2012. The loss in 2012 resulted from expenditures associated with re-entering the Alaska market prior to the rigs going to work in Alaska in late 2012 and into early 2013.

International Drilling

International Drilling segment revenues increased $42.2 million, or 14.5 percent, to $334.0 million for the year ended December 31, 2013, compared with $291.8 million for the year ended December 31, 2012. The increase in revenues is primarily due to higher revenues generated by our O&M contracts coupled with higher drilling revenues through the operation of rigs we own.

Revenues related to Parker-owned rigs increased $19.4 million, or 10.6 percent, to $202.9 million for the year ended December 31, 2013 compared with $183.5 million for the year ended December 31, 2012. The increase in revenues was primarily due to the contribution of revenues from a previously idle rig added to our Sakhalin Island operations and two previously idle rigs added to our operations in the Kurdistan Region of Iraq partially offset by lower utilization in Algeria. Additionally, there were increased revenues related to our arctic-class barge rig in the Caspian Sea and the contribution of revenues from a previously idle rig in the Karachaganak field in Kazakhstan.

O&M revenues increased $22.8 million, or 21.1 percent, to $131.1 million, for the year ended December 31, 2013 compared to $108.3 million for the year ended December 31, 2012. The increase in revenues was primarily due to higher reimbursable revenues associated with our services contracts related to the Berkut platform project in South Korea and Orlan platform project on Sakhalin Island. Reimbursable revenues are generated through our purchasing support for the O&M rigs we operate for our customers. Approximately $46.4 million and $31.3 million of O&M revenues were attributable to reimbursable costs for the years ended December 31, 2013 and 2012, respectively. Reimbursable revenues add to revenues but have a minimal impact on operating margins.

International Drilling operating gross margin excluding depreciation and amortization increased $10.6 million, or 17.5 percent, to $71.1 million for the year ended December 31, 2013, compared with $60.5 million for the year ended December 31, 2012. The increase in operating gross margin excluding depreciation and amortization for the year ended December 31, 2013 was from our Parker-owned rig operations slightly offset by a decrease in O&M margins.

Operating gross margin excluding depreciation and amortization related to Parker-owned rigs was $51.0 million and $39.6 million for the years ended December 31, 2013 and 2012, respectively. The increase in operating gross margin excluding depreciation and amortization was primarily due to the contribution of revenues from a previously idle rig in Kazakhstan, in our Karachaganak field operations, and a previously idle rig in our Sakhalin Island operations. Additionally, there were increased revenues from higher utilization of our arctic-class barge rig in the Caspian Sea. The increase was partially offset by costs associated with the mobilization and start-up of the two rigs located in the Kurdistan Region of Iraq, decreased utilization resulting from two Algeria rigs stacked in Tunisia and lower revenues and higher costs in our Latin America region.

Operating gross margin excluding depreciation and amortization generated by our O&M operations was $20.0 million and $20.9 million for the years ended December 31, 2013 and 2012, respectively. The decrease in operating gross margin excluding depreciation and amortization is primarily due to the completion of an O&M contract in China that was active during all of 2012, a decrease in revenues from our Coral Sea project in Papua New Guinea, and higher operating costs related to the Orlan platform project in Sakhalin. These decreases were partially offset by an increase in labor revenues related to the Berkut platform project in South Korea.

Technical Services

Technical Services segment revenues increased $12.4 million, or 88.1 percent, to $26.4 million for the year ended December 31, 2013, compared with $14.0 million for the year ended December 31, 2012. This increase was primarily due to increased activity under the vendor services phase of the Berkut platform project which started during the 2012 third quarter and a new customer FEED project that together more than offset the mid-2012 completion of two other customer FEED projects.

Operating gross margin excluding depreciation and amortization for this segment increased by $2.1 million to $2.2 million for the year ended December 31, 2013, compared with nominal gross margin excluding depreciation and amortization for the year ended December 31, 2012. The increase is primarily the result of change in the scope of projects noted above. The Technical Services segment incurs minimal depreciation and amortization which primarily relates to office furniture and fixtures.

Construction Contract

This segment was created for and only includes the Liberty extended-reach drilling rig construction project which our customer canceled in 2011 prior to final completion. Our construction contract segment revenues were zero for the years ended December 31, 2013 and 2012. This segment reported $4.7 million and zero operating gross margin excluding depreciation and amortization for the years ended December 31, 2013 and 2012, respectively. The operating gross margin excluding depreciation and amortization generated during the year ended December 31, 2013 resulted from close-out of the Liberty project.

The Liberty rig construction contract was a fixed-fee and reimbursable contract that we accounted for on a percentage of completion basis. We recognized $335.5 million in revenues and $11.7 million of operating gross margin over the life of the contract. Over the course of the project, we established a project contingency reserve, which we maintained for potential claims by our subcontractors, vendors and customer. Due to the closure of all material claims, for which payments have been made or otherwise resolved or which are barred by the applicable statute of limitations, during the fourth quarter of 2013, we reversed the contingency reserve resulting in the operating gross margin excluding depreciation and amortization recognized for the year ended December 31, 2013.

Other Financial Data

General and administrative expense increased $21.8 million to $68.0 million for the year ended December 31, 2013, compared with $46.3 million for the year ended December 31, 2012. The general and administrative expense increase was due primarily to approximately $22.5 million of costs incurred during 2013 related to the ITS Acquisition slightly offset by decreased costs relating to the settlement with the DOJ and SEC, and decreased legal fees associated with the related SEC and DOJ investigations (see further discussion in Note 15 - *Commitments and Contingencies*).

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. During 2013, management concluded, based on the facts and circumstances at the time, it was no longer probable that the sales of the rigs sale would be consummated.

Net gains recorded on asset dispositions for the years ended December 31, 2013 and 2012 were $4.0 million and $2.0 million, respectively. During 2013, we sold two rigs located in New Zealand, a building located in Tulsa and a barge rig located in Mexico. These sales resulted in gains totaling $1.2 million. Additionally, during the normal course of operations, we periodically sell equipment deemed to be excess, obsolete, or not currently required for operations.

Interest expense increased $14.3 million to $47.8 million for the year ended December 31, 2013 compared with $33.5 million for the year ended December 31, 2012. The increase in interest expense primarily resulted from an $11.6 million increase in debt-related interest expense primarily related to the full-year impact of the $125.0 million of 9.125% Notes issued in the second quarter of 2012, the $225.0 million 7.50% Notes issued in July 2013 and the $125.0 million debt incurred in April 2013 used to initially fund the ITS Acquisition. Additionally, we experienced a $7.9 million decrease in interest capitalized on internal construction projects resulting from the completion of the two new arctic-class drilling rigs in Alaska, which increased overall interest expense. The increase in interest expense is partially offset by a decrease due to the repayment of our 2.125% Convertible Notes in the 2013 second quarter and a decrease in amortization of debt issuance costs. Interest income was $2.5 million and $0.2 million for the years ended December 31, 2013 and 2012, respectively. Interest income in 2013 primarily related to interest earned on an IRS refund received during the year.

Loss on extinguishment of debt was $5.2 million and $2.1 million for the years ended December 31, 2013 and December 31, 2012, respectively. The loss on extinguishment of debt for 2013 is related to the extinguishment in July 2013 of the $125 million debt incurred in April 2013 used to initially fund the ITS Acquisition. The loss on extinguishment of debt for 2012 resulted from the repurchase of $122.9 million of outstanding 2.125% Convertible Notes in May 2012.

Other income and expense was $1.5 million of income and $0.8 million of expense for the years ended December 31, 2013 and December 31, 2012, respectively. 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 2013 fourth quarter.

Income tax expense was $25.6 million for the year ended December 31, 2013, compared with $33.9 million for the year ended December 31, 2012. The 2013 tax expense decrease was primarily due to lower pre-tax earnings in addition to discrete items relating to enactment of new tax legislation in Mexico, research and development tax credits and other less significant items related to return-to-accrual adjustments.

Our effective tax rate was 48.5% for the year ended December 31, 2013, compared with 47.7% for the year ended December 31, 2012. Our tax rate is affected by recurring items, such as tax rates in state and non-U.S. jurisdictions and the relative amounts of income we earn in those jurisdictions, which we expect to be fairly consistent in the near term. It is also affected by discrete items, such as return-to-accrual adjustments and changes in reserves for uncertain tax positions, which may occur in any given year but are not consistent from year to year.

Year Ended December 31, 2012 Compared with Year Ended December 31, 2011

Revenues of $677.8 million for the year ended December 31, 2012 decreased $8.5 million, or 1.2 percent, from the comparable 2011 period. The years ended December 31, 2012 and 2011 included construction contract revenues of zero and $9.6 million, respectively, for the Liberty rig construction project that was canceled by our customer in 2011. Excluding that individual project, revenues from ongoing operations for the year ended December 31, 2012 would have been approximately the same as in 2011. Operating gross margin, including depreciation and amortization decreased 3.7 percent to $151.6 million for the year ended December 31, 2012 as compared to $157.4 million for the year ended December 31, 2011.

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

	Year Ended December 31,			
	2012		2011	
	(Dollars in Thousands)			
Revenues:				
Rental Tools	$ 246,900	36%	$ 237,068	35%
U.S. Barge Drilling	123,672	18%	93,763	14%
U.S. Drilling	1,387	1%	—	—%
International Drilling	291,772	43%	318,481	46%
Technical Services	14,030	2%	27,284	4%
Construction Contract	—	—%	9,638	1%
Total revenues	677,761	100%	686,234	100%
Operating gross margin excluding depreciation and amortization:				
Rental Tools gross margin	158,016	64%	162,577	69%
U.S Barge Drilling gross margin	54,100	44%	28,619	31%
U.S. Drilling gross margin	(8,151)	n/a	(1,692)	n/a
International Drilling gross margin	60,492	21%	73,602	23%
Technical Services gross margin	116	n/a	5,680	n/a
Construction Contract gross margin	—	—%	771	—%
Total operating gross margin excluding depreciation and amortization	264,573	39%	269,557	39%
Depreciation and amortization	(113,017)		(112,136)	
Total operating gross margin	151,556		157,421	
General and administrative expense	(46,257)		(31,567)	
Impairments and other charges	—		(170,000)	
Provision for reduction in carrying value of certain assets	—		(1,350)	
Gain on disposition of assets, net	1,974		3,659	
Total operating income	$ 107,273		$ (41,837)	

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 amounts and operating gross margin percentages should not be used as a substitute for those amounts reported under generally accepted accounting principles in the U.S. (U.S. GAAP). However, we monitor our business segments based on several criteria, including operating gross margin. Management believes that this information is useful to our investors because it more accurately reflects cash generated by segment. Such operating gross margin amounts are reconciled to our most comparable U.S. GAAP measure as follows:

	Rental Tools	U.S. Barge Drilling	U.S. Drilling	International Drilling	Technical Services	Construction Contract(2)
	(Dollars in Thousands)					
Year Ended December 31, 2012						
Operating gross margin[1]	$ 113,899	$ 39,608	$ (15,168)	$ 13,138	$ 79	$ —
Depreciation and amortization	44,117	14,492	7,017	47,354	37	—
Operating gross margin excluding depreciation and amortization	$ 158,016	$ 54,100	$ (8,151)	$ 60,492	$ 116	$ —
Year Ended December 31, 2011						
Operating gross margin[1]	$ 120,822	$ 11,115	$ (3,915)	$ 22,948	$ 5,680	$ 771
Depreciation and amortization	41,755	17,504	2,223	50,654	—	—
Operating gross margin excluding depreciation and amortization	$ 162,577	$ 28,619	$ (1,692)	$ 73,602	$ 5,680	$ 771

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

(2) The Construction Contract segment does not incur depreciation and amortization.

Operations

Rental Tools

Rental Tools segment revenues increased $9.8 million, or 4.1 percent, to $246.9 million for the year ended December 31, 2012 compared to revenues for the year ended December 31, 2011. The increase is primarily due to an increase in rentals to offshore GOM customers and greater tool sales and repair revenues. This was partially offset by the impact of soft U.S. natural gas prices that led to reduced demand from the U.S. land drilling market and lower rental tools utilization in key operating areas.

Rental Tools segment operating gross margin excluding depreciation and amortization decreased by $4.6 million, or 2.8 percent, for the year ended December 31, 2012 compared with operating gross margin excluding depreciation and amortization for the year ended December 31, 2011, primarily due to increased price competition in key U.S. land drilling markets, and the impact of an increase in lower-margin total sales and repair revenues.

U.S. Barge Drilling

U.S. Barge Drilling segment revenues increased $29.9 million, or 31.9 percent, to $123.7 million for the year ended December 31, 2012, compared with revenues for the year ended December 31, 2011. The increase in revenues was primarily due to an increase in rig fleet utilization and overall higher average dayrates for 2012. Both of these factors reflect a general increase in overall drilling activity in the U.S. GOM inland waters. Additionally, our dayrates benefit from our ability to renegotiate dayrates during multi-well contracts based on our ability to deliver higher levels of performance.

U.S. Barge Drilling segment operating gross margin excluding depreciation and amortization increased $25.5 million or 89.0 percent to $54.1 million for the year ended December 31, 2012, compared with segment operating gross margin excluding depreciation and amortization for the year ended December 31, 2011. This increase is primarily a result of overall improved rig fleet utilization and average dayrates and the continued control of operating costs.

U.S. Drilling

U.S. Drilling segment began generating revenue in early December 2012 as the first of the two arctic-class drilling rigs commenced drilling operations. The second rig completed client acceptance testing and began drilling in February 2013. Revenues were $1.4 million and zero for the years ended December 31, 2012 and 2011, respectively. The introduction of these rigs to the Alaskan North Slope is expected to improve drilling efficiency, operating consistency and safety in this remote and challenging environment.

U.S. Drilling segment operating gross margin excluding depreciation and amortization was a loss of $8.2 million and $1.7 million for the years ended December 31, 2012 and 2011, respectively. Operating expenses include start-up costs associated with re-entering the Alaskan market, such as salaries and employee hiring-related expenditures, training and rental of facilities in Alaska to support our operations. Additionally, early in the third quarter of 2012 we began incurring depreciation expense and ceased capitalizing interest costs related to one of the rigs when it was presented to the customer to begin the acceptance testing process.

International Drilling

International Drilling segment revenues decreased $26.7 million, or 8.4 percent, to $291.8 million for the year ended December 31, 2012, compared with the year ended December 31, 2011. The lower revenues are primarily due to a decrease in revenue generated by our O&M contracts and a decline in our drilling revenues generated through the operation of rigs we own.

O&M revenues decreased to $108.3 million, or 14.7 percent for the year ended December 31, 2012 compared to $127.0 million for the year ended December 31, 2011. The decrease in revenues was primarily due to the completion in 2011 of a drilling rig relocation project on Sakhalin Island, Russia and lower rates associated with our services contracts on Sakhalin Island. This was partially offset by increased operating and reimbursable revenues associated with the Orlan platform contract as it moved from warm-stack mode to fully-operational mode during 2012, the benefits of a new one-rig service contract in China, and the operation during much of 2012 of a customer-owned rig in Papua New Guinea. O&M projects included $31.3 million and $51.9 million of reimbursable costs for the years ended December 31, 2012 and 2011. Reimbursable costs add to revenues but have little direct impact on operating margins.

Revenues related to Parker-owned rigs decreased to $183.5 million or 4.2 percent for the year ended December 31, 2012 compared with $191.5 million for the year ended December 31, 2011. Revenues declined in the EMEA region primarily due to lower utilization of our arctic-class barge rig in the Caspian Sea and reduced dayrates on our rig in Papua New Guinea. The decrease was partially offset by increased revenues in Algeria as a result of the mobilization and start-up of two rigs during 2012 and a contribution from demobilization fees in the Latin America region as two rigs completed work during the year.

International Drilling operating gross margin excluding depreciation and amortization decreased $13.1 million, or 17.8 percent, to $60.5 million for the year ended December 31, 2012, compared with $73.6 million for the year ended December 31, 2011. The decrease in operating gross margin excluding depreciation and amortization for the year ended December 31, 2012 was due to decreased margins for both our O&M operations and our Parker-owned rig operations. Operating gross margin excluding depreciation and amortization generated by our O&M operations were $20.9 million and $25.7 million for the years ended December 31, 2012 and 2011, respectively. The decrease is primarily due to a decrease in handling fees associated with lower reimbursable costs charged back to customers and lower project management fees related to the drilling rig relocation project on Sakhalin Island, Russia that was completed prior to December 31, 2011, and lower rates associated with our service contracts on Sakhalin Island as we transitioned from higher value operating contracts to cost-plus contracts during 2012. This was partially offset by the operating gross margin excluding depreciation and amortization associated with the Orlan platform contract as it moved from warm-stack mode to fully-operational mode during 2012 and the benefits of a new one-rig service contract in China.

Our operating gross margin excluding depreciation and amortization related to Parker-owned rigs was $39.6 million and $47.9 million for the years ended December 31, 2012 and 2011, respectively. The decrease in operating gross margin excluding depreciation and amortization was primarily the result of lower rig utilization related to our arctic-class barge rig in the Caspian Sea and a non-cash charge to reserve certain value-added tax assets resulting from a strategic decision to move two rigs out of the Kazakhstan market. Partially offsetting this decrease were increased operating gross margin excluding depreciation and amortization resulting from the start-up of two rigs in Algeria during 2012 and increased utilization and demobilization revenues in Latin America. In addition, results for 2011 included $1.9 million of expense related to equity tax assessments in Latin America.

Technical Services

Technical Services segment revenues decreased $13.3 million, or 48.6 percent, to $14.0 million for the year ended December 31, 2012, compared with $27.3 million for the year ended December 31, 2011. This decrease was primarily due to expiration of the “pre-operations” phase of the Liberty project at the end of the second quarter of 2011 and the transition of the Berkut platform project from its engineering phase to a less revenue-intensive construction oversight and assistance phase. Also contributing to the decrease was the completion of a pre-FEED project at the end of the second quarter of 2012.

Operating gross margin excluding depreciation and amortization for this segment decreased by $5.6 million to $0.1 million for the year ended December 31, 2012, compared with $5.7 million for the year ended December 31, 2011. The decrease in operating gross margin excluding depreciation and amortization was primarily due to the completion of a pre-FEED project at the end of the second quarter of 2012, the transition of the Berkut platform project into a less revenue-intensive construction oversight and assistance phase, and the costs to retain technical capabilities as we transition between projects. The Technical Services segment incurs minimal depreciation and amortization primarily related to office furniture and fixtures.

Construction Contract

This segment includes only the Liberty extended-reach drilling rig construction project. Construction Contract segment revenues were zero for the year ended December 31, 2012 compared with $9.6 million for the year ended December 31, 2011. This segment reported zero and $0.8 million operating gross margin for the years ended December 31, 2012 and December 31, 2011, respectively. The operating gross margin generated during the year ended December 31, 2011 resulted from the preliminary close-out of the Liberty project and recognition of final percentage of completion revenues. The Construction Contract segment does not incur depreciation and amortization.

The Liberty rig construction contract was a fixed fee and reimbursable contract that we accounted for on a percentage of completion basis. As of December 31, 2011, we had recognized $335.5 million in project-to-date revenues. Over the life of the contract, we recognized $11.7 million of operating gross margin on the contract.

Other Financial Data

During the fourth quarter of 2011 we recorded a non-cash pre-tax impairment charge of $170.0 million ($109.1 million, net of taxes of $60.9 million) to adjust our arctic-class drilling rigs in Alaska to their fair value from the existing net book value (see Note 4 to the Consolidated Financial Statements). In 2011, we recognized a $1.4 million reduction in carrying value of assets related to a final settlement of a customer bankruptcy matter as it was deemed that the Company's rights to mineral reserves no longer supported the outstanding receivable.

Gain on asset dispositions for the year ended December 31, 2012 and 2011 was $2.0 million and $3.7 million, respectively. We periodically sell equipment deemed to be excess, obsolete, or not currently required for operations.

Interest expense increased $10.9 million for the year ended December 31, 2012 compared with the year ended December 31, 2011. The increase primarily resulted from a $5.2 million increase in interest on the additional $125.0 million of 9.125% Notes, which have a higher interest rate than our 2.125% Convertible Notes that were repaid during 2012, and a $9.0 million decrease in interest capitalized on major projects, resulting from a reduction in the value of the arctic-class drilling rigs in Alaska following the impairment charge recorded during the fourth quarter of 2011 and the placement of one of the arctic-class drilling rigs into service during the fourth quarter of 2012. The net increase was partially offset by a decrease in amortization of the debt discount on the 2.125% Convertible Notes as they were tendered or matured during 2012 and amortization of the debt premium related to the additional $125.0 million of 9.125% Notes. Interest income was $0.2 million and $0.3 million for the years ended December 31, 2012 and 2011, respectively.

Loss on extinguishment of debt of $2.1 million resulted from the repurchase prior to maturity of $122.9 million of the 2.125% Convertible Notes pursuant to a tender offer on May 9, 2012 and the write-off of debt issuance costs related to refinancing our Secured Credit Agreement in December 2012. The loss included a $0.4 million premium paid to repurchase the 2.125% Convertible Notes prior to maturity, $1.4 million accelerated amortization of the related debt discount and debt issuance costs of the 2.125% Convertible Notes, and $0.3 million accelerated amortization of the debt issuance costs related to our Secured Credit Agreement.

General and administration expense increased $14.7 million for the year ended December 31, 2012, compared with general and administrative expense for the year ended December 31, 2011. The general and administrative cost increase was due primarily to a proposed settlement with the DOJ and SEC recorded during the fourth quarter of 2012, offset by a decrease in legal fees associated with the related SEC and DOJ investigations.

Income tax expense was $33.9 million for the year ended December 31, 2012, compared with an income tax benefit of $14.8 million for the year ended December 31, 2011. The 2012 tax expense was primarily due to the mix of our domestic and international pretax earnings and losses, the mix of international tax jurisdictions in which we operate, and adjustments related to the settlement of our examination with the U.S. Internal Revenue Service for tax periods through 2010 including carryover adjustments impacting the 2011 period. The 2011 period tax benefit was driven primarily by the $170.0 million non-cash pretax charge for our arctic-class drilling rigs in Alaska resulting in a $60.9 million federal and state tax benefit, offset by operating income (excluding the impairment), differences in the mix of our domestic and international pretax earnings and losses, as well as the mix of international tax jurisdictions in which we operate. Included in tax expense for the year ended December 31, 2012 was an expense of $1.5 million related to an uncertain tax position and a benefit of $7.0 million related to the effective settlement of uncertain tax positions.

LIQUIDITY AND CAPITAL RESOURCES

We periodically evaluate our liability 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. However, we have recently sought, and may in the future seek, to raise additional capital. We expect that for the foreseeable future, cash generated from operations 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.

In connection with the ITS Acquisition, on April 18, 2013, we entered into a $125 million term loan, fully funded by Goldman Sachs Bank USA as Sole Lead Arranger and Administrative Agent (Goldman Term Loan) with a stated maturity date of April 18, 2018. On July 30, 2013, we issued the 7.50% Notes. Net proceeds from the 7.50% Notes offering were used to repay in full the Goldman Term Loan, to repay $45.0 million of term loan borrowings under our Secured Credit Agreement and for general corporate purposes.

On January 22, 2014, we issued the 6.75% Notes. Net proceeds from the offering, plus a $40.0 million draw under the 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. The tender offer price was $1,061.98, inclusive of a $30.00 consent payment, for each $1,000.00 principal amount of 9.125% Notes tendered, 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 for the aggregate principal amount of the tendered 9.125% Notes, $25.8 million of tender and consent premiums and $11.7 million of accrued interest. After payment for the tendered 9.125% Notes, $8.8 million aggregate principal amount of our 9.125% Notes remained outstanding.

Liquidity

As of December 31, 2013, we had cash and cash equivalents of $148.7 million, an increase of $60.8 million from December 31, 2012. The following table provides a cash flow summary for the last three years:

	2013	2012	2011
		(Dollars in thousands)	
Operating Activities	$ 161,497	$ 189,699	$ 225,885
Investing Activities	(265,418)	(187,606)	(184,614)
Financing Activities	164,724	(12,076)	5,167
Net change in cash and cash equivalents	$ 60,803	$ (9,983)	$ 46,438

Operating Activities

Cash flows from operating activities were $161.5 million in 2013, compared with $189.7 million in 2012. We have reinvested a substantial portion of our operating cash flows to expand our business through acquisition and to enhance our fleet of drilling rigs and rental tools equipment. We do not pay dividends to our shareholders. Changes in working capital were a use of cash of $34.0 million and a source of cash of $1.0 million for the years ended December 31, 2013 and December 31, 2012, respectively. Uses of operating cash flows during 2013 primarily related to the ITS Acquisition which resulted in increased receivables, inventory and accounts payable. Changes in cash from operating activities were also 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. Depreciation expense increased due to our two Alaska rigs commencing work in late 2012 and early 2013. Additionally, during 2013, we more aggressively disposed of assets deemed not core to the current strategy resulting in an increase in gain on disposition of assets. It is our current intention to continue to utilize our operating cash flows to finance further investments into our rental tools inventories, rig purchases or upgrades as well as other strategic investments aligned to our strategies.

Cash flows from operating activities were $189.7 million in 2012, compared with $225.9 million in 2011. Before changes in operating assets and liabilities, cash from operating activities was impacted primarily by net income of $37.1 million plus non-cash charges of $151.6 million. Non-cash charges primarily consisted of $113.0 million of depreciation expense and deferred tax benefit of $15.8 million. Net changes in operating assets and liabilities provided $1.0 million and $32.2 million of cash in 2012 and 2011 respectively.

Investing Activities

Cash flows used in investing activities were $265.4 million for 2013 compared with $187.6 million in 2012. Our primary use of cash was $118.0 million for the ITS Acquisition and $155.6 million for capital expenditures. Capital expenditures in 2013 were primarily for tubular and other products for our rental tools business, rig-related enhancements and maintenance and costs related to our new enterprise resource planning system. Sources of cash included $8.2 million of proceeds from asset sales.

Cash flows used in investing activities were $187.6 million for 2012. Our primary use of cash was $191.5 million for capital expenditures. Capital expenditures in 2012 were primarily for the construction of our two arctic-class drilling rigs, tubular and other products for our rental tools business, and costs related to our new enterprise resource planning system.

In addition, we incurred capital to support ongoing drilling activities. Sources of cash included $3.9 million of proceeds from asset sales.

Capital expenditures for 2014 are estimated to range from $180.0 million to $200.0 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. We believe that our operating cash flows and borrowings under our revolving credit facility (Revolver), will provide us sufficient cash and available liquidity to sustain operation and fund our capital expenditures for 2014, though there can be no assurance that we will continue to generate cash flows at sufficient levels or be able to obtain additional financing if necessary. See “Item 1A. Risk Factors” for a discussion of additional risks related to our business.

Financing Activities

Cash flows provided by financing activities were $164.7 million for 2013. Cash flows provided by financing activities 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% 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 (defined below) and payments of debt issuance costs.

Cash flows used in financing activities were $12.1 million for 2012. Our primary financing activities included the repayment of $125.0 million of 2.125% Convertible Notes and $18.0 million in quarterly payments against our Term Loan then-outstanding. In addition, we received proceeds from the issuance of an additional $125.0 million aggregate principal amount of 9.125% Notes at a price of 104.0 percent, resulting in gross proceeds of $130.0 million, less $4.9 million of associated debt issuance costs. We also made a $7.0 million draw on our Revolver (defined below).

6.75% Senior Notes, due July 2022

On January 22, 2014, we issued $360.0 million aggregate principal amount of 6.75% Notes. Net proceeds from the 6.75% Notes offering plus a $40.0 million draw under the Secured Credit Agreement and cash on hand, were utilized to purchase $416.2 million aggregate principal amount of our 9.125% Notes pursuant to a tender and consent solicitation offer commenced on January 7, 2014. 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 tendered 9.125% Notes, $25.8 million of tender and consent premiums and $11.7 million of accrued interest. After payment for the tendered 9.125% Notes, $8.8 million aggregate principal amount of our 9.125% Notes remains outstanding.

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 our Secured Credit Agreement and our other outstanding 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 are estimated to be $7.1 million and will be 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 7.50% Notes. 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 under our Secured Credit Agreement 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 our Secured Credit Agreement. 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 were $5.3 million ($5.2 million, net of amortization as of December 31, 2013) and will be 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 March 22, 2010, we issued $300.0 million aggregate principal amount of the 9.125% Notes. Net proceeds from the 9.125% Notes offering were primarily used to redeem the $225.0 million aggregate principal amount of our 9.625% Senior Notes due 2013 and to repay $42.0 million of borrowings under our then-existing senior secured credit agreement dated May 15, 2008 (Prior Credit Agreement).

On April 25, 2012, we issued an additional $125.0 million aggregate principal amount of 9.125% Notes under the same indenture at a price of 104.0 percent of par, resulting in gross proceeds of $130.0 million. Net proceeds from the offering were utilized to refinance $125.0 million aggregate principal amount of the 2.125% Convertible Senior Notes due July 2012 (2.125% Convertible Notes). We repurchased $122.9 million aggregate principal amount of the 2.125% Convertible Notes tendered pursuant to a tender offer on May 9, 2012 and paid off the remaining $2.1 million at their stated maturity on July 15, 2012.

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. After payment for the tendered 9.125% Notes, $8.8 million aggregate principal amount of our 9.125% Notes remains outstanding.

At any time after April 1, 2014, we may redeem all or a part of the 9.125% Notes upon appropriate notice, at a redemption price of 104.563 percent of the principal amount, and at redemption prices decreasing each year thereafter to par beginning April 1, 2016. The 9.125% 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 9.125% Notes are jointly and severally guaranteed by substantially all of our material domestic subsidiaries other than subsidiaries generating revenues primarily outside the United States. Interest on the 9.125% Notes is payable on April 1 and October 1 of each year. Debt issuance costs related to the 9.125% Notes of approximately $11.6 million ($7.7 million, net of amortization) are being amortized over the term of the notes using the effective interest rate method.

2.125% Convertible Senior Notes, due July 2012

On July 5, 2007, we issued $125.0 million aggregate principal amount of the 2.125% Convertible Notes. As noted above, on May 9, 2012, we repurchased $122.9 million aggregate principal amount of the 2.125% Convertible Notes pursuant to a tender offer. The tender offer price was $1,003.27 for each $1,000 principal amount of 2.125% Convertible Notes, plus accrued and unpaid interest. This repurchase resulted in the recording of debt extinguishment costs of $1.8 million related to the accelerated amortization of both the unamortized debt issuance costs and debt discount associated with the 2.125% Convertible Notes. The remaining $2.1 million aggregate principal amount of non-tendered 2.125% Convertible Notes was subsequently paid off at their stated maturity on July 15, 2012.

Goldman Term Loan

In connection with the ITS Acquisition described in Note 2 on April 18, 2013, we entered into the Goldman Term Loan. The Goldman Term Loan was repaid on July 30, 2013 with net proceeds from the issuance of $225.0 million aggregate principal amount of 7.50% Notes. In connection with the repayment of the Goldman Term Loan we incurred debt extinguishment costs of $5.2 million.

Amended and Restated Credit Agreement

On December 14, 2012, we entered into the Secured Credit Agreement consisting of a senior secured $80.0 million revolving credit facility (Revolver) and a senior secured term loan facility (Term Loan) of $50.0 million. The Secured Credit Agreement matures on December 14, 2017. The Secured Credit Agreement provides that, subject to certain conditions, including the approval of the Administrative Agent and the lenders' acceptance (or additional lenders being joined as new lenders), the amount of the Term Loan or Revolver can be increased by an additional $50.0 million, so long as after giving effect to such increase, the Aggregate Commitments shall not be in excess of $180.0 million.

Our obligations under the Secured Credit Agreement are guaranteed by substantially all of our material domestic subsidiaries, each of which has executed guaranty agreements; and are secured by first priority liens on our accounts receivable, specified barge rigs and rental equipment. The Secured Credit Agreement contains customary affirmative and negative covenants with which we were in compliance as of December 31, 2013 and December 31, 2012. The Secured Credit Agreement terminates on December 14, 2017.

Our loans pursuant to the Secured Credit Agreement, the 9.125% Notes, the 7.50% Notes and the 6.75% Notes 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 have executed guaranty agreements; and are secured by first priority liens on our accounts receivable, specified barge rigs and rental equipment. The Secured Credit Agreement contains customary affirmative and negative covenants with which we were in compliance as of December 31, 2013 and December 31, 2012. The Secured Credit Agreement matures on December 14, 2017.

On July 19, 2013, we entered into an amendment to our Secured Credit Agreement which, among other things, permits us or any of our subsidiaries (other than certain immaterial subsidiaries) to incur indebtedness pursuant to additional unsecured senior notes in an aggregate principal amount not to exceed $250.0 million at any one time outstanding; provided that any such notes shall (x) have a scheduled maturity occurring after the maturity date of our Secured Credit Agreement, (y) contain terms (including covenants and events of default) no more restrictive, taken as a whole, to us and our subsidiaries than those contained in our Secured Credit Agreement and (z) have no scheduled amortization, no sinking fund requirements and no maintenance financial covenants. In addition, pursuant to the amendment, and subject to the terms and conditions set forth in the Secured Credit Agreement, to the extent we repay the principal amount of Term Loans outstanding under our Secured Credit Agreement, until April 30, 2014 we may re-borrow, in the form of additional term loans, up to $45.0 million of the principal amount of such outstanding term loans we have repaid, provided that such $45.0 million borrowing amount will decrease by $2.5 million at the end of each quarter beginning September 30, 2013 and ending March 31, 2014, such that the borrowing availability on December 31, 2013 was $40.0 million and on April 30, 2014 would be $37.5 million.

Revolver

Our Revolver is available for general corporate purposes and to support letters of credit. Interest on Revolver loans accrues at a Base Rate plus an Applicable Rate or LIBOR plus an Applicable Rate. Under the Secured Credit Agreement, the Applicable Rate varies from a rate per annum ranging from 2.50 percent to 3.00 percent for LIBOR rate loans and 1.50 percent to 2.00 percent for base rate loans, determined by reference to the consolidated leverage ratio (as defined in the Credit Agreement). Revolving loans are available subject to a borrowing base calculation based on a percentage of eligible accounts receivable, certain specified barge drilling rigs and rental equipment of the Company and its subsidiary guarantors. There were no revolving loans outstanding at December 31, 2013 and December 31, 2012. Letters of credit outstanding as of December 31, 2013 and December 31, 2012 totaled $4.6 million and $4.5 million, respectively.

Term Loan

The Term Loan originated at $50.0 million on December 14, 2012 and required quarterly principal payments of $2.5 million beginning March 31, 2013. Interest on the Term Loan accrued at a Base Rate plus 2.00 percent or LIBOR plus 3.00 percent. There were no borrowings on the Term Loans at December 31, 2013. The outstanding balance on the Term Loans as of December 31, 2012 was $50.0 million. Pursuant to the July 19, 2013 amendment, and subject to the terms and conditions set forth in the Secured Credit Agreement, until April 30, 2014 we may re-borrow, in the form of additional term loans, up to $45.0 million of the principal amount of the term loans we repaid, provided that such $45.0 million borrowing amount will decrease by $2.5 million at the end of each quarter beginning September 30, 2013 and ending March 31, 2014, such that the borrowing availability on December 31, 2013 was $40.0 million and on April 30, 2014 would be $37.5 million.

Other Liquidity

Our principal amount of long-term debt, including current portion, was $650.0 million as of December 31, 2013, which consisted of:

- $425.0 million aggregate principal amount of 9.125% Senior Notes, due April 1, 2018; and
- $225.0 million aggregate principal amount of 7.50% Senior Notes, due August 1, 2020.

As of December 31, 2013, we had approximately $264.1 million of liquidity, which consisted of $148.7 million of cash and cash equivalents on hand, $75.4 million of availability under the Revolver and $40.0 million of reborrowing capability under our Term Loan. As of January 31, 2014, subsequent to the issuance of the 6.75% Notes and tender of 9.125% Notes, we had approximately $157.0 million of liquidity, which consisted of $81.6 million of cash and cash equivalents on hand, $75.4 million available under our Secured Credit Agreement. We do not have any unconsolidated special-purpose entities, off-balance sheet financing arrangements or guarantees of third-party financial obligations. We have no energy, commodity, or foreign currency derivative contracts at December 31, 2013.

The following table summarizes our future contractual cash obligations as of December 31, 2013:

	Total	Less than 1 Year	Years 1 - 3	Years 3 - 5	More than 5 Years
			(Dollars in Thousands)		
Contractual cash obligations:					
Long-term debt — principal(1)	$ 650,000	$ —	$ —	$ 425,000	$ 225,000
Long-term debt — interest(1)	292,735	55,750	111,313	91,922	33,750
Operating leases(2)	52,105	13,979	17,080	13,058	7,988
Purchase commitments(3)	43,100	43,100	—	—	—
Total contractual obligations	$ 1,037,940	$ 112,829	$ 128,393	$ 529,980	$ 266,738
Commercial commitments:					
Standby letters of credit(4)	4,583	4,583	—	—	—
Total commercial commitments	$ 4,583	$ 4,583	$ —	$ —	$ —

1) Long-term debt includes the principal and interest cash obligations of the 9.125% Notes. The remaining unamortized premium of $3.8 million on the additional $125.0 million of 9.125% Notes is not included in the contractual cash obligations schedule.
2) Operating leases consist of lease agreements in excess of one year for office space, equipment, vehicles and personal property.
3) We have purchase commitments outstanding as of December 31, 2013, related to rental tools and rig upgrade projects.
4) We have an $80.0 million Revolver pursuant to our Secured Credit Agreement. As of December 31, 2013, there were no borrowings under the Revolver and $4.6 million of availability has been used to support letters of credit that have been issued, resulting in an estimated $75.4 million of availability. The Revolver expires December 14, 2017.

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 annually, typically during the fourth quarter, or when events occur or circumstances change that indicate the carrying value 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.

Accrual for Self-Insurance. Our operations are subject to many hazards inherent to the drilling industry, including blowouts, explosions, fires, loss of well control, loss of hole, damaged or lost drilling equipment and damage or loss from inclement weather or natural disasters. Any of these hazards could result in personal injury or death, damage to or destruction of equipment and facilities, suspension of operations, environmental damage and damage to the property of others. Generally, drilling contracts provide for the division of responsibilities between a drilling company and its customer, and we seek to obtain indemnification from our customers by contract for certain of these 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 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 the expiration of our net operating loss (NOL) and foreign tax credit (FTC) carryforwards. In the event that our earnings performance projections do not indicate that we will be able to benefit from our NOL and FTC carryforwards, valuation allowances are established following the "more likely than not" criteria. We periodically evaluate our ability to utilize our NOL and FTC carryforwards 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 are deemed to be permanently reinvested. If such earnings were to be distributed, we would be subject to U.S. taxes, which may have a material impact on our results of operations. 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 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. Technical Services contracts include engineering, consulting, and project management scopes of work and revenue is typically recognized on a time and materials basis.

During 2013 the Company entered into a FEED contract including long-lead equipment procurement services accounted for under the milestone method of revenue recognition. Milestone payments are based on achievement of specified procurement coordination and delivery events in regards to our customer's newly manufactured drilling rig. The quantity of specific long-lead items to be procured is spelled out in the contract and the payment terms are identified with each piece of equipment as well as each specific milestone. Management concluded that each of these payments, constitute substantive milestones. This conclusion was based primarily on the facts that (i) each triggering event represents a specific outcome that can be achieved only through successful performance by the Company of one or more of its deliverables, (ii) achievement of each triggering event was subject to inherent risk and uncertainty and would result in additional payments becoming due to the Company, (iii) each of the milestone payments is non-refundable, (iv) substantial effort is required to complete each milestone, (v) the amount of each milestone payment is reasonable in relation to the value created in achieving the milestone, and (vi) the milestone payments relate solely to past performance.

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 Notes to Consolidated Financial Statements — Note 20 — Recent Accounting Pronouncements.

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 foreign currency exchange rate risk forward contracts, or spot purchases, may be used to mitigate foreign exchange rate currency risk. A foreign currency exchange rate risk forward contract obligates us to exchange predetermined amounts of specified foreign currencies at specified exchange rates on specified dates or to make an equivalent U.S. dollar payment equal to the value of such an exchange. We do not enter into derivative transactions for speculative purposes. At December 31, 2013, 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 $425.0 million principal amount of 9.125% Notes, based on quoted market prices, was $446.3 million at December 31, 2013. The estimated fair value of our $225.0 million principal amount of 7.50% Notes, based on quoted market prices, was $236.3 million at December 31, 2013. A hypothetical 100 basis point increase in interest rates relative to market interest rates at December 31, 2013 would decrease the fair market value of our 9.125% Notes by approximately $46.1 million and decrease the fair market value of our 7.50% Notes by approximately $29.0 million.

In 2011, we entered into two variable-to-fixed interest rate swap agreements as a strategy to manage the floating rate risk on the Term Loan borrowings under the Secured Credit Agreement. The two agreements fixed the interest rate on a notional amount of $73.0 million of borrowings at 3.878 percent for the period beginning June 27, 2011 and terminating May 14, 2013. The notional amount of the swap agreements decreased correspondingly with amortization of the Term Loan. We did not apply hedge accounting to the agreements and, accordingly, reported the mark-to-market change in the fair value of the interest rate swaps in earnings. As of December 31, 2013 the swap agreements had expired and as of December 31, 2012, the fair value of the interest rate swap was a liability of $0.1 million.

Impact of Fluctuating Commodity Prices

We are exposed to fluctuations that arise from economic or political risks that have, and will, impact underlying commodity prices for natural gas, oil and natural gas/oil mixtures. The Company’s business is subject to price fluctuations in commodities, and may be impacted by prolonged pricing reductions. Currently, the price of natural gas has been depressed due in some part to high levels of natural gas inventory. Drilling for natural gas has been negatively impacted; however, drilling activity and our rental tools business has remained active with the focus on oil/liquids-rich shale plays.

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, 2013, based on criteria established in Internal Control - Integrated Framework (1992) 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 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.

Parker Drilling Company acquired International Tubular Services Limited and certain of its affiliates (collectively, ITS) during 2013, and management excluded from its assessment of the effectiveness of Parker Drilling Company's internal control over financial reporting as of December 31, 2013, ITS's internal control over financial reporting. ITS represents approximately 11.0 percent of total assets as of December 31, 2013 and approximately 10.0 percent and 37.0 percent of revenues and net income, respectively, included in the consolidated financial statements of Parker Drilling Company as of and for the year ended December 31, 2013. Our audit of internal control over financial reporting of Parker Drilling Company also excluded an evaluation of the internal control over financial reporting of ITS.

In our opinion, Parker Drilling Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

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, 2013 and 2012, 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, 2013, and our report dated March 10, 2014 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
March 10, 2014

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, 2013 and 2012, 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, 2013. In connection with our audits of the consolidated financial statements, we also have audited financial statement Schedule II - Valuation and Qualifying Accounts. These consolidated financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule 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, 2013 and 2012, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2013, 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, 2013, based on criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 10, 2014 expressed an unqualified opinion on the effectiveness of Parker Drilling Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
March 10, 2014

PARKER DRILLING COMPANY AND SUBSIDIARIES

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

	Year Ended December 31,		
	2013	2012	2011
Revenues	$ 874,172	$ 677,761	$ 686,234
Expenses:			
Operating expenses	571,672	413,188	416,677
Depreciation and amortization	134,053	113,017	112,136
	705,725	526,205	528,813
Total operating gross margin	168,447	151,556	157,421
General and administration expense	(68,025)	(46,257)	(31,567)
Impairments and other charges	—	—	(170,000)
Provision for reduction in carrying value of certain assets	(2,544)	—	(1,350)
Gain on disposition of assets, net	3,994	1,974	3,659
Total operating income (loss)	101,872	107,273	(41,837)
Other income and (expense):			
Interest expense	(47,820)	(33,542)	(22,594)
Interest income	2,450	153	256
Loss on extinguishment of debt	(5,218)	(2,130)	—
Change in fair value of derivative positions	53	55	(110)
Other	1,450	(832)	(1,127)
Total other expense	(49,085)	(36,296)	(23,575)
Income (loss) before income taxes	52,787	70,977	(65,412)
Income tax expense (benefit):			
Current tax expense	12,909	18,042	33,608
Deferred tax expense (benefit)	12,699	15,837	(48,375)
Total income tax expense (benefit)	25,608	33,879	(14,767)
Net income (loss)	27,179	37,098	(50,645)
Less: Net (loss) attributable to noncontrolling interest	164	(215)	(194)
Net income (loss) attributable to controlling interest	$ 27,015	$ 37,313	$ (50,451)
Basic earnings per share:	$ 0.23	$ 0.32	$ (0.43)
Diluted earnings per share:	$ 0.22	$ 0.31	$ (0.43)
Number of common shares used in computing earnings per share:			
Basic	119,284,468	117,721,135	116,081,590
Diluted	121,224,550	119,093,590	116,081,590

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,		
	2013	2012	2011
Comprehensive income:			
Net income (loss)	$ 27,179	$ 37,098	$ (50,645)
Other comprehensive gain, net of tax:			
Currency translation difference on related borrowings	(1,525)	—	—
Currency translation difference on foreign currency net investments	3,051	—	—
Total other comprehensive gain, net of tax:	1,526	—	—
Comprehensive income	28,705	37,098	(50,645)
Comprehensive (income) loss attributable to noncontrolling interest	198	215	194
Comprehensive income (loss) attributable to controlling interest	$ 28,903	$ 37,313	$ (50,451)

See accompanying notes to the consolidated financial statements.

PARKER DRILLING COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET
(Dollars in Thousands)

	December 31, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 148,689	$ 87,886
Accounts and notes receivable, net of allowance for bad debts of $12,853 in 2013 and $8,117 in 2012	257,889	168,615
Rig materials and supplies	41,781	29,422
Deferred costs	13,682	1,089
Deferred income taxes	9,940	8,742
Other tax assets	24,079	33,524
Other current assets	23,223	12,853
Total current assets	519,283	342,131
Property, plant and equipment, at cost:		
Drilling equipment	1,418,582	1,232,891
Rental tools	395,626	337,874
Buildings, land and improvements	49,518	38,736
Other	61,273	57,185
Construction in progress	82,381	190,445
	2,007,380	1,857,131
Less accumulated depreciation and amortization	1,136,024	1,063,934
Property, plant and equipment, net	871,356	793,197
Other assets:		
Rig materials and supplies	10,221	12,930
Debt issuance costs	14,208	8,863
Deferred income taxes	102,420	95,295
Other assets	17,268	3,317
Total other assets	144,117	120,405
Total assets	$ 1,534,756	$ 1,255,733
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 25,000	$ 10,000
Accounts payable	90,033	62,090
Accrued liabilities	84,853	75,656
Accrued income taxes	7,266	4,120
Total current liabilities	207,152	151,866
Long-term debt	628,781	469,205
Other long-term liabilities	26,914	23,182
Long-term deferred tax liability	38,767	20,847
Commitments and contingencies (Note 15)	—	—
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, 120,491,164 shares (118,968,396 shares in 2012)	20,075	19,818
Capital in excess of par value	657,349	646,217
Accumulated deficit	(47,616)	(74,631)
Accumulated Other Comprehensive Income	1,888	—
Total controlling interest stockholders' equity	631,696	591,404
Noncontrolling interest	1,446	(771)
Total equity	633,142	590,633
Total liabilities and stockholders' equity	$ 1,534,756	$ 1,255,733

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,		
	2013	**2012**	**2011**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 27,179	$ 37,098	$ (50,645)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	134,053	113,017	112,136
Impairment of property, plant and equipment	—	—	170,000
Loss on extinguishment of debt	5,218	2,130	—
Gain on disposition of assets	(3,994)	(1,974)	(3,659)
Deferred tax expense (benefit)	12,699	15,837	(48,375)
Provision for reduction in carrying value of certain assets	2,544	—	1,350
Expenses not requiring cash	17,764	22,600	12,833
Change in assets and liabilities:			
Accounts and notes receivable	(33,512)	15,241	(6,841)
Rig materials and supplies	1,754	344	(913)
Other current assets	(11,715)	(4,313)	63,816
Accounts payable and accrued liabilities	(286)	(2,657)	(24,908)
Accrued income taxes	10,454	(6,102)	2,141
Other assets	(661)	(1,522)	(1,050)
Net cash provided by operating activities	161,497	189,699	225,885
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(155,645)	(191,543)	(190,399)
Proceeds from the sale of assets	8,218	3,937	5,535
Acquisition of ITS, net of cash acquired	(117,991)	—	—
Proceeds from insurance claims	—	—	250
Net cash used in investing activities	(265,418)	(187,606)	(184,614)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from issuance of debt	350,000	130,000	50,000
Proceeds from draw on revolver credit facility	—	7,000	—
Repayments of long-term debt	(125,000)	—	—
Repayments of senior notes	—	(125,000)	—
Repayments of term loan	(50,000)	(18,000)	(21,000)
Repayments of revolver	—	—	(25,000)
Payments of debt issuance costs	(11,172)	(4,859)	(504)
Payments of debt extinguishment costs	—	(555)	—
Proceeds from stock options exercised	—	—	183
Excess tax benefit (expense) from stock-based compensation	896	(662)	1,488
Net cash provided by (used in) financing activities	164,724	(12,076)	5,167
Net increase (decrease) in cash and cash equivalents	60,803	(9,983)	46,438
Cash and cash equivalents at beginning of year	87,886	97,869	51,431
Cash and cash equivalents at end of year	148,689	87,886	97,869
Supplemental cash flow information:			
Interest paid	42,236	37,405	32,785
Income taxes paid	17,036	40,234	21,742

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	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, 2010	116,369	$ 19,397	$ 630,409	$ (61,493)	—	$ 588,313	(247)	$ 588,066
Activity in employees’ stock plans	692	111	(343)	—	—	(232)	—	(232)
Excess tax benefit from stock based compensation	—	$ —	$ 988	$ —	—	$ 988	—	$ 988
Amortization of restricted stock plan compensation	—	—	5,988	—	—	5,988	—	5,988
Comprehensive Income:								
Net income	—	—	—	(50,451)	—	(50,451)	(194)	(50,645)
Other, net			—	—	—	—	(115)	(115)
Balances, December 31, 2011	117,061	$ 19,508	$ 637,042	$ (111,944)	$ —	$ 544,606	$ (556)	$ 544,050
Activity in employees’ stock plans	1,907	310	2,620	—	—	2,930	—	2,930
Excess tax deficit from stock options exercised	—	—	(662)	—	—	(662)	—	(662)
Amortization of restricted stock plan compensation	—	—	7,217	—	—	7,217	—	7,217
Comprehensive Income:								
Net income	—	—	—	37,313	—	37,313	(215)	37,098
Balances, December 31, 2012	118,968	$ 19,818	$ 646,217	$ (74,631)	$ —	$ 591,404	$ (771)	$ 590,633
Activity in employees’ stock plans	1,523	257	805	—	—	1,062	—	1,062
Excess tax benefit from stock options exercised	—	—	896	—	—	896	—	896
Amortization of restricted stock plan compensation	—	—	9,431	—	—	9,431	—	9,431
Fair value of acquired noncontrolling 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	$ 20,075	$ 657,349	$ (47,616)	$ 1,888	$ 631,696	$ 1,446	$ 633,142

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1 — Summary of Significant Accounting Policies

Nature of Operations — Parker Drilling, together with its subsidiaries, is 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 24 countries, 10 of which we entered through our acquisition in 2013 of International Tubular Services Limited and certain of its affiliates (collectively, ITS) and other related assets (the ITS Acquisition). We own and operate drilling rigs and drilling-related equipment and also perform drilling-related services, referred to as Operations & Maintenance (O&M) work, for customer-owned drilling rigs on a contracted basis. 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 rental tools business supplies premium equipment to operators on land and offshore in the U.S. and select international markets. We have significant knowledge of the equipment needs of drilling operators and the logistical and product quality requirements of an effective rental tools supplier. We believe we are among the industry leaders in quality, health, safety and environmental practices.

Our business is currently comprised of five operating segments: Rental Tools, U.S. Barge Drilling, U.S. Drilling, International Drilling, and Technical Services. Our rental tools business provides premium rental tools for land and offshore oil and natural gas drilling and workover and production applications. Tools we provide include drill pipe, heavy-weight drill pipe, tubing, high-torque connections, BOPs, drill collars, casing running systems, tools for fishing services and more. Our U.S. barge drilling business operates barge rigs that drill for oil and natural gas in the shallow waters in and along the inland waterways and coasts of Louisiana, Alabama, and Texas. Our U.S. drilling business primarily consists of two new-design arctic-class drilling rigs in Alaska intended to address the challenges presented by the remote location, harsh climate and sensitive environment that characterize the Alaskan North Slope in addition to O&M work in support of ExxonMobil's Santa Ynez Unit offshore platform operations located in the Channel Islands region of California. Our international drilling business includes operations related to Parker-owned and customer-owned rigs. Operations related to customer rigs includes operations and maintenance and other project management services, such as labor, maintenance, and logistics for operators who own their own drilling rigs, but choose Parker Drilling to operate the rigs for them. Our Technical services business includes engineering and related project services during Front End Engineering Design (FEED), pre-FEED and concept development phases of customer-owned drilling facility projects. During the EPCI phase we focus primarily on drilling systems engineering, procurement, commissioning and installation and we typically provide customer support during construction.

At December 31, 2013, our marketable rig fleet consisted of 13 barge drilling rigs and 23 land rigs located in the United States, Latin America and the EMEA regions.

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. The entities that comprise the noncontrolling interest include Parker SMNG Drilling Limited Liability Company and Primorsky Drill Rig Services B.V. 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.

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

Revenue Recognition — Contract drilling revenues and expenses, comprised of daywork drilling contracts, call-outs against MSAs 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. Construction contract revenues and costs are recognized on a percentage of completion basis utilizing the cost-to-cost method.

During 2013 the Company entered into a FEED contract including long-lead equipment procurement services accounted for under the milestone method of revenue recognition. Milestone payments are based on achievement of specified procurement coordination and delivery events in regards to our customer's newly manufactured drilling rig. The quantity of specific long-lead items to be procured is spelled out in the contract and the payment terms are identified with each piece of equipment as well as each specific milestone. Management concluded that each of these payments, constitute substantive milestones. This conclusion was based primarily on the facts that (i) each triggering event represents a specific outcome that can be achieved only through successful performance by the Company of one or more of its deliverables, (ii) achievement of each triggering event was subject to inherent risk and uncertainty and would result in additional payments becoming due to the Company, (iii) each of the milestone payments is non-refundable, (iv) substantial effort is required to complete each milestone, (v) the amount of each milestone payment is reasonable in relation to the value created in achieving the milestone, and (vi) the milestone payments relate solely to past performance.

Reimbursable Costs — 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 $69.7 million, $44.9 million, and $64.2 million during the years ended December 31, 2013, 2012, and 2011, 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 U.S. GAAP requires us 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 revenue 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, revenue and cost accounting for projects that follow the percentage of completion method, self-insured medical/dental plans, 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 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 are made in determining the estimated fair value assigned to each class of assets acquired and liabilities assumed, as well as asset lives, which can materially impact our results of operations.

Intangible Assets – We recorded $10.0 million and $0.2 million, upon the ITS Acquisition, to recognize the fair values of definite and indefinite lived intangible assets, respectively. Preliminary estimates of fair value of identifiable assets acquired and liabilities assumed in the ITS Acquisition were based on management’s estimates, judgments and assumptions and are subject to change upon final valuation. As of December 31, 2013, the fair value estimate of the definite lived and indefinite lived intangibles have been adjusted to $8.5 million and zero, respectively. Definite lived intangible assets recorded in connection with the ITS Acquisition primarily relate to trade names, customer relationships, and developed technology and will be amortized over a weighted average period of approximately 3 years. See Note 2 - *Acquisition of ITS* for further discussion of the ITS Acquisition and preliminary fair value estimates.

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 Doubtful Accounts — Trade accounts receivable are recorded at the invoice amount and typically do not bear interest. 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 exist 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.

	December 31, 2013	December 31, 2012
	(Dollars in Thousands)	
Trade	$ 270,498	$ 176,082
Notes receivable	244	650
Allowance for doubtful accounts[1]	(12,853)	(8,117)
Total accounts and notes receivable, net of allowance for bad debt	$ 257,889	$ 168,615

(1) Additional information on the allowance for doubtful accounts for the years ended December 31, 2013, 2012 and 2011 is reported on Schedule II — Valuation and Qualifying Accounts.

Property, Plant and Equipment — Property, plant and equipment is carried at cost. Maintenance and 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 10 years
Buildings and improvements	5 to 30 years

Impairment — We review the carrying amounts of long-lived assets for potential impairment annually, typically during the fourth quarter, or when events occur or circumstances change that indicate the carrying value of such assets may not be recoverable. 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 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.

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 2013, 2012 and 2011, capitalized interest costs were $2.4 million, $10.2 million and $19.3 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 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. Accordingly, the impact of the Mexican tax reform, which was enacted October 31, 2013, has been recognized in 2013. 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% 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, 2013 and 2012, we had deposits in domestic banks in excess of federally insured limits of approximately $104.3 million and $12.2 million, respectively. The increase is primarily because as of January 1, 2013, all regular checking account deposits are only guaranteed up to $250,000 at each institution while prior to January 1, 2013, all regular checking account deposits were guaranteed, except investments. In addition, we had deposits in foreign banks, which were not insured at December 31, 2013 and 2012 of $50.1 million and $34.5 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 15.6 percent of our revenues for 2013.

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.

Derivative Financial Instruments — We periodically use derivative instruments to manage risks associated with changes in associated interest rate fluctuations in connection with our Secured Credit Agreement (see Note 9, *Derivative Financial Instruments*). These derivative instruments, which consist of variable-to-fixed interest rate swaps, are not designated as hedges. Accordingly, the change in the fair value of the interest rate swaps is recognized in earnings at each reporting period.

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 plans, we grant restricted stock awards (RSA), restricted stock units (RSU) and performance-based award units (PAU). Our RSUs and RSAs are service-based awards and compensation expense is recognized ratably over the applicable vesting period, which is typically three years. The grant-date fair value of nonvested RSAs and RSUs is determined based on the closing trading price of the company's shares on the grant date. Our RSAs and RSUs are settled in stock upon vesting. 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. Our PAU awards contain market conditions which are 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 effect of the market condition is reflected in the grant-date fair value of the award using a lattice model for valuation. PAUs can be settled in cash or stock, or a combination of cash and stock. We evaluate the terms of each PAU award to determine if the award should be accounted for as equity or a liability under the stock compensation rules of U.S. GAAP. Compensation costs for PAUs is recognized ratably over the service period.

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.

Note 2 — Acquisition of ITS

On April 22, 2013 we acquired International Tubular Services Limited and certain of its affiliates (collectively, ITS) and other related assets (the ITS Acquisition) for an initial purchase price of $101.0 million paid at the closing of the ITS Acquisition. An additional $24.0 million was deposited into an escrow account, which will either be paid to the seller or to us, as the case may be, in accordance with the Agreement. As of December 31, 2013 $5.0 million of escrow funds has been released to the seller. The ITS Acquisition closed simultaneously with the execution of the agreement on April 22, 2013.

Fair value of Consideration Transferred

The following details the fair value of the consideration transferred to effect the ITS Acquisition (dollars in thousands).

Cash paid to, or on behalf of, ITS and its equity holders	$	101,000
Cash deposited in escrow		19,000
Fair value of contingent consideration deposited in escrow for assets not acquired (1)		5,000
Total fair value of the consideration transferred	$	125,000

(1) Based on the terms of the acquisition agreement, $5.0 million of the $24.0 million in escrow to be paid to the seller is contingent upon certain future liabilities that could become due by ITS in certain jurisdictions. Any payments in relation to these liabilities will be deducted from the $5.0 million escrow amount and the net balance of the escrow will be paid to the seller. We estimate that the entire $5.0 million in escrow will be paid to the seller, and therefore, the estimated fair value of the consideration in escrow related to these liabilities is $5.0 million. We do not expect to receive any amount back from escrow, and therefore did not record a receivable from the escrow. Any changes to the fair value of the contingent consideration in the future of less than $5.0 million will result in recording a receivable from escrow. The receivable will be recorded at fair value. As of December 31, 2013, the fair value of the receivable is $0.0 million.

Preliminary Allocation of Consideration Transferred to Net Assets Acquired

Preliminary estimates of fair value of identifiable assets acquired and liabilities assumed in the ITS Acquisition were based on management's estimates, judgments and assumptions and are subject to change upon final valuation. As of December 31, 2013, the fair value estimate of certain identifiable assets acquired and liabilities assumed has been adjusted. These estimates, judgments and assumptions are subject to change upon final valuation and should be treated as preliminary values. Management estimated that the fair value of the net assets acquired less noncontrolling interest equals consideration paid. Therefore, there was no goodwill recorded.

The final allocation of consideration will include changes in (1) amounts deposited in escrow, (2) estimated fair values of property and equipment, (3) allocations to intangible assets and liabilities, (4) changes in contingent consideration, and (5) other assets and liabilities. These amounts will be finalized as soon as possible, but no later than one year from the acquisition date.

	April 22, 2013
	(In thousands)
Cash and cash equivalents	$ 7,009
Accounts and notes receivable, net [1]	50,043
Other current assets	1,803
Accounts payable and accrued liabilities	(39,156)
Accrued income taxes	(1,251)
Working capital excluding rig materials and supplies	18,448
Rig materials and supplies	11,514
Property, plant and equipment, net [2]	73,863
Investment in joint venture	4,134
Other noncurrent assets	2,818
Total tangible assets	110,777
Deferred income tax assets - current	222
Deferred income tax assets - noncurrent [3]	11,249
Intangible assets [4]	8,500
Total assets acquired	130,748
Other long-term liabilities	(211)
Long-term deferred tax liability	(2,856)
Net assets acquired	127,681
Less: Noncontrolling interest [5]	(2,681)
Total consideration transferred	$ 125,000

(1) Gross contractual amounts receivable totaled $55.9 million as of the acquisition date.

(2) We recorded an adjustment of $40.2 million to reduce the historical carrying value of the acquired property, plant and equipment to its estimated fair value.

(3) In connection with the ITS Acquisition, we recorded a $5.0 million adjustment to increase deferred income tax assets primarily related to the differences between acquisition date estimated fair value and tax basis of acquired property, plant and equipment.

(4) We recorded $8.5 million to reflect the estimated fair value of definite lived intangible assets recognized in connection with the ITS Acquisition. Our depreciation and amortization expense will reflect this valuation adjustment as the definite lived intangible assets are amortized in future periods. Definite lived intangible assets recorded in connection with the ITS Acquisition, which primarily relate to trade names, customer relationships, and developed technology will be amortized over a weighted average period of approximately 3.4 years.

(5) We recorded an adjustment of $1.0 million to write-down the noncontrolling interest to its estimated fair value. The estimated fair value of the noncontrolling interest was calculated as a percentage of the net assets acquired related to certain subsidiaries in which ITS holds less than a 100 percent controlling interest. The fair value of the net assets of these subsidiaries was primarily based on the income approach valuation model.

Acquisition Related Costs

Acquisition-related transaction costs consisted of various advisory, compliance, legal, accounting, valuation and other professional or consulting fees totaled approximately $22.5 million for the year ended December 31, 2013. The costs were expensed as incurred and are included in general and administrative expense in our consolidated statement of operations. Debt issuance costs of $5.4 million associated with our $125 million term loan, fully funded by Goldman Sachs Bank USA as Sole Lead Arranger and Administrative Agent (the Goldman Term Loan) issued on April 18, 2013 were initially deferred to be amortized to interest expense over the life of the term loan. However, the Goldman Term Loan was repaid on July 30, 2013 with net proceeds from the issuance of $225.0 million aggregate principal amount of 7.50% Senior Notes due August 1, 2020 (7.50% Notes) (see Note 8 - *Long-Term Debt*, for further discussion) and the unamortized deferred costs of $5.2 million were expensed during the 2013 third quarter.

Supplemental Pro forma Results

ITS' results of operations have been included in our financial statements for periods subsequent to April 22, 2013, the effective date of the ITS Acquisition. ITS contributed revenues of $88.0 million and net income of approximately $10.0 million to Parker Drilling for the period from the closing of the ITS Acquisition through December 31, 2013.

The following unaudited supplemental pro forma results present consolidated information for the years ended December 31, 2013 and 2012 as if the ITS Acquisition had been completed on January 1, 2012. The pro forma results have been calculated after applying our accounting policies and include, among others, (i) the amortization associated with the fair value of the acquired intangible assets, (ii) interest expense associated with the Goldman Term Loan and (iii) the impact of certain fair value adjustments such as a decrease in depreciation expense related to the write-down in property, plant and equipment. The pro forma results do not include any potential synergies, non-recurring charges which result directly from the ITS Acquisition, cost savings or other expected benefits of the ITS Acquisition. The pro forma financial information does not necessarily represent what would have occurred if the transaction had taken place at the beginning of the period presented and should not be taken as representative of our future consolidated results of operations. We have not concluded our integration work. Accordingly, this pro forma information does not include all costs related to the integration nor the benefits we expect to realize from operating synergies.

	Year ended December 31, (unaudited)	
	2013	2012
	(Dollars in thousands, except per share data)	
Revenue	$ 914,992	$ 794,640
Net income	$ 45,785	$ (14,117)
Net income attributable to Parker Drilling	$ 45,391	$ (13,981)
Earnings per share - basic	$ 0.38	$ (0.12)
Earnings per share - diluted	$ 0.37	$ (0.12)
Basic number of shares	119,284,468	117,721,135
Diluted number of shares	121,224,550	119,093,590

Note 3 — Accumulated Other Comprehensive Income

Accumulated other comprehensive loss consisted of the following:

	Foreign Currency Items
	(in thousands)
December 31, 2012	$ —
Current period other comprehensive income	1,888
December 31, 2013	$ 1,888

No amounts were reclassified out of accumulated other comprehensive income for the year ended December 31, 2013.

Note 4 — Asset Impairment

Asset Impairment

During the fourth quarter of 2011, we evaluated the present value of the future cash flows related to our arctic-class drilling rigs in accordance with the U.S. GAAP guidance for impairment or disposal of long-lived assets. The evaluation was performed as a result of the delay in completion of the rigs to modify the rigs to meet their design and functional requirements and an increase in the cost of the rigs. The need for the modifications was determined as a result of comprehensive safety, technical and operational reviews during commissioning activities of these prototype drilling rigs. The modification work extended the commissioning activities and increased the rigs' total costs. At the time of the impairment evaluation, the two rigs' cost at completion was estimated to be $385 million, which included capitalized interest estimates of approximately $50.7 million. This cost exceeded the estimated fair value of the rigs based on their projected cash flows. Based on this evaluation, the Company determined that the long-lived assets with a carrying amount of $339.5 million as of December 31, 2011, were no longer recoverable and were in fact impaired and recorded a charge in the 2011 fourth quarter of $170.0 million ($109.1 million, net of taxes) to reflect their estimated fair value of $169.5 million. Fair value was based on expected future cash flows using Level 3 inputs under the fair value measurement requirements. The cash flows are those expected to be generated by our assets, discounted at the 10 percent rate of interest. In December 2012 we commenced drilling operations with the first arctic-class drilling rig. The second rig completed client acceptance testing and began drilling in February 2013. The rigs are reported as part of the U.S. Drilling segment.

Provision for Reduction in Carrying Value of an Asset

During the 2013 fourth quarter, for two rigs previously reported as assets held for sale as of December 31, 2012, management concluded that facts and circumstances no longer support the expectation that a sale would be consummated within a reasonable time period. As a result, we reclassified these assets back to assets held and used in accordance with generally accepted accounting principles. Concurrently, we performed an impairment analysis of the two rigs and determined the fair value was less than the carrying amount before the assets were classified as held for sale, adjusted for any depreciation expense that would have been recognized had the assets been continuously classified as held and used. Therefore, during the 2013 fourth quarter we recorded a non-cash charge of $1.9 million to reflect the rigs current estimated fair value. Additionally, during the 2013 fourth quarter a sales agreement was terminated for three additional rigs which were previously expected to be sold prior to December 31, 2013. Upon termination of the sales agreement we performed a fair value analysis of the rigs and concluded for one rig, the carrying value of the rig exceeded fair value. Therefore, during the 2013 fourth quarter we recorded a non-cash charge of $0.6 million. Fair value was based on expected future cash flows using Level 3 inputs in accordance with fair value measurement requirements. The two rigs are reported as part of the International Drilling segment.

In 2011, we recognized a charge of $1.4 million related to a final settlement of a bankruptcy proceeding.

Note 5 — Disposition of Assets

During the 2013 fourth quarter, we sold two rigs located in New Zealand, including rig related inventory, property and leasehold improvements. The assets had a carrying value at the time of sale of $2.3 million and were sold for proceeds of $3.2 million resulting in a gain of approximately $0.9 million. The assets were part of our international drilling rig fleet. During the 2013 fourth quarter we also completed the sale of a building located in Tulsa, OK. As a result of the completed sale, we recognized proceeds of $0.8 million and $0.1 million gain on the sale. Additionally, during the 2013 third quarter we sold a barge rig located in Mexico with carrying value at the time of sale of $0.3 million for proceeds of $0.5 million, resulting in a $0.2 million gain. The barge rig was part of our Latin America rig fleet and has historically been included in the international drilling segment.

In December 2012, we sold a 33 year old posted barge drilling rig for proceeds of $0.2 million, resulting in a $0.5 million loss. There were no individually significant asset dispositions in 2011.

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

Note 6 — Assets Held for Sale

We had no assets classified as assets held for sale as of December 31, 2013. During 2013, for five rigs previously reported as assets held for sale, management concluded that facts and circumstances no longer support the expectation that a sale would be consummated within a reasonable time period. During the 2013 second quarter, we reclassified three rigs from assets held for sale to assets held and used and inventory. We initially classified the three rigs as assets held for sale as of December 31, 2010. We performed an analysis of the fair value of the three rigs and determined the rigs' carrying amount was less than fair value; therefore, the rigs were reclassified at their carrying amount at the time the assets were classified as held for sale, adjusted for depreciation expense that would have been recognized had the assets been continuously classified as held and used. The amount of additional depreciation recorded during the 2013 second quarter to place the assets in held and used categorization was $0.7 million.

Additionally, during the 2013 fourth quarter we reclassified two rigs from assets held for sale to assets held and used and inventory. We initially classified these rigs as held for sale as of September 30, 2012. We performed an analysis of the fair value of the two rigs and determined the fair value was less than the carrying amount before the assets were classified as held for sale, adjusted for any depreciation expense that would have been recognized had the assets been continuously classified as held and used. Therefore, during the 2013 fourth quarter we recorded a non-cash charge of $1.9 million to reflect the rigs current estimated fair value.

We have adjusted the Assets held for sale, Inventory, and Property, plant and equipment balances for the year ended December 31, 2012 from what was reported in our December 31, 2012 Form 10-K, to reflect the reclassification of these assets.

Note 7 — Income Taxes

Income (loss) before income taxes is summarized below:

	Year Ended December 31,		
	2013	2012	2011
	(Dollars in Thousands)		
United States	$ 32,136	$ 52,422	$ (61,434)
Foreign	20,651	18,555	(3,978)
	$ 52,787	$ 70,977	$ (65,412)

Income tax expense (benefit) is summarized as follows:

	Year Ended December 31,		
	2013	2012	2011
	(Dollars in Thousands)		
Current:			
United States:			
Federal	$ (3,658)	$ 7,791	$ 17,168
State	1,968	733	1,264
Foreign	14,599	9,518	15,176
Deferred:			
United States:			
Federal	10,720	15,612	(46,694)
State	2,820	4,296	1,864
Foreign	(841)	(4,071)	(3,545)
	$ 25,608	$ 33,879	$ (14,767)

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,					
	2013		2012		2011	
	(Dollars in thousands)					
	Amount	% of Pre-Tax Income	Amount	% of Pre-Tax Income	Amount	% of Pre-Tax Income
Computed Expected Tax Expense	$ 18,476	35 %	$ 24,842	35 %	$ (22,894)	35 %
Foreign Taxes	12,470	24 %	13,171	19 %	11,752	(17)%
Tax Effect Different From Statutory Rates	(8,920)	(17)%	(8,080)	(11)%	(1,571)	2 %
State Taxes, net of federal benefit	4,099	8 %	4,757	7 %	2,689	(4)%
Foreign Tax Credits	(1,484)	(3)%	(1,867)	(3)%	(14,595)	22 %
Kazakhstan Tax Settlement	—	— %	—	— %	(536)	1 %
Change in Valuation Allowance	1,975	4 %	(1,662)	(2)%	2,542	(4)%
Uncertain Tax Positions	2,472	5 %	(6,642)	(9)%	3,647	(6)%
Permanent Differences	4,005	7 %	5,477	8 %	6,356	(10)%
Prior Year Return to Provision Adjustments	(6,268)	(12)%	4,057	5 %	4,156	(6)%
Other	(1,217)	(2)%	(174)	(1)%	(829)	1 %
Unremitted Foreign Earnings-Current Year Adjustment	—	— %	—	— %	(5,484)	8 %
Actual Tax Expense	$ 25,608	49 %	$ 33,879	48 %	$ (14,767)	22 %

The balances for the years ended December 31, 2012 and 2011 have been adjusted to reflect reclassifications of $1.3 million and $5.6 million, respectively, between foreign taxes and, primarily, prior year return to provision adjustments and amendments and other. Management concluded based on the facts and circumstances during 2013 the adjustments are closely related to items included in foreign taxes.

The components of the Company's deferred tax assets and liabilities as of December 31, 2013 and 2012 are shown below:

	December 31, 2013	December 31, 2012
	(Dollars in Thousands)	
Deferred tax assets		
Current deferred tax assets:		
Reserves established against realization of certain assets	$ 1,504	$ 1,634
Accruals not currently deductible for tax purposes	7,223	6,747
Other state deferred tax asset, net	990	361
Foreign Local Office	223	—
Gross current deferred tax assets	9,940	8,742
Current deferred tax valuation allowance	—	—
Net current deferred tax assets	9,940	8,742
Non-current deferred tax assets:		
Federal net operating loss carryforwards	—	—
State net operating loss carryforwards	864	3,095
Other state deferred tax asset, net	1,909	914
Foreign Tax Credits	27,462	25,977
FIN 48	8,317	8,015
Foreign tax	18,499	5,838
Asset Impairment	48,743	56,190
Accruals not currently deductible for tax purposes	1,017	—
Deferred compensation	2,436	—
Other	—	71
Gross long-term deferred tax assets	109,247	100,100
Valuation Allowance	(6,827)	(4,805)
Net non-current deferred tax assets, net of valuation allowance	102,420	95,295
Net deferred tax assets	112,360	104,037
Deferred tax liabilities:		
Non-current deferred tax liabilities:		
Property, Plant and equipment	(32,505)	(19,139)
Accruals	—	(1,066)
Foreign tax local	(1,440)	—
Deferred Compensation	—	2,001
Other state deferred tax liability, net	(4,819)	(2,643)
Other	(3)	—
Gross non-current deferred tax liabilities	(38,767)	(20,847)
Net deferred tax asset	$ 73,593	$ 83,190

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 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. Based upon the factors considered by management in assessing the realizability of the deferred tax assets, management believes it is more likely than not that the Company will realize the benefits of these deductible differences, net of the existing valuation allowances at December 31, 2013. The amount of the deferred tax asset considered realizable, however, could be reduced in the near term if estimates of future taxable income during the carryforward period are reduced.

On September 13, 2013, the U.S. Treasury Department and the Internal Revenue Service issued final regulations that address costs incurred in acquiring, producing, or improving tangible property (the "tangible property regulations"). The tangible property regulations are generally effective for tax years beginning on or after January 1, 2014. The tangible property regulations required the Company to make additional tax accounting method changes as of January 1, 2014; however, the impact of these changes has not been material to the Company's consolidated financial position, its results of operations, or both.

The 2013 results include income tax benefits of $3.3 million related to the enacted Mexican tax reform as applied to the expected future utilization of deferred tax assets and liabilities and $20.9 million for depreciation and amortization relating to our arctic-class drilling rigs in Alaska. In addition, we increased our valuation allowance by $2.0 million primarily related to foreign net operating losses.

The 2012 results include income tax expenses of $1.7 million related to the effective settlement of our US Federal Internal Revenue Service examination for the 2006 through 2010 periods and $7.7 million for depreciation and amortization relating to our arctic-class drilling rigs in Alaska. In addition, we decreased our valuation allowance by $1.7 million primarily related to foreign NOLs.

The 2011 results include an income tax benefit of $60.9 million (federal and state combined) related to the $170.0 million non-cash pretax impairment charge relating to our arctic-class drilling rigs in Alaska. In addition, we increased our valuation allowance by $2.5 million primarily related to foreign NOLs.

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

	In Thousands
Balance at January 1, 2013	$ (10,030)
Additions based on tax positions taken during a prior period	(3,245)
Reductions related to settlement of tax matters	1,066
Reductions related to a lapse of applicable statute of limitations	—
Balance at December 31, 2013	$ (12,209)

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, 2013:

Colombia	2008-present
Kazakhstan	2007-present
Mexico	2008-present
Papua New Guinea	2010-present
Russia	2010-present
United States — Federal	2011-present
United Kingdom	2010-present

At December 31, 2013, we had a liability for unrecognized tax benefits of $12.2 million ($5.4 million of which, if recognized, would favorably impact our effective tax rate).

The Company recognized interest and penalties related to uncertain tax positions in income tax expense. As of December 31, 2013 and December 31, 2012 we had approximately $7.9 million and $7.0 million of accrued interest and penalties related to uncertain tax positions, respectively. We recognized an increase of $0.9 million of interest and no penalties on unrecognized tax benefits for the year ended December 31, 2013.

As of December 31, 2013, 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 would likely be subject to US 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 because of the application of US foreign tax credits. While we currently claim foreign tax credits, we may not be in a credit position if and when future remittances of foreign earnings occur, or the limitation imposed by the Internal

Revenue Code and regulations thereunder may not allow the credits to be utilized during the applicable carryback and carryforward periods.

Note 8 — Long-Term Debt

The following table illustrates the Company's current debt portfolio as of December 31, 2013 and December 31, 2012:

	December 31, 2013	December 31, 2012
	(Dollars in Thousands)	
7.50% Senior Notes, due August 2020	$ 225,000	$ —
9.125% Senior Notes, due April 2018	428,781	429,205
Term Note - Effective interest rate of 3.21 percent at December 31, 2012	—	50,000
Total debt	653,781	479,205
Less current portion	25,000	10,000
Total long-term debt	$ 628,781	$ 469,205

As of December 31, 2013, we have no debt maturities prior to 2018. However, we have classified $25.0 million of 9.125% Senior Notes (9.125% Notes) due April 2018, as current debt as management intends to repay this debt prior to maturity. The aggregate maturities of long-term debt, including unamortized premiums of $3.8 million, for 2018 and thereafter is $628.8 million. Subsequent to December 31, 2013, we issued $360.0 million aggregate principal amount of 6.75% Senior Notes due 2022 (6.75% Notes). Net proceeds from the 6.75% Notes offering plus a $40.0 million draw on the Secured Credit Agreement and cash on hand, were utilized to redeem $416.2 million aggregate principal amount of our outstanding 9.125% Notes. After payment for the tendered notes, $8.8 million aggregate principal amount of our 9.125% Notes remains outstanding. At December 31, 2013 management had the ability and intent to refinance the 9.125% Notes. With the issuance of the 6.75% Notes and the $40.0 million borrowing on the Secured Credit Agreement, we refinanced $400.0 million of our long-term debt, which remains classified as long-term debt as of December 31, 2013. The remaining $25.0 million of 9.125% Notes is classified as current debt as management intends to repay this portion of the debt prior to maturity. See Note 21 - Subsequent Events, for further discussion.

7.50% Senior Notes, due August 2020

On July 30, 2013, we issued $225.0 million aggregate principal amount of 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 under our Secured Credit Agreement 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 our Secured Credit Agreement 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 were $5.3 million ($5.1 million, net of amortization as of December 31, 2013) and will be 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 March 22, 2010, we issued $300.0 million aggregate principal amount of 9.125% 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 9.125% Notes offering were primarily used to redeem the $225.0 million aggregate principal amount of our 9.625% Senior Notes due 2013 and to repay $42.0 million of borrowings under our Secured Credit Agreement.

On April 25, 2012, we issued an additional $125.0 million aggregate principal amount of 9.125% Notes under the same indenture at a price of 104.0 percent of par, resulting in gross proceeds of $130.0 million. Net proceeds from the offering were utilized to refinance $125.0 million aggregate principal amount of the 2.125% Convertible Notes due July 2012. We repurchased $122.9 million aggregate principal amount of the 2.125% Convertible Notes tendered pursuant to a tender offer on May 9, 2012 and paid off the remaining $2.1 million at their stated maturity on July 15, 2012.

The 9.125% 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 9.125% Notes are jointly and severally guaranteed by substantially all of our direct and indirect subsidiaries other than immaterial subsidiaries and subsidiaries generating revenues primarily outside the United States. Interest on the 9.125% Notes is payable on April 1 and October 1 of each year. Debt issuance costs related to the 9.125% Notes of approximately $11.6 million ($7.7 million, net of amortization) are being amortized over the term of the notes using the effective interest rate method.

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. After payment for the tendered 9.125% Notes, $8.8 million aggregate principal amount of our 9.125% Notes remains outstanding.

At any time after to April 1, 2014, we may redeem all or a part of the 9.125% Notes upon appropriate notice, at a redemption price of 104.563 percent of the principal amount, and at redemption prices decreasing each year thereafter to par beginning April 1, 2016. If we experience certain changes in control, we must offer to repurchase the 9.125% 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.

On January 24, 2014, the Indenture was amended to remove most of the restrictions on 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. The Indenture also was amended to remove certain restrictive covenants designating certain events as Events of Default. Additionally, the remaining restrictive covenants are subject to a number of important exceptions and qualifications.

Goldman Term Loan

In connection with the ITS Acquisition described in Note 2, *Acquisition of ITS*, on April 18, 2013, we entered into the $125 million Goldman Term Loan. The Goldman Term Loan was repaid on July 30, 2013 with net proceeds from issuance of the 7.50% Notes. In connection with the repayment of the Goldman Term Loan we incurred debt extinguishment costs of $5.2 million.

2.125% Convertible Senior Notes, due July 2012

On July 5, 2007, we issued $125.0 million aggregate principal amount of 2.125% Convertible Notes. As noted above, on May 9, 2012, we repurchased $122.9 million aggregate principal amount of the 2.125% Convertible Notes pursuant to a tender offer. The tender offer price was $1,003.27 for each $1,000 principal amount of 2.125% Convertible Notes, plus accrued and unpaid interest. This repurchase resulted in the recording of debt extinguishment costs of $1.8 million related to the accelerated amortization of both the unamortized debt issuance costs and debt discount associated with the 2.125% Convertible Notes. The remaining $2.1 million aggregate principal amount of non-tendered 2.125% Convertible Notes was subsequently paid off at their stated maturity on July 15, 2012.

Amended and Restated Credit Agreement

On December 14, 2012, we entered into an Amended and Restated Credit Agreement (Secured Credit Agreement) consisting of a senior secured $80.0 million Revolver and senior secured term loan facility (Term Loan) of $50.0 million. The Secured Credit Agreement amended and restated the Prior Credit Agreement. We entered into the Secured Credit Agreement to extend its maturity from May 14, 2013 to December 14, 2017 and to decrease the range of Applicable Rates under our Revolver. The Secured Credit Agreement provides that, subject to certain conditions, including the approval of the Administrative Agent and the lenders' acceptance (or additional lenders being joined as new lenders), the amount of the Term Loan or Revolver can be increased by an additional $50.0 million, so long as after giving effect to such increase, the Aggregate Commitments shall not be in excess of $180.0 million.

Our obligations under the Secured Credit Agreement are guaranteed by substantially all of our domestic subsidiaries, each of which has executed guaranty agreements; and are secured by first priority liens on our accounts receivable, specified barge rigs and rental equipment. The Secured Credit Agreement contains customary affirmative and negative covenants with which we were in compliance as of December 31, 2013 and December 31, 2012. The Secured Credit Agreement terminates on December 14, 2017.

On July 19, 2013, we entered into an amendment to our Secured Credit Agreement which, among other things, permits us or any of our subsidiaries (other than certain immaterial subsidiaries) to incur indebtedness pursuant to additional unsecured senior notes in an aggregate principal amount not to exceed $250.0 million at any one time outstanding; provided that any such notes shall (x) have a scheduled maturity occurring after the maturity date of our Secured Credit Agreement, (y) contain terms (including covenants and events of default) no more restrictive, taken as a whole, to us and our subsidiaries than those contained in our Secured Credit Agreement and (z) have no scheduled amortization, no sinking fund requirements and no maintenance financial covenants. In addition, pursuant to the amendment, and subject to the terms and conditions set forth in the Secured Credit Agreement, to the extent we repay the principal amount of Term Loans outstanding under our Secured Credit Agreement, until April 30, 2014 we may re-borrow, in the form of additional term loans, up to $45.0 million of the principal amount of such outstanding term loans we have repaid, provided that such $45.0 million borrowing amount will decrease by $2.5 million at the end of each quarter beginning September 30, 2013 and ending March 31, 2014, such that the borrowing availability on December 31, 2013 was $40.0 million and on April 30, 2014 would be $37.5 million.

Revolver

Our Revolver is available for general corporate purposes and to support letters of credit. Interest on Revolver loans accrues at a Base Rate plus an Applicable Rate or LIBOR plus an Applicable Rate. Under the Secured Credit Agreement, the Applicable Rate varies from a rate per annum ranging from 2.50 percent to 3.00 percent for LIBOR rate loans and 1.50 percent to 2.00 percent for base rate loans, determined by reference to the consolidated leverage ratio (as defined in the Secured Credit Agreement). Under the Prior Credit Agreement, the Applicable Rate varied from a rate per annum ranging from 2.75 percent to 3.25 percent for LIBOR rate loans and 1.75 percent to 2.25 percent for base rate loans. Revolving loans are available subject to a borrowing base calculation based on a percentage of eligible accounts receivable, certain specified barge drilling rigs and rental equipment of the Company and its subsidiary guarantors. There were no revolving loans outstanding at December 31, 2013 and December 31, 2012. Letters of credit outstanding as of December 31, 2013 and December 31, 2012 totaled $4.6 million and $4.5 million, respectively.

Term Loan

The Term Loan originated at $50.0 million on December 14, 2012 and requires quarterly principal payments of $2.5 million beginning March 31, 2013. Interest on the Term Loan accrues at a Base Rate plus 2.00 percent or LIBOR plus 3.00 percent. The Prior Credit Agreement required quarterly principal payments of $6.0 million, and interest accrued at a Base Rate plus 2.25 percent or LIBOR plus 3.25 percent. The were no borrowings on the Term Loan at December 31, 2013. The outstanding balance under the Term Loan as of December 31, 2012 was $50.0 million.

Note 9 — Derivative Financial Instruments

During the 2011 second quarter, we entered into two variable-to-fixed interest rate swap agreements as a strategy to manage the floating rate risk on the Term Loan borrowings under the Secured Credit Agreement. The two agreements fixed the interest rate on a notional amount of $73.0 million of borrowings at 3.878 percent for the period beginning June 27, 2011 and terminating May 14, 2013. The notional amount of the swap agreements decreased correspondingly with amortization of the Term Loan under the Prior Credit Agreement. We did not apply hedge accounting to the agreements and, accordingly, change in the fair value of the interest rate swaps were recognized in earnings. As of December 31, 2013 the swap agreements had expired and as of December 31, 2012, the fair value of the interest rate swap was a liability of $0.1 million and was recorded in accrued liabilities in our consolidated balance sheets. For the year ended December 31, 2013, we recognized in earnings a nominal gain relating to these contracts. For both years ended December 31, 2012 and December 31, 2011 we recognized a nominal loss, relating to these contracts.

Note 10 — 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 FASB fair value measurement and disclosure guidance 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 inactive markets or identical assets or liabilities in less active markets and

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 measurement even though we may have also 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. The carrying amount of our interest rate swap agreements represents the estimated fair value, measured using Level 2 inputs. As of December 31, 2013 the swap agreements had expired and as of December 31, 2012, the fair value of the interest rate swap was a liability of $0.1 million and was recorded in accrued liabilities in our consolidated balance sheets.

Fair value of our debt instruments is determined using Level 2 inputs. Fair values and related carrying values of our debt instruments are as follows:

	December 31, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Long-term Debt				
7.50% Notes	$ 225,000	$ 236,250	$ —	$ —
9.125% Notes	425,000	446,250	425,000	453,688
Total	$ 650,000	$ 682,500	$ 425,000	$ 453,688

As discussed in Note 4, in accordance with the impairment or disposal of long-lived assets guidance, during the fourth quarter of 2011, our arctic-class rigs with a carrying value as of December 31, 2011 of $339.5 million were written down to their estimated fair value of $169.5 million, resulting in a pretax non-cash charge of $170.0 million which is included in earnings for the period. The fair value was based on expected future cash flows using Level 3 inputs.

The assets acquired and liabilities assumed in the ITS 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, 2013.

Note 11 — Common Stock and Stockholders' Equity

Stock Plans — The Company's employee and non-employee director stock plans are summarized as follows:

The 2010 Long-Term Incentive Plan, as amended and restated (the Plan) was approved by the stockholders at the Annual Meeting of Stockholders on May 8, 2013. The Plan authorizes the compensation committee or the board of directors to issue stock options, stock appreciation rights, RSAs, RSUs, PAUs 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 Amended and Restated 2010 Long Term Incentive Plan is 11,000,000 shares of common stock. As of December 31, 2013 there were 5,130,182 shares remaining available under the Plan.

For service-based awards and 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. Share-based awards generally vest over three years. 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. The fair value of nonvested RSAs and RSUs is determined based on the closing trading price of the company's shares on the grant date. Our RSAs and RSUs are settled in stock upon vesting. Our PAU awards can be settled in cash or stock, or a combination of cash and stock. We evaluate the terms of each PAU award to determine if the award should be accounted for as equity or a liability under the stock compensation rules of U.S. GAAP.

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.

On September 17, 2012, Gary Rich was elected as President, Chief Executive Officer and Director of the Company. As part of his employment agreement, he was granted 349,651 RSUs. Additionally, 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. Both of these awards were granted outside of the Company's 2010 Plan but are subject to substantially the same terms and conditions of other service-based RSUs granted by the Company to its executive officers.

Information regarding the Company's Long-Term Incentive plans is summarized below:

Nonvested Shares	Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2013	2,812,482	$ 5.15
Granted	2,602,973	4.77
Vested	(1,636,373)	5.00
Forfeited	(370,727)	5.02
Nonvested at December 31, 2013	3,408,355	$ 4.97

In 2013 and 2012, we issued 2,602,973 and 1,558,347, respectively, of restricted shares to selected key personnel. Total stock-based compensation expense recognized for the years ended December 31, 2013, 2012, and 2011 was $9.4 million, $7.2 million, and $5.9 million, respectively, all of which was related to nonvested stock. The total fair value of the shares vested during the years ended December 31, 2013, 2012, and 2011 was $7.4 million, $5.2 million, and $6.9 million, respectively. The fair value of RSAs and RSUs is determined based on the closing trading price of the company's shares on the grant date. The weighted-average grant-date fair value of shares granted during the years 2013, 2012, and 2011 was $4.77, $5.37, and $5.61, respectively. Stock-based compensation expense is included in our consolidated statements of operations in both "General and administration expense" and "Operating expenses."

Nonvested RSUs at December 31, 2013 totaled 3,408,355 shares and total unrecognized compensation cost related to unamortized nonvested stock awards was $8.4 million as of December 31, 2013. The remaining unrecognized compensation cost related to non-vested stock awards will be amortized over a weighted-average vesting period of approximately 20.8 months.

During the years ended December 31, 2013 and 2012, we granted to certain of our officers and key employees a total of 18,000 and 38,429 PAUs under the Plan, respectively. Subsequent to the award of these PAUs, 13,358 and 3,955 units were forfeited during 2013 and 2012, respectively. Incentive grants included in this issuance were based on the attainment of pre-established performance goals. Each PAU has a nominal value of $100.00. Awards are dependent upon our total stockholder return and return on capital employed relative to a peer group of companies over a three-year performance period. A maximum of 200 percent of the number of PAUs granted may be earned if performance at the maximum level is achieved. Compensation expense recognized related to the PAUs for the years ended December 31, 2013, 2012, and 2011 was $1.8 million, $0.5 million, and $2.1 million, respectively.

As of December 31, 2013 and 2012, we had no stock options outstanding or exercisable and we had 668,897 and 1,709,963 shares held in treasury stock, respectively.

Note 12 — Reconciliation of Income and Number of Shares Used to Calculate Basic and Diluted Earnings per Share (EPS)

	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, 2012		
	Income (Numerator)	Shares (Denominator)	Per-Share Amount
Basic EPS	$ 37,313,000	117,721,135	$ 0.32
Effect of dilutive securities:			
Stock options and restricted stock		1,372,455	$ (0.01)
Diluted EPS:	$ 37,313,000	119,093,590	$ 0.31

	For the Year Ended December 31, 2011		
	Income (Numerator)	Shares (Denominator)	Per-Share Amount
Basic EPS	$ (50,451,000)	116,081,590	$ (0.43)
Effect of dilutive securities:			
Stock options and restricted stock		—	$ —
Diluted EPS:	$ (50,451,000)	116,081,590	$ (0.43)

For the years ended December 31, 2013 and 2012, weighted-average shares outstanding used in our computation of diluted EPS includes the dilutive effect of potential common shares. For the year ended December 31, 2011, all potential common shares have been excluded from the calculation of weighted-average shares outstanding used in our computation of diluted EPS as the company incurred a loss for that year, and therefore, inclusion of potential common shares in the calculation of diluted EPS would be anti-dilutive.

Note 13 — 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 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 amounts of contributions allowed by law. The costs of our matching contributions to the Plan were $3.6 million, $2.8 million and $2.4 million in 2013, 2012 and 2011, respectively. Employees become 100 percent vested in the employer match contributions immediately upon participation in the Plan. Coverage for office based employees begins on the date of hire. For rig-based and rental tools employees, coverage begins on the first of the month following completion of 30 calendar days of continuous full-time employment.

Note 14 — Reportable Segments

Our business is comprised of five segments: (1) Rental Tools, (2) U.S. Barge Drilling, (3) U.S. Drilling, (4) International Drilling, and (5) Technical Services. Historically, we reported a sixth segment, Construction Contract, for which there was no activity during the nine months ended September 30, 2013 or the year ended December 31, 2012. As a result of activity in the fourth quarter of 2013, this segment has been included in this report. We eliminate inter-segment revenue and expenses. The following table represents the results of operations by reportable segment:

Operations by Reportable Industry Segment:	Year Ended December 31, 2013	2012	2011
	(Dollars in Thousands)		
Revenues:			
Rental Tools(1)	$ 310,041	$ 246,900	$ 237,068
U.S. Barge Drilling(1)	136,855	123,672	93,763
U.S. Drilling(1)	66,928	1,387	—
International Drilling(1)	333,962	291,772	318,481
Technical Services(1)	26,386	14,030	27,284
Construction Contract(1)	—	—	9,638
Total revenues	874,172	677,761	686,234
Operating income:			
Rental Tools(2)	91,164	113,899	120,822
U.S. Barge Drilling(2)	51,257	39,608	11,115
U.S. Drilling(2)	(4,484)	(15,168)	(3,915)
International Drilling(2)	23,732	13,138	22,948
Technical Services(2)	2,050	79	5,680
Construction Contract(2)	4,728	—	771
Total operating gross margin	168,447	151,556	157,421
General and administrative expense	(68,025)	(46,257)	(31,567)
Impairments and other charges	—	—	(170,000)
Provision for reduction in carrying value of certain assets	(2,544)	—	(1,350)
Gain on disposition of assets, net	3,994	1,974	3,659
Total operating income (loss)	101,872	107,273	(41,837)
Interest expense	(47,820)	(33,542)	(22,594)
Interest income	2,450	153	256
Loss on extinguishment of debt	(5,218)	(2,130)	—
Changes in fair value of derivative positions	53	55	(110)
Other	1,450	(832)	(1,127)
Income (loss) from continuing operations before income taxes	$ 52,787	$ 70,977	$ (65,412)

	2013	2012
Identifiable assets:		
Rental Tools	$ 350,429	$ 194,600
U.S. Barge Drilling	89,884	99,409
U.S. Drilling	354,208	369,683
International Drilling	460,461	414,546
Total identifiable assets	1,254,982	1,078,238
Corporate and other assets(3)	279,774	177,495
Total assets	$ 1,534,756	$ 1,255,733

1) In 2013, our largest customer, Exxon Neftegas Limited (ENL), constituted approximately 15.6 percent, respectively, of our total consolidated revenues and approximately 38.3 percent of our International Drilling segment and 33.9 percent of our Technical Services segment. In 2012, our two largest customers, ENL and Schlumberger, constituted approximately 12 percent and 10 percent, respectively, of our total consolidated revenues and approximately 27 percent and 24 percent of our International Drilling segment, respectively. In 2011, our largest customer, ENL constituted approximately 16 percent of our total revenues and approximately 34 percent of our International Drilling segment.
2) Operating income is calculated as revenues less direct operating expenses, including depreciation and amortization expense.
3) This category includes corporate assets as well as minimal assets for our Technical Services segment primarily related to office furniture and fixtures.

Operations by Reportable Industry Segment:	Year Ended December 31, 2013	2012	2011
	(Dollars in Thousands)		
Capital expenditures:			
Rental Tools	$ 76,928	$ 61,958	$ 61,702
U.S. Barge Drilling	23,694	8,808	7,339
U.S. Drilling	1,809	86,786	99,915
International Drilling	39,115	15,240	15,011
Corporate	14,099	18,751	6,432
Total capital expenditures	$ 155,645	$ 191,543	$ 190,399
Depreciation and amortization:			
Rental Tools	54,625	42,944	40,497
U.S. Barge Drilling	13,796	13,906	17,006
U.S. Drilling	16,120	7,011	2,223
International Drilling	46,022	45,967	48,965
Corporate and other (1)	3,490	3,189	3,445
Total depreciation and amortization	$ 134,053	$ 113,017	$ 112,136

1) This category includes depreciation of corporate assets as well as minimal depreciation for our Technical Services segment primarily related to office furniture and fixtures.

Operations by Geographic Area:	Year Ended December 31, 2013	2012	2011
	(Dollars in Thousands)		
Revenues:			
Africa and Middle East	$ 58,416	$ 26,528	$ 6,774
Asia Pacific	170,165	117,392	147,643
CIS	55,165	44,312	67,255
Europe	16,788	—	—
Latin America	120,261	103,540	96,810
United States	453,377	385,989	367,752
Total revenues	874,172	677,761	686,234
Operating gross margin:			
Africa and Middle East(1)	(383)	(2,027)	(8,724)
Asia Pacific(1)	21,995	16,550	23,528
CIS(1)	11,888	(9,580)	8,709
Europe(1)	274	—	—
Latin America(1)	1,140	9,581	1,126
United States(1)	133,533	137,032	132,782
Total operating gross margin	168,447	151,556	157,421
General and administrative expense	(68,025)	(46,257)	(31,567)
Impairments and other charges	—	—	(170,000)
Provision for reduction in carrying value of certain assets	(2,544)	—	(1,350)
Gain on disposition of assets, net	3,994	1,974	3,659
Total operating income (loss)	101,872	107,273	(41,837)
Interest expense	(47,820)	(33,542)	(22,594)
Interest income	2,450	153	256
Loss on extinguishment of debt	(5,218)	(2,130)	—
Changes in fair value of derivative positions	53	55	(110)
Other	1,450	(832)	(1,127)
Income (loss) from continuing operations before income taxes	$ 52,787	$ 70,977	$ (65,412)
Long-lived assets:(2)			
Africa and Middle East	$ 110,336	$ 25,032	
Asia Pacific	44,606	18,688	
CIS	55,722	110,848	
Europe	82,473	—	
Latin America	15,198	63,899	
United States	563,021	574,730	
Total long-lived assets	$ 871,356	$ 793,197	

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

2) Long-lived assets primarily consist of property, plant and equipment, net and exclude assets held for sale, if any.

Note 15 — 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, 2013, under operating leases with non-cancelable terms are as follows:

	Year Ended December 31,
	(Dollars in Thousands)
2014	13,979
2015	9,488
2016	7,592
2017	7,114
2018	5,944
Thereafter	7,988
Total	$ 52,105

Total rent expense for all operating leases amounted to $19.9 million for 2013, $11.8 million for 2012 and $12.1 million for 2011.

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, employer's liability, $500,000 general liability, protection and indemnity and maritime employers' liability (Jones Act). In addition, we assume a $500,000 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, 2013 and 2012, our gross self-insurance accruals for workers' compensation, employers' liability, general liability, protection and indemnity and maritime employers' liability totaled $5.7 million and $4.7 million, respectively and the related insurance recoveries/receivables were $1.7 million and $1.2 million, respectively.

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.

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.

Asbestos-Related Claims

We are from time to time a party to various lawsuits that are incidental to our operations in which the claimants seek an unspecified amount of monetary damages for personal injury, including injuries purportedly resulting from exposure to asbestos on drilling rigs and associated facilities. At December 31, 2013, there were approximately 15 of these lawsuits in which we are one of many defendants. These lawsuits have been filed in the United States in the State of Mississippi.

Our subsidiaries named in these asbestos-related lawsuits intend to defend themselves vigorously and, based on the information available to us at this time, we do not expect the outcome to have a material adverse effect on our financial condition, results of operations or cash flows. However, we are unable to predict the ultimate outcome of these lawsuits. No amounts were accrued at December 31, 2013.

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 will defer 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 SEC in a United States District Court.

Demand Letter and Derivative Litigation

In April 2010, we received a demand letter from a law firm representing Ernest Maresca. The letter states that Mr. Maresca is one of our stockholders and that he believes that certain of our current and former officers and directors violated their fiduciary duties related to the issues described above under "Customs Agent and Foreign Corrupt Practices Act (FCPA) Settlement." The letter requests that our Board of Directors take action against the individuals in question. In response to this letter, the Board formed a special committee to evaluate the issues raised by the letter and determine a course of action for the Company. The special committee engaged its own counsel for the investigation and evaluated potential claims against all individuals identified in the demand letter. The special committee considered whether pursuing each of the individuals named in the demand letter was in the best interests of the Company based upon a variety of factors, including among others, whether the Company had a potential cause of action against the individual, the defenses the individual might offer to such a claim, the ability of the individual to satisfy any judgment the Company might secure as a result of a claim asserted, and other risks to the Company of pursuing the claims. After taking various factors into account, on July 29, 2013, the special committee recommended to the Board that the Company not pursue any action against the current and former officers and directors named in the demand letter, and the Board accepted such recommendation.

ITS Internal Controls

Our due diligence process with respect to the ITS Acquisition identified certain transactions that suggest that ITS' internal controls may have failed to prevent violations of potentially applicable international trade and anti-corruption laws, including those of the United Kingdom. We have investigated such violations and have and will, as appropriate, make any identified violations known to relevant authorities, cooperate with any resulting investigations and take proper remediation measures (including seeking any necessary government authorizations). While it is possible that matters may arise where a contingency may require further accounting considerations, we do not believe that as a result of these matters a loss is probable and estimable at this time.

Note 16 — Related Party Transactions

Consulting Agreement

The Company was a party to a consulting agreement with Robert L. Parker Sr., the former Chairman of the Board of Directors of the Company and the father of our current Executive Chairman, Robert L. Parker Jr. The consulting agreement expired on April 30, 2011. Under the agreement, Mr. Parker Sr. was paid consulting fees of $40,000 during the year ended December 31, 2011. For one year after the termination of the consulting agreement, Mr. Parker Sr. was prohibited from soliciting business from any of our customers or individuals with which we have done business, from becoming interested in any business that competes with the Company, and from recruiting any employees of the Company. Under the consulting agreement, Mr. Parker Sr. also represented the Company on the U.S.-Kazakhstan Business Council. In addition, we pay a monthly rental fee to Mr. Parker Sr. for various pieces of artwork which are displayed throughout our corporate office. We paid Mr. Parker $36,000 for each of the years ended December 31, 2013, 2012, and 2011 for the artwork rental.

Effective January 1, 2012, the Company entered into two separate ranch lease agreements under which the Company agreed to pay a daily usage fee per person for utilization of the Cypress Springs Ranch owned by the Robert L. Parker, Sr. and Catherine M. Parker Family Limited Partnership and the Camp Verde Ranch owned by Robert L. Parker, Jr. During 2013, the Company incurred fees of $14,281 in 2013 for the Cypress Springs Ranch. During 2012, the company incurred fees of $39,875 and $1,650 in 2012 for the Cypress Springs Ranch and Camp Verde Ranch, respectively, pursuant to the ranch lease agreements for the right to utilize the premises of the ranches for the purpose of hosting business meetings.

Other Related Party Agreements

During 2013 and 2012, 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. During 2013 and 2012, affiliates of Apache paid affiliates of the Company a total of $40.8 million and $31.2 million, respectively, for performance of drilling services and provision of rental tools. Also during 2013, one of our directors served on the board of directors of Gardner Denver, Inc. (GD). During 2013, affiliates of the Company paid affiliates of GD $0.2 million for goods and services provided to the Company. This information is considered and discussed annually in connection with the Board of Directors' assessment of facts and circumstances that could preclude a determination that such director is independent under the New York Stock Exchange governance listing standards.

Note 17 — Supplementary Information

At December 31, 2013, accrued liabilities included $8.1 million of deferred mobilization fees, $16.8 million of accrued interest expense, $2.7 million of worker's compensation liabilities and $33.5 million of accrued payroll and payroll taxes. Other long-term obligations included $3.0 million of workers' compensation liabilities as of December 31, 2013.

At December 31, 2012, accrued liabilities included $1.6 million of deferred mobilization fees, $9.7 million of accrued interest expense, $2.3 million of worker's compensation liabilities and $26.0 million of accrued payroll and payroll taxes. Other long-term obligations included $2.5 million of workers' compensation liabilities as of December 31, 2012.

Note 18 — *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 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, 2013 and December 31, 2012 and for the years ended December 31, 2013, 2012, and 2011. The consolidating condensed financial statements present investments in both consolidated and unconsolidated subsidiaries using the equity method of accounting.

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)
Changes in fair value of derivative positions	53	—	—	—	53
Interest income	3,824	1,761	10,749	(13,884)	2,450
Loss on extinguishment of debt	(5,218)	—	—	—	(5,218)
Other	(1)	(143)	1,594	—	1,450
Equity in net earnings of subsidiaries	55,430	—	—	(55,430)	—
Total other income (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
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 OPERATIONS
(Dollars in Thousands)
(Unaudited)

	Year ended December 31, 2012				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
Total revenues	$ —	$ 393,738	$ 385,279	$ (101,256)	$ 677,761
Operating expenses	—	184,946	329,498	(101,256)	413,188
Depreciation and amortization	—	65,354	47,663	—	113,017
Total operating gross margin	—	143,438	8,118	—	151,556
General and administration expense (1)	(182)	(45,758)	(317)	—	(46,257)
Gain on disposition of assets, net	—	775	1,199	—	1,974
Total operating income (loss)	(182)	98,455	9,000	—	107,273
Other income and (expense):					
Interest expense	(37,326)	(151)	(8,739)	12,674	(33,542)
Interest income	9,863	5,073	41,999	(56,782)	153
Loss on extinguishment of debt	(2,130)	—	—	—	(2,130)
Changes in fair value of derivative positions	55	—	—	—	55
Other	—	(206)	(626)	—	(832)
Equity in net earnings of subsidiaries	43,884	—	—	(43,884)	—
Total other income (expense)	14,346	4,716	32,634	(87,992)	(36,296)
Income (loss) before income taxes	14,164	103,171	41,634	(87,992)	70,977
Income tax expense (benefit):					
Current	(25,406)	32,781	10,667	—	18,042
Deferred	2,257	15,429	(1,849)	—	15,837
Income tax expense (benefit)	(23,149)	48,210	8,818	—	33,879
Net income (loss)	37,313	54,961	32,816	(87,992)	37,098
Less: Net (loss) attributable to noncontrolling interest	—	—	(215)	—	(215)
Net income (loss) attributable to controlling interest	37,313	54,961	33,031	(87,992)	37,313

(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, 2011				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
Total revenues	$ —	$ 375,798	$ 426,491	$ (116,055)	$ 686,234
Operating expenses	—	174,955	357,777	(116,055)	416,677
Depreciation and amortization	—	62,744	49,392	—	112,136
Total operating gross margin	—	138,099	19,322	—	157,421
General and administration expense (1)	(218)	(30,968)	(381)	—	(31,567)
Impairment and other charges	—	(170,000)	—	—	(170,000)
Provision for reduction in carrying value of certain assets	—	(1,350)	—	—	(1,350)
Gain on disposition of assets, net	—	2,706	953	—	3,659
Total operating income (loss)	(218)	(61,513)	19,894	—	(41,837)
Other income and (expense):					
Interest expense	(26,654)	(17,889)	(8,865)	30,814	(22,594)
Interest income	18,131	750	12,189	(30,814)	256
Loss on extinguishment of debt	—	—	—	—	—
Changes in fair value of derivative positions	(110)	—	—	—	(110)
Other	—	(315)	(812)	—	(1,127)
Equity in net earnings of subsidiaries	(23,484)	—	—	23,484	—
Total other income and (expense)	(32,117)	(17,454)	2,512	23,484	(23,575)
Income (loss) before income taxes	(32,335)	(78,967)	22,406	23,484	(65,412)
Income tax expense (benefit):					
Current	(13,402)	27,169	19,841	—	33,608
Deferred	31,518	(57,030)	(22,863)	—	(48,375)
Total income tax expense (benefit)	18,116	(29,861)	(3,022)	—	(14,767)
Net income (loss)	(50,451)	(49,106)	25,428	23,484	(50,645)
Less: Net (loss) attributable to noncontrolling interest	$ —	$ —	$ (194)	$ —	$ (194)
Net income (loss) attributable to controlling interest	(50,451)	(49,106)	25,622	23,484	(50,451)

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

PARKER DRILLING COMPANY AND SUBSIDIARIES

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

	December 31, 2013				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 88,697	$ 8,310	$ 51,682	$ —	$ 148,689
Accounts and notes receivable, net	—	101,299	156,590	—	257,889
Rig materials and supplies	—	3,002	38,779	—	41,781
Deferred costs	—	—	13,682	—	13,682
Deferred income taxes	(57)	8,435	1,562	—	9,940
Other tax assets	54,524	(46,770)	16,325	—	24,079
Other current assets	—	9,089	14,134	—	23,223
Total current assets	143,164	83,365	292,754	—	519,283
Property, plant and equipment, net	60	562,148	309,148	—	871,356
Investment in subsidiaries and intercompany advances	1,906,128	(336,570)	1,667,937	(3,237,495)	—
Other noncurrent assets	(457,954)	468,864	250,983	(117,776)	144,117
Total assets	$ 1,591,398	$ 777,807	$ 2,520,822	$ (3,355,271)	$ 1,534,756
LIABILITIES AND STOCKHOLDERS’ EQUITY					
Current liabilities:					
Current portion of long-term debt	$ 25,000	$ —	$ —	$ —	$ 25,000
Accounts payable and accrued liabilities	75,268	92,546	261,436	(254,364)	174,886
Accrued income taxes	—	725	6,541	—	7,266
Total current liabilities	100,268	93,271	267,977	(254,364)	207,152
Long-term debt	628,781	—	—	—	628,781
Other long-term liabilities	5,037	6,743	15,134	—	26,914
Long-term deferred tax liability	—	51,747	(12,980)	—	38,767
Intercompany payables	227,504	291,783	422,645	(941,932)	—
Contingencies	—	—	—	—	—
Stockholders’ equity:					
Common stock	20,075	18,049	43,003	(61,052)	20,075
Capital in excess of par value	657,349	740,438	1,572,919	(2,313,357)	657,349
Accumulated other comprehensive income	—	—	1,888	—	1,888
Retained earnings (accumulated deficit)	(47,616)	(424,224)	208,790	215,434	(47,616)
Total controlling interest stockholders’ equity	629,808	334,263	1,826,600	(2,158,975)	631,696
Noncontrolling interest	—	—	1,446	—	1,446
Total Equity	629,808	334,263	1,828,046	(2,158,975)	633,142
Total liabilities and stockholders’ equity	$ 1,591,398	$ 777,807	$ 2,520,822	$ (3,355,271)	$ 1,534,756

PARKER DRILLING COMPANY AND SUBSIDIARIES

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

	December 31, 2012				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 42,251	$ 11,023	$ 34,612	$ —	$ 87,886
Accounts and notes receivable, net	(7)	77,927	90,695	—	168,615
Rig materials and supplies	—	2,835	26,587	—	29,422
Deferred costs	—	—	1,089	—	1,089
Deferred income taxes	—	7,615	1,127	—	8,742
Other tax assets	46,249	(31,136)	18,411	—	33,524
Other current assets	—	8,708	4,145	—	12,853
Total current assets	88,493	76,972	176,666	—	342,131
Property, plant and equipment, net	60	548,794	244,343	—	793,197
Investment in subsidiaries and intercompany advances	1,492,708	(523,143)	1,467,617	(2,437,182)	—
Other noncurrent assets	(378,297)	370,877	219,196	(91,371)	120,405
Total assets	$ 1,202,964	$ 473,500	$ 2,107,822	$ (2,528,553)	$ 1,255,733
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities:					
Current portion of long-term debt	$ 10,000	$ —	$ —	$ —	$ 10,000
Accounts payable and accrued liabilities	65,839	94,037	205,864	(227,994)	137,746
Accrued income taxes	—	612	3,508	—	4,120
Total current liabilities	75,839	94,649	209,372	(227,994)	151,866
Long-term debt	469,205	—	—	—	469,205
Other long-term liabilities	3,933	6,129	13,120	—	23,182
Long-term deferred tax liability	—	36,894	(16,047)	—	20,847
Intercompany payables	62,583	43,657	216,369	(322,609)	—
Contingencies	—	—	—	—	—
Stockholders' equity:					
Common stock	19,818	18,049	43,003	(61,052)	19,818
Capital in excess of par value	646,217	733,112	1,455,246	(2,188,358)	646,217
Retained earnings (accumulated deficit)	(74,631)	(458,990)	187,530	271,460	(74,631)
Total controlling interest stockholders' equity	591,404	292,171	1,685,779	(1,977,950)	591,404
Noncontrolling interest	—	—	(771)	—	(771)
Total Equity	591,404	292,171	1,685,008	(1,977,950)	590,633
Total liabilities and stockholders' equity	$ 1,202,964	$ 473,500	$ 2,107,822	$ (2,528,553)	$ 1,255,733

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	$ 27,015	$ 36,214	$ 19,380	$ (55,430)	$ 27,179
Other comprehensive gain, 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, net of tax:	—	—	1,526	—	1,526
Comprehensive income	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 STATEMENT OF COMPREHENSIVE INCOME (LOSS)
(Dollars in Thousands)
(Unaudited)

	Year Ended December 31, 2012				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
Comprehensive income:					
Net income	$ 37,313	$ 54,961	$ 32,816	$ (87,992)	$ 37,098
Other comprehensive gain, net of tax:					
Currency translation difference on related borrowings	—	—	—	—	—
Currency translation difference on foreign currency net investments	—	—	—	—	—
Total other comprehensive gain, net of tax:	—	—	—	—	—
Comprehensive income	37,313	54,961	32,816	(87,992)	37,098
Comprehensive (income) loss attributable to noncontrolling interest	—	—	215	—	215
Comprehensive income (loss) attributable to controlling interest	$ 37,313	$ 54,961	$ 33,031	$ (87,992)	$ 37,313

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

	Year ended December 31, 2011				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
Comprehensive income:					
Net income	$(50,451)	$ (49,106)	$ 25,428	$ 23,484	$ (50,645)
Other comprehensive gain, net of tax:					
Currency translation difference on related borrowings	—	—	—	—	—
Currency translation difference on foreign currency net investments	—	—	—	—	—
Total other comprehensive gain, net of tax:	—	—	—	—	—
Comprehensive income	(50,451)	(49,106)	25,428	23,484	(50,645)
Comprehensive (income) loss attributable to noncontrolling interest	—	—	194	—	194
Comprehensive income (loss) attributable to controlling interest	$(50,451)	$ (49,106)	$ 25,622	$ 23,484	$ (50,451)

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 accounts receivable	(7)	(12,888)	(20,617)	—	(33,512)
Change in other assets	74,411	(85,520)	487	—	(10,622)
Change in accrued income taxes	6,617	(1,052)	4,889	—	10,454
Change in liabilities	6,934	(877)	(6,343)	—	(286)
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
Acquisition of ITS, net of cash acquired	—	(6,903)	(111,088)	—	(117,991)
Intercompany dividend payment	—	—	—	—	—
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
Proceeds from draw on revolver credit facility	—	—	—	—	—
Repayment of long term debt	(125,000)	—	—	—	(125,000)
Repayment of term loan	(50,000)	—	—	—	(50,000)
Paydown on revolver credit facility	—	—	—	—	—
Payment of debt issuance costs	(11,172)	—	—	—	(11,172)
Payment of debt extinguishment costs	—	—	—	—	—
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.

PARKER DRILLING COMPANY AND SUBSIDIARIES

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

	Year Ended December 31, 2012				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
Cash flows from operating activities:					
Net income (loss)	$ 37,313	$ 54,961	$ 32,816	$ (87,992)	$ 37,098
Adjustments to reconcile net income (loss)to net cash provided by operating activities:					
Depreciation and amortization	—	65,354	47,663	—	113,017
Loss on extinguishment of debt	2,130	—	—	—	2,130
Gain on disposition of assets	—	(775)	(1,199)	—	(1,974)
Deferred income tax expense	2,257	15,429	(1,849)	—	15,837
Expenses not requiring cash	16,558	33,644	(27,602)	—	22,600
Equity in net earnings of subsidiaries	(43,884)	—	—	43,884	—
Change in accounts receivable	(445)	(1,788)	17,474	—	15,241
Change in other assets	1,649	2,060	(9,200)	—	(5,491)
Change in accrued income taxes	(4,055)	220	(2,267)	—	(6,102)
Change in liabilities	3,914	(4,158)	(2,413)	—	(2,657)
Net cash provided by (used in) operating activities	15,437	164,947	53,423	(44,108)	189,699
Cash flows from investing activities:					
Capital expenditures	—	(176,333)	(15,210)	—	(191,543)
Proceeds from the sale of assets	—	2,062	1,875	—	3,937
Intercompany dividend payment	(8,387)	(4,357)	(31,364)	44,108	—
Net cash provided by (used in) investing activities	(8,387)	(178,628)	(44,699)	44,108	(187,606)
Cash flows from financing activities:					
Proceeds from debt issuance	130,000	—	—	—	130,000
Proceeds from draw on revolver credit facility	7,000	—	—	—	7,000
Paydown on senior notes	(125,000)	—	—	—	(125,000)
Paydown on term note	(18,000)	—	—	—	(18,000)
Paydown on revolver credit facility	—	—	—	—	—
Payment of debt issuance costs	(4,859)	—	—	—	(4,859)
Payment of debt extinguishment costs	(555)	—	—	—	(555)
Excess tax benefit from stock-based compensation	(662)	—	—	—	(662)
Intercompany advances, net	(8,393)	20,492	(12,099)	—	—
Net cash provided by (used in) financing activities	(20,469)	20,492	(12,099)	—	(12,076)
Net change in cash and cash equivalents	(13,419)	6,811	(3,375)	—	(9,983)
Cash and cash equivalents at beginning of year	55,670	4,212	37,987	—	97,869
Cash and cash equivalents at end of year	$ 42,251	$ 11,023	$ 34,612	$ —	$ 87,886

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, 2011				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
Cash flows from operating activities:					
Net income (loss)	$ (50,451)	$ (49,106)	$ 25,428	$ 23,484	$ (50,645)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:					
Depreciation and amortization	—	62,744	49,392	—	112,136
Loss on extinguishment of debt	—	—	—	—	—
Gain on disposition of assets	—	(2,706)	(953)	—	(3,659)
Deferred income tax expense	31,518	(57,030)	(22,863)	—	(48,375)
Impairment and other charges	—	170,000	—	—	170,000
Provision for reduction in carrying value of certain assets	—	1,350	—	—	1,350
Expenses not requiring cash	16,411	376	(3,954)	—	12,833
Equity in net earnings of subsidiaries	23,484	—	—	(23,484)	—
Change in accounts receivable	(288,333)	347,344	(65,852)	—	(6,841)
Change in other assets	62,173	(16,724)	16,404	—	61,853
Change in accrued income taxes	(12,852)	(2,053)	17,046	—	2,141
Change in liabilities	2,398	(51,351)	24,045	—	(24,908)
Net cash provided by (used in) operating activities	(215,652)	402,844	38,693	—	225,885
Cash flows from investing activities:					
Capital expenditures	—	(174,999)	(15,400)	—	(190,399)
Proceeds from the sale of assets	—	4,335	1,200	—	5,535
Proceeds from insurance settlements	—	250	—	—	250
Intercompany dividend payment	—	—	—	—	—
Net cash provided by (used in) investing activities	—	(170,414)	(14,200)	—	(184,614)
Cash flows from financing activities:					
Proceeds from debt issuance	50,000	—	—	—	50,000
Paydown on term note	(21,000)	—	—	—	(21,000)
Paydown on revolver credit facility	(25,000)	—	—	—	(25,000)
Payment of debt issuance costs	(504)	—	—	—	(504)
Payment of debt extinguishment costs	—	—	—	—	—
Proceeds from stock options exercised	183	—	—	—	183
Excess tax benefit from stock-based compensation	1,488	—	—	—	1,488
Intercompany advances, net	252,320	(230,535)	(21,785)	—	—
Net cash provided by (used in) financing activities	257,487	(230,535)	(21,785)	—	5,167
Net change in cash and cash equivalents	41,835	1,895	2,708	—	46,438
Cash and cash equivalents at beginning of year	13,835	2,317	35,279	—	51,431
Cash and cash equivalents at end of year	$ 55,670	$ 4,212	$ 37,987	$ —	$ 97,869

See accompanying notes to unaudited consolidated condensed financial statements.

Note 19 — Selected Quarterly Financial Data

Year 2013	Quarter				
	First	Second	Third	Fourth	Total
	(Dollars in Thousands Except Per Share Amounts) (Unaudited)				
Revenues	$ 167,135	$ 225,954	$ 237,762	$ 243,321	$ 874,172
Operating gross margin[2]	$ 20,877	$ 50,273	$ 48,733	$ 48,564	$ 168,447
Operating income	$ 9,180	$ 28,587	$ 35,589	$ 28,516	$ 101,872
Net income attributable to controlling interest	$ 592	$ 8,281	$ 7,970	$ 10,172	$ 27,015
Basic earnings per share — net income[1]	$ 0.00	$ 0.07	$ 0.07	$ 0.08	$ 0.23
Diluted earnings per share — net income[1]	$ 0.00	$ 0.07	$ 0.07	$ 0.08	$ 0.22

Year 2012	Quarter				
	First	Second	Third	Fourth	Total
	(Dollars in Thousands Except Per Share Amounts) (Unaudited)				
Revenues	$ 176,495	$ 178,895	$ 165,200	$ 157,171	$ 677,761
Operating gross margin[2]	$ 53,744	$ 46,914	$ 34,261	$ 16,637	$ 151,556
Operating income	$ 48,689	$ 40,978	$ 25,903	$ (8,297)	$ 107,273
Net income (loss) attributable to controlling interest	$ 26,392	$ 20,083	$ 10,936	$ (20,098)	$ 37,313
Basic earnings per share — net income (loss)[1]	$ 0.23	$ 0.17	$ 0.09	$ (0.17)	$ 0.32
Diluted earnings per share — net income (loss)[1]	$ 0.22	$ 0.17	$ 0.09	$ (0.17)	$ 0.31

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 2013 year to date results.

2) As the Company modified its reporting segments to be consistent with recent organizational changes to improve our drilling organization, expenses related to our U.S. Barge Drilling segment were found to be incorrectly included in our general and administrative expense during the first through third quarters of the current year. These expenses have been appropriately reclassified to be included as part of the segment operating expenses, therefore our operating gross margin for each of the first three quarters will not agree to the respective 10-Q reports for the current year only.

Note 20 — Recent Accounting Pronouncements

Fair value measurements — Effective January 1, 2012, we adopted the accounting standards update that changes the wording used to describe many of the requirements in U.S. GAAP for measuring fair value and for disclosing information about fair value measurements. Some of the amendments included in this update are intended to clarify the applications of existing fair value measurement requirements. The update is effective for annual periods beginning after December 15, 2011. This adoption did not have a material effect on the disclosures contained in our notes to the consolidated financial statements.

Comprehensive Income — On January 1, 2012, we adopted an update issued by the FASB to existing guidance on the presentation of comprehensive income. The update eliminates the option to present the components of other comprehensive income (OCI) as part of the statement of changes in stockholders' equity. Public entities are required to comply with the new reporting requirements for fiscal years beginning after December 15, 2011 and interim periods within those years. Calendar year-end companies must adopt the requirements for the quarter ended March 31, 2012. The adoption of this update did not have a material impact on our financial position, results of operations, cash flows, or disclosures.

Impairment — In July 2012, the FASB issued an update to existing guidance on the impairment assessment of indefinite-lived intangibles. This update simplifies the impairment assessment of indefinite-lived intangibles by allowing companies to consider qualitative factors to determine whether it is more likely than not that the fair value of an indefinite-lived intangible asset is less than its carrying amount before performing the two step impairment review process. The adoption of this update did not have an impact on our condensed consolidated financial statements.

Note 21 — Subsequent Events

6.75% Senior Notes, due July 2022

On January 22, 2014, we issued $360.0 million aggregate principal amount of 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 on the Secured Credit Agreement and cash on hand, were utilized to redeem $416.2 million aggregate principal amount of our outstanding 9.125% Notes due 2018 pursuant to a tender and consent solicitation offer commenced on January 7, 2014. The tender offer price was $1,061.98, inclusive of a $30.00 consent payment, for each $1,000.00 principal amount of 9.125% Notes, plus accrued and unpaid interest. On January 22, 2014, we paid $453.7 million for the tendered bonds, comprised of $416.2 million of aggregate principal amount of the bonds, $25.8 million of tender and consent premiums and $11.7 million of accrued interest. After payment for the tendered notes, $8.8 million aggregate principal amount of our 9.125% Notes remains outstanding.

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 our Secured Credit Agreement. 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 are estimated to be $7.1 million and will be amortized over the term of the notes using the effective interest rate method. The Term Loan amortizes quarterly with required payments of $2.5 million. For further discussion of the Term Loan see Note 8 - *Long-Term Debt.*

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.

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 issued pursuant to an Indenture between the Company and The Bank of New York Mellon Trust Company, N.A., as trustee.. 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. After payment for the tendered 9.125% Notes, $8.8 million aggregate principal amount of our 9.125% Notes remains outstanding.

At any time prior to April 1, 2014, we may redeem all or a part of the 9.125% Notes upon appropriate notice, at a redemption price of 104.563 percent of the principal amount, and at redemption prices decreasing each year thereafter to par beginning April 1, 2016. If we experience certain changes in control, we must offer to repurchase the 9.125% 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.

On January 24, 2014, the Indenture was amended to remove most of the restrictions on 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. The Indenture also was amended to remove certain restrictive covenants designating certain events as Events of Default. Additionally, the remaining restrictive covenants are subject to a number of important exceptions and qualifications.

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

None

ITEM 9A. *CONTROLS AND PROCEDURES*

Evaluation of Disclosure Controls and Procedures — In accordance with the Securities Exchange Act of 1934 Rules 13a-15 and 15d-15, 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, as defined in the Exchange Act Rules 13a-15 and 15d-15, were effective, as of December 31, 2013, 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 (2) recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms.

Management's Report on Internal Control over Financial Reporting — The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). 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 that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States, and 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 that 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, 2013 based on criteria established in Internal Control — Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. 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, 2013.

KPMG LLP, our independent registered public accounting firm that audited the consolidated financial statements included in this Annual Report Form 10-K, has issued a report with respect to our internal control over financial reporting as of December 31, 2013.

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 ITS Acquisition, on April 22, 2013. ITS represents approximately 11.0 percent of our total assets as of December 31, 2013 and approximately 10.0 percent and 37.0 percent of revenues and net income, respectively, for the year ended December 31, 2013. The ITS Acquisition had 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, 2013 excluded an assessment of the internal control over financial reporting of ITS. We are now in the process of integrating ITS' operations including internal controls and processes. We are in the process of extending to ITS our Section 404 compliance program under the Sarbanes-Oxley Act of 2002 and the applicable rules and regulations under such Act.

Other than changes resulting from the ITS 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 has materially affected, or is 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 2014 Proxy Statement for the Annual Meeting of Stockholders to be held on May 1, 2014. Such information is incorporated herein by reference.

Information with respect to executive officers is shown in Item 1 of this Annual Report on 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 2014 Proxy Statement for the Annual Meeting of Stockholders to be held on May 1, 2014 and is incorporated herein by reference.

The information in our 2014 Proxy Statement for the Annual Meeting of Stockholders to be held on May 1, 2014 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 Corporate Conduct (CCC) 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 CCC 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 CCC is publicly available on our website at http://www.parkerdrilling.com. If any waivers of the CCC 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 CCC, we will disclose the nature of the waiver or amendment on the website and 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,” “2013 Director Compensation Table,” and “Compensation Committee Report” in our 2014 Proxy Statement for the Annual Meeting of Stockholders to be held on May 1, 2014 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 2014 Proxy Statement for the Annual Meeting of Stockholders to be held on May 1, 2014.

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 2014 Proxy Statement for the Annual Meeting of Stockholders to be held on May 1, 2014.

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 2014 Proxy Statement for the Annual Meeting of the Stockholders to be held on May 1, 2014.

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:

(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	—	Parker Drilling Company By-Laws, effective as amended March 11, 2011 (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed on March 16, 2011).
4.1	—	Indenture, dated March 22, 2010, among Parker Drilling Company, the guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed on March 22, 2010).
4.2	—	First Supplemental Indenture, dated June 21, 2013, among Parker Drilling Company, as Guarantor and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed August 7, 2013).
4.3	—	Second Supplemental Indenture, dated January 24, 2014, among Parker Drilling Company, the guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed on January 28, 2014).
4.4	—	Form of 9 1 / 8 % Senior Note due 2018 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed on March 22, 2010).
4.5	—	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).
4.6	—	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).

4.7	—	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 file on January 28, 2014).
4.8	—	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).
4.9	—	Registration Rights Agreement, dated July 30, 2013, by and among Parker Drilling Company, the guarantors named therein, Goldman, Sachs & Co., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Wells Fargo Securities, LLC and RBS Securities Inc. (incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K filed on July 31, 2013).
4.10	—	Registration Rights Agreement, dated January 22, 2014, by and among Parker Drilling Company, the guarantors named therein, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Wells Fargo Securities, LLC, Barclays Capital Inc., Deutsche Bank Securities Inc. and Goldman, Sachs & Co. (incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K filed on January 28, 2014).
10.1	—	Amended and Restated Credit Agreement dated as of December 14, 2012, among Parker Drilling Company, as Borrower, Bank of America, N.A., as Administrative Agent and L/C Issuer, the several banks and other financial institutions or entities from time to time parties thereto, NATIXIS, New York Branch, Wells Fargo Bank, N.A., and Whitney Bank as Co-Documentation Agents, and Merrill Lynch, Fenner & Smith Incorporated as Sole Lead Arranger and Book Manager.
10.2	—	First Amendment to Term Loan Agreement dated July 19, 2013, among Parker Drilling Company, the lenders party thereto, Goldman Sachs Bank USA and certain other parties thereto (Incorporated by reference to Exhibit 10.5 to Parker Drilling Company's Current Report on Form 8-K filed on July 22, 2013).
10.3	—	First Amendment to Amended and Restated Credit Agreement, dated as of July 19, 2013, among Parker Drilling Company, as Borrower, certain Subsidiaries of the Borrower, as Guarantors, the Lenders party thereto, and Bank of America N.A., as administrative agent (Incorporated by reference to Exhibit 10.2 to Parker Drilling Company's Current Report on Form 8-K filed on July 22, 2013).
10.4	—	Parker Drilling Company Incentive Compensation Plan, dated December 17, 2008, and as amended and restated effective January 1, 2008 (incorporated by reference to Exhibit 10(b) to the Company’s Annual Report on Form 10-K filed on March 2, 2009).*
10.5	—	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)*

Exhibit Number		Description
10.6	—	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).*
10.7	—	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).*
10.8	—	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).*
10.9	—	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).*
10.10	—	Employment Agreement between Mr. Robert L. Parker, Jr. and Parker Drilling Company, effective March 21, 2011 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on March 25, 2011).*
10.11	—	First Amendment dated August 29, 2011 to First Amended and Restated Employment Agreement between Mr. Robert L. Parker Jr. and Parker Drilling Company, effective March 21, 2011 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on August 30, 2011).*

Exhibit Number		Description
10.12	—	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).*
10.13	—	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).*
10.14	—	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).*
10.15	—	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	—	Termination of Split Dollar Life Insurance Agreement between Parker Drilling Company, Robert L. Parker Sr., and Robert L. Parker Sr. and Catherine M. Parker Family Trust dated April 12, 2006 (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on April 12, 2006).*
10.17	—	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).
10.18	—	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).
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.

Exhibit Number		Description
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
(Dollars in Thousands)

Classifications	Balance at beginning of year	Charged to cost and expenses	Charged to other accounts	Deductions	Balance at end of year
Year ended December 31, 2013					
Allowance for doubtful accounts and notes	$ 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
Year ended December 31, 2012					
Allowance for doubtful accounts and notes	$ 1,544	$ 4,264	$ 3,195	$ (886)	$ 8,117
Allowance for obsolete rig materials and supplies	$ 316	—	$ —	$ (4)	$ 312
Deferred tax valuation allowance	$ 6,467	$ (1,662)	$ —	$ —	$ 4,805
Year ended December 31, 2011					
Allowance for doubtful accounts and notes	$ 7,020	$ 2,258	$ (2,034)	$ (5,700)	$ 1,544
Allowance for obsolete rig materials and supplies	$ 309	$ 26	$ —	$ (19)	$ 316
Deferred tax valuation allowance	$ 5,532	$ 2,542	$ (1,607)	$ —	$ 6,467

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: March 10, 2014

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	President, Chief Executive Officer, and Director (Principal Executive Officer)	March 10, 2014
By: /s/ Christopher T. Weber Christopher T. Weber	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	March 10, 2014
By: /s/ Philip A. Schlom Philip A. Schlom	Controller (Principal Accounting Officer)	March 10, 2014
By: /s/ Robert L. Parker Jr. Robert L. Parker Jr.	Chairman and Director	March 10, 2014
By: /s/ Jonathan M. Clarkson Jonathan M. Clarkson	Director	March 10, 2014
By: /s/ George J. Donnelly George J. Donnelly	Director	March 10, 2014
By: /s/ Robert W. Goldman Robert W. Goldman	Director	March 10, 2014
By: /s/ Gary R. King Gary R. King	Director	March 10, 2014
By: /s/ Richard D. Paterson Richard D. Paterson	Director	March 10, 2014
By: /s/ Roger B. Plank Roger B. Plank	Director	March 10, 2014
By: /s/ R. Rudolph Reinfrank R. Rudolph Reinfrank	Director	March 10, 2014
By: /s/ Peter C. Wallace Peter C. Wallace	Director	March 10, 2014

INDEX TO EXHIBITS

Exhibit Number		Description
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.

BOARD OF DIRECTORS

Robert L. Parker, Jr.
Chairman of the Board of Directors, Parker Drilling

Gary G. Rich
President and Chief Executive Officer, Parker Drilling

Jonathan M. Clarkson
Retired Chairman, Texas Capital Bank

George J. Donnelly
Managing Partner, Lilo Ventures

Robert W. Goldman
Retired Chief Financial Officer, Conoco, Inc.

Gary R. King
Chief Executive Officer, Dutco Natural Resources Investments Limited

Richard D. Paterson
Retired Managing Partner, PriceWaterhouseCoopers, LLP

Roger B. Plank
Retired President, Apache Corporation

R. Rudolph Reinfrank
Managing General Partner, Riverford Partners, LLC

Peter C. Wallace
Former President and Chief Executive Officer, Robbins & Myers, Inc.

CEO AND CFO CERTIFICATIONS

Parker Drilling submitted the annual CEO certification to the NYSE as required under the corporate governance rules of the NYSE. Parker Drilling also filed as an exhibit to its 2013 Annual Report on Form 10-K the CEO and CFO certifications required under Section 302 of the Sarbanes-Oxley Act of 2002.

EXECUTIVE OFFICERS

Gary G. Rich
President and Chief Executive Officer

Christopher T. Weber
Senior Vice President and Chief Financial Officer

Jon-Al Duplantier
Senior Vice President, Chief Administrative Officer and General Counsel

Philip L. Agnew III
Senior Vice President and Chief Technical Officer

David R. Farmer
Senior Vice President Europe, Middle East and Asia

OTHER OFFICERS

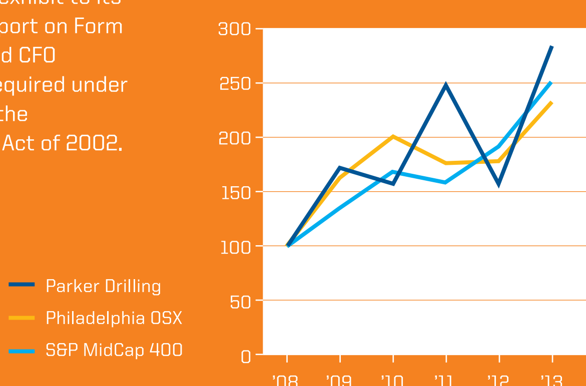
Philip A. Schlom
Principal Accounting Officer and Controller

J. Daniel Chapman
Chief Compliance Officer and Counsel

David W. Tucker
Treasurer

PERFORMANCE GRAPH

The following performance graph compares cumulative total shareholder returns on Parker Drilling's common stock to the Philadelphia Oil Service Index (Philadelphia OSX) and the S&P MidCap 400 stock index, calculated as of the end of each year during the period beginning December 31, 2008 and ending on December 31, 2013. The graph assumes $100 was invested on December 31, 2008 in the Company's common stock and in each of the referenced indices.



CORPORATE INFORMATION

Corporate Headquarters
Parker Drilling Company
5 Greenway Plaza, Suite 100
Houston, Texas 77046
Telephone: 281.406.2000
www.parkerdrilling.com

Notice of Annual Meeting
The Annual Meeting of Stockholders will be held at 9 A.M. CDT
May 1, 2014
DoubleTree by Hilton Hotel–Greenway Plaza
6 East Greenway Plaza
Houston, Texas 77046

Investor Relations and Information Requests
Copies of Parker Drilling's Annual Report, its Annual Report on Form 10-K and Quarterly Reports on Form 10-Q to the Securities and Exchange Commission, and quarterly earnings releases are available on www.parkerdrilling.com or by contacting Investor Relations:

Richard Bajenski
Director, Investor Relations
Parker Drilling Company
5 Greenway Plaza, Suite 100
Houston, Texas 77046
Telephone: 281.406.2030
Email: richard.bajenski@parkerdrilling.com

Transfer Agent and Registrar
Stockholders should refer specific questions concerning stock certificates directly to the stock transfer agent and registrar, Wells Fargo Bank N.A., at the address and phone number shown below:

Wells Fargo Bank, N.A.
Shareowner Services
P.O. Box 64854
St. Paul, Minnesota 55164-0854
Toll-Free 800.468.9716 or 651.450.4064

Independent Auditors
KPMG LLP
811 Main Street, Suite 4400
Houston, Texas 77002

Stock Exchange Listing
Shares of Parker Drilling Company are listed and traded on the New York Stock Exchange. The trading symbol is PKD.

PKD LISTED NYSE

PARKER DRILLING

5 Greenway Plaza, Suite 100 | Houston, Texas 77046 | TEL 281.406.2000 FAX 281.406.2001 | **www.parkerdrilling.com**