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, 2011

Or

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

FOR THE TRANSITION PERIOD FROM TO

COMMISSION FILE NUMBER 1-7573

PARKER DRILLING COMPANY

(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate 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 ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2011 was $664.8 million. At February 29, 2012, there were 117,198,933 shares of common stock issued and outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of our definitive proxy statement for the Annual Meeting of Shareholders to be held on April 26, 2012 are incorporated by reference in Part III.

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PART I

ITEM 1. *BUSINESS*

General

Unless otherwise indicated, the terms “Company,” “Parker,” “we,” “us” and “our” refer to Parker Drilling Company together with its subsidiaries and “Parker Drilling” refers solely to the parent, Parker Drilling Company. Parker Drilling Company 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 through the merger of the Oklahoma corporation into its wholly-owned subsidiary Parker Drilling Company, a Delaware corporation. Our principal executive offices are located at 5 Greenway Plaza, Suite 100, Houston, Texas 77046.

We are a provider of contract drilling and drilling-related services currently operating in 11 countries. We have operated in over 50 foreign countries and the United States since beginning operations in 1934, making us among the most geographically experienced drilling contractors in the world. 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. We believe our quality, health, safety and environmental practices are among the leaders in our industry.

Our 2011 revenues were derived from the following six reportable segments:

- Rental Tools
- U.S. Barge Drilling
- U.S. Drilling
- International Drilling
- Technical Services
- Construction Contract

Our Rental Tools Business

We provide premium rental tools for land and offshore oil and gas drilling and workover activities, offering a full line of drill pipe, drill collars, tubing, high- and low-pressure blowout preventers (BOPs), choke manifolds, junk and cement mills and casing scrapers. Our Rental Tools business is headquartered in New Iberia, Louisiana. Other facilities where we hold an inventory of rental tools and provide service to our customers are located in Texas, Wyoming, North Dakota and West Virginia.

Our largest market for rental tools is U.S. land drilling, a cyclical market driven by commodity pricing and availability of project financing. The increase in unconventional lateral drilling, often used in drilling shale formations, has added to the market demand for rental tools, keeping our current market focus in the regions of the primary shale plays. The current depressed natural gas price has kept our emphasis on oil/liquid-rich shale plays where we estimate we derive roughly 65 percent of our Rental Tools revenues. We also have a relatively small and growing portion of our business that supplies primarily tubular goods to international and offshore Gulf of Mexico (GOM) customers.

Our principal customers are major and independent oil and gas exploration and production companies operating in the U.S. energy producing markets on land and in the GOM. Generally, rental tools are used for only a portion of a well drilling program and are requested by the customer when they are required. As a result, rental tools are usually rented on a daily or monthly basis, requiring us to keep a broad inventory in stock. Approximately 13 percent of revenues from our Rental Tools business are derived from equipment used in offshore and coastal water operations of the GOM. In addition, from our locations within the United States, we have provided rental tools to customers operating internationally. In 2011, we provided rental tools for use in Angola, Congo, Egypt, Mexico, Suriname, Turkey, Trinidad & Tobago, Singapore, Cameroon, Colombia, and Jordan, among others. During the years ended December 31, 2011, 2010 and 2009, approximately 5 percent, 5 percent and 9 percent of Rental Tools’ revenues were derived from equipment used in international applications, respectively.

Our U.S. Barge Drilling Business

The barge drilling industry in the GOM is characterized by cyclical activity where utilization and dayrates are typically driven by current oil and natural gas prices and our customers' access to project financing. Within this area, we operate barge rigs in the shallow waters in and along the inland waterways and coasts of Louisiana, Mississippi and Texas. Our rigs drill for oil, natural gas, and a combination of oil and natural gas. Contract terms tend to be well-to-well or multi-well programs, with durations typically averaging 45 to 150 days. During periods of strong market demand, driven by high commodity prices, contract drilling terms can extend up to twelve months and longer.

Since 2010, the barge drilling industry has been impacted by the Macondo well fire and ensuing oil spill in the U.S. GOM, primarily resulting from increased regulatory focus on the industry. The drilling moratorium that followed the Macondo event had marginal impact on the barge drilling permit process. However, we were required to accelerate certain upgrades to our barge rig fleet in order to fully comply with the new regulations enacted as a result of the Macondo event.

Our U.S. Drilling Business

We expect to begin operating two new-design land rigs in the Alaska drilling market in 2012. Our new-design rigs, which as of December 31, 2011 were on the North Slope at our operating base, are intended to address the challenges presented by the remote location, harsh climate and sensitive environment that characterize the Alaskan North Slope. The rigs include features in use in other applications but not currently available as a drilling package in Alaska and are expected to deliver improved drilling efficiency, operating consistency and safety in this very demanding setting. For further discussion see Item 1A. *Risk Factors.*

The Alaskan North Slope drilling market is a focus of global and regional exploration and production (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 will contribute to expanded drilling capabilities in this market for our customers.

The Company has one rig in our storage yard in New Iberia, Louisiana, that is currently being marketed for use in either the United States or international markets.

Our International Drilling Business

Our international drilling business includes operations related to Parker-owned and operated rigs as well as customer-owned rigs. Our fleet of Company-owned rigs is strategically deployed in markets where we expect to have opportunities to keep the rigs regularly at work. In addition, we perform drilling-related activities for operators who own their drilling rigs and who choose to engage our drilling experience and technical expertise to perform services on a contracted basis, including Operations and Maintenance (O&M) work, and other project management services (*e.g.*, labor, maintenance, and logistics). We have ongoing O&M and project management activities in Russia, Papua New Guinea, and Kuwait.

The international drilling markets in which we operate have one or more of the following characteristics:

- customers who typically are major, independent or national oil and 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 (*e.g.*, 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 multi-year drilling programs.

Our Technical Services Business

We provide engineering and related project services during the concept development, pre-FEED, and FEED (Front End Engineering Design) phases of customer-owned drilling facility projects. As these projects mature, we continue providing the same services during the Engineering, Procurement, Construction and Installation (EPCI) phase. During the EPCI phase, we focus primarily on the drilling systems engineering, procurement, commissioning and installation and typically provide customer support during construction. Currently, we provide these services on the Berkut platform project (previously described as the Arkutun Dagi project) for Exxon Neftegas Limited (ENL). Additionally, we are engaged with one concept development project and one FEED project for two offshore drilling facility projects. Because these projects are customer-owned and customer-funded, the Technical Services business is non-capital intensive and helps to position the company for future potential expansion in the drilling O&M business.

Our Technical Services business is also the Company's engineering expertise center and provides our ongoing drilling businesses with services similar to those provided to our external customers; including engineering design, retrofitting of existing rigs, modification, upgrades and other technology related advancements.

Our Construction Contract Business

This segment includes only the BP-owned Liberty extended-reach drilling rig construction project. In 2008, we commenced the construction phase of the Liberty project. In November 2010, BP informed us that it was suspending construction on the project to review the rig's engineering and design, including its safety systems. The Liberty rig construction contract expired on February 8, 2011 prior to completion of the rig. Prior to expiration of the construction contract, BP identified several areas of concern relating to design, construction and invoicing for which it asked us to provide explanations and documentation, and we have done so. Although we provided BP with the requested information, we do not know when or how these issues will be resolved with our client.

After expiration of the construction contract, we continued activities to preserve and maintain the rig under the "preoperations" phase of our contract, which was entered into in August 2009 and expired on July 1, 2011. A new consulting services agreement was reached between the Company and BP effective July 1, 2011. Under the consulting services agreement, the Company assisted BP in a review of the rig's design, the creation of a new statement of requirements for the rig, and the transition of documentation and materials to BP. All work under the consulting agreement has been completed and we are engaged with BP on construction contract close-out discussions.

For more information, see Part II, Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations — Other Matters — "Liberty Project Status."

Our Strategy

Our strategy is to achieve and maintain market leadership in selected markets as a provider of drilling and drilling-related services including rental tools and technical services; to grow our business through select investments in our core businesses and new assets and lines of business; and to achieve consistent execution excellence and exercise financial discipline. Key elements of our strategy include:

- *Achieving and Maintaining Market Leadership*. We believe we achieve and sustain the preference for our services by the quality, efficiency and dependability of our performance and its cost. We achieve this by:
  - providing premium rental tools with premier customer service;
  - building, upgrading and maintaining a fleet of barge and land rigs that are preferred by operators because of the value they provide;

- supplying trained and experienced operating crews, rig leadership teams and an array of support services; and
- offering engineering and other technical services that have a record of developing innovative solutions to drilling challenges in difficult, hazardous or environmentally sensitive areas.

- *Growing Through Selective Investment*. We believe we can improve our competitive position and financial performance through investments in our core businesses and in new assets or lines of business that complement and expand our capabilities. We are focused on:
  - expanding and broadening our non-capital intensive technical services and O&M activities by leveraging our experience;
  - growing our rental tools operation by adding inventory and locating new service facilities in markets with growing demand from new and existing customers;
  - adding new equipment to and upgrading our drilling rig fleet that improves opportunities with operators; and
  - entering new markets that we believe present long-term oil and natural gas development opportunities.

- *Strive for Execution Excellence and Maintain Financial Discipline*. We believe we significantly enhance our operating and financial performance potential by how well we plan, execute and manage. Our operating culture is to align resources, responsibility and accountability with achievable objectives. Our management team has extensive experience in the industry and we work diligently to continue to attract new talent to the Company that can improve our management performance and provide for excellence in leadership in the future. We maintain strong financial controls and disciplines in all aspects of our business to ensure that we adhere to solid financial principles and provide attentive stewardship of our capital. These principles are intended to lead to consistency in operational performance, stronger-than-peer financial performance and value to our shareholders.

In 2012, our focus will be on specific goals that align with these strategies. These are intended to improve our safety performance; manage the geopolitical risks associated with our asset deployment; improve the financial returns from operations and our overall financial results; improve the predictability and reliability of operational, planning and project management processes; and continue to strengthen our enterprise talent.

Our Competitive Strengths

We differentiate ourselves from other providers of similar services by focusing on our core competencies, or "four pillars": safety, training, technology and performance. We seek to provide our customers increased performance, innovation in our services, and safe and efficient operations through these four pillars as follows:

Safety: We believe industry-leading safety performance is a crucial factor in our status as a preferred drilling contractor and rental tools supplier. We have a portfolio of metrics and processes we apply to reinforce and continually improve our safety and environmental performance.

We continue to have an outstanding safety record. In 2011, our Total Recordable Incident Rate (TRIR) was 16% ahead of our targeted goal. Our safety record, as evidenced by our low TRIR results, has made us one of the leaders in occupational injury prevention.

Our TRIR has been below the industry average for more than ten years, with rates approximately half the industry average since 2004. Our safety and training programs also contain consideration of environmental safety and conservation, helping us avoid environmental incidents. We believe that this safety record, along with integrated quality, safety, maintenance and supply chain management programs, has contributed to our success in obtaining drilling contracts, as well as contracts to manage and provide labor resources for drilling rigs owned by third parties.

Training: The challenges of our business are magnified when considering the technological requirements of our work and our customers. We have invested significant resources to provide a full curriculum of standardized training to overcome barriers to working safely and operating efficiently. Our training centers in Louisiana, Alaska and New Zealand provide safety and technical training curricula in four different languages and provide regulatory compliance training throughout the world. We also provide structured training programs and on-site instruction to our customers and clients in the use of equipment we furnish as rental tools.

Technology: Applying new technology to create greater efficiencies in the drilling process lies at the heart of our competitive edge. We have a 77-year legacy of applying new technologies for drilling in frontier environments and a demonstrated history of technological leadership within the drilling industry. Our previous contributions to the industry include the patented heli-hoist rig design, winterized rigs on wheels for arctic drilling, and an arctic-class barge rig to explore the Caspian Sea. We have established extended reach drilling depth records on several occasions. Our new-design arctic class land rigs, the prototypes of which are being delivered for drilling on the Alaskan North Slope, are intended to increase drilling efficiency, consistency and safety in the extreme climate and harsh conditions of the arctic environment. Our rental tools offering focuses on premium equipment, maintained to high standards, that complements advanced drilling technologies like those developed to exploit oil and gas deposits in shale.

Performance: A primary aim is to provide services that benefit both our customers and our Company. We strive to achieve this by planning, executing and measuring our performance against our goals and our customers’ expectations. We utilize performance metrics in our business and regularly share them with our customers. Our planned maintenance programs, including preventive maintenance to facilitate dependable operating efficiency and minimize down time, helps to establish us as a contractor of choice. Our management team has extensive experience in the drilling industry and utilizes this experience to set performance standards and assess the performance of our operations and individual employees.

Customers

Our customer base consists of major, independent and national oil and gas companies and integrated service providers. We depend on a limited number of significant customers. In 2011, our largest customer, Exxon Neftegas Limited (ENL), accounted for approximately 15.9 percent of our year-to-date total revenues. Included in the total revenue for ENL is $48.0 million of reimbursable costs which increase revenues but have little direct impact on operating margins. Our ten most significant customers collectively accounted for approximately 56.4 percent of our total revenues in 2011.

Competition

The contract drilling industry is a highly competitive business characterized by high capital requirements and challenges in securing and retaining qualified field personnel.

In international land 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 technical expertise and quality of equipment 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 our equipment, planned maintenance and experience. In international markets, our experience in operating in challenging environments has been a significant factor in securing contracts. We believe that the market for drilling contracts will continue to be highly competitive for the foreseeable future.

In the GOM barge drilling markets, we are awarded most contracts through a competitive bidding process. We have achieved some success in differentiating ourselves from competitors through our upgraded fleet, planned maintenance programs and general strategy to ready-stack rigs, a standby mode of operational readiness where our support costs are reduced while the equipment is maintained in a near market-ready condition for quick return to operations. This strategy can result in safer and more efficient operations.

In the U.S. rental tools market we compete with suppliers both larger and smaller than our own business, some of which are parts of larger enterprises. We believe that our rental tools business is one of the leading rental tools companies in the U.S. oil and gas drilling markets. Our Rental Tools segment competes against other rental tool companies based on its breadth of inventory, the availability and price of its product and its quality of service.

A number of our customers have been seeking to establish exploration or development drilling programs based on partnering relationships or alliances with a limited number of preferred drilling contractors. Such relationships can result in longer-term work and higher efficiencies that increase profitability for drilling contractors and result in a lower overall well cost for oil and gas operators. We believe we are currently a preferred contractor for operators in both U.S. and international locations, which we believe is a result of our reputation for providing efficient, safe, environmentally conscious and innovative drilling services, in addition to quality equipment, personnel, service and experience.

Contracts

Most drilling contracts are awarded based on competitive bidding. The rates specified in drilling contracts vary depending upon the type of rig employed, equipment and services supplied, geographic location, term of the contract, competitive conditions and other variables. Our contracts generally provide for an operating dayrate during drilling operations, with lower rates for periods of equipment downtime, customer stoppage, adverse weather or other conditions, and no payment when certain conditions continue beyond a contractually established duration metric. When a rig mobilizes to or demobilizes from an operating area, the contract typically provides for a different dayrate or specified fixed payments during the 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. Many of our 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.

Rental tools contracts are typically on a dayrate basis with rates based on type of equipment, investment 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.

Seasonality

Our rigs in 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 and demobilization of rigs in arctic regions can be affected by seasonal changes in weather or weather so severe the equipment is not safe 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, punch throughs, craterings, 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, 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 drilling 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 contract, for liability due to control-of-well events, liability arising from named windstorms 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 $200 million, with a retention of $1 million or less.

Control-of-well 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 pollution from a control-of-well event up to $200 million per occurrence. A separate limit of $10 million exists to cover the costs of re-drilling of the well and control-of-well costs under a Contingent Operators Extra Expense policy. 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 pollution events originating from our rigs up to $200 million per occurrence. We retain the risk for liability not indemnified by the customer below the retention and in excess of our insurance coverage. In addition, our insurance program covers only sudden and accidental pollution.

Our insurance program also provides coverage for physical damage to, including total loss or constructive total loss of, our rigs, including damage arising from a named windstorm in the U.S. Gulf of Mexico up to $20 million.

Our drilling contracts provide for varying levels of indemnification from our customers and may require us to indemnify our customers. Under our drilling contracts, liability with respect to personnel and property is customarily assigned on a “knock-for-knock” basis, which means that we and our customers assume liability for our respective personnel and property. However, in certain drilling contracts we may assume liability for damage to our customer’s property and other third-party property on the rig resulting from our negligence, subject to negotiated caps per occurrence, 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. 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.

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 blow-outs or cratering of the well. In some drilling 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 drilling contracts is only a summary as of the date hereof and is general in nature. Our insurance program and the terms of our drilling contracts may change in the future. In addition, the indemnification provisions of our drilling contracts may be subject to differing interpretations, and enforcement of those provisions may be limited by public policy and other considerations.

Employees

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

	December 31, 2011	December 31, 2010
Rental Tools	253	250
U.S. Barge Drilling	387	329
U.S. Drilling(1)	153	138
International Drilling	1,301	1,067
Technical Services, Construction Contract and Corporate	223	227
Total employees	2,317	2,011

(1) Includes employees in Alaska who are supporting the business expansion into this region.

Environmental Considerations

Our operations are subject to numerous 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 domestic 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 prevent 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 removal 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. A “responsible party” includes 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. A failure to comply with ongoing requirements or inadequate cooperation in a spill may even subject a responsible party to civil or criminal enforcement actions.

In addition, 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. 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 can result from either governmental or citizen prosecution.

All of our operating U.S. barge drilling rigs have zero-discharge as required by law, such as 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 in our operations depend upon a number of factors. We believe that we have all such miscellaneous 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 each responsible party for all response and remediation costs, as well as natural resource damages. Few defenses exist to the liability imposed by CERCLA.

RCRA generally does not regulate most wastes generated by the exploration and production of oil and gas. RCRA 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, waste solvents, laboratory wastes, and waste 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 including 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 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 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 2012. 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. In addition, the EPA is taking steps that would result in the regulation of GHGs as pollutants under the CAA. To-date, the EPA has issued (i) a "Mandatory Reporting of Greenhouse Gases" final rule, effective December 29, 2009, which establishes a new comprehensive scheme requiring operators of stationary sources 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. Finally, on November 8, 2010, the EPA finalized new GHG reporting requirements for upstream petroleum and natural gas systems, which will be added to the EPA's GHG reporting rule. Facilities containing petroleum and natural gas systems that emit 25,000 metric tons or more of CO_2 equivalent per year will now be required to report annual GHG emissions to EPA, with the first report due on September 28, 2012.

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.

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FINANCIAL INFORMATION ABOUT INDUSTRY SEGMENTS AND GEOGRAPHIC AREAS

We operate in six segments: Rental Tools, U.S. Barge Drilling, U.S. Drilling, International Drilling, Technical Services and Construction Contract. Information about our reportable segments and operations by geographic areas for the years ended December 31, 2011, 2010 and 2009 is set forth in Note 12 in the notes to the consolidated financial statements included in Item 8 of this report.

EXECUTIVE OFFICERS

Officers are elected each year by the board of directors following the annual meeting for a term of one year and until the election and qualification of their successors. As of the date of this filing, the executive officers of the Company and their ages, positions with the Company and business experience are presented below. The Company announced that effective March 9, 2012 Mr. Mannon resigned from the offices of President and Chief Executive Officer and from the Company's board of directors. Concurrently, Mr. Parker, Jr. will assume the role of President and Chief Executive Officer in addition to his current role of Executive Chairman.

- *Robert L. Parker Jr., 63,* is the executive chairman of the board of directors. Mr. Parker joined the Company in 1973 as a contract representative, and was appointed manager of U.S. operations and a vice president later in 1973. He was elected executive vice president in 1976, and president and chief operating officer in 1977. In 1991, he was elected chief executive officer, was appointed chairman in 2006, and has retained the position of executive chairman since 2009. He has been a director since 1973.

- *David C. Mannon, 54,* is president, chief executive officer and a member of the board of directors. Mr. Mannon joined the Company in 2004 as senior vice president and chief operating officer, and was elected president in 2007, and chief executive officer and director in 2009. From 2003 to 2004, Mr. Mannon held the positions of president and chief executive officer of Triton Engineering Services Company (Triton), a subsidiary of Noble Drilling Corporation. From 1988 to March 2003 he held various other positions with Triton. From 1980 through 1988, Mr. Mannon was employed by Sedco-Forex, formerly Sedco, as a drilling engineer.

- *W. Kirk Brassfield, 56,* was elected senior vice president and chief financial officer in 2005. Mr. Brassfield joined the Company in 1998 as controller and principal accounting officer, and was appointed vice president, finance and accounting in 2004. From 1991 through 1998, Mr. Brassfield served in various positions, including subsidiary controller and director of financial planning of MAPCO Inc., a diversified energy company. From 1979 through 1991, Mr. Brassfield served at the public accounting firm KPMG.

- *Jon-Al Duplantier, 44,* 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, managing counsel – Indonesia, executive assistant – Exploration and Production, and counsel – Dubai. Prior to joining ConocoPhillips, he served as a patent attorney for DuPont from 1992 to 1995.

- *Philip Agnew, 43,* 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.

- *David Farmer, 50,* 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, and North 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.

- *Don Hare, 56,* joined the Company in 2011 as vice president administration. Mr. Hare has held positions of leadership at Lyondell Chemical, DIMON Inc., Citizens Utilities, Diageo PLC, Scott Paper Company and International Paper Company. Before joining the Company, Mr. Hare was an independent consultant specializing in human resource leadership and has served as an independent consultant at various times throughout his career.

Other Parker Drilling Company Officers

- *J. Daniel Chapman, 41,* 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 of Freshfields (London) and King & Spalding (Atlanta and Houston).
- *Philip A. Schlom, 47,* 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, 56,* 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 the Company's 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). We also provide paper or electronic copies of our reports free of charge upon request. Additionally, these reports are available on an Internet website maintained by the SEC at http://www.sec.gov.

ITEM 1A. *RISKFACTORS*

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, before deciding to invest in our securities. 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.

Risks Related to Our Business

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 gas 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 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 other factors, many of 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 foreign countries;
- 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.

Our operations were impacted by the 2010 drilling rig accident in the U.S. Gulf of Mexico and its consequences and could be adversely affected in the future.

On April 22, 2010, the Deepwater Horizon, a deepwater drilling rig owned by another contractor that was operating in the U.S. Gulf of Mexico, sank after an apparent blowout and fire (Macondo well blowout). In response to the incident, on May 30, 2010, the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), of the U.S. Department of the Interior, at the time known as the Minerals Management Service implemented a moratorium on certain drilling activities in the U.S. Gulf of Mexico (GOM). On

October 12, 2010, the BOEMRE announced that it was lifting the moratorium subject to certain specified conditions. During the pendency of the moratorium, the BOEMRE implemented various environmental, technological and safety measures intended to improve offshore safety systems and environmental protection.

Effective October 1, 2011, the BOEMRE's responsibilities (and its regulations) were divided between agencies known as the Bureau of Ocean Energy Management (BOEM), Bureau of Safety and Environmental Enforcement (BSEE), and Office of Natural Resources Revenue (ONRR). Among other things, each operator is required to conduct a specific review of its operations and to certify to the BSEE that it is in compliance with the new requirements and current regulations. Operators are also required to submit independent third-party reports on the design and operation of certain pieces of drilling equipment, including BOPs and other well control systems and to conduct tests on the functionality of various rig parts and to submit the results of those tests to the BSEE. Additional regulations address new standards for certain equipment involved in the construction of offshore wells, especially BOPs, and require operators to implement and enforce a safety and environmental management system including regular third-party audits of safety procedures and drilling equipment to insure that offshore rig personnel and equipment remain in compliance with the new regulations. With respect to operations that were subject to the moratorium, the reports and certifications are required to be provided to the BSEE prior to commencement of operations following expiration of the moratorium. In addition, regulations were proposed (within BSEE's jurisdiction) on September 14, 2011 to expand safety and environmental management system requirements.

As a consequence of the Macondo well blowout, the resulting moratorium, increased regulation and longer times to obtain required permits, offshore drilling operations in the GOM have been significantly reduced. Although we had no ongoing drilling operations directly subject to the now lifted moratorium, our Rental Tools segment has customers with operations that were negatively affected. We cannot currently predict the rate at which new well permits will be issued or the rate at which rigs will be allowed to return to work once compliance with the new regulations has been demonstrated. The process followed by the BOEMRE/BSEE to review and approve well permit applications is likely to continue to be protracted relative to past experience, resulting in significant delays in the resumption of drilling in deepwater GOM that could persist through 2012. Significant continuing delay in the issuance of drilling permits or the resumption of operations, the possibility of additional regulations and government oversight and the possibility of increased legal liability could cause additional floating rigs to depart the U.S. GOM, with fewer customers operating in the region. If this were to occur, the market for our rental tools could be further adversely affected.

A continued slow recovery from the economic recession 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 slow recovery from the economic recession or another slowdown in economic activity 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 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 day rates and utilization of our rigs and limit our future growth prospects. Any significant decrease in day rates 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, a slow recovery from the economic recession also 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, capital expenditures for rig upgrade, refurbishment or construction projects could exceed our planned capital expenditures, impairing our ability to service our debt obligations.

The construction and commissioning schedule for our two new Arctic Alaska Drilling Units (AADUs) has experienced numerous delays and cost overruns, and our customer has notified us that our failure to supply operationally-ready rigs by December 31, 2011 constituted a default under our drilling contract relating to the rigs. Although we are continuing to work diligently to complete commissioning of the rigs and are in discussions with our customer regarding possible timeframes when the rigs could undergo acceptance testing, we may not be able to reach an agreement regarding a delivery schedule for the rigs. If we fail to do so, our customer may attempt to terminate our drilling contract. If such termination occurs and we ultimately are not able to obtain drilling contracts for the AADUs, it could have a material adverse effect on our financial condition and results of operations.

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

We require skilled, trained and experienced personnel to provide our customers with the highest quality technical services and support for our drilling operations. We compete with other oilfield services businesses and other employers to attract and retain qualified personnel with the technical skills and experience we require.

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

We may not be able to repay our 2.125% Convetible Senior Notes upon maturity. A failure to repay such Notes would cause us to be in default under most of our existing indebtedness.

Our 2.125% Convertible Senior Notes due 2012 (2.125% Notes) are scheduled to mature in July 2012. If we are unable to complete a refinancing or otherwise repay such debt using cash on hand and borrowings under our Revolver, we would be in default under the indenture governing the 2.125% Notes, which would also cause us to be in default under our Credit Agreement and the indenture governing our 9.125% Senior Notes due 2018 (9.125% Notes), which would result in all $486 million principal amount of current indebtedness outstanding under those agreements to be declared immediately due and payable.

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, 2011, we had:

- $482.7 million of long-term debt of which $145.7 million was classified as current portion of long-term debt
- $29.4 million of operating lease commitments; and
- $2.7 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 securities, sell assets; or
- 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 by us 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 2012 will be approximately $160 to $180 million, including approximately $90 to $100 million for maintenance projects and investments in rental tool equipment. We may require additional capital in the event of significant departures from our current business plan or unanticipated expenses. Sources of funding for our future capital requirements may include any or all of the following:

- cash on hand;
- funds generated from our operations;
- public offerings or private placements of equity and debt securities;
- revolving credit facility;
- commercial bank loans;
- capital leases; and
- sales of assets.

Additional financing may not be available on a timely basis or on terms acceptable to us and within the limitations contained in the indentures governing the 9.125% Notes and the 2.125% Notes and the documentation governing our senior secured credit facility. Failure to obtain appropriate financing, should the need for it develop, could impair our ability to fund our capital expenditure requirements and meet our debt service requirements and could have an adverse effect on our business.

Certain of our contracts are subject to cancellation or delay 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 that is currently under contract or may be able to obtain a comparable rig at a lower day rate. 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 drilling contracts if we experience operational problems. If our equipment fails to function properly and cannot be repaired promptly, we will not be able to engage in drilling operations, and customers may have the right to terminate the drilling contracts. If a rig 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 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 drilling contracts could materially reduce our revenue and profitability. In November 2010, BP suspended construction on the Liberty extended-reach drilling rig in Alaska, which is the sole project in our Construction Contract segment. Our contract with respect to the Liberty rig expired on July 1, 2011. BP has identified several areas of concern for which it has asked us to provide explanation and documentation, and we have done so. It is not possible to predict when or if BP will resume construction on the Liberty rig, or what additional actions it may request that we take with respect to the areas of concern it has raised. For more information about the status of the Liberty project, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Other Matters — "Liberty Project Status."

In addition, the construction and commissioning schedule for our two new AADUs has experienced numerous delays and cost overruns, and our customer has notified us that our failure to supply operationally-ready rigs by December 31, 2011 constituted a default under our drilling contract relating to the rigs. Although we are continuing to work diligently to complete commissioning of the rigs and are in discussions with our customer regarding possible timeframes when the rigs could undergo acceptance testing, we may not be able to reach an agreement regarding a delivery schedule for the rigs. If we fail to do so, our customer may attempt to terminate our drilling contract. If such termination occurs and we ultimately are not able to obtain drilling contracts for the AADUs, it could have a material adverse effect on our financial condition and results of operations.

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 major customer could adversely affect us. In 2011, our largest customer, ENL accounted for approximately 15.9 percent of our total revenues. Included in the total revenue from ENL is $48.0 million of reimbursable costs which increase revenues but have little direct impact on gross margins. Our ten most significant customers collectively accounted for approximately 56.4 percent of our total revenues in 2011. Our 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 although we believe no single competitor is dominant, many of our competitors in both the contract drilling and rental tools business 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 the previous period 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 and workover 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 rig supply and high dayrates often followed by periods of low demand, excess rig supply and low dayrates. Periods of low demand and excess rig supply intensify the competition in the industry and often result in rigs being idle for long periods of time. During periods of decreased demand we typically experience significant reductions in dayrates and utilization. If we experience reductions in dayrates or if we cannot keep our rigs operating, 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 2011, we derived approximately 46.4 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, many 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 11 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 Syria, Tunisia, Egypt, Libya and other North African countries may affect our operations. We currently have two rigs in Algeria. To the extent that Algeria experiences similar events, our operations in Algeria could be adversely affected. 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 whose political, regulatory and judicial systems and regimes may differ significantly from those in the United States. Our ability to compete in international contract drilling 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 often results 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.

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 demonstrating some of these hazards. We may not be able to insure against these risks or to obtain indemnification agreements 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 or for which we are not indemnified against, 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, so as to make 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 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.

The oil and natural gas industry has sustained several catastrophic losses in recent years, including damage from hurricanes in the GOM. As a result, insurance underwriters have increased insurance premiums and restricted certain insurance coverage such as for losses arising from a named windstorm.

Although not a hazard specific to our drilling operations, we could incur significant liability in the event of loss or damage to proprietary data of operators or third parties during our transmission of this valuable data.

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 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 2012. In the United States, federal legislation imposing restrictions on GHGs is under consideration. In addition, the EPA is taking steps that would result in the regulation of 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, effective December 29, 2009, which establishes a new comprehensive scheme requiring operators of stationary sources 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. Finally, on November 8, 2010, the EPA finalized new GHG reporting requirements for upstream petroleum and natural gas systems, which will be added to the EPA's GHG reporting rule. Facilities containing petroleum and natural gas systems that emit 25,000 metric tons or more of CO_2 equivalent per year will now be required to report annual GHG emissions to EPA, with the first report due on September 28, 2012.

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 involve claims for significant monetary amounts, some of which would not be covered by insurance. We undertake all reasonable steps to defend ourselves in such lawsuits. Nevertheless, we cannot predict the ultimate outcome of such lawsuits and any resolution which is adverse to us could have a material adverse effect on our financial condition. See Note 13, "Commitments and Contingencies," in Item 8 of this Form 10-K for a discussion of the material legal proceedings affecting us.

We are currently conducting an investigation into possible violations of the Foreign Corrupt Practices Act (FCPA) and other laws concerning our international operations. The Securities and Exchange Commission and the Department of Justice are conducting parallel investigations into possible FCPA violations. If we are found to have violated the FCPA or other legal requirements, we may be subject to criminal and civil penalties and other remedial measures, which could materially harm our business, results of operations, financial condition and liquidity.

As previously disclosed, we received requests from the United States Department of Justice (DOJ) in July 2007 and the United States Securities and Exchange Commission (SEC) in January 2008 relating to our utilization of the services of a customs agent. The DOJ and the SEC are conducting parallel investigations into possible violations of U.S. law by the Company, including the FCPA. In particular, the DOJ and the SEC are investigating our use of customs agents in certain countries in which we currently operate or formerly operated, including Kazakhstan and Nigeria. The Company is fully cooperating with the DOJ and SEC investigations and is conducting an internal investigation into potential customs and other issues in Kazakhstan and Nigeria. At this point, we are unable to predict the duration, scope or result of the DOJ or the SEC investigation or whether either agency will commence any legal action. We are currently in continuing discussions with the DOJ and SEC regarding a potential settlement, but no agreement has been reached with either agency. We cannot predict or estimate whether or when a resolution with each will occur, or the terms, conditions, or other parameters of any such resolution (including the size of any monetary penalties or disgorgement).

The DOJ and the SEC have a broad range of civil and criminal sanctions under the FCPA and other laws and regulations, which they may seek to impose against corporations and individuals in appropriate circumstances including, but not limited to, injunctive relief, disgorgement, fines, penalties and modifications to business practices and compliance programs. These authorities have entered into agreements with, and obtained a range of sanctions against, several public corporations and individuals arising from allegations of improper payments and deficiencies in books and records and internal controls, whereby civil and criminal penalties were imposed. Recent civil and criminal settlements have included multi-million dollar fines, deferred prosecution agreements, guilty pleas, and other sanctions, including the requirement that the relevant corporation retain a monitor to oversee its compliance with the FCPA. In addition, corporations may have to end or modify existing business relationships. Any of these remedial measures, if applicable to us, could have a material adverse impact on our business, results of operations, financial condition and liquidity.

We are subject to laws and regulations concerning our international operations, including export restrictions, U.S. economic sanctions and other activities that we conduct abroad. We have conducted an internal review concerning our compliance with these legal requirements and have voluntarily disclosed the results of our review to the U.S. government. If we are not in compliance with applicable legal requirements, we may be subject to civil or criminal penalties and other remedial measures, which could materially harm our business, results of operations, financial condition and liquidity.

We are subject to laws and regulations restricting our international operations, including activities involving restricted countries, organizations, entities and persons that have been identified as unlawful actors or that are subject to U.S. economic sanctions. Pursuant to an internal review, we have identified certain shipments of equipment and supplies that were routed through Iran as well as other activities, including drilling activities, which may have violated applicable U.S. laws and regulations. We have reviewed these shipments, transactions and drilling activities to determine whether the timing, nature and extent of such activities or other conduct may have given rise to violations of these laws and regulations, and we voluntarily disclosed the results of our review to the U.S. government. At this point, we are unable to predict whether the government will initiate an investigation or any proceedings against us, or the ultimate outcome that may result from our voluntary disclosure. If U.S. enforcement authorities determine that we were not in compliance with export restrictions, U.S. economic sanctions or other laws and regulations that apply to our international operations, we may be subject to civil or criminal penalties and other remedial measures, which could have an adverse impact on our business, results of operations, financial condition and liquidity.

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 gas wells whereby water, sand and chemicals are injected under pressure into subsurface formations to stimulate 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, several state governments now require the disclosure of chemicals used in the fracturing process. The U.S. EPA has taken the position that some hydraulic fracturing operations are subject to permitting requirements under the Safe Drinking Water Act; has proposed new air emissions standards that would apply to well completion activities; is developing new standards for wastewater discharges associated with hydraulic fracturing; and has commenced a study on the impacts of hydraulic fracturing on groundwater. The Bureau of Land Management is also in the process of developing 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.

Risks Related to Our Common Stock

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 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.

A hostile takeover of our company would be difficult.

Some of the provisions of our Restated Certificate of Incorporation and of the Delaware General Corporation Law may make it difficult for a hostile suitor to acquire control of our company and to replace our incumbent management. For example, our Restated Certificate of Incorporation provides for a staggered Board of Directors and permits the Board of Directors, without stockholder approval, to issue additional shares of common stock or a new series of preferred stock.

Risks Related to our Debt Securities

We may not be able to repurchase our 9.125% Senior Notes upon a change of control.

Upon the occurrence of specific change of control events affecting us, the holders of our 9.125% Notes will have the right to require us to repurchase our notes at 101 percent of their principal amount, plus accrued and unpaid interest. Our ability to repurchase our notes upon such a change of control event would be limited by our access to funds at the time of the repurchase and the terms of our other debt agreements. Upon a change of control event, we may be required immediately to repay the outstanding principal, any accrued interest on and any other amounts owed by us under our senior secured credit facilities, our notes and other outstanding indebtedness. The source of funds for these repayments would be our available cash or cash generated from other sources. However, we may not have sufficient funds available upon a change of control to make any required repurchases of this outstanding indebtedness.

In addition, the change of control provisions in the indenture governing our 9.125% Notes may not protect the holders of our notes from certain important corporate events, such as a leveraged recapitalization (which would increase the level of our indebtedness), reorganization, restructuring, merger or other similar transaction, unless such transaction constitutes a “Change of Control” under the indenture. Such a transaction may not involve a change in voting power or beneficial ownership or, even if it does, may not involve a change that constitutes a “Change of Control” as defined in the indenture that would trigger our obligation to repurchase the notes. Therefore, if an event occurs that does not constitute a “Change of Control” as defined in the indenture, we will not be required to make an offer to repurchase the notes and the holders may be required to continue to hold their notes despite the event.

We may not have sufficient cash to repurchase the 2.125% Convertible Senior Notes at the option of the holder upon a fundamental change or to pay the cash payable upon a conversion or at maturity.

Upon the occurrence of a fundamental change as defined in the indenture governing our 2.125% Notes, subject to certain conditions, we will be required to make an offer to repurchase for cash all outstanding notes at 100 percent of their principal amount plus accrued and unpaid interest, including additional amounts, if any, up to but not including the date of repurchase. In addition, unless we elect to satisfy our conversion obligation entirely in shares of our common stock, upon a conversion, we will be required to make a cash payment of up to $1,000 for each $1,000 in principal amount of notes converted. However, we may not have enough available cash or be able to obtain financing at the time we are required to make repurchases of tendered notes or settlement of converted notes. Additionally, any credit facility in place at the time of a repurchase or conversion of the notes may also limit our ability to use borrowings under that credit facility to pay for a repurchase or conversion of the notes and may prohibit us from making any cash payments on the repurchase or conversion of the notes if a default or event of default has occurred under that facility without the consent of the lenders under that credit facility. Our failure to repurchase tendered notes at a time when the repurchase is required by the indenture or to pay any cash payable on a conversion of the notes would constitute a default under the indenture. A default under the indenture or the fundamental change itself could lead to a default under the other existing and future agreements governing our indebtedness. If the repayment of the related indebtedness were to be accelerated after any applicable notice or grace periods, we may not have sufficient funds to repay the indebtedness and repurchase the notes or make cash payments upon conversion thereof.

In addition, the 2.125% Notes will mature in July 2012. We may not have sufficient cash or borrowing capacity to repay them in full. A failure to repay the 2.125% Notes could have a material adverse effect on our financial condition and results of operations. See risk “ We may not be able to repay 2.125% Notes upon maturity. A failure to repay such Notes would cause us to be in default under most of our existing indebtedness” above for further discussion.

The indenture for our 9.125% Senior Notes and our senior secured credit agreement impose significant operating and financial restrictions, which may prevent us from capitalizing on business opportunities and taking some actions.

The indenture governing our 9.125% Notes and the agreement governing our senior secured credit facility 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 senior 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 holders of our 9.125% Notes and the lenders under our senior secured credit facility 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.

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 contracts and our expectations concerning when our rigs will commence operations under such contracts;
- growth through acquisitions of companies or assets;
- organic growth of our operations;
- construction or upgrades of rigs and expectations regarding when these rigs will commence operations;
- capital expenditures for acquisition of rigs, construction of new rigs or major upgrades to existing rigs;
- scheduled delivery, commissioning and subsequent operation of drilling rigs for operation in Alaska under the terms of our agreement with BP Exploration (Alaska) Inc.;
- entering into joint venture agreements;

- our future liquidity, including the ability to refinance our 2.125% Notes;
- availability and sources of funds to reduce our debt and expectations of when debt will be reduced;
- the outcome of pending or future legal proceedings, investigations, tax assessments and other claims;
- the availability of insurance coverage for pending or future claims;
- the enforceability of contractual indemnification in relation to pending or future claims; and
- compliance with covenants under our debt agreements.

In some cases, you can identify these statements by forward-looking words such as “anticipate,” “believe,” “could,” “estimate,” “expect,” “intend,” “outlook,” “may,” “should,” “will” and “would” or similar words. Forward-looking statements are based on certain assumptions and analyses made by our management in light of their experience and perception of historical trends, current conditions, expected future developments and other factors they believe are relevant. Although our management believes that their 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 Euro 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;
- worldwide demand for oil;
- fluctuations in the market prices of oil and natural gas;
- 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 our investigation and the parallel investigations by the SEC and the Department of Justice into possible violations of U.S. law, including the Foreign Corrupt Practices Act;
- 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;
- 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;

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- unanticipated cancellation of contracts by operators;
- breakdown of equipment;
- other operational problems including delays in start-up or commissioning of rigs;
- changes in competition;
- 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 Rental Tools headquarter office in New Iberia, Louisiana. Additionally, we own and/or lease office space and operating facilities in various locations including facilities where we hold an inventory of rental tools and locations with close proximity to where we provide service to our customers. Additionally, we own and/or lease facilities necessary for administrative and operational support functions.

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Land and Barge Rigs

The following table shows, as of December 31, 2011, the locations and drilling depth ratings of our rigs available for service:

Name	Type(2)	Year entered into service/ upgraded	Drilling depth rating (in feet)	Location
International				
Eastern Hemisphere(1)				
Rig 231	L	1981/1997	13,000	Indonesia
Rig 253	L	1982/1996	15,000	Indonesia
Rig 188	L	1979/2003	18,000	New Zealand
Rig 246	L	1981/1998	18,000	New Zealand
Rig 226	HH	1989/2010	18,000	Papua New Guinea
Rig 264	L	2007	20,000	Algeria
Rig 265	L	2007	20,000	Algeria
Rig 107	L	1983/2009	16,800	Kazakhstan
Rig 216	L	2001/2009	25,000	Kazakhstan
Rig 230	L	1980/2003	18,000	Kazakhstan
Rig 236	L	1978/2008	21,000	Kazakhstan
Rig 247	L	1981/2008	25,000	Kazakhstan
Rig 249	L	2000/2009	30,000	Kazakhstan
Rig 257	B	1999/2010	30,000	Kazakhstan
Rig 258	L	2001/2009	30,000	Kazakhstan
Rig 269	L	2008	25,000	Kazakhstan
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 53	B	1978/2007	18,000	Mexico
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 20	B	1981/2007	13,000	GOM
Rig 21	B	1979/2007	14,000	GOM
Rig 12	B	1979/2006	18,000	GOM
Rig 15	B	1978/2007	15,000	GOM
Rig 50	B	1981/2006	20,000	GOM
Rig 51	B	1981/2008	20,000	GOM
Rig 54	B	1980/2006	25,000	GOM
Rig 55	B	1981/2010	25,000	GOM
Rig 56	B	1979/2005	25,000	GOM
Rig 72	B	1982/2005	30,000	GOM
Rig 76	B	1977/2009	30,000	GOM
Rig 77	B	2006/2006	30,000	GOM
Rig 270	L	2011	21,000	Louisiana

(1) Excludes three rigs classified for accounting purposes as assets held for sale as of December 31, 2011.

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

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The following table presents our utilization rates and rigs available for service for the years ended December 31, 2011 and 2010:

	December 31, 2011	December 31, 2010
U.S. Land & Barge Rigs		
U.S. Barge Drilling Rigs		
Rigs available for service(1)	13.0	13.0
Utilization rate of rigs available for service(2)	72%	63%
U.S. Drilling Rigs (4)		
Rigs available for service(1)	1.0	1.0
Utilization rate of rigs available for service(2)	0%	0%
International Land & Barge Rigs		
Eastern Hemisphere Region		
Rigs available for service(1)(3)	16.0	19.0
Utilization rate of rigs available for service(2)	35%	42%
Latin America Region		
Rigs available for service(1)	10.0	10.0
Utilization rate of rigs available for service(2)	70%	78%
Total International Land & Barge Rigs		
Rigs available for service(1)	26.0	29.0
Utilization rate of rigs available for service(2)	48%	55%

(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.

(3) At December 31, 2010 three rigs were removed from the marketable rig count and classified as assets held for sale. These rigs remained classified as assets held for sale as of December 31, 2011.

(4) As of December 31, 2011 the Company has two-new build rigs undergoing commissioning and construction completion in Alaska. We believe that these rigs will be ready for service in 2012. These rigs are not included in rigs available for service in the table above.

ITEM 3. *LEGALPROCEEDINGS*

For information on Legal Proceedings, see Note 13, 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.

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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:

	2011		2010	
Quarter	High	Low	High	Low
First	$7.10	$3.98	$5.85	$4.55
Second	7.45	5.36	5.76	3.75
Third	6.95	4.17	4.44	3.43
Fourth	7.48	3.60	4.95	3.85

Most of our stockholders maintain their shares as beneficial owners in "street name" accounts and are not, individually, stockholders of record. As of February 29, 2012, our common stock was held by 1,700 holders of record and we had an estimated 22,846 beneficial owners.

Our existing credit agreement and the indenture for the 9.125% Notes restrict the payment of dividends. We have no present intention to pay dividends on our common stock in the foreseeable future.

Issuer Purchases of Equity Securities

The Company currently has no active share repurchase programs. 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, 2011	14,836	$ 4.65
November 1-30, 2011	3,527	$ 5.26
December 1-31, 2011	12,844	$ 6.90
Total	31,207	$ 5.85

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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, 2011. 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,				
	2011(1)	2010	2009(2)	2008(2)(3)	2007(2)
	(Dollars in Thousands, Except Per Share Amounts)				
Income Statement Data					
Total revenues	$ 686,646	$ 659,475	$ 752,910	$ 829,842	$ 654,573
Total operating income (loss)	(42,639)	45,107	39,322	59,180	190,983
Equity in loss of unconsolidated joint venture, net of tax	—	—	—	(1,105)	(27,101)
Other income and (expense), net	(22,773)	(33,602)	(29,495)	(28,405)	(24,141)
Income tax expense (benefit)	(14,767)	26,213	560	6,942	36,895
Net income (loss)	(50,645)	(14,708)	9,267	22,728	102,846
Net income (loss) attributable to controlling interest	(50,451)	(14,461)	9,267	22,728	102,846
Basic earnings per share:					
Income (loss) from continuing operations	$ (0.43)	$ (0.13)	$ 0.08	$ 0.20	$ 0.94
Net income (loss)	$ (0.43)	$ (0.13)	$ 0.08	$ 0.20	$ 0.94
Diluted earnings per share:					
Income (loss) from continuing operations	$ (0.43)	$ (0.13)	$ 0.08	$ 0.20	$ 0.93
Net income (loss)	$ (0.43)	$ (0.13)	$ 0.08	$ 0.20	$ 0.93
Balance Sheet Data					
Cash and cash equivalents	$ 97,869	$ 51,431	$ 108,803	$ 172,298	$ 60,124
Property, plant and equipment, net	719,809	816,147	716,798	675,548	585,888
Assets held for sale	5,315	5,287	—	—	—
Total assets	1,216,246	1,274,555	1,243,086	1,205,720	1,067,173
Total long-term debt including current portion of long-term debt	482,723	472,862	423,831	441,394	349,309
Total equity	544,050	588,066	595,899	582,172	549,322

(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 AADUs located in Alaska that is further described in Note 2 to the Consolidated Financial Statements in Item 8 of this Form 10-K.

(2) The Company adopted, effective January 1, 2009, newly issued accounting guidance regarding *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion* which applies to all convertible debt instruments that have a "net settlement feature." We reflected the impact of the new accounting guidance during each of the quarterly periods in our respective Quarterly Reports on Form 10-Q filed with the SEC during 2009. The adoption of this accounting guidance impacted the historical accounting for our 2.125% Notes due 2012 issued on July 5, 2007 by requiring adjustments to related interest expense, deferred income taxes, long-term debt, and shareholders' equity for 2008 and 2007, which are illustrated in the notes to the consolidated financial statements

(3) The 2008 results reflect a $100.3 million non-cash pretax charge for impairment of goodwill.

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

OVERVIEW AND OUTLOOK

Overview

We produced solid growth in revenues and operating gross margin in 2011. Our Rental Tools business continued to respond to the shifting focus of U.S. drilling activity while investing in inventory to meet the growing needs of land and offshore customers. The U.S. Barge Drilling business achieved higher fleet-average utilization and a higher average dayrate. Our International Drilling operations benefited from a higher fleet-average dayrate and an additional O&M contract that more than offset the impact of a decline in fleet-average utilization. Our program to introduce new drilling technology to the Alaskan North Slope has taken more time and a larger investment than we had anticipated. The delays and increased costs resulted in a fourth quarter 2011 $170.0 million non-cash pretax impairment charge of the two Alaskan rigs.

Some of our achievements in 2011 were:

- We continued to infuse our rental tools business with capital, investing over $60 million in 2011. Most of this investment went directly for new equipment to serve the increased demand for rental tools created by the growth in U.S. unconventional shale drilling as well as to replace equipment lost in hole or worn-out and unserviceable equipment.
- We continued to hold the number one position in the U.S. GOM barge drilling market, measured by barge drilling rigs working. According to industry compiled information, over 50 percent of all wells drilled by barge rigs in the shallow waters of the Gulf of Mexico during 2011 were drilled by our rigs.
- We successfully completed two significant O&M-related projects. One was for the 100 kilometer relocation of the ENL-owned Yastreb rig, returning it to its original drilling site for a new drilling program on Sakhalin Island, Russia. Another was the refurbishment and delivery of the Talisman-owned heli-hoist land rig for service in Papua New Guinea and being awarded a three-year operating contract for that rig.
- We continued our involvement in the development of the ENL-sponsored Berkut platform, advancing from providing engineering and design services for the drilling package on this multi-purpose platform to providing construction oversight of the drilling package during the platform's shipyard construction phase.

The Rental Tools segment continued to benefit from the shift in the U.S. land rig count from dry gas to oil and liquids-rich fields that also has been accompanied by a shift to longer well bores. This has increased the need for premium drill pipe and other tubulars. To meet that growing demand we continued to add to our inventory of tubulars, BOPs and other products in 2011. As demand has continued to grow, we have additional pipe scheduled for delivery in 2012. These purchases will allow us to continue to meet the growth in customer needs and maintain service levels.

Our U.S. Barge Drilling business benefited from improvements in dayrates and the rig fleet's average utilization in 2011 compared with 2010. In the latter part of 2011 we had a pause in deep gas drilling after an active summer, with all three of our ultra-deep drilling rigs being idle for a time in the fourth quarter. All three are scheduled to return to work before or during the first quarter of 2012. The improvement in our fleet average dayrate contributed to the continued improvement in this segment's profitability. There has been a notable shift to oil-focused drilling in the GOM barge market. This is not unique to us, but an industry-wide occurrence, with over two-thirds of barge drilling targeted to oil, specifically, or dual oil and gas legs, based on industry information, driven by the current price for the oil and liquids content from these fields. This is expected to continue to support drilling demand in this market.

In 2011 we made progress on the construction and completion of the AADUs in preparation for drilling. By the end of 2011 we were in the process of commissioning the rigs, including making modifications needed to meet the operational and safety objectives we desire. Based on the work requirements we have identified and the progress we have made so far, we expect these rigs to be operationally ready during 2012.

The International Drilling segment's performance was benefitted by the increase in O&M activities and higher fleet-average dayrate which together more than offset the lower average utilization of the Parker-owned fleet for 2011 as compared to the prior year. While the overall fleet-average utilization declined in both our geographic regions for the year, we had returned to 80 percent utilization in the Latin America region and had two previously idle rigs in the Eastern Hemisphere region contracted to begin work in early 2012. We continue to market idle rigs for work in their operational areas and for suitable applications in other markets.

The addition of two significant projects to the International Drilling segment's portfolio of O&M contracts provided a lift in 2011 to the segment's overall performance. The segment's 2011 O&M projects included:

- Operating the extended-reach Yastreb land rig and the offshore Orlan platform for ENL on the Sakhalin-1 project.
- Relocating the Yastreb rig on Sakhalin Island, returning it to its original drilling location for a new drilling program.
- Operating the Coral Sea land rig for Talisman Energy in Papua New Guinea.
- Managing a fleet of 25 rigs owned for Kuwait Drilling Company in Kuwait.

Our Technical Services segment is primarily engaged in engineering and engineering management services we provide in the development, design, construction and commissioning of innovative drilling solutions for third party customers as well as Parker operations. In 2011, the segment's activities included the engineering and design of the drilling package for the ENL-owned Berkut platform and several early-stage engineering and design projects for other E&P clients. The segment's revenue decline in 2011, compared with revenues for 2010, was primarily the result of having completed work on the Liberty project in early 2011 and the transition to a less revenue intensive phase of the Berkut platform project. Much of this work has the potential to evolve into future O&M opportunities.

Outlook

We are encouraged by the state of our operations and our performance potential and expect to see solid results in 2012 in line with that potential. Our business outlook remains driven by the growing needs for the services, operational efficiency and safety we deliver to our customers.

During the past several years we invested in our rental tools business – people, facilities and equipment – to meet the surge in demand for premium drill pipe and to provide premier customer service. We expect the demand to continue to grow as a result of the shift in the U.S. land drilling market away from dry gas targets to oil and liquids-rich targets and the continued increase in footage drilled due to longer lateral wells in the shale plays. We continue to be proactive in meeting customer needs and expect to add inventory in 2012 to meet their requirements. In addition, the growing fleet of deepwater drilling vessels in the GOM is a further source of opportunities for our rental tools business.

We continue to lead in the GOM barge drilling market. Drilling remains active in the shallow waters of the GOM and is more oil-focused today than it has traditionally been. We expect this shift to oil-focused drilling and the continued interest in deep gas plays will provide ongoing support.

We expect our two new technology Alaska land rigs, the foundation of our U.S. Drilling operations, to be commissioned and presented for work during 2012.

We have been transforming our international drilling activities, focused both on enhancing the deployment of the assets we have in the field and on leveraging our drilling expertise through O&M contracts. Growth in international E&P spending, long expected by the industry, should provide opportunities to expand the deployment of our international rig fleet, grow our contract drilling services, and generate business for our Technical Services segment. While much of the current work in our Technical Services segment will continue into 2012, there are several early-stage engineering and development opportunities that could expand our activities this year and beyond.

RESULTS OF OPERATIONS

As of December 31, 2011, the Company has modified our reporting segments to be consistent with recent organizational changes to improve our drilling organization. The Company is aligned in six distinct operating segments:

- Rental Tools
- U.S. Barge Drilling
- U.S. Drilling
- International Drilling
- Technical Services
- Construction Contract

We have expanded our segments by one, adding a U.S. Drilling segment, represented primarily by our two AADU rigs in Alaska. Our U.S. Barge Drilling segment, previously referred to as the U.S. Drilling segment, represents our GOM barge business and remains unchanged. We have aligned our international operations more closely with the management structure we now have in place. Our previous three geographic regions (Americas, CIS/AME, and Asia Pacific) are now two – Latin America and Eastern Hemisphere. Each region includes all drilling-related operations, whether performed using a Parker-owned rig or a customer-owned rig on an O&M contract. Our Technical Services segment, which primarily includes our engagement in engineering support initiatives, pre-FEED, FEED and EPC/EPCI projects that have the potential to evolve into future O&M opportunities, is now reported as an individual segment with the O&M component moving to International Drilling as described above. Our Rental Tools segment remains unchanged. We have reclassified revenues, expenses and related overhead amounts between the segments as of December 31, 2011 to reflect this alignment. Amounts presented throughout this document for the years ended December 31, 2010 and 2009 have been revised to conform to current period presentation.

Year Ended December 31, 2011 Compared with Year Ended December 31, 2010

Revenues of $686.6 million for the year ended December 31, 2011 increased $27.2 million, or 4.1%, from the comparable 2010 period. The years ended December 31, 2011 and 2010 included construction contract revenues of $9.6 million and $91.1 million, respectively, for the Liberty rig construction project. Excluding that individual project, revenues from ongoing operations for the year ended December 31, 2011 would have been $108.6 million or 19.1%, higher than 2010. Operating gross margin including depreciation and amortization increased 113.7% to $156.4 million for the year ended December 31, 2011 as compared to $73.2 million for the year ended December 31, 2010. We recorded a net loss attributable to controlling interest of $50.5 million for the year ended December 31, 2011, as compared to a net loss of $14.5 million for the year ended December 31, 2010. 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 AADU rigs to their fair value from the existing net book value (see Note 2 to the Consolidated Financial Statements). Excluding this non-cash charge, net income attributable to controlling interest for the year ended December 31, 2011 would have been $58.7 million.

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

	Year Ended December 31,			
	2011		2010	
	(Dollars in Thousands)			
Revenues:				
Rental Tools	$ 237,068	35%	$ 172,598	26%
U.S. Barge Drilling	93,763	14%	64,543	10%
U.S. Drilling	—	0%	—	0%
International Drilling	318,482	46%	294,821	45%
Technical Services	27,695	4%	36,423	5%
Construction Contract	9,638	1%	91,090	14%
Total revenues	$ 686,646	100%	$ 659,475	100%
Operating gross margin:				
Rental Tools gross margin excluding depreciation and amortization	$ 162,577	69%	$ 112,562	65%
U.S Barge Drilling gross margin excluding depreciation and amortization	28,620	31%	11,209	17%
U.S. Drilling gross margin excluding depreciation and amortization	(1,692)		(217)	
International Drilling gross margin excluding depreciation and amortization	72,891	23%	59,389	20%
Technical Services gross margin	5,335	19%	5,052	14%
Construction Contract gross margin	771	8%	202	0%
Total operating gross margin excluding depreciation and amortization	$ 268,502	39%	$ 188,197	29%
Depreciation and amortization	(112,136)		(115,030)	
Total operating gross margin	$ 156,366		$ 73,167	
General and administrative expense	(31,314)		(30,728)	
Impairments and other charges	(170,000)		—	
Provision for reduction in carrying value of certain assets	(1,350)		(1,952)	
Gain on disposition of assets, net	3,659		4,620	
Total operating income	$ (42,639)		$ 45,107	

Segment gross margins, excluding depreciation and amortization, are computed as revenues less direct operating expenses, excluding depreciation and amortization expense, where applicable; segment 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 (2)	Construction Contract (2)
	(Dollars in Thousands)					
Year Ended December 31, 2011						
Operating gross margin(1)	$120,822	$ 11,116	$(3,915)	$ 22,237	$ 5,335	$ 771
Depreciation and amortization	41,755	17,504	2,223	50,654	—	—
Operating gross margin excluding depreciation and amortization	$162,577	$ 28,620	$(1,692)	$ 72,891	$ 5,335	$ 771
Year Ended December 31, 2010						
Operating gross margin(1)	$ 74,541	$(11,503)	$ (217)	$ 5,092	$ 5,052	$ 202
Depreciation and amortization	38,021	22,712	—	54,297	—	—
Operating gross margin excluding depreciation and amortization	$112,562	$ 11,209	$ (217)	$ 59,389	$ 5,052	$ 202

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

(2) The Technical Services segment and the Construction Contract segment do not incur depreciation and amortization.

Operations

Rental Tools

Rental Tools segment revenues increased $64.5 million, or 37.4%, to $237.1 million for the year ended December 31, 2011 compared to revenues for the year ended December 31, 2010. The increase is primarily due to the growth in demand for rental tools, higher utilization of our rental tool inventory and better pricing. The growing use of lateral drilling and longer well-bores to exploit both shale deposits and conventional oil and gas reservoirs continued to lead to greater demand for rental tools. Our 2011 investments in rental tool inventory of approximately $61.5 million expanded our ability to serve this growing demand.

Rental Tools segment operating gross margin, excluding depreciation and amortization, increased by $50.0 million, or 44.4%, for the year ended December 31, 2011 compared with operating gross margin, excluding depreciation and amortization, for the year ended December 31, 2010, primarily due to higher revenues and the ability to leverage costs across the increased revenue stream.

U.S. Barge Drilling

U.S. Barge Drilling segment revenues increased $29.2 million, or 45.3%, to $93.8 million for the year ended December 31, 2011, compared with revenues for the year ended December 31, 2010. The increase in revenues was primarily due to higher rig fleet utilization and a higher average dayrate for 2011. The market's continued shift to more oil-focused drilling supported the demand for drilling throughout the year.

U.S. Barge Drilling segment operating gross margin, excluding depreciation and amortization, increased $17.4 million or 155.3% to $28.6 million for the year ended December 31, 2011, compared with segment operating gross margin, excluding depreciation and amortization, for the year ended December 31, 2010. The increase reflects the impact of improved utilization and the continued control of operating costs.

U.S. Drilling

As of December 31, 2011, the U.S. Drilling segment had not begun generating revenue. We anticipate re-entry into the Alaska drilling market in 2012 with two new-design land rigs intended to deliver improved drilling efficiency, operating consistency and safety to address the challenges presented by the remote location, harsh climate and sensitive environment that characterize the Alaskan North Slope. Operating gross margin, excluding depreciation and amortization, was a loss of $1.7 million and $0.2 million for the years ended December 31, 2011 and 2010, respectively, and includes expenditures associated with re-entering the Alaskan market. The start-up costs include salaries and employee hiring-related expenditures, training and rental of facilities in Alaska to support our operations. For further discussion see *Item 1A. Risk Factors.*

International Drilling

International Drilling segment revenues increased $23.7 million, or 8.0%, to $318.5 million for the year ended December 31, 2011, compared with the year ended December 31, 2010. The higher revenues are primarily due to an increase in revenue generated by our O&M contracts offset by a decline in our drilling revenues generated through the operation of rigs that we own.

O&M revenues increased to $127.0 million, or 70.5% for the year ended December 31, 2011 compared to $74.5 million for the year ended December 31, 2010. The increase in revenues generated through our O&M contracts was primarily due to a drilling rig relocation project which began during the fourth quarter of 2010 and a shipyard refurbishment and operations project which began during the first quarter of 2011. The projects included approximately $50.3 million of reimbursable costs for the year ended December 31, 2011, which add to revenues but have little direct impact on operating margins. The increase in O&M revenues was partially offset by a lower average dayrate associated with our services on the Orlan Platform in Sakhalin Island, Russia as the rig was in warm stack mode in 2011 compared with workover mode in 2010.

Revenues related to Parker-owned rigs decreased to $191.5 million or 13.1% for the year ended December 31, 2011 compared to $220.4 million for the year ended December 31, 2010. Revenues declined in the Eastern Hemisphere operations due to reduced average utilization and lower reimbursable revenues, partially offset by a higher average dayrate for our rigs in this region. The decrease in revenues in the Latin America operations is primarily due to reduced average utilization and lower reimbursables partially offset by higher average dayrates for rigs in certain locations in this region.

International Drilling operating gross margin, excluding depreciation and amortization, increased $13.5 million, or 22.7%, to $72.9 million for the year ended December 31, 2011, compared with $59.4 million for the year ended December 31, 2010. The increase in operating gross margin for the year ended December 31, 2011 was due to increased margins for our O&M operations in addition to increased margins for our Parker-owned rig operations. Operating margins generated by our O&M operations were $25.3 million and $16.6 million for the years ended December 31, 2011 and 2010, respectively. The increase is primarily due to the Yastreb drilling rig move and the Coral Sea refurbishment program. Our margins related to Parker-owned rigs were $47.6 million and $42.8 million for the years ended December 31, 2011 and 2010, respectively. The increase is due to the inclusion in 2010 of $6.4 million of expense related to a non-cash charge to write-off certain value added tax (VAT) assets and expense for property tax assessments and other tax matters. In addition to the impacts from lower utilization and higher average dayrates in both the Eastern Hemisphere and Latin American regions, we achieved benefits from lower labor costs in our operations in the Eastern Hemisphere region. The increase in operating margins was partially offset by a $2.3 million non-cash charge to write-off certain VAT assets and the recording of expenses related to the estimated salvage cost of a barge rig that was stranded in Nigeria. We have no ongoing operations in Nigeria.

Technical Services

Technical Services segment revenues decreased $8.7 million, or 24.0%, to $27.7 million for the year ended December 31, 2011, compared with $36.4 million for the year ended December 31, 2010. This decrease was primarily due to the transition of the Berkut platform project from its engineering phase to a less revenue-intensive construction oversight phase and the expiration at the end of the second quarter of 2011 of the “pre-operations” phase of the Liberty rig contract. This was partially offset by revenues related to two front-end engineering projects that are in the early development stages.

Operating gross margin for this segment increased by $0.3 million, or 5.6%, to $5.3 million for the year ended December 31, 2011, compared with the year ended December 31, 2010. The increase in operating gross margin was primarily due to revenues related to two front-end engineering projects that are in the early development stages and an increase in operating margin on the Liberty project resulting from increased margin for resources contracted to BP to support and maintain the Liberty rig. This was partially offset by a decrease due to the transition in the work content of the Berkut platform project. The Technical Services segment does not incur depreciation and amortization.

Construction Contract

This segment includes only the Liberty extended-reach drilling rig construction project for use in the Alaskan Beaufort Sea. Construction Contract segment revenues were $9.6 million for the year ended December 31, 2011 compared with $91.1 million for the year ended December 31, 2010. This segment reported $0.8 million operating gross margin for the year ended December 31, 2011 resulting from preliminary close-out of the Liberty project and recognition of final percentage of completion revenues. The segment reported a $0.2 million operating gross margin for the year ended December 31, 2010 due to an increase in total estimated construction costs and a longer construction period. The construction contract segment does not incur depreciation and amortization.

The Liberty rig construction contract was a fixed fee and reimbursable contract accounted for on a percentage of completion basis. As of December 31, 2011 and 2010, we had recognized $335.5 million and $325.9 million in project-to-date revenues, respectively. We have recognized the entire $11.7 million fixed fee margin on the contract.

In November 2010, BP informed us that it was suspending construction on the project to review the rig’s engineering and design, including its safety systems. The Liberty rig construction contract expired on February 8, 2011 prior to completion of the rig. Before expiration of the construction contract, BP identified several areas of concern relating to design, construction and invoicing for which it asked us to provide explanations and documentation, and we have done so. Although we provided BP with the requested information, we do not know when or how these issues will be resolved with our client.

After expiration of the construction contract, the Company and BP continued activities to preserve and maintain the rig under the “pre-operations” phase of an O&M contract, which was entered into in August 2009 and expired on July 1, 2011. A new consulting services agreement was reached between the Company and BP effective July 1, 2011. Under the consulting services agreement, we assisted BP in a review of the rig’s design, the creation of a new statement of requirements for the rig, and the transition of documentation and materials to BP. All work under the consulting agreement has been completed and we are engaged with BP on construction contract close-out discussions.

Other Financial Data

During 2011 we recorded a provision for reduction in the carrying value of assets of $1.4 million related to a final settlement of a customer bankruptcy proceeding. In 2010, the Company recognized a $2.0 million provision for reduction in carrying value related to this same 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, 2011 and 2010 was $3.7 million and $4.6 million, respectively, and resulted from the sale of equipment deemed to be excess or not currently required for operations.

Interest expense decreased $4.2 million for the year ended December 31, 2011 compared with the year ended December 31, 2010, due to a $5.8 million increase in capitalized interest on major projects (primarily the two rigs being built in Alaska) which reduced overall interest expense. This was partially offset by a $0.9 million increase in debt-related interest expense and $0.7 million increase in debt amortization costs. Interest income was $0.3 million for each of the years ended December 31, 2011 and 2010.

General and administration expense increased $0.6 million for the year ended December 31, 2011, compared with general and administrative expense for the year ended December 31, 2010. The general and administrative cost increase was due primarily to an increase in legal expenses and salaries and wages, partially offset by a decrease in professional and consulting fees and other corporate administrative expenses.

Income tax benefit was $14.8 million for the year ended December 31, 2011, compared with income tax expense of $26.2 million for the year ended December 31, 2010. The 2011 period tax benefit is driven primarily by the $170.0 million non-cash pretax charge for our AADU 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 benefit for the year ended December 31, 2011 is an expense of $0.8 million related to an uncertain tax position and a benefit of $0.8 million related to the effective settlement of an uncertain tax position.

Year Ended December 31, 2010 Compared with Year Ended December 31, 2009

We recorded a net loss attributable to controlling interest of $14.5 million for the year ended December 31, 2010, compared with net income of $9.3 million for the year ended December 31, 2009. Operating gross margin, including depreciation and amortization, for the year ended December 31, 2010 was $73.2 million, compared with $83.5 million for the year ended December 2009. The decrease was primarily driven by decreases in operating gross margin from our International Drilling, and Construction Contract segments, partially offset by increases in operating gross margin from our Rental Tools and U.S. Barge Drilling segments.

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

	Year Ended December 31,			
	2010		2009	
	(Dollars in Thousands)			
Revenues:				
Rental Tools	$ 172,598	26%	$ 115,057	15%
U.S. Barge Drilling	64,543	10%	49,628	7%
U.S. Drilling	—	0%	—	0%
International Drilling	294,821	45%	379,344	50%
Technical Services	36,423	5%	23,438	3%
Construction Contract	91,090	14%	185,443	25%
Total revenues	$ 659,475	100%	$ 752,910	100%
Operating gross margin:				
Rental Tools gross margin excluding depreciation and amortization	$ 112,562	65%	$ 62,317	54%
U.S. Barge Drilling gross margin excluding depreciation and amortization	11,209	17%	1,574	3%
U.S. Drilling gross margin excluding depreciation and amortization	(217)		—	
International Drilling gross margin excluding depreciation and amortization	59,389	20%	121,121	32%
Technical Services gross margin	5,052	14%	4,376	19%
Construction Contract gross margin	202	0%	8,132	4%
Total operating gross margin excluding depreciation and amortization	$ 188,197	29%	$ 197,520	26%
Depreciation and amortization	(115,030)		(113,975)	
Total operating gross margin	$ 73,167		$ 83,545	
General and administrative expense	(30,728)		(45,483)	
Provision for reduction in carrying value of certain assets	(1,952)		(4,646)	
Gain on disposition of assets, net	4,620		5,906	
Total operating income	$ 45,107		$ 39,322	

Segment gross margins, excluding depreciation and amortization, are computed as revenues less direct operating expenses, excluding depreciation and amortization expense; gross margin percentages are computed as segment gross margin, excluding depreciation and amortization, as a percentage of revenues. The segment gross margin amounts, excluding depreciation and amortization, and gross margin percentages should not be used as a substitute for those amounts reported under U.S. GAAP. However, we monitor our business segments based on several criteria, including segment gross margin. Management believes that this information is useful to our investors because it more accurately reflects cash generated by a segment.

Segment 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(2)	Construction Contract(2)
			(Dollars in Thousands)			
Year Ended December 31, 2010						
Operating gross margin(1)	$ 74,541	$(11,503)	$ (217)	$ 5,092	$ 5,052	$ 202
Depreciation and amortization	38,021	22,712	—	54,297	—	—
Operating gross margin excluding depreciation and amortization	$112,562	$ 11,209	$ (217)	$ 59,389	$ 5,052	$ 202
Year Ended December 31, 2009						
Operating gross margin(1)	$ 27,841	$(26,797)	$ —	$ 69,993	$ 4,376	$ 8,132
Depreciation and amortization	34,476	28,371	—	51,128	—	—
Operating gross margin excluding depreciation and amortization	$ 62,317	$ 1,574	$ —	$ 121,121	$ 4,376	$ 8,132

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

(2) The Technical Services segment and the Construction Contract segment do not incur depreciation and amortization.

Operations

Rental Tools

Rental Tools segment revenues increased $57.5 million, or 50.0% to $172.6 million during the year ended December 31, 2010 compared with 2009. The increase in revenue was attributable to an increase in utilization resulting from improved market conditions, timely investments in rental tool inventory, and reduced customer discounting during the 2010 period compared with the same period during 2009. The expanding use of lateral drilling and longer well-bores to exploit both shale deposits and conventional oil and gas reservoirs continued to contribute to greater market demand for rental tools. With its facilities strategically located in the major centers of drilling in the U.S., our Rental Tools business benefited from servicing this growing demand. The increased revenues from domestic land markets was somewhat offset by a moderate decline in revenues to GOM offshore customers and the international offshore market in 2010 compared with 2009. The decline in revenues from GOM customers is due to the cessation and slow restart of drilling in that market following the Macondo well blowout in April 2010. The decline in international revenues for this segment was due to fewer placements of rental tools for offshore applications.

The rental tools segment operating gross margins, excluding depreciation and amortization, increased $50.2 million, or 80.6% to $112.6 million for 2010 compared with 2009 as a result of the increase in revenues described above and reduced discounting in 2010 compared with 2009.

U.S. Barge Drilling

U.S. Barge Drilling segment revenues increased $14.9 million, or 30.1% to $64.5 million for the year ended December 31, 2010 compared with revenues for the year ended December 31, 2009. The increase in revenue was attributable to a recovering market, which has led to improved utilization for our barge drilling rig fleet. Utilization for our U.S. Barge Drilling rig fleet increased to 63% for 2010 from 35% for 2009 and was partially offset by a decline in average dayrates of approximately 17% due to a barge rig finishing a term contract at substantially higher rates in 2009.

The U.S. Barge Drilling segment operating gross margins, excluding depreciation and amortization, increased $9.6 million to $11.2 million for the year ended December 31, 2010 compared with operating gross margin for the same period of 2009 primarily as a result of the improved market and operating conditions and continued cost management.

U.S. Drilling

As of December 31, 2010, the U.S. Drilling segment had not begun generating revenue. Operating gross margin, excluding depreciation and amortization, was a loss of $0.2 million for the year ended December 31, 2010, and includes expenditures associated with start-up costs in preparation for re-entering the Alaskan market. The start-up costs include salaries and employee hiring related expenditures, training and rental of facilities in Alaska to support our operations.

International Drilling

International Drilling segment revenues decreased $84.5 million, or 22.3% to $294.8 million for the year ended December 31, 2010 compared with December 31, 2009. The decline was due to a decrease in revenue generated by both Parker-owned rigs and our O&M contracts related to customer-owned rigs. The largest decline related to the rigs that we own occurred in the Eastern Hemisphere as a result of lower average fleet utilization for our operations throughout this region as spending on drilling programs continued to be adversely impacted by weaker financial conditions and reduced spending on state-involved E&P programs. In addition, our Caspian Sea Arctic barge, located in this region, was on reduced dayrates, including a zero dayrate for a period during 2010, as it underwent a planned refurbishment and upgrade project before ending the year on reduced day rates while our customer completed necessary permitting processes. Revenues in our Latin America region declined primarily due to lower average fleet utilization and lower average dayrates in Mexico and the recognition of a demobilization fee during the second quarter of 2009, which was not repeated in 2010. This was offset by increased revenues from our operations in Colombia, a result of growing activity in this market that led to higher utilization for our rigs. Revenues related to our O&M operations declined due to lower reimburseable expenses related to the operation of the Yastreb rig in Sakhalin Island and the services provided to the customer-owned rig fleet in Kuwait. For our Sakhalin operations, during 2009 we earned a fixed fee during the rig move, upgrade and customer modification phase of the contract, which was not repeated in 2010. The decline was offset by higher revenues on our Orlan project where we experienced higher dayrates offset by lower reimbursable revenues.

International Drilling segment operating gross margin, excluding depreciation and amortization, decreased $61.7 million, or 51.0%, to $59.4 million during the year ended December 31, 2010 compared with the year ended December 31, 2009, with decreases in our Eastern Hemisphere and Latin America regions. The decline in the Eastern Hemisphere was primarily attributable to the overall lower revenues as well as increased expenses related to the planned repair, refurbishment, and upgrade project for our Caspian Sea Arctic barge. The decrease in the Latin America region is primarily due to the lower revenues and extended rig move costs and higher labor and fuel costs in Colombia.

Technical Services

Revenues for this segment increased $13.0 million, or 55.4%, during 2010 compared with 2009. This increase was primarily the result of higher revenues related to the Berkut platform project and increased revenues from our BP Liberty rig construction contract. For the year ended December 31, 2010, the BP Liberty contract included approximately $5.6 million of reimbursable costs, which increased Company revenues but had little direct impact on operating margins.

Technical Services typically does not incur depreciation and amortization. Gross margin for this segment increased $0.7 million in 2010 compared with 2009 primarily due to higher revenues related to the Berkut platform project.

Construction Contract

Revenues from the construction contract segment were $91.1 million for the year ended December 31, 2010, from $185.4 million for the year ended December 31, 2009. The Liberty rig project is accounted for on a percentage-of-completion basis with revenues and earnings recognized based on progress made relative to estimated total project costs. The decline in reported revenues reflects reduced work effort as the construction transitioned to rig-up labor from major construction in 2010. The construction contract segment does not incur depreciation and amortization, and as such, gross margin recognized during 2010 was $0.2 million compared with $8.1 million in 2009. The 2010 margin reduction is due to the increase in total estimated construction costs over a longer construction phase. For more information on the Liberty project, see Part II, Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations — Other Matters — "Liberty Project Status."

Other Financial Data

During 2010 we recorded a provision for reduction in carrying value of certain assets of $2.0 million related to disputed customer accounts receivable related to a customer bankruptcy proceeding. In 2009, we recorded a $4.6 million provision for reduction in carrying value related to certain drilling rigs and equipment that were deemed to no longer be marketable upon changing market conditions and increased competition in the market for which these rigs were working.

Gains on asset dispositions were $4.6 million in 2010 as compared with $5.9 million in 2009. The gain recorded in 2010 was primarily a result of various asset sales in 2010. The gain on asset dispositions in 2009 is primarily attributable to a $4.0 million settlement with a tugboat company in regards to a barge rig that was overturned in 2005.

Interest expense for 2010 was $26.8 million, a decrease of $2.6 million as compared with 2009. The decrease in interest expense is primarily the result of a $7.5 million increase in 2010 in capitalized interest on major projects offset by a $4.9 million increase in 2010 in debt-related interest expense. Interest income for 2010 decreased $0.8 million to $0.3 million as compared with 2009.

General and administration expense for 2010 decreased $14.8 million to $30.7 million compared with 2009. The decrease in general and administrative costs was primarily related to lower legal fees in 2010 associated with the ongoing DOJ and SEC investigations and our work product related to various matters further discussed in Note 13, Commitments and Contingencies in the notes to the consolidated financial statements. In addition, we experienced lower employee insurance costs and travel related administrative costs resulting from lower overall company headcount. These decreases were slightly offset by an increase in professional fees related to consulting services.

Income tax expense was $26.2 million for the year ended December 31, 2010, compared with income tax expense of $0.6 million for the year ended December 31, 2009. The increase in income tax expense for 2010 is primarily related to the unfavorable ruling by the Atyrau Oblast Court to uphold the lower court decision and allow the revised Tax Notification to stand as discussed in Note 11, Kazakhstan Ministry of Finance Tax Audit, in the notes to the consolidated financial statements. The Kazakhstan tax matter increased expense by approximately $14.5 million ($6.8 million, net of anticipated tax benefits), which includes approximately $6.5 million in tax, $4.8 million in interest and $3.2 million in penalties. The Company also adjusted reserves for tax uncertainties downward by $2.0 million for uncertainties where statute of limitations had expired, partially offset by increased reserves for potential disallowed costs related to currently disputed matters and unresolved matters in certain tax jurisdictions. In addition, tax expense increased from the Company's settlement of a foreign tax audit for one of its subsidiaries for $1.2 million, which includes approximately $0.6 million of tax, $0.1 million of interest, and $0.5 million of penalties. Income tax expense for 2009 includes a benefit of an additional $5.4 million in addition to the $12.2 million claimed in 2008 for the recovery of prior years foreign taxes as a credit in the U.S. versus a deduction, the establishment of a valuation allowance of $0.5 million related to excess current year foreign tax credits and a charge of $1.8 million related to a characterization of certain intercompany notes for foreign tax credit calculation in accordance with accounting for tax uncertainties.

LIQUIDITY AND CAPITAL RESOURCES

We periodically evaluate our liability requirements, capital needs and availability of resources in view of expansion plans, debt service requirements, inventory levels 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, as well as in the past, sought to raise additional capital. Assuming that we are able to complete our debt refinancing as discussed below, 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.

Our 2.125% Convertible Notes due 2012 (2.125% Notes) are scheduled to mature in July 2012. As a result, the $125.0 million aggregate principal amount of the 2.125% Notes is classified as a current obligation on our consolidated balance sheet at December 31, 2011. We intend to refinance the 2.125% Notes with either an add-on to our existing 9.125% Notes or with a new note issuance or a combination of cash and debt. Although management believes we will be able to complete a refinancing transaction prior to the maturity of the 2.125% Notes, no assurances can be made that we will be able to do so. If we are unable to complete a refinancing or otherwise repay such debt using cash on hand and borrowings under our Revolver, we would be in default under the indenture governing the 2.125% Notes, which would also cause us to be in default under our Credit Agreement and the indenture governing our 9.125% Notes, which would result in all $486.0 million principal amount of current indebtedness outstanding under those agreements to be declared immediately due and payable.

Liquidity

As of December 31, 2011, we had cash and cash equivalents of $97.9 million, an increase of $46.4 million from December 31, 2010. The following table provides a summary for the last three years:

	2011	2010	2009
		(Dollars in thousands)	
Operating Activities	$ 225,885	$ 123,550	$ 110,872
Investing Activities	(184,614)	(212,709)	(150,718)
Financing Activities	5,167	31,787	(23,649)
Net change in cash and cash equivalents	$ 46,438	$ (57,372)	$ (63,495)

Operating Activities

Cash flows from operating activities were $225.9 million in 2011, compared with $123.6 million in 2010. Before changes in operating assets and liabilities, cash from operating activities was impacted primarily by a net loss of $50.6 million plus non-cash charges of $244.3 million. Non-cash charges primarily consisted of the impairment charge of $170.0 million and $112.1 million of depreciation expense, partially offset by deferred tax expense of $48.4 million. Net changes in operating assets and liabilities provided $32.2 million of cash in 2011, compared to $5.2 million provided in 2010.

Cash flows from operating activities were $123.6 million in 2010, compared with $110.9 million in 2009. Before changes in operating assets and liabilities, cash was impacted primarily by a net loss of $14.7 million plus non-cash charges of $133.1 million. Net changes in operating assets and liabilities provided $5.2 million of cash in 2010, compared to $7.9 million used in 2009.

Investing Activities

Cash flows used in investing activities were $184.6 million for 2011. Our primary use of cash was $190.4 million for capital expenditures. Major capital expenditures for the period included $77.9 million for the construction of two new Alaska rigs and $61.5 million for tubular and other products for Rental Tools. Capital incurred to support ongoing drilling activities was $51.0 million. Sources of cash included $5.5 million of proceeds from asset sales.

Cash flows used in investing activities were $212.7 million for 2010. Our primary use of cash was $219.2 million for capital expenditures. Major capital expenditures for the period included $112.5 million for the construction of two new Alaska rigs and $61.7 million for tubular and other rental tools for Quail Tools. Sources of cash included $6.5 million of proceeds from asset sales.

Capital expenditures for 2012 are estimated to be $160.0 million to $180.0 million and will primarily be directed to our Rental Tools inventory, completion of our two new Alaska rigs and maintenance capital. 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 operations, repay our 2.125% Notes which mature during 2012 and fund our capital expenditures for 2012, 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 $5.2 million for 2011. Our primary financing activities included a $50.0 million draw on the accordion feature of our Credit Agreement in the form of a Term Loan, offset by the repayment of the $25.0 million outstanding balance on our Revolver and $21.0 million in quarterly payments against our Term Loans.

Cash flows provided by financing activities were $31.8 million for 2010. Our primary financing activities included proceeds from the issuance of $300.0 million aggregate principal amount of 9.125% Notes, less $8.0 million of associated debt issuance costs, offset by the repayment of $225.0 million aggregate principal value of 9.625% Senior Notes including payment of $7.5 million of related debt extinguishment cost. In addition, we made payments of $42.0 million and $12.0 million on our Revolver and Term Loan, respectively, and made a $25 million draw on the Revolver.

9.125% Senior Notes, due April 2018

On March 22, 2010, the Company issued $300,000,000 aggregate principal amount of 9.125% Senior Notes due 2018 (9.125% Notes) pursuant to an Indenture between the Company and The Bank of New York Mellon Trust Company, N.A. (Trustee). The 9.125% Notes were issued at par with interest payable on April 1 and October 1 of each year, beginning October 1, 2010. 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 Revolver.

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 domestic subsidiaries other than immaterial subsidiaries and subsidiaries generating revenue primarily outside the United States.

At any time prior to April 1, 2013, we may redeem up to thirty-five percent of the aggregate principal amount of 9.125% Notes at a redemption price of 109.125 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 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 principal amount, and at redemption prices decreasing each year thereafter to par. If we experience certain changes in control, we must offer to repurchase the 9.125% Notes at 101 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.

9.625% Senior Notes, due October 2013

At December 31, 2009, we had outstanding $225.0 million in aggregate principal amount of 9.625% Senior Notes due 2013 (9.625% Notes). On March 8, 2010, we commenced a cash tender offer (Tender Offer) and consent solicitation for all of our outstanding 9.625% Notes, which expired on April 2, 2010. On March 22, 2010, we voluntarily called for redemption of all our 9.625% Notes that were not tendered pursuant to the Tender

Offer, at the redemption price of 103.208 percent of the principal amount of the 9.625% Notes, or $1,032.08 per $1,000 principal amount of the 9.625% Notes. On April 21, 2010, we redeemed in full the remaining $128.7 million principal amount of 9.625% Notes. This redemption resulted in the Company recording debt extinguishment costs of $7.2 million during 2010.

2.125% Convertible Senior Notes, due July 2012

On July 5, 2007, we issued $125.0 million aggregate principal amount of 2.125% Notes due July 15, 2012. As of December 31, 2011, the 2.125% Notes are classified as current debt in our consolidated balance sheet. The 2.125% Notes were issued at par and interest is payable semiannually on July 15th and January 15th.

The significant terms of the 2.125% Notes are as follows:

- *2.125% Notes Conversion Feature* — The initial conversion price for holders to convert their 2.125% Notes into shares is at a common stock share price equivalent of $13.85 (72.2217 shares of common stock per $1,000 note value). Conversion rate adjustments occur for any issuances of stock, warrants, rights or options (except for stock purchase plans or dividend re-investments) or any other transfer of benefit to substantially all stockholders, or as a result of a tender or exchange offer. We may, under advice of our Board of Directors, increase the conversion rate at our sole discretion for a period of at least 20 days.

- *2.125% Notes Settlement Feature* — Upon tender of the 2.125% Notes for conversion, we can either settle entirely in shares of common stock or a combination of cash and shares of common stock, solely at our option. Our intent is to satisfy conversion obligation for our 2.125% Notes in cash, rather than in common stock, for at least the aggregate principal amount of the 2.125% Notes. This reduces the resulting potential earnings dilution to only include any possible conversion premium, which would be the difference between the average price of our shares and the conversion price per share of common stock.

- *Contingent Conversion Feature* — Holders may only convert 2.125% Notes when either sales price or trading price conditions are met, on or after the 2.125% Notes' due date or upon certain accounting changes or certain corporate transactions (fundamental changes) involving stock distributions. Make-whole provisions are only included in the accounting and fundamental change conversions such that holders do not lose value as a result of the changes.

- *Settlement Feature* — Upon conversion, we will pay either cash or provide shares of our common stock, if any, based on a daily conversion rate multiplied by a volume weighted average price of our common stock during a specified period following the conversion date. Conversions can be settled in cash or shares, solely at our discretion.

As of December 31, 2011, none of the conditions allowing holders of the 2.125% Notes to convert had been met.

Concurrently with the issuance of the 2.125% Notes, we purchased a convertible note hedge (note hedge) and sold warrants in private transactions with counterparties that were different than the ultimate holders of the 2.125% Notes. The note hedge included purchasing free-standing call options and selling free-standing warrants, both exercisable in our common shares. The note hedge allows us to receive shares of our common stock from the counterparties to the transaction equal to the amount of common stock related to the excess conversion value that we would issue and/or pay to the holders of the 2.125% Notes upon conversion.

The terms of the call options mirror the 2.125% Notes' major terms whereby the call option strike price is the same as the initial conversion price as are the number of shares callable, $13.85 per share and 9,027,713 shares, respectively. This feature prevents dilution of our outstanding shares. The warrants allow us to sell 9,027,713 common shares at a strike price of $18.29 per share. The conversion price of the 2.125% Notes remains at $13.85 per share, and the existence of the call options and warrants serve to guard against dilution at share prices less than $18.29 per share, since we would be able to satisfy our obligations and deliver shares upon conversion of the 2.125% Notes with shares that are obtained by exercising the call options.

We paid a premium of approximately $31.5 million for the call options, and received proceeds for a premium of approximately $20.3 million for the sale of the warrants. This reduced the net cost of the note hedge to $11.2 million. The expiration date of the note hedge is the earlier of the last day on which the 2.125% Notes remain outstanding and the maturity date of the 2.125% Notes.

The 2.125% Notes are classified as a liability in our consolidated financial statements. Because we have the choice of settling the call options and the warrants in cash or shares of our common stock and these contracts meet all of the applicable criteria for equity classification, the cost of the call options and proceeds from the sale of the warrants are classified in stockholders' equity in the Consolidated Balance Sheet. In addition, because both of these contracts are classified in stockholders' equity and are solely indexed to our own common stock, they are not accounted for as derivatives.

Debt issuance costs related to the 2.125% Notes totaled approximately $3.6 million and are being amortized over the five year term of the 2.125% Notes using the effective interest method. Proceeds from the transaction of $110.2 million were used to redeem our outstanding senior floating rate notes, to pay the net cost of hedge and warrant transactions, and for general corporate purposes.

Credit Agreement:

On May 15, 2008, we entered into a credit agreement (Credit Agreement) consisting of a senior secured $80.0 million Revolver and senior secured term loan facility (Term Loan) of up to $50.0 million. The 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. On April 1, 2011, the Company exercised the additional $50.0 million accordion feature and entered into an amendment to the Credit Agreement that increased the Aggregate Commitment under the Credit Agreement to $159.0 million and borrowed an additional $50.0 million in a Term Loan. When the facility was increased, all other terms of the Credit Agreement remained the same, including covenants and Applicable Rates (as defined in the Credit Agreement). The Credit Agreement terminates on May 14, 2013.

Our obligations under the Credit Agreement are guaranteed by substantially all of our domestic subsidiaries, 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 Credit Agreement contains customary affirmative and negative covenants, our most restrictive of which requires we maintain a consolidated leverage ratio of less than 4.00 to 1. The consolidated leverage ratio is based on the ratio of consolidated total debt to consolidated EBITDA as defined in the Credit Agreement. EBITDA, while not a U.S. GAAP measure, reflects a measurement of cash flow and is calculated as income before income taxes plus interest, income taxes, and depreciation and amortization, and other noncash charges. As of December 31, 2011 we were in compliance with all of our covenants. We do not anticipate triggering any of these covenants during 2012.

Revolver:

Our Revolver, with a contractual capacity of $80.0 million, 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. The Applicable Rate varies 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, determined by reference to our 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 Revolver borrowings outstanding at December 31, 2011 and $25.0 million in Revolver borrowings outstanding at December 31, 2010. Letters of credit outstanding as of December 31, 2011 and December 31, 2010 totaled $2.7 million and $16.3 million, respectively.

Term Loan:

The Term Loan originated at $50.0 million and required quarterly principal payments of $3.0 million. Interest on the Term Loan accrues at either a Base Rate plus 2.25 percent or LIBOR plus 3.25 percent. On April 1, 2011, the company expanded its Term Loan Facility by $50.0 million. Funding was provided by certain current lenders and Barclays Bank PLC, which joined as a lender under the Credit Agreement. We used the proceeds from the additional Term Loan to repay $25.0 million outstanding on the Revolver, purchase additional rental tool inventory, and for general corporate purposes. Upon the completion of the transaction, total borrowings under the Term Loan were $79.0 million. Payments and amortization on the Term Loan is $6.0 million per quarter. The outstanding balances on the Term Loan at December 31, 2011 and December 31, 2010 were $61.0 million and $32.0 million, respectively.

Other Liquidity

Our principal amount of long-term debt, including current portion, was $482.7 million as of December 31, 2011, which consists of:

- $125.0 million aggregate principal amount of 2.125% Convertible Senior Notes due July 15, 2012, less an associated $3.3 million in unamortized debt discount which is included in equity pursuant to applicable accounting standards for convertible debt instruments, all of which is classified as current;
- $300.0 million aggregate principal amount of 9.125% Senior Notes, due April 1, 2018; and
- $61.0 million drawn against our 2008 Credit Facility, including no borrowings under our Revolver and $61.0 million under our Term Loan, $24.0 million of which is classified as current.

As of December 31, 2011, we had approximately $175.2 million of liquidity, which consisted of $97.9 million of cash and cash equivalents on hand and $77.3 million of availability under the Revolver. 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, foreign currency or interest rate derivative contracts at December 31, 2011.

The following table summarizes our future contractual cash obligations as of December 31, 2011:

	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)	$486,000	$149,000	$37,000	$ —	$300,000
Long-term debt — interest(1)	176,463	32,076	55,418	54,750	34,219
Operating leases(2)	29,441	9,382	6,932	4,972	8,155
Purchase commitments(3)	14,357	14,357	—	—	—
Total contractual obligations	$706,261	$204,815	$99,350	$59,722	$342,374
Commercial commitments:					
Long-term debt — standby					
Revolving credit facility	$ —	$ —	$ —	$ —	$ —
standby letters of credit(4)	2,661	2,661	—	—	—
Total commercial commitments	$ 2,661	$ 2,661	$ —	$ —	$ —

(1) Long-term debt includes the principal and interest cash obligations of the 9.125% Notes and the 2.125% Notes. The remaining unamortized discount of $3.3 million on the 2.125% 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, 2011, related to rig upgrade projects and new rig construction.

(4) We have an $80.0 million Revolver. As of December 31, 2011, there were no borrowings and $2.7 million of availability has been used to support letters of credit that have been issued, resulting in an estimated $ 77.3 million of availability. The Revolver expires May 14, 2013.

OTHER MATTERS

Business Risks

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

Liberty Project Status

In November 2010, BP informed us that it was suspending construction on the project to review the rig's engineering and design, including its safety systems. We commenced construction of this rig for BP in April 2008 pursuant to an EPCI contract. In August 2009, BP also awarded us a contract for the first phase of drilling on the Liberty field, which is expected to be a two-year project to drill an ultra extended-reach well, nearly two miles deep and as far as eight miles from the pad. BP has not announced a schedule for resuming construction on the rig or new target dates for drilling and production start-up.

The Liberty rig construction contract is a fixed fee and reimbursable contract accounted for on a percentage of completion basis. Costs on the project are reimbursed without markup, except for costs associated with changes in work scope, for which we are entitled to a markup. As of December 31, 2011, we had recognized $335.5 million in project-to-date revenues and the entire $11.7 million fixed fee margin on the contract.

The Liberty rig construction contract expired on February 8, 2011 prior to completion of the rig. Before expiration of the construction contract, BP indentified several areas of concern relating to design, construction and invoicing, for which it asked us to provide explanations and documentation, and we have done so. Although we provided BP with the requested information, we do not know when or how these issues will be resolved with our client.

After expiration of the construction contract, the Company and BP continued activities to preserve and maintain the rig under the "preoperations" phase of our contract, which was entered into in August 2009 and expired on July 1, 2011. A new consulting services agreement was reached between the Company and BP effective July 1, 2011. Under the consulting services agreement, the Company assisted BP in a review of the rig's design, the creation of a new statement of requirements for the rig, and the transition of documentation and materials to BP. All work under the consulting agreement has been completed and we are engaged with BP on construction contract close-out discussions.

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 are 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, or 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.

Derivative Financial Instruments — We use derivative instruments to manage risks associated with interest rate fluctuations in connection with our Credit Agreement. 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.

Insurance Reserves. 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 record reserves for these amounts in our consolidated financial statements. Reserves 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 reserves are critical.

Accounting for Income Taxes. We are a U.S. company and we operate through our various foreign 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. 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 periodically 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. We recognize revenues and expenses on dayrate contracts as drilling progresses. Revenues from rental activities are recognized ratably over the rental term which is generally less than six months. Mobilization fees received and related mobilization costs incurred are deferred and amortized over the term of the contract period. Construction contract revenues and costs are recognized on a percentage of completion basis utilizing the cost-to-cost method.

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 18 — 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, which is our functional currency, 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 exchange. We do not enter into derivative transactions for speculative purposes. At December 31, 2011, 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 $300.0 million principal amount of 9.125% Notes due 2018, based on quoted market prices, was $315.0 million at December 31, 2011. The estimated fair value of our $125.0 million principal amount of 2.125% Notes due 2012 was $123.2 million on December 31, 2011. A hypothetical 100 basis point increase in interest rates relative to market interest rates at December 31, 2011 would decrease the fair market value of our long-term debt at December 31, 2011 by approximately $32.5 million for the 9.125% Notes and $39.0 million for the 2.125% Notes.

The Company 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 Credit Agreement. The two agreements fix the interest rate on a notional amount of $73.0 million of borrowings at 3.878% for the period beginning June 27, 2011 and terminating May 14, 2013. The notional amount of the swap agreements will decrease correspondingly with amortization of the Term Loan. We will not apply hedge accounting to the agreements and, accordingly, the Company will report the mark-to-market change in the fair value of the interest rate swaps in earnings. For the year ended December 31, 2011, the Company recognized in earnings a $0.1 million loss on interest rate swaps. At December 31, 2010, we had no open interest rate risk derivative contracts.

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 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 tool 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 the accompanying consolidated balance sheets of Parker Drilling Company and subsidiaries (the Company) as of December 31, 2011 and 2010, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2011. In connection with our audits of the consolidated financial statements, we also have audited the financial statement Schedule II — Valuation and Qualifying Accounts for each of the years in the three-year period ended December 31, 2011. We also have audited the Company's internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these consolidated financial statements and financial statement schedule, 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. Controls and Procedures. Our responsibility is to express an opinion on these consolidated financial statements, the financial statement schedule and the Company's internal control over financial reporting 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the consolidated financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting 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 audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

In our opinion, 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, 2011 and 2010, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2011, 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. Also in our opinion, Parker Drilling Company and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/S/ KPMG LLP

Houston, Texas
March 6, 2012

PARKER DRILLING COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF OPERATIONS

	Year Ended December 31,		
	2011	2010	2009
	(Dollars in Thousands, Except Per Share Data)		
Revenues	$ 686,646	$ 659,475	$ 752,910
Expenses:			
Operating expenses	418,144	471,278	555,390
Depreciation and amortization	112,136	115,030	113,975
	530,280	586,308	669,365
Total operating gross margin	156,366	73,167	83,545
General and administration expense	(31,314)	(30,728)	(45,483)
Impairments and other charges	(170,000)	—	—
Provision for reduction in carrying value of certain assets	(1,350)	(1,952)	(4,646)
Gain on disposition of assets, net	3,659	4,620	5,906
Total operating income (loss)	(42,639)	45,107	39,322
Other income and (expense):			
Interest expense	(22,594)	(26,805)	(29,450)
Interest income	256	257	1,041
Loss on extinguishment of debt	—	(7,209)	—
Change in fair value of derivative positions	(110)	—	—
Other	(325)	155	(1,086)
Total other expense	(22,773)	(33,602)	(29,495)
Income (loss) before income taxes	(65,412)	11,505	9,827
Income tax expense (benefit):			
Current tax expense	33,608	27,521	15,424
Deferred tax benefit	(48,375)	(1,308)	(14,864)
Total income tax expense (benefit)	(14,767)	26,213	560
Net income (loss)	(50,645)	(14,708)	9,267
Less: Net (loss) attributable to noncontrolling interest	(194)	(247)	—
Net income (loss) attributable to controlling interest	$ (50,451)	$ (14,461)	$ 9,267
Basic earnings per share:	$ (0.43)	$ (0.13)	$ 0.08
Diluted earnings per share:	$ (0.43)	$ (0.13)	$ 0.08
Number of common shares used in computing earnings per share:			
Basic	116,081,590	114,258,965	113,000,555
Diluted	116,081,590	114,258,965	114,925,446

See accompanying notes to the consolidated financial statements.

PARKER DRILLING COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEET

	December 31, 2011	December 31, 2010
	(Dollars in Thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 97,869	$ 51,431
Accounts and notes receivable, net of allowance for bad debts of $1,544 in 2011 and $7,020 in 2010	183,923	168,876
Rig materials and supplies	29,947	25,527
Deferred costs	3,249	2,229
Deferred income taxes	6,650	9,278
Other tax assets	25,358	46,429
Assets held for sale	5,315	5,287
Other current assets	15,302	59,067
Total current assets	367,613	368,124
Property, plant and equipment, at cost:		
Drilling equipment	1,094,366	996,255
Rental tools	310,429	269,474
Buildings, land and improvements	33,817	31,918
Other	57,111	54,806
Construction in progress	194,362	338,873
	1,690,085	1,691,326
Less accumulated depreciation and amortization	970,276	875,179
Property, plant and equipment, net	719,809	816,147
Other assets:		
Rig materials and supplies	10,395	13,930
Debt issuance costs	7,025	9,214
Deferred income taxes	108,311	61,016
Other assets	3,093	6,124
Total other assets	128,824	90,284
Total assets	$1,216,246	$1,274,555
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 145,723	$ 12,000
Accounts payable	76,706	107,894
Accrued liabilities	58,544	50,877
Accrued income taxes	4,837	4,492
Total current liabilities	285,810	175,263
Long-term debt	337,000	460,862
Other long-term liabilities	33,452	30,193
Long-term deferred tax liability	15,934	20,171
Commitments and contingencies (Note 13)	—	—
Stockholders' equity:		
Preferred stock, $1 par value, 1,942,000 shares authorized, no shares outstanding	—	—
Common stock, $0.16 2/3 par value, authorized 280,000,000 shares, issued and outstanding, 117,061,203 shares (116,369,044 shares in 2010)	19,508	19,397
Capital in excess of par value	637,042	630,409
Accumulated deficit	(111,944)	(61,493)
Total controlling interest stockholders' equity	544,606	588,313
Noncontrolling interest	(556)	(247)
Total equity	544,050	588,066
Total liabilities and stockholders' equity	$1,216,246	$1,274,555

See accompanying notes to the consolidated financial statements.

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PARKER DRILLING COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF CASH FLOWS

	Year Ended December 31, 2011	2010	2009
	(Dollars in Thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (50,645)	$ (14,708)	$ 9,267
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	112,136	115,030	113,975
Impairment of property, plant and equipment	170,000	—	—
Loss on extinguishment of debt	—	7,209	—
Gain on disposition of assets	(3,659)	(4,620)	(5,906)
Deferred tax expense	(48,375)	(1,308)	(14,864)
Provision for reduction in carrying value of certain assets	1,350	1,952	4,646
Expenses not requiring cash	12,833	14,829	11,626
Change in assets and liabilities:			
Accounts and notes receivable	(6,841)	20,752	1,656
Rig materials and supplies	(913)	(856)	(3,464)
Other current assets	63,816	(2,969)	(29,903)
Accounts payable and accrued liabilities	(24,908)	(10,868)	29,735
Accrued income taxes	2,141	(4,124)	(13,004)
Other assets	(1,050)	3,231	7,108
Net cash provided by operating activities	225,885	123,550	110,872
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(190,399)	(219,184)	(160,054)
Proceeds from the sale of assets	5,535	6,475	9,336
Proceeds from insurance claims	250	—	—
Net cash used in investing activities	(184,614)	(212,709)	(150,718)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from issuance of debt	50,000	300,000	—
Proceeds from draw on revolver credit facility	—	25,000	4,000
Repayments of senior notes	—	(225,000)	—
Repayments of term loan	(21,000)	(12,000)	(6,000)
Repayments of revolver	(25,000)	(42,000)	(20,000)
Payments of debt issuance costs	(504)	(7,976)	—
Payments of debt extinguishment costs	—	(7,466)	—
Proceeds from stock options exercised	183	26	199
Excess tax benefit (expense) from stock-based compensation	1,488	1,203	(1,848)
Net cash provided by (used in) financing activities	5,167	31,787	(23,649)
Net increase (decrease) in cash and cash equivalents	46,438	(57,372)	(63,495)
Cash and cash equivalents at beginning of year	51,431	108,803	172,298
Cash and cash equivalents at end of year	$ 97,869	$ 51,431	$ 108,803
Supplemental cash flow information:			
Interest paid	$ 32,785	$ 30,377	$ 28,721
Income taxes paid	$ 21,742	$ 41,024	$ 17,462

See accompanying notes to the consolidated financial statements.

PARKER DRILLING COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

	Shares	Common Stock	Capital in Excess of Par Value	Accumulated Deficit	Total Controlling Stockholders' Equity	Noncontrolling Interest	Total Stockholders' Equity
	(Dollars and Shares in Thousands)						
Balances, December 31, 2008	113,456	$18,910	$619,561	$ (56,299)	$ 582,172	—	$ 582,172
Activity in employees' stock plans	2,783	464	1,483	—	1,947		1,947
Excess tax benefit from stock based compensation	—	—	(1,848)	—	(1,848)		(1,848)
Amortization of restricted stock plan compensation	—	—	4,361	—	4,361		4,361
Net income (total comprehensive income of $9,267)	—	—	—	9,267	9,267	—	9,267
Balances, December 31, 2009	116,239	$19,374	$623,557	$ (47,032)	$ 595,899	$ —	$ 595,899
Activity in employees' stock plans	130	23	114	—	137		137
Excess tax benefit from stock based compensation	—	—	1,203	—	1,203		1,203
Amortization of restricted stock plan compensation	—	—	5,535	—	5,535		5,535
Net income (total comprehensive income of $14,708)	—	—	—	(14,461)	(14,461)	(247)	(14,708)
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 options exercised	—	—	988	—	988		988
Amortization of restricted stock plan compensation	—	—	5,988	—	5,988		5,988
Net income (total comprehensive net loss of $(50,645)	—	—	—	(50,451)	(50,451)	(194)	(50,645)
Other, net	—	—	—	—	—	(115)	(115)
Balances, Dec 31, 2011	117,061	$19,508	$637,042	$ (111,944)	$ 544,606	$ (556)	$ 544,050

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 (the Company), is a worldwide provider of contract drilling and drilling-related services. Our rental tools subsidiary specializes in oil and gas drilling rental tools providing high-quality, reliable equipment, such as drill pipe, heavy-weight drill pipe, tubing, high-torque connections, BOPs and drill collars used for drilling, workover and production applications.

Our U.S. barge drilling business operates barge rigs in the shallow waters in and along the inland waterways of Louisiana and Texas. Our barge rigs drill for natural gas, oil, and a combination of oil and natural gas. Our international drilling business provides 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. Additionally, our international drilling business 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. At December 31, 2011, our marketable rig fleet consisted of 15 barge drilling rigs and 25 land rigs located in the United States, Latin America and the Eastern Hemisphere regions. Our Technical services business includes engineering and related project services during the concept development, pre-FEED, and FEED (Front End Engineering Design) phases of our customer owned drilling facility projects. As these projects mature, we continue providing the same services during the Engineering, Procurement, Construction and Installation (EPCI) phase.

Segment Reporting — As of December 31, 2011, the Company has re-aligned its reporting segments to be consistent with recent changes to improve our drilling organization. The Company is aligned in six distinct operating segments:

- Rental Tools
- U.S. Barge Drilling
- U.S. Drilling
- International Drilling
- Technical Services
- Construction Contract

We have expanded our segments by one, adding a U.S. Drilling segment, represented primarily by our two AADU rigs in Alaska. Our U.S. Barge Drilling segment, previously referred to as the U.S. Drilling segment, represents our GOM barge business and remains unchanged. We have aligned our international operations more closely with the management structure we now have in place. Our previous three geographic regions (Americas, CIS/AME, and Asia Pacific) are now two – Latin America and Eastern Hemisphere. Each region includes all drilling-related operations, whether done using a Parker-owned rig or a customer-owned rig on an O&M contract. Our technical services activities, which primarily include our engagement in engineering support initiatives, pre-FEED, FEED and EPC/EPCI projects that have the potential to evolve into future O&M opportunities, is now reported as an individual segment. Our Rental Tools segment remains unchanged. We have reclassified revenues, expenses and related overhead amounts between the segments as of December 31, 2011 to reflect this alignment. Amounts presented throughout this document for the years ended December 31, 2010 and 2009 have been revised to conform to current period presentation.

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 the 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 have a material effect on our consolidated statements of operations, consolidated balance sheets or statements of cash flows.

Revenue Recognition — We recognize revenues and expenses on dayrate contracts as drilling progresses. Revenues from rental activities are recognized ratably over the rental term. Mobilization fees received and related mobilization costs incurred are deferred and amortized over the term of the contract period. Construction contract revenues and costs are recognized on a percentage of completion basis utilizing the cost-to-cost method.

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 $64.2 million, $40.1 million, and $43.9 million during the years ended December 31, 2011, 2010, and 2009, respectively.

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.

During the third quarter of 2010, we corrected an accounting error relating to value added taxes (VAT) in our Western Kazakhstan branch (PDKBV). In Kazakhstan, companies are permitted to elect the use of either the proportional or separate method for filing periodic VAT returns. PDKBV utilized the proportional method which can limit future recoverability of VAT derived from vendor purchases and rig importation against VAT derived from customer invoicing activities. On the erroneous belief that certain VAT amounts would be recoverable in future periods, PDKBV recorded VAT assets in connection with several transactions occurring during the period 2007 through 2008. However, due to a customer having VAT exempt status, the recoverability of a portion of the VAT assets created was limited, and certain amounts should have been expensed during the periods in which the original transactions occurred. The cumulative effect of the error and related foreign currency translation impact overstated net income and retained earnings by $6.4 million over the period 2007 through 2009. The impact of the error was determined not to be material to our results of operations and financial position for any previously reported periods. Consequently, during the third quarter of 2010, the cumulative effect of this correction was recorded in operating expenses and is reflected in year to date operating expenses for the year ended December 31, 2010.

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 generally do not bear interest. The allowance for doubtful accounts is our best estimate 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 exits 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,	
	2011	2010
	(Dollars in Thousands)	
Trade	$184,817	$175,246
Notes receivable	650	650
Allowance for doubtful accounts[(1)]	(1,544)	(7,020)
Total accounts and notes receivable, net ofallowance for bad debt	$183,923	$168,876

(1) Additional information on the allowance for doubtful accounts for the years ended December 31, 2011, 2010 and 2009 is reported on Schedule II — Valuation and Qualifying Accounts.

Property, Plant and Equipment — 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 7 years
Buildings and improvements	15 to 30 years

When assets are retired or otherwise disposed of, the related cost and accumulated depreciation are removed from the accounts and any resulting gain or loss is included within the statement of operations. In the first quarter of 2009, we implemented a change in accounting estimate to more accurately reflect the useful life of certain of the long-lived assets in our U.S. barge drilling and international drilling segments. This resulted in an approximate $16.0 million reduction in the depreciation expense in the year ended December 31, 2009, or $0.14 per share. We extended the useful lives of these long-lived assets based on our review of their service lives, technological improvements in the assets and recent changes to our refurbishment and maintenance practices which helped to extend the lives. Maintenance and repairs are charged to operating expense as incurred.

Annual Impairment Review — 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 concluded current fair value is below the net carrying value.

During the fourth quarter of 2011, we evaluated the present value of our future cash flows related to our Arctic Alaska Drilling Units (AADU) as a result of their extended construction and commissioning schedule and the related increase in costs. The current estimated cost of the two rigs combined is approximately $385.0 million, which includes estimated total capitalized interest of approximately $50.7 million. Based on this evaluation, the Company determined the rigs were impaired because their carrying value of $339.5 million exceeded their fair value of $169.5 million. As a result, we recorded a pretax, non-cash charge of $170.0 million, with an after-tax impact on net income of $109.1 million. Fair value was based on expected future cash flows using Level 3 inputs under the fair value measurement requirements of U.S. GAAP. The cash flows are those expected to be generated by the market participants, discounted at the 10 percent rate of interest.

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 2011, 2010 and 2009, we capitalized interest costs related to the construction of rigs of $19.3 million, $13.5 million and $6.0 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. At December 31, 2011, we have net assets held for sale, included in current assets, in the amount of $5.3 million. For further information, see Note 4.

Goodwill — Goodwill, when recorded upon the result of a qualifying event, is assessed for impairment on at least an annual basis. As of December 31, 2011 there was no existing goodwill.

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. 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 debt financings and refinancing, and amortize those costs over the term of the related debt.

Income Taxes — Income taxes 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 because 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 liabilities and assets are determined based on the difference between the financial statement treatment and tax basis treatment of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse. Valuation allowances are recognized against deferred tax assets unless it is “more likely than not” that the Company can realize the benefit of the net operating loss (NOL) and foreign tax credit (FTC) carryforwards and deferred tax assets in future periods.

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 gas companies. We generally do not require collateral on our trade receivables.

At December 31, 2011 and 2010, we had deposits in domestic banks in excess of federally insured limits of approximately $10.2 million and $25.9 million respectively. In addition, we had deposits in foreign banks, which were not insured at December 31, 2011 and 2010 of $38.4 million and $31.1 million, respectively.

Our customer base consists of major, independent and national oil and gas companies and integrated service providers. We depend on a limited number of significant customers. Our largest customer, Exxon Neftegas Limited (ENL), constituted $109.2 million or 15.9 percent of our year-to-date revenues as of December 31, 2011. Included in the total revenue for ENL is $48.0 million of reimbursable costs which increase revenues but have little direct impact on operating margins.

Construction Contract — For the periods reported, our construction contract business included only the Liberty drilling rig construction project for BP. In November 2010, our customer, BP, informed us that it was suspending construction on the project to review the rig's engineering and design, including its safety systems. The Liberty rig construction contract was a fixed fee and reimbursable contract accounted for on a percentage of completion basis. As of December 31, 2011 and 2010 we had recognized $335.5 million and $325.9 million in project-to-date revenues, respectively. We have recognized the entire $11.7 million fixed fee margin on the contract.

The Liberty rig construction contract expired on February 8, 2011 prior to completion of the rig. Before expiration of the construction contract, BP identified several areas of concern relating to design, construction and invoicing for which it asked us to provide explanations and documentation, and we have done so. Although we provided BP with the requested information, we do not know when or how these issues will be resolved with our client.

After expiration of the construction contract, the Company and BP continued activities to preserve and maintain the rig under the "pre-operations" phase of our contract, which was entered into in August 2009 and expired on July 1, 2011. A new consulting services agreement was reached between the Company and BP effective July 1, 2011. Under the consulting services agreement, the Company assisted BP with technical support in a review of the rig's design, the creation of a new statement of requirements for the rig, and the transition of documentation and materials to BP. All work under the consulting agreement has been completed and we are engaged with BP on construction contract close-out discussions.

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 use derivative instruments to manage risks associated with interest rate fluctuations in connection with our Credit Agreement (see Note 7). 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.

Stock-Based Compensation — Under our long term incentive plans, we grant restricted stock awards (RSA), restricted stock units (RSU) and performance units (PU). 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 RSA's and RSU's is determined based on the closing trading price of the company's shares on the grant date. Our RSA's and RSU's are settled in stock upon vesting. Our PU awards can be settled in cash or stock at the discretion of the compensation committee of the board of directors and are, therefore, accounted for as liability awards under the stock compensation rules of U.S. GAAP.

We utilize the Black-Scholes option-pricing model to estimate the fair value of our stock options. Expected volatility is determined by using historical volatilities based on historical stock prices for a period that matches the expected term. The expected term of options represents the period of time that options granted are expected to be outstanding and typically falls between the options' vesting and contractual expiration dates. The expected term assumption is developed by using historical exercise data adjusted as appropriate for future expectations. The risk-free rate is based on the yield at the date of grant of a zero-coupon U.S. Treasury bond whose maturity period equals the option's expected term. The fair value of each option is estimated on the date of grant. There were no option grants during any of the three-years ended December 31, 2011 and as of December 31, 2011 all previously existing options has been exercised or forfeited.

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 — Asset Impairment

During the fourth quarter of 2011, in accordance with the Impairment or disposal of long-lived assets subsections of ASC 360-10, Property, Plant and Equipment, we evaluated our major asset grouping as well as the ongoing construction related value of our Arctic Alaska Drilling Units (AADU). The AADU rigs evaluation identified that an impairment existed which resulted in recording a non-cash pretax charge of $170.0 million in the 2011 fourth quarter. The evaluation was performed as a result of the delay in completion of the AADUs to allow the Company 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 recent commissioning activities of these prototype drilling rigs. The modification work will extend the commissioning activities and increase the rigs' total costs. As a result of the extended construction and commissioning schedule and related increased costs, the two rigs' cost at completion is currently estimated to be $385 million, which includes capitalized interest estimates of approximately $50.7 million. This cost exceeds 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 of $170.0 million ($109.1 million, net of taxes) to reflect their current 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 the market participants, discounted at the 10 percent rate of interest. The AADUs are reported as part of the U.S. Drilling segment.

Note 3 — Disposition of Assets

Disposition of Assets — Asset dispositions in 2009 included the settlement of claims related to a barge that was overturned in 2005 and the sale of miscellaneous equipment that resulted in a recognized gain of $5.9 million. The single largest asset disposition item included in this category was related to the settlement in lieu of legal action in connection with the overturning of a barge rig that was being towed in advance of Hurricane Dennis in July 2005. The Company settled with various counterparties to the claim in December 2009, and received cash reimbursement, in the amount of $4.0 million, which was recorded as a gain in December 2009 as we had previously charged to earnings the remaining carrying value of the barge rig.

There were no individually significant asset dispositions in 2011 and 2010.

Provision for Reduction in Carrying Value of an Asset — In 2011 the Company recognized a charge of $1.4 million related to a final settlement of a bankruptcy proceeding. The Company and the bankruptcy trustee settled claims through this final settlement. In 2010, the Company recorded a $2.0 million charge in order to reduce the carrying value related to this same bankruptcy matter as it was deemed that the Company's rights to mineral reserves no longer supported the outstanding receivable. In 2009, we recorded a $4.6 million charge in order to reduce the carrying value related to certain drilling rigs and equipment that were deemed to no longer be marketable upon changing market conditions and increased competition in the market for which these rigs were working.

Note 4 — Assets Held for Sale

Assets held for sale of $5.3 million as of December 31, 2011 was comprised of the net book value of three land rigs and related inventory. We have received a down payment on these assets and associated inventories and consummation of the sales is expected to be completed during 2012. The three rigs are part of our Eastern Hemisphere fleet and have historically been included in the international drilling segment. We expect the carrying amount of the assets, less costs to sell, will be fully recoverable through sale of the assets.

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Note 5 — Income Taxes

Income (loss) before income taxes is summarized below:

	Year Ended December 31, 2011	2010	2009
	(Dollars in Thousands)		
United States	$(61,434)	$ 1,865	$(62,265)
Foreign	(3,978)	9,640	72,092
	$(65,412)	$11,505	$ 9,827

Income tax expense (benefit) is summarized as follows:

	Year Ended December 31, 2011	2010	2009
	(Dollars in Thousands)		
Current:			
United States:			
Federal	$ 17,168	$ (273)	$ (4,541)
State	1,264	184	128
Foreign	15,176	27,610	19,837
Deferred:			
United States:			
Federal	(46,694)	(3,981)	(14,818)
State	1,864	1,459	(1,793)
Foreign	(3,545)	1,214	1,747
	$(14,767)	$26,213	$ 560

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, 2011		2010		2009	
	Amount	% of Pre-Tax Income	Amount	% of Pre-Tax Income	Amount	% of Pre-Tax Income
Computed Expected Tax Expense	$(22,894)	35%	$ 4,027	35%	$ 3,439	35%
Foreign Taxes	15,644	(24)%	18,951	165%	20,432	208%
Tax Effect Different From Statutory Rates	(1,571)	2%	(7,996)	(70)%	(10,658)	(108)%
State Taxes, net of federal benefit	2,689	(4)%	1,579	14%	(1,355)	(14)%
Foreign Tax Credits	(14,595)	22%	(15,442)	(134)%	(14,152)	(144)%
Kazakhstan Tax Settlement	(536)	1%	13,304	116%	—	0%
Mexico Tax Settlement	—	0%	1,022	9%	—	0%
Change in Valuation Allowance	2,542	(4)%	506	4%	638	6%
Foreign Corporation Income	—	0%	—	0%	5,116	52%
FIN 48-Uncertain Tax Positions	1,348	(2)%	983	9%	2,982	30%
State NOL	—	0%	—	0%	(165)	(2)%
Permanent Differences	6,356	(10)%	6,003	52%	2,893	29%
Prior Year Return to Provision Adjustments	835	(1)%	1,775	15%	(3,237)	(33)%
Foreign Tax Credits-Prior Years	—	0%	—	0%	(5,389)	(55)%
Other	899	(1)%	1,501	13%	16	0%
Unremitted Foreign Earnings-Current Year Adjustment	(5,484)	8%	—	0%	—	0%
Actual Tax Expense	$(14,767)	22%	$ 26,213	228%	$ 560	5%

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The components of the Company's deferred tax assets and liabilities as of December 31, 2011 and 2010 are shown below:

	December 31, 2011	December 31, 2010
	(Dollars in Thousands)	
Deferred tax assets		
Current deferred tax assets:		
Reserves established against realization of certain assets	$ 3,284	$ 4,287
Accruals not currently deductible for tax purposes	3,065	4,991
Other state deferred tax asset, net	301	—
Gross current deferred tax assets	6,650	9,278
Current deferred tax valuation allowance	—	—
Net current deferred tax assets	6,650	9,278
Non-current deferred tax assets:		
Federal net operating loss carryforwards	361	4,337
State net operating loss carryforwards	6,393	7,879
Other state deferred tax asset, net	656	702
Foreign tax credits	28,146	29,594
Other long term liabilities	—	369
Note hedge interest	1,318	4,925
Percentage of completion construction projects	22	18
Goodwill	—	1,156
FIN 48	8,188	10,487
Foreign tax local	9,824	6,244
Asset impairment	59,500	—
Other	370	837
Gross long-term deferred tax assets	114,778	66,548
Valuation allowance	(6,467)	(5,532)
Net non-current deferred tax assets	108,311	61,016
Net deferred tax assets	114,961	70,294
Deferred tax liabilities:		
Non-current deferred tax liabilities:		
Property, plant and equipment	(8,986)	(1,747)
Deferred tax impact of foreign earnings-APB 23	—	(5,484)
Foreign tax local	(6,379)	(8,912)
Federal benefit of foreign tax	—	(1,039)
Convertible debt-State	(31)	(46)
Convertible debt-Federal	(1,151)	(3,198)
Deferred compensation	1,243	255
Other	(630)	—
Net non-current deferred tax liabilities	(15,934)	(20,171)
Net deferred tax asset	$ 99,027	$ 50,123

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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 NOL carryforwards result in deferred tax assets and liabilities. In each period, we assess the likelihood that our deferred tax assets will be recovered from existing deferred tax liabilities or future taxable income in each taxing jurisdiction. 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.

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 AADU rigs in Alaska. In addition, we increased our valuation allowance by $2.5 million primarily related to foreign NOL's.

The 2010 results include income tax expense primarily related to an unfavorable ruling by the Atyrau Oblast Court upholding a lower court's decision allowing the revised Tax Notification to stand as further discussed in Note 13 to the consolidated financial statements The Kazakhstan tax matter increased tax expense by approximately $14.5 million ($6.8 million net of anticipated tax benefits), which includes approximately $6.5 million in tax, $4.8 million in interest and $3.2 million in penalties. PKD Kazakhstan intends to submit a further discretionary appeal to the Supreme Court of the Republic of Kazakhstan. In addition, tax expense increased from our settlement of a foreign tax audit for one of our subsidiaries for $1.2 million, which includes approximately $0.6 million of tax, $0.1 million in interest, and $0.5 million in penalties.

The 2009 results include a $5.4 million benefit related to our ability to claim foreign tax credits from prior years due to a change from deductions to credits, and additional valuation allowances related to state NOL carryforwards and current year foreign tax credits. After considering all available evidence, both positive and negative, we concluded that a valuation allowance of approximately $0.5 million was appropriate relating to the utilization of our current year foreign tax credits. At December 31, 2009, we had $124 million of gross state NOL carryforwards. For tax purposes, the state NOL carryforwards expire over a 15-year period from December 31, 2010 through 2024 for which a $0.6 million state valuation allowance has been established. During 2009, we paid $17.5 million for income taxes, net of refunds of $6.2 million received during the year.

The company applies the accounting guidance related to accounting for uncertainty in income taxes. This guidance prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of tax positions taken or expected to be taken in a tax return. For those benefits to be recognized, a tax position must be more likely than not to be sustained upon examination by taxing authorities.

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

	In Millions
Balance at January 1, 2011	(15.5)
Additions based on tax positions taken during a prior period	(0.1)
Reductions based on tax positions taken during a prior period	0.0
Additions based on tax positions taken during the current period	(0.7)
Reductions based on tax positions taken during the current period	0.1
Reductions related to settlement of tax matters	0.7
Reductions related to a lapse of applicable statute of limitations	0.0
Balance at December 31, 2011	(15.5)

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, 2011:

Colombia	2007-present
Kazakhstan	2008-present
Mexico	2006-present
Papua New Guinea	2007-present
Russia	2008-present
United States — Federal	1992-present

At December 31, 2011, we had a liability for unrecognized tax benefits of $15.5 million (8.5 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, 2011 and December 31, 2010 we had approximately $8.4 million and $7.0 million of accrued interest and penalties related to uncertain tax positions, respectively. We recognized an increase of $1.3 million of interest and an increase of $0.1 million of penalties on unrecognized tax benefits for the year ended December 31, 2011.

Note 6 — Long-Term Debt

Our 2.125% Convertible Senior Notes (2.125% Notes) are scheduled to mature in July 2012. As a result, the $125.0 million aggregate principal amount of the 2.125% Notes is classified as a current obligation on our consolidated balance sheet at December 31, 2011. We intend to refinance the 2.125% Notes with either an add-on to our existing 9.125% Notes or with a new note issuance or a combination of cash and debt. In the event that we are not able to refinance the 2.125% Notes, we intend to repay them using cash on hand and borrowings under the Revolver, which we currently anticipate will be sufficient for such repayment. Although management believes we will be able to complete a refinancing transaction prior to the maturity of the 2.125% Notes, no assurances can be made that we will be able to do so. If we are unable to complete a refinancing or otherwise repay such debt using cash on hand and borrowings under our Revolver, we would be in default under the indenture governing the 2.125% Notes, which would also cause us to be in default under our Credit Agreement and the indenture governing our 9.125% Notes, which would result in all $486 million principal amount of current indebtedness outstanding under those agreements to be declared immediately due and payable.

The following table illustrates the Company’s current debt portfolio as of December 31, 2011 and December 31, 2010:

	December 31, 2011	December 31, 2010
	(Dollars in Thousands)	
Senior Notes — payable in April 2018; fixed interest at 9.125% payable semi-annually in April and October.	$ 300,000	$ 300,000
$125.0 million aggregate principal Convertible Senior Notes — payable in July 2012; interest at 2.125% payable semi-annually in January and July, net of unamortized discount of $3,277 at December 31, 2011 and $14,596 at December 31, 2010.	121,723	115,862
Term Note — amortizes $6.0 million per quarter beginning April 1, 2011 ($3.0 million per quarter prior to April 1, 2011); interest at prime, plus anapplicable margin or LIBOR, plus an applicable margin. (Effective interest rate of 3.55% at December 31, 2011 and 3.50% at December 31, 2010)	61,000	32,000
Revolving Credit Facility — interest at prime, plus an applicable margin or LIBOR, plus an applicable margin. (Effect interest rate of 5.25% at December 31, 2010)	—	25,000
Total debt	482,723	472,862
Less current portion	145,723	12,000
Total long-term debt	$ 337,000	$ 460,862

The aggregate maturities of long-term debt are as follows:

- 2012 — $145.7 million
- 2013 — $37.0 million
- 2014 — $0 million
- 2015 — $0 million
- 2016 and thereafter — $300.0 million

9.125% Senior Notes, due April 2018

On March 22, 2010, we issued $300.0 million aggregate principal amount of 9.125% Senior Notes due 2018 (9.125% Notes) pursuant to an Indenture between the Company and The Bank of New York Mellon Trust Company, N.A. (Trustee). The 9.125% Notes were issued at par with interest payable on April 1 and October 1 of each year, beginning October 1, 2010. 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 (9.625% Notes) and to repay $42.0 million of borrowings under our Revolver.

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 domestic subsidiaries other than immaterial subsidiaries and subsidiaries generating revenue primarily outside the United States.

At any time prior to April 1, 2013, we may redeem up to 35 percent of the aggregate principal amount of the 9.125% Notes at a redemption price of 109.125 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 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. 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.

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.

9.625% Senior Notes, due October 2013

At December 31, 2009, we had outstanding $225.0 million in aggregate principal amount of 9.625% Notes. On March 8, 2010, we commenced a cash tender offer (Tender Offer) and consent solicitation for all of our outstanding 9.625% Notes, which expired on April 2, 2010. On March 22, 2010, we voluntarily called for redemption of all of our 9.625% Notes that were not tendered pursuant to the Tender Offer, at the redemption price of 103.208 percent of the principal amount of the 9.625% Notes, or $1,032.08 per $1,000 principal amount of the 9.625% Notes. On April 21, 2010, we redeemed in full the remaining $128.7 million principal amount of the 9.625% Notes. This redemption resulted in the Company recording debt extinguishment costs of $7.2 million during 2010.

2.125% Convertible Senior Notes, due July 2012

On July 5, 2007, we issued $125.0 million aggregate principal amount of 2.125% Notes. As of September 30, 2011, the 2.125% Notes are classified as current debt in our consolidated balance sheet.

The significant terms of the 2.125% Notes are as follows:

- *2.125% Notes Conversion Feature* — The initial conversion price for holders to convert their 2.125% Notes into shares is at a common stock share price equivalent of $13.85 (72.2217 shares of common stock per $1,000 note value). Conversion rate adjustments occur for any issuances of stock, warrants, rights or options (except for stock purchase plans or dividend re-investments) or any other transfer of benefit to substantially all stockholders, or as a result of a tender or exchange offer. We may, under advice of our Board of Directors, increase the conversion rate at our sole discretion for a period of at least 20 days.

- *2.125% Notes Settlement Feature* — Upon tender of the 2.125% Notes for conversion, we can either settle entirely in shares of common stock or a combination of cash and shares of common stock, solely at our option. Our intent is to satisfy our conversion obligation for our 2.125% Notes in cash, rather than in common stock, for at least the aggregate principal amount of the 2.125% Notes. This reduces the resulting potential earnings dilution to only include any possible conversion premium, which would be the difference between the average price of our shares and the conversion price per share of common stock.

- *Contingent Conversion Feature* — Holders may only convert the 2.125% Notes when either sales price or trading price conditions are met, on or after the 2.125% Notes' due date or upon certain accounting changes or certain corporate transactions (fundamental changes) involving stock distributions. Make-whole provisions are only included in the accounting and fundamental change conversions such that holders do not lose value as a result of the changes.

- *Settlement Feature* — Upon conversion, we will pay either cash or provide shares of our common stock if any, based on a daily conversion rate multiplied by a volume weighted average price of our common stock during a specified period following the conversion date. Conversions can be settled in cash or shares, solely at our discretion.

As of December 31, 2011 and 2010, none of the conditions allowing holders of the Notes to convert had been met.

Concurrently with the issuance of the 2.125% Notes, we purchased a convertible note hedge (note hedge) and sold warrants in private transactions with counterparties that were different than the ultimate holders of the 2.125% Notes. The note hedge included purchasing free-standing call options and selling free-standing warrants, both exercisable in our common shares. The note hedge allows us to receive shares of our common stock from the counterparties to the transaction equal to the amount of common stock related to the excess conversion value that we would issue and/or pay to the holders of the 2.125% Notes upon conversion.

The terms of the call options mirror the 2.125% Notes' major terms whereby the call option strike price is the same as the initial conversion price as are the number of shares callable, $13.85 per share and 9,027,713 shares, respectively. This feature prevents dilution of our outstanding shares. The warrants allow us to sell 9,027,713 common shares at a strike price of $18.29 per share. The conversion price of the 2.125% Notes remains at $13.85 per share, and the existence of the call options and warrants serve to guard against dilution at share prices less than $18.29 per share, since we would be able to satisfy our obligations and deliver shares upon conversion of the 2.125% Notes with shares that are obtained by exercising the call options.

We paid a premium of approximately $31.5 million for the call options, and received proceeds for a premium of approximately $20.3 million for the sale of the warrants. This reduced the net cost of the note hedge to $11.2 million. The expiration date of the note hedge is the earlier of the last day on which the 2.125% Notes remain outstanding or the maturity date of the 2.125% Notes.

The 2.125% Notes are classified as a liability in our consolidated balance sheets. Because we have the choice of settling the call options and the warrants in cash or shares of our common stock and these contracts meet all of the applicable criteria for equity classification, the cost of the call options and proceeds from the sale of the warrants are classified in stockholders' equity in the consolidated balance sheets. In addition, because both of these contracts are classified in stockholders' equity and are indexed solely to our common stock, they are not accounted for as derivatives.

Debt issuance costs related to the 2.125% Notes of approximately $3.6 million are being amortized over the five year term of the 2.125% Notes using the effective interest method. Proceeds from the transaction of $110.2 million were used to redeem our outstanding senior floating rate notes, to pay the net cost of hedge and warrant transactions, and for general corporate purposes.

Credit Agreement:

On May 15, 2008, we entered into a credit agreement (Credit Agreement) consisting of a senior secured $80.0 million Revolver and senior secured term loan facility (Term Loan) of up to $50.0 million. The 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 could 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. On April 1, 2011, the Company exercised the additional $50.0 million accordion feature and entered into an amendment to the Credit Agreement that increased the Aggregate Commitment under the Credit Agreement to $159.0 million, and borrowed an additional $50.0 million in a Term Loan. When the facility was increased, all other terms of the Credit Agreement remained the same, including covenants and Applicable Rates (as defined in the Credit Agreement).

Our obligations under the Credit Agreement are guaranteed by substantially all of our domestic subsidiaries, each of which has executed guaranty agreements. The Credit Agreement contains customary affirmative and negative covenants with which we were in compliance as of December 31, 2011 and December 31, 2010. The Credit Agreement terminates on May 14, 2013.

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. The Applicable Rate varies 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, 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, 2011 and $25.0 million in revolving loans outstanding at December 31, 2010. Letters of credit outstanding as of December 31, 2011 and December 31, 2010 totaled $2.7 million and $16.3 million, respectively.

Term Loan:

The Term Loan originated at $50.0 million and required quarterly principal payments of $3.0 million. Interest on the Term Loan accrues at either a Base Rate plus 2.25 percent or LIBOR plus 3.25 percent. On April 1, 2011, the company expanded its Term Loan Facility by $50.0 million. Funding was provided by certain current lenders and Barclays Bank PLC, which joined as a lender under the Credit Agreement. We used the proceeds from the additional Term Loan to repay $25.0 million outstanding on the Revolver, purchase additional rental tool inventory, and for general corporate purposes. The additional Term Loan amortizes $3.0 million per quarter beginning June 30, 2011. Upon the completion of the transaction, total borrowings under the Term Loan Facility were $79.0 million. Amortization on the Term Loans is $6.0 million per quarter. The outstanding balances on the Term Loan at December 31, 2011 and December 31, 2010 were $61.0 million and $32.0 million, respectively.

Note 7 — Derivative Financial Instruments

The Company 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 Credit Agreement. The two agreements fix the interest rate on a notional amount of $73.0 million of borrowings at 3.878% for the period beginning June 27, 2011 and terminating May 14, 2013. The notional amount of the swap agreements will decrease correspondingly with amortization of the Term Loan. We will not apply hedge accounting to the agreements and, accordingly, mark-to-market change in the fair value of the interest rate swaps are recognized in earnings. As of December 31, 2011, the fair value of the interest rate swap was a liability of $0.1 million and is recorded in Other long-term liabilities in our Consolidated balance sheets. For the year ended December 31, 2011, the Company recognized in earnings a $0.1 million loss relating to these contracts.

Note 8 — Fair Value of Financial Instruments

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

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

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

Level 2 — Direct or indirect observable inputs, including quoted prices or other market data, for similar assets or liabilities in active markets or identical assets or liabilities in less active markets 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. At December 31, 2011, the carrying amount of our interest rate swap agreements was a liability of $0.1 million, recorded in other long-term liabilities on our consolidated balance sheets. We did not have any outstanding derivative instruments as of December 31, 2010.

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, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Long-term Debt				
9.125% Notes	$ 300,000	$315,000	$ 300,000	$314,300
2.125% Notes	125,000	123,204	125,000	119,400
Total	$ 425,000	$438,204	$ 425,000	$433,700

As discussed in Note 2, in accordance with the Impairment or disposal of long-lived assets subsections of ASC 360-10, Property, Plant and Equipment, during the fourth quarter of 2011, our AADU assets with a carrying value of $339.5 million were written down to their 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 following table summarizes the fair value measurements of assets measured at fair value on a nonrecurring basis subsequent to their initial recognition during the year ended December 31, 2011:

Description	Year ended December 31, 2011	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Gains (Losses)
	(in millions)				
Long-lived assets held and used	$ 169.5	$ —	$ —	$ 169.5	$(170.0)
Total	$ 169.5	$ —	$ —	$ 169.5	$(170.0)

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, 2011.

Note 9 — 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 (2010 Plan) was approved by the stockholders at the Annual Meeting of Stockholders on May 7, 2010. The 2010 Plan authorizes the compensation committee or the board of directors to issue stock options, stock appreciation rights, restricted stock, restricted stock units, performance-based awards and other types of awards in cash or stock to key employees, consultants, and directors. The maximum number of shares of our common stock that may be delivered pursuant to the awards granted under the 2010 Plan is 5,800,000 shares of common stock.

The 2005 Long-Term Incentive Plan (2005 Plan) was approved by the stockholders at the Annual Meeting of Stockholders on April 27, 2005. The 2005 Plan authorizes the compensation committee or the board of directors to issue stock options, stock grants and various types of incentive awards in cash or stock to key employees, consultants and directors. During 2008 we obtained stockholder's approval to increase the total number of common shares available for future awards under the 2005 Plan. This amendment to the 2005 Plan was approved by stockholders at our Annual Meeting on March 21, 2008. No further grants can be made under this plan.

The Amended and Restated 1997 Stock Plan ("1997 Stock Plan") authorized 8,800,000 shares available for grant to officers and key employees. The 1997 Plan was frozen as of April 27, 2005, the date on which the 2005 Plan (as defined above) was approved by shareholders.

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

Nonvested Shares	Shares (000)	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2011	3,469,163	$ 4.00
Granted	1,457,039	5.61
Vested	(1,930,968)	3.57
Forfeited	(181,825)	4.38
Nonvested at December 31, 2011	2,813,409	$ 6.91

In 2011 and 2010, we issued 1,457,039 and 2,278,189, respectively, of restricted shares to selected key personnel. Total stock-based compensation expense recognized for the years ended December 31, 2011, 2010, and 2009 was $5.9 million, $5.5 million, and $4.6 million, respectively, all of which was related to nonvested stock. The weighted-average grant-date fair value of restricted shares granted during 2010 and 2009 was $4.54 and $1.98, respectively. The total fair value of the shares vested during the years ended December 31, 2011, 2010, and 2009 was $6.9 million, $4.1 million, and $7.5 million, respectively. The fair value of RSA's and RSU's is determined based on the closing trading price of the company's shares on the grant date. Stock-based compensation expense is included in our consolidated statements of operations in both "General and administration expense" and "Operating expenses".

Non-vested restricted stock awards and restricted stock units at December 31, 2011 was 2,813,409 shares and total unrecognized compensation cost related to unamortized non-vested stock awards was $8.2 million as of December 31, 2011. The remaining unrecognized compensation cost related to non-vested stock awards will be amortized over a weighted-average vesting period of approximately 22 months.

For the year ended December 31, 2011, the restricted stock vestings resulted in a tax benefit that was more than the deferred tax asset previously recognized. As a result, an excess tax benefit of $1.5 million was recorded to "Capital in excess of par value."

During the year ended December 31, 2011, we granted to certain of our officers and key employees a total of 44,500 performance units under the 2010 Long Term Incentive Plan. Subsequent to the award of these performance units, 2,424 units were forfeited during 2011. During the year ended December 31, 2010, we granted to certain of our officers and key employees a total of 35,326 and 46,015 performance units under the 2005 Long Term Incentive Plan and the 2010 Long Term Incentive Plan, respectively. Incentive grants included in this issuance were based on the attainment of pre-established performance goals. Each performance unit 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 performance units granted may be earned if performance at the maximum level is achieved. Performance units can be settled in cash or stock at the discretion of the compensation committee of the board of directors and are, therefore, accounted for as liability awards and remeasured at each reporting date until settlement. Compensation expense recognized related to the performance units for the years ended December 31, 2011, 2010, and 2009 was $2.1 million, $2.7 million, and $1.6 million, respectively.

Information regarding the Company's stock option plans is summarized below:

	1997 Stock Plan Non-Qualified Options		
	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term
Outstanding at December 31, 2010	98,500	$ 3.98	—
Granted	—	—	—
Exercised	(73,500)	3.91	—
Forfeited	—	—	—
Expired	(25,000)	4.20	—
Outstanding at December 31, 2011	—	$ —	—

As of December 31, 2011, we had no stock options outstanding or exercisable.

The Company had 1,709,963 and 1,631,511 shares held in treasury stock at December 31, 2011 and 2010, respectively. The total intrinsic value of options exercised during the years ended December 31, 2011, 2010 and 2009 was $0.5 million, $0 and $0.2 million, respectively.

Stock Reserved for Issuance — The following is a summary of common stock reserved for issuance:

	December 31, 2011	December 31, 2010
Stock plans	8,645,057	9,441,168
Stock bonus plan	24,666	24,666
Total shares reserved for issuance	8,669,723	9,465,834

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

	For the Year Ended December 31, 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 Year Ended December 31, 2010		
	Income (Numerator)	Shares (Denominator)	Per-Share Amount
Basic EPS	$(14,461,000)	114,258,965	$(0.13)
Effect of dilutive securities:			
Stock options and restricted stock	—	—	$ —
Diluted EPS:	$(14,461,000)	114,258,965	$(0.13)

	For the Year Ended December 31, 2009		
	Income (Numerator)	Shares (Denominator)	Per-Share Amount
Basic EPS	$ 9,267,000	113,000,555	$ 0.08
Effect of dilutive securities:			
Stock options and restricted stock	—	1,924,891	$ —
Diluted EPS:	$ 9,267,000	114,925,446	$ 0.08

For the years ended December 31, 2011 and 2010, all potential common shares have been excluded from the calculation of diluted EPS as the company incurred a loss for each year, and therefore, inclusion of potential common shares in the calculation of diluted EPS would be anti-dilutive.

For the year ended December 31, 2009, options to purchase 58,500 shares of common stock at a price of $4.20 were outstanding during the period but were not included in the computation of diluted EPS because the options' exercise prices were greater than the average market price of the common shares.

Note 11 — Employee Benefit Plan

The Company sponsors a defined contribution 401(k) plan (Plan) in which substantially all U.S. employees are eligible to participate. Company matching contributions to the Plan are based on the amount of employee contributions. The costs of our matching contributions to the Plan were $2.4 million, $2.4 million and $2.3 million in 2011, 2010 and 2009, respectively. Employees become 100 percent vested in the employer match contributions immediately upon participation in the Plan. The participation waiting period is 60 days after the date of hire.

Note 12 — Reportable Segments

We report our business activities in six business segments: (1) Rental Tools, (2) U.S. Barge Drilling, (3) U.S. Drilling, (4) International Drilling, (5) Technical Services, and (6) Construction Contract. 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, 2011	2010	2009
	(Dollars in Thousands)		
Revenues:			
Rental Tools(1)	$ 237,068	$ 172,598	$115,057
U.S. Barge Drilling(1)	93,763	64,543	49,628
U.S. Drilling(1)(3)	—	—	—
International Drilling(1)	318,482	294,821	379,344
Technical Services(1)	27,695	36,423	23,438
Construction Contract(1)	9,638	91,090	185,443
Total revenues	686,646	659,475	752,910
Operating income:			
Rental Tools(2)	120,822	74,541	27,841
U.S. Barge Drilling(2)	11,116	(11,503)	(26,797)
U.S. Drilling(2)	(3,915)	(217)	—
International Drilling(2)	22,237	5,092	69,993
Technical Services(2)	5,335	5,052	4,376
Construction Contract(2)	771	202	8,132
Total operating income	156,366	73,167	83,545
General and administrative expense	(31,314)	(30,728)	(45,483)
Impairments and other charges	(170,000)	—	—
Provision for reduction in carrying value of certain assets	(1,350)	(1,952)	(4,646)
Gain on disposition of assets, net	3,659	4,620	5,906
Total operating income	(42,639)	45,107	39,322
Interest expense	(22,594)	(26,805)	(29,450)
Changes in fair value of derivative positions	(110)	—	—
Loss on extinguishment of debt	—	(7,209)	—
Other	(69)	412	(45)
Income from continuing operations before income taxes	$ (65,412)	$ 11,505	$ 9,827
Identifiable assets:			
Rental Tools	$ 188,520	$ 178,193	
U.S. Barge Drilling	108,396	113,035	
U.S. Drilling	265,166	325,286	
International Drilling	426,490	454,576	
Total identifiable assets	988,572	1,071,090	
Corporate assets	227,674	203,464	
Total assets	$1,216,246	$1,274,554	

(1) In 2011, Exxon Neftegas Limited (ENL) constituted 15.9 percent of our total revenues or approximately $109.2 of our International Drilling segment. In 2010, BP accounted for approximately 12.4 percent of the Company's total revenues and approximately $81.9 million of our construction contract segment revenues. In 2010, ExxonMobil accounted for approximately 11.6 percent of our total revenues, with $63.7 million included in International Drilling segment and $12.7 million included in our Rental Tools segment. In 2009, BP accounted for approximately 23.0 percent of the Company's total revenues, which was primarily included in our Construction Contract segment. In 2009, ExxonMobil accounted for approximately 14.6 percent of the Company's total revenues with $75.7 million included in our International Drilling segment and $20.7 million included in our Rental Tools segment.

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

(3) As of December 31, 2011, this segment had not begun generating revenue. We anticipate re-entry into the Alaska drilling market in 2012 with two new-design land rigs.

	Year Ended December 31,		
Operations by Reportable Industry Segment	**2011**	**2010**	**2009**
	(Dollars in Thousands)		
Capital expenditures:			
Rental Tools	$ 61,702	$ 48,872	$ 36,822
U.S. Barge Drilling	7,339	5,315	13,752
U.S. Drilling	99,915	113,177	72,352
International Drilling	15,011	50,482	30,189
Corporate	6,432	1,338	9,669
Total capital expenditures	$190,399	$219,184	$162,784
Depreciation and amortization:			
Rental Tools	40,497	36,558	33,798
U.S. Barge Drilling	17,006	22,165	29,200
U.S. Drilling	2,223	—	—
International Drilling	48,965	52,429	48,383
Corporate	3,445	3,878	2,594
Total depreciation and amortization	$112,136	$115,030	$113,975

Operations by Geographic Area	Year Ended December 31, 2011	2010	2009
	(Dollars in Thousands)		
Revenues:			
Africa and Middle East	$ 6,774	$ 22,621	$ 32,003
Asia Pacific	38,477	26,416	33,883
CIS	176,421	149,963	195,807
Latin America	96,810	103,885	117,651
United States	368,164	356,590	373,566
Total revenues	686,646	659,475	752,910
Operating income:			
Africa and Middle East(1)	(6,383)	659	(2,795)
Asia Pacific(1)	1,933	2,374	7,539
CIS(1)	26,402	8,139	44,647
Latin America(1)	377	1,210	20,964
United States(1)	134,037	60,785	13,190
Total operating income	156,366	73,167	83,545
General and administrative expense	(31,314)	(30,728)	(45,483)
Impairments and other charges	(170,000)	—	—
Provision for reduction in carrying value of certain assets	(1,350)	(1,952)	(4,646)
Gain on disposition of assets, net	3,659	4,620	5,906
Total operating income	(42,639)	45,107	39,322
Interest expense	(22,594)	(26,805)	(29,450)
Changes in fair value of derivative positions	(110)	—	—
Loss on extinguishment of debt	—	(7,209)	—
Other	(69)	412	(45)
Income from continuing operations before income taxes	$ (65,412)	$ 11,505	$ 9,827
Long-lived assets:(2)			
Africa and Middle East	$ 28,427	$ 32,288	
Asia Pacific	18,300	21,883	
CIS	119,282	151,365	
Latin America	57,710	53,273	
United States	496,090	557,338	
Total long-lived assets	$ 719,809	$816,147	

(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 13 — Commitments and Contingencies

The Company has various lease agreements for office space, equipment, vehicles and personal property. These obligations extend through 2012 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, 2010, under operating leases with non-cancelable terms are as follows:

	Year Ended December 31, (Dollars in Thousands)
2012	9,382
2013	3,863
2014	3,069
2015	3,041
2016	1,931
Thereafter	8,155
Total	$ 29,441

Total rent expense for all operating leases amounted to $12.1 million for 2011, $12.0 million for 2010 and $11.4 million for 2009.

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, 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 $250,000 per occurrence retention. We continue to assume straight $250,000 retention for workers' compensation, employers' liability, and 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, 2011 and 2010, our gross self-insurance accruals for workers' compensation, employers' liability, general liability, protection and indemnity and maritime employers' liability totaled $6.6 million and $6.7 million, respectively and the related insurance recoveries/receivables were $1.9 million and $1.8 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, 2011, 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.

The 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, 2011.

Gulfco Site

In 2003, we received an information request under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) designating Parker Drilling Offshore Corporation, a subsidiary of Parker Drilling, as a potentially responsible party with respect to the Gulfco Marine Maintenance, Inc. Superfund Site in Freeport, Texas (EPA No. TX 055144539). The subsidiary responded to this request and in January 2008 received an administrative order to participate in an investigation of the site and a study of the remediation needs and alternatives. The EPA alleges that the subsidiary is a successor to a party who owned the Gulfco site during the time when chemical releases took place there. In December 2010, we entered into an agreement with two other potentially responsible parties, pursuant to which we agreed to pay 20 percent of past and future costs to study and remediate the site. The EPA recently issued notice letters to several other parties who may also participate in funding the site remediation costs. As of December 31, 2011, the Company had made certain participating payments and had accrued $0.7 million for our portion of certain unreimbursed past costs and the estimated future cost of remediation.

Customs Agent and Foreign Corrupt Practices Act (FCPA) Investigation

As previously disclosed, we received requests from the United States Department of Justice (DOJ) in July 2007 and the United States Securities and Exchange Commission (SEC) in January 2008 relating to our utilization of the services of a customs agent. The DOJ and the SEC are conducting parallel investigations into possible violations of U.S. law by us, including the FCPA. In particular, the DOJ and the SEC are investigating certain of our operations relating to countries in which we currently operate or formerly operated, including Kazakhstan and Nigeria. We are fully cooperating with the DOJ and SEC investigations and conducted an internal investigation into potential customs and other issues in Kazakhstan and Nigeria. The internal investigation has identified issues relating to potential non-compliance with applicable laws and regulations, including the FCPA, with respect to operations in Kazakhstan and Nigeria. At this point, we are unable to predict the duration, scope, or result of the DOJ or the SEC investigation or whether either agency will commence any legal action. We are currently in continuing discussions with the DOJ and SEC regarding a potential settlement, but no agreement has been reached with either agency. We cannot predict or estimate whether or when a resolution with each will occur, or the terms, conditions, or other parameters of any such resolution (including the size of any monetary penalties or disgorgement). Therefore, we have not made any accrual in our consolidated financial statements as of December 31, 2011, with respect to the investigations.

The DOJ and the SEC have a broad range of civil and criminal sanctions under the FCPA and other laws and regulations, which they may seek to impose against corporations and individuals in appropriate circumstances including, but not limited to, injunctive relief, disgorgement, fines, penalties and modifications to business practices and compliance programs. These authorities have entered into agreements with, and obtained a range of sanctions against, several public corporations and individuals arising from allegations of improper payments and deficiencies in books and records and internal controls, whereby civil and criminal penalties were imposed. Recent civil and criminal settlements have included multi-million dollar fines, deferred prosecution agreements, guilty pleas, and other sanctions, including the requirement that the relevant corporation retain a monitor to oversee its compliance with the FCPA. In addition, corporations may have to end or modify existing business relationships. Any of these remedial measures, if applicable to us, could have a material adverse impact on our business, results of operations, financial condition and liquidity.

We have taken certain steps to enhance our anti-bribery compliance efforts, including retaining a full-time Chief Compliance Officer who reports to the Chief Executive Officer and Audit Committee; adopting revised FCPA policies, procedures, and controls; increasing training and testing requirements; strengthening contractual provisions for our service providers that interface with foreign government officials; improving due diligence and continuing oversight procedures for the review and selection of such service providers; and implementing a compliance awareness improvement initiative that includes issuance of periodic anti-bribery compliance alerts.

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) Investigation.” 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. On August 25, 2010, Mr. Maresca filed a derivative action in the United States District Court for the Southern District of Texas against our current directors, select officers, and the Company as a nominal defendant. The lawsuit, like the demand letter, alleged that the individual defendants breached their fiduciary duties to the Company related to the issues described above under “Customs Agent and Foreign Corrupt Practices Act (FCPA) Investigation.” The lawsuit sought damages in an unspecified amount, along with various other forms of relief and an award of attorney fees, other costs, and expenses to the plaintiff. The lawsuit was voluntarily dismissed by the plaintiff in December 2010.

On June 3, 2010, Mohamed Kassamali, a purported stockholder of the Company, filed a derivative action in the state court of Harris County, Texas against our current directors and the Company as a nominal defendant. The lawsuit alleges that the individual defendants breached their fiduciary duties to the Company related to the issues described above under “Customs Agent and Foreign Corrupt Practices Act (FCPA) Investigation.” On June 22, 2010, the Fuchs Family Trust, a purported stockholder of the Company, filed a substantially similar lawsuit in the state court of Harris County, Texas. On June 23, 2010, Kenneth Flacks, a purported stockholder of the Company, also filed a substantially similar lawsuit in the state court of Harris County, Texas. The lawsuits seek damages related to the alleged breaches of duty, unjust enrichment, abuse of control, gross mismanagement and waste of corporate assets. The damages sought include both compensatory and exemplary damages in an unspecified amount, along with various other forms of relief and an award of attorney fees, other costs, and expenses to the plaintiffs. All defendants have retained counsel, and on October 15, 2010, the three cases pending in the state court of Harris County, Texas were consolidated under the Kassamali case number and restyled as In re Parker Drilling Derivative Litigation. Plaintiffs filed a consolidated amended petition on April 7, 2011. On May 23, 2011, defendants filed special exceptions to that petition, which were fully briefed as of August 8, 2011. On December 9, 2011, the Court granted a 90-day deferral of the action.

On August 31, 2010, Douglas Freuler, a purported stockholder of the Company, filed a derivative action in the United States District Court for the Southern District of Texas against our current directors, select officers, and the Company as a nominal defendant. The lawsuit was substantially similar to those filed in the state court of Harris County, Texas, and alleges breach of fiduciary duties to the Company related to the issues described above under “Customs Agent and Foreign Corrupt Practices Act (FCPA) Investigation,” as well as abuse of control, gross mismanagement, waste of corporate assets, and unjust enrichment. The damages sought included both compensatory and exemplary damages in an unspecified amount, along with various other forms of relief and an award of attorney fees, other costs, and expenses to the plaintiffs. Defendants’ motions to dismiss the amended complaint were granted on June 30, 2011, and plaintiff was given thirty days to replead. Mr. Freuler filed his second amended complaint on July 20, 2011, and defendants’ motions to dismiss this complaint were fully briefed as of November 18, 2011.

Economic Sanctions Compliance

We are subject to laws and regulations restricting our international operations, including activities involving restricted countries, organizations, entities and persons that have been identified as unlawful actors or that are subject to U.S. economic sanctions. Pursuant to an internal review, we have identified certain shipments of equipment and supplies that were routed through Iran as well as other activities, including drilling activities, which may have violated applicable U.S. laws and regulations. We have reviewed these shipments, transactions and drilling activities to determine whether the timing, nature and extent of such activities or other conduct may have given rise to violations of these laws and regulations, and we voluntarily disclosed the results of our review to the U.S. government. At this point, we are unable to predict whether the government will initiate an investigation or any proceedings against us or the ultimate outcome that may result from our voluntary disclosure. If U.S. enforcement authorities determine that we were not in compliance with export restrictions, U.S. economic sanctions or other laws and regulations that apply to our international operations, we may be subject to civil or criminal penalties and other remedial measures, which could have an adverse impact on our business, results of operations, financial condition and liquidity.

Kazakhstan Ministry of Finance Tax Audit

On August 14, 2009, the Kazakhstan Branch (PKD Kazakhstan) of Parker Drilling's subsidiary, Parker Drilling Company International Limited (PDCIL), received an Act of Tax Audit from the Ministry of Finance of Kazakhstan (MinFin) for the period January 1, 2005 through December 31, 2007. PKD Kazakhstan was assessed additional taxes in the amount of KZT 1.45 billion (approximately USD $9.7 million) and associated interest in the amount of KZT 700 million (approximately USD $4.7 million). The amounts assessed relate to corporate income taxes and interest in connection with the disallowance of the head office's management and administrative expenses, loan interest and state duties, as well as Value Added Taxes (VAT) and interest in connection with VAT offset on debts classified as doubtful by MinFin, and for property taxes and interest in connection with Barge Rig 257 as a result of MinFin applying a lower rate of depreciation.

On September 25, 2009, PKD Kazakhstan appealed the Act of Tax Audit with MinFin on the basis that PKD Kazakhstan was exercising its rights provided by the Convention between the Governments of the Republic of Kazakhstan and the United States of America on the Avoidance of Double Taxation and the Prevention of Fiscal Evasion with respect to Taxes on Income and Capital, as well as improper application of Kazakhstan Tax Code provisions.

On January 13, 2010, PKD Kazakhstan received a response from MinFin to the appeal filed September 25, 2009. MinFin agreed with PKD Kazakhstan to remove the assessment related to property taxes and interest in connection with Barge Rig 257 which reduced the overall assessment by KZT 741 million (approximately USD $5.0 million). The residual assessment of KZT 959 million (approximately USD $6.5 million) of taxes and KZT 450 million (approximately USD $3 million) of associated interest remains outstanding.

On March 1, 2010, PKD Kazakhstan filed a claim against the Tax Department, in the Special Inter-district Economic Court of Atyrau Oblast, seeking to invalidate the revised Tax Notification. On May 5, 2010, the court elected not to issue a ruling on the merits of the case on the basis of an alleged lack of standing. PKD Kazakhstan adjusted and re-filed its claim in June 2010. On August 17, 2010, the Special Inter-district Economic Court of Atyrau Oblast rendered a decision rejecting PKD Kazakhstan's re-filed claim. PKD Kazakhstan filed on September 17, 2010 an appeal to the Atyrau Oblast Court. That appeal was heard by a single judge on October 27, 2010, at the conclusion of which the court announced its decision to let the lower court decision stand without amendment or cancellation.

On November 18, 2010, PKD Kazakhstan filed an appeal to a three-judge panel of the Atyrau Oblast Court. On December 9, 2010, the court announced its decision to uphold the lower court decision and allow the revised Tax Notification to stand. As a result of the decision on December 9, 2010, PKD Kazakhstan had an obligation to pay the residual assessment. The amount due related to the tax assessment and applicable interest was approximately $11.3 million, plus an administrative penalty of approximately $3.2 million arising from the same alleged underpayment of taxes. PKD Kazakhstan paid these amounts in full prior to December 31, 2010 to avoid enforcement actions and additional interest while we pursue further challenges.

PKD Kazakhstan continues to believe that it properly exercised its rights provided by the Convention and that MinFin improperly applied certain provisions of the Kazakhstan Tax Code. PKD Kazakhstan submitted a discretionary appeal to the Supreme Court of the Republic of Kazakhstan, and on October 13, 2011 the Supreme Court verbally announced its decision to not accept and consider the merits of the appeal. PKD Kazakhstan is considering its remaining available options for relief under Kazakhstan law and the Convention.

Note 14 — 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. Under the agreement, Mr. Parker Sr. was paid consulting fees of $40,000, $123,750, and $180,667 in each of the years ending December 31, 2011, 2010 and 2009, respectively.

During the term of the consulting agreement, Mr. Parker Sr. was required to maintain the confidentiality of any information he obtained while an employee or consultant and to disclose to us any ideas he conceived and assign to us any inventions he developed. For one year after the termination of the consulting agreement, Mr. Parker Sr. is 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. For his services in 2011, he received a monthly payment of $10,000. The consulting agreement expired on April 30, 2011.

Other Related Party Agreements

During 2011 and 2010, 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 2011 and 2010, affiliates of Apache paid affiliates of the Company a total of $22.7 million and $19.8 million, respectively, for performance of drilling services and provision of rental tools.

Note 15 — Supplementary Information

At December 31, 2011, accrued liabilities included $2.2 million of deferred mobilization fees, $8.1 million of accrued interest expense, $3.0 million of worker's compensation liabilities and $26.8 million of accrued payroll and payroll taxes. Other long-term obligations included $3.6 million of workers' compensation liabilities as of December 31, 2011.

At December 31, 2010, accrued liabilities included $2.8 million of deferred mobilization fees, $8.1 million of accrued interest expense, $2.8 million of worker's compensation liabilities and $21.3 million of accrued payroll and payroll taxes. Other long-term obligations included $3.9 million of workers' compensation liabilities as of December 31, 2010.

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

Set forth on the following pages are the consolidating condensed financial statements of Parker Drilling. The Company's 9.125% Notes are guaranteed by substantially all of the restricted subsidiaries of Parker Drilling. 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, all guarantees are full and unconditional and all guarantees are joint and several.

We are providing consolidating condensed financial information of the parent, Parker Drilling, the guarantor subsidiaries, and the non-guarantor subsidiaries as of December 31, 2011 and December 31, 2010 and for the years ended December 31, 2011, 2010 and 2009. The consolidating condensed financial statements present investments in both consolidated and unconsolidated subsidiaries using the equity method of accounting.

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PARKER DRILLING COMPANY AND SUBSIDIARIES

CONSOLIDATING CONDENSED STATEMENT OF OPERATIONS

PARKER DRILLING COMPANY AND SUBSIDIARIES
CONSOLIDATING CONDENSED STATEMENT OF OPERATIONS

	Year ended December 31, 2011				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
	(Dollars in Thousands) (Unaudited)				
Total revenues	$ —	$ 376,229	$426,491	$(116,074)	$ 686,646
Operating expenses	—	175,465	358,753	(116,074)	418,144
Depreciation and amortization	—	62,744	49,392	—	112,136
Total operating gross margin	—	138,020	18,346	—	156,366
General and administration expens(1)	(218)	(30,859)	(237)	—	(31,314)
Impairment and other charges	—	(170,000)	—	—	(170,000)
Provision for reduction in carrying value of certainassets	—	(1,350)	—	—	(1,350)
Gain on disposition of assets, net	—	2,706	953	—	3,659
Total operating income (loss)	(218)	(61,483)	19,062	—	(42,639)
Other income and (expense):					
Interest expense	(26,654)	(17,889)	(8,865)	30,814	(22,594)
Changes in fair value of derivative positions	(110)	—	—	—	(110)
Interest income	18,131	750	12,189	(30,814)	256
Other	—	(345)	20	—	(325)
Equity in net earnings of subsidiaries	(23,484)	—	—	23,484	—
Total other income and (expense)	(32,117)	(17,484)	3,344	23,484	(22,773)
Income (benefit) 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 STATEMENT OF OPERATIONS

	Year Ended December 31, 2010				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
	(Unaudited) (Dollars in Thousands)				
Total revenues	$ —	$366,947	$401,617	$(109,089)	$ 659,475
Operating expenses	—	237,584	342,783	(109,089)	471,278
Depreciation and amortization	—	63,402	51,628	—	115,030
Total operating gross margin	—	65,961	7,206	—	73,167
General and administration expense(1)	(225)	(30,193)	(310)	—	(30,728)
Provision for reduction in carrying value of certain assets	—	(1,952)	—	—	(1,952)
Gain on disposition of assets, net	—	2,067	2,553	—	4,620
Total operating income (loss)	(225)	35,883	9,449	—	45,107
Other income and (expense):					
Interest expense	(30,771)	(35,640)	(16,185)	55,791	(26,805)
Interest income	42,000	757	23,291	(65,791)	257
Loss on extinguishment of debt	(7,209)	—	—	—	(7,209)
Other	—	88	67	—	155
Equity in net earnings of subsidiaries	(22,962)	—	—	22,962	—
Total other income and (expense)	(18,942)	(34,795)	7,173	12,962	(33,602)
Income (benefit) before income taxes	(19,167)	1,088	16,622	12,962	11,505
Income tax expense (benefit):					
Current	139	(189)	27,571	—	27,521
Deferred	(4,845)	2,323	1,214	—	(1,308)
Total income tax expense (benefit)	(4,706)	2,134	28,785	—	26,213
Net income (loss)	(14,461)	(1,046)	(12,163)	12,962	(14,708)
Less: Net (loss) attributable to noncontrolling interest	—	—	(247)	—	(247)
Net income (loss) attributable to controlling interest	$(14,461)	$ (1,046)	$(11,916)	$ 12,962	$ (14,461)

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

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PARKER DRILLING COMPANY AND SUBSIDIARIES
CONSOLIDATING CONDENSED STATEMENT OF OPERATIONS

	Year Ended December 31, 2009				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
			(Unaudited) (Dollars in thousands)		
Total revenues	$ —	$381,145	$430,430	$ (58,665)	$ 752,910
Operating expenses	—	300,620	313,435	(58,665)	555,390
Depreciation and amortization	—	65,595	48,380	—	113,975
Total operating gross margin	—	14,930	68,615	—	83,545
General and administration expense(1)	(180)	(44,973)	(330)	—	(45,483)
Provision for reduction in carrying value of certain assets	—	(3,206)	(1,440)	—	(4,646)
Gain on disposition of assets, net	—	4,190	1,716	—	5,906
Total operating income (loss)	(180)	(29,059)	68,561	—	39,322
Other income and (expense):					
Interest expense	(33,203)	(35,838)	(13,959)	53,550	(29,450)
Interest income	43,183	1,184	16,585	(59,911)	1,041
Other	(3)	(1,133)	50	—	(1,086)
Equity in net earnings of subsidiaries	(20,797)	—	—	20,797	—
Total other income and (expense)	(10,820)	(35,787)	2,676	14,436	(29,495)
Income (benefit) before income taxes	(11,000)	(64,846)	71,237	14,436	9,827
Income tax expense (benefit):					
Current	(3,655)	226	18,853	—	15,424
Deferred	(16,612)	1	1,747	—	(14,864)
Total income tax expense (benefit)	(20,267)	227	20,600	—	560
Net income (loss)	9,267	(65,073)	50,637	14,436	9,267
Net income attributable to noncontrolling interest	—	—	—	—	—
Net income (loss) attributable to controlling interest	$ 9,267	$ (65,073)	$ 50,637	$ 14,436	$ 9,267

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

PARKER DRILLING COMPANY AND SUBSIDIARIES
CONSOLIDATING CONDENSED BALANCE SHEET

	December 31, 2011				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
	(Dollars in Thousands) (Unaudited)				
ASSETS					
Current assets:					
Cash and cash equivalents	$ 55,670	$ 4,212	$ 37,987	$ —	$ 97,869
Accounts and notes receivable, net	289,512	94,748	285,326	(485,663)	183,923
Rig materials and supplies	—	762	29,185	—	29,947
Deferred costs	—	—	3,249	—	3,249
Deferred income taxes	—	5,311	853	486	6,650
Other tax assets	47,834	(25,218)	2,742	—	25,358
Assets held for sale	—	—	5,315	—	5,315
Other current assets	788	6,381	8,133	—	15,302
Total current assets	393,804	86,196	372,790	(485,177)	367,613
Property, plant and equipment, net	79	474,942	244,787	1	719,809
Investment in subsidiaries and intercompany advances	720,214	(212,883)	1,347,719	(1,855,050)	—
Other noncurrent assets	44,962	66,660	16,839	363	128,824
Total assets	$1,159,059	$ 414,915	$1,982,135	$(2,339,863)	$1,216,246
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities:					
Current portion of long-term debt	$ 145,723	$ —	$ —	$ —	$ 145,723
Accounts payable and accrued liabilities	60,120	94,056	181,010	(199,936)	135,250
Accrued income taxes	(205)	921	4,121	—	4,837
Total current liabilities	205,638	94,977	185,131	(199,936)	285,810
Long-term debt	337,000	—	—	—	337,000
Other long-term liabilities	8,081	9,474	15,897	—	33,452
Long-term deferred tax liability	1,151	25,232	(11,296)	847	15,934
Intercompany payables	62,583	43,657	111,619	(217,859)	—
Contingencies	—	—	—	—	—
Stockholders' equity:					
Common stock	19,508	18,049	43,003	(61,052)	19,508
Capital in excess of par value	637,042	733,120	1,444,091	(2,177,211)	637,042
Retained earnings (accumulated deficit)	(111,944)	(509,594)	194,246	315,348	(111,944)
Total controlling interest stockholders' equity	544,606	241,575	1,681,340	(1,922,915)	544,606
Noncontrolling interest	—	—	(556)	—	(556)
Total Equity	544,606	241,575	1,680,784	(1,922,915)	544,050
Total liabilities and stockholders' equity	$1,159,059	$ 414,915	$1,982,135	$(2,339,863)	$1,216,246

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PARKER DRILLING COMPANY AND SUBSIDIARIES

CONSOLIDATING CONDENSED BALANCE SHEET

	December 31, 2010				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
	(Unaudited) (Dollars in thousands)				
ASSETS					
Current assets:					
Cash and cash equivalents	$ 13,835	$ 2,317	$ 35,279	$ —	$ 51,431
Accounts and notes receivable, net	1,179	99,734	215,650	(147,687)	168,876
Rig materials and supplies	—	(1,655)	27,182	—	25,527
Deferred costs	—	—	2,229	—	2,229
Deferred income taxes	8,981	297	—	—	9,278
Other tax assets	97,896	(62,678)	11,211	—	46,429
Assets held for sale	—	—	5,287	—	5,287
Other current assets	557	41,564	30,129	(13,183)	59,067
Total current assets	122,448	79,579	326,967	(160,870)	368,124
Property, plant and equipment, net	79	538,005	278,063	0	816,147
Investment in subsidiaries and intercompany advances	996,018	499,987	1,310,792	(2,806,797)	—
Other noncurrent assets	72,202	14,542	6,653	(3,113)	90,284
Total assets	$1,190,747	$1,132,113	$1,922,475	$(2,970,780)	$1,274,555
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities:					
Current portion of long-term debt	$ 12,000	$ —	$ —	$ —	$ 12,000
Accounts payable and accrued liabilities	55,257	338,626	160,316	(395,428)	158,771
Accrued income taxes	609	93	3,790	—	4,492
Total current liabilities	67,866	338,719	164,106	(395,428)	175,263
Long-term debt	460,862	—	—	—	460,862
Other long-term liabilities	7,762	7,610	12,131	2,690	30,193
Long-term deferred tax liability	3,361	21,958	(5,148)	—	20,171
Intercompany payables	62,583	473,144	103,667	(639,394)	—
Contingencies	—	—	—	—	—
Stockholders' equity:					
Common stock	19,397	18,050	43,003	(61,053)	19,397
Capital in excess of par value	630,409	733,120	1,436,338	(2,169,458)	630,409
Retained earnings (accumulated deficit)	(61,493)	(460,488)	168,625	291,863	(61,493)
Total controlling interest stockholders' equity	588,313	290,682	1,647,966	(1,938,648)	588,313
Noncontrolling interest	—	—	(247)	—	(247)
Total Equity	588,313	290,682	1,647,719	(1,938,648)	588,066
Total liabilities and stockholders' equity	$1,190,747	$1,132,113	$1,922,475	$(2,970,780)	$1,274,555

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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 liabilities	(10,454)	(53,404)	41,091	—	(22,767)
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
Proceeds from draw on revolver credit facility	—	—	—	—	—
Paydown on senior notes	—	—	—	—	—
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

PARKER DRILLING COMPANY AND SUBSIDIARIES

CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2010				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
			(Unaudited) (Dollars in thousands)		
Cash flows from operating activities:					
Net income (loss)	$ (14,461)	$ (1,046)	$(12,163)	$ 12,962	$ (14,708)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:					
Depreciation and amortization	—	63,402	51,628	—	115,030
Loss on extinguishment of debt	7,209	—	—	—	7,209
Gain on disposition of assets	—	(2,067)	(2,553)		(4,620)
Deferred income tax expense	(4,845)	2,323	1,214	—	(1,308)
Provision for reduction in carrying value of certain assets	—	1,952	—	—	1,952
Expenses not requiring cash	14,829	—	—	—	14,829
Equity in net earnings of subsidiaries	22,962	—	—	(22,962)	—
Change in accounts receivable	16,178	(14,763)	19,337	—	20,752
Change in other assets	(2,505)	(13,454)	15,365	—	(594)
Change in liabilities	(144)	7,793	(22,641)	—	(14,992)
Net cash provided by (used in) operating activities	39,223	44,140	50,187	(10,000)	123,550
Cash flows from investing activities:					
Capital expenditures	—	(169,784)	(49,400)	—	(219,184)
Proceeds from the sale of assets	—	4,646	1,829	—	6,475
Intercompany dividend payment	—	—	(10,000)	10,000	—
Net cash provided by (used in) investing activities	—	(165,138)	(57,571)	10,000	(212,709)
Cash flows from financing activities:					
Proceeds from debt issuance	300,000	—	—	—	300,000
Proceeds from draw on revolver credit facility	25,000	—	—	—	25,000
Paydown on Senior notes	(225,000)	—	—	—	(225,000)
Paydown on term note	(12,000)	—	—	—	(12,000)
Paydown on revolver credit facility	(42,000)	—	—	—	(42,000)
Payment of debt issuance costs	(7,976)	—	—	—	(7,976)
Payment of debt extinguishment costs	(7,466)	—	—	—	(7,466)
Proceeds from stock options exercised	26	—	—	—	26
Excess tax benefit from stock-based compensation	1,203	—	—	—	1,203
Intercompany advances, net	(115,364)	121,547	(6,183)	—	—
Net cash provided by (used in) financing activities	(83,577)	121,547	(6,183)	—	31,787
Net change in cash and cash equivalents	(44,354)	549	(13,567)	—	(57,372)
Cash and cash equivalents at beginning of period	58,189	1,768	48,846	—	108,803
Cash and cash equivalents at end of period	$ 13,835	$ 2,317	$ 35,279	$ —	$ 51,431

PARKER DRILLING COMPANY AND SUBSIDIARIES
CONSOLIDATING CONDENSED STATEMENT OF CASH FLOWS

	Year Ended December 31, 2009				
	Parent	Guarantor	Non-Guarantor	Eliminations	Consolidated
	(Unaudited) (Dollars in thousands)				
Cash flows from operating activities:					
Net income (loss)	$ 9,267	$ (65,073)	$ 50,637	$ 14,436	$ 9,267
Adjustments to reconcile net income (loss) to net cash provided by operating activities:					
Depreciation and amortization	—	65,596	48,380	—	113,975
Gain on disposition of assets	—	(4,190)	(1,716)	—	(5,906)
Deferred income tax expense (benefit)	(16,612)	0	1,747	—	(14,864)
Provision for reduction in carrying value of certain assets	—	3,206	1,440	—	4,646
Expenses not requiring cash	11,626	—	—	—	11,626
Equity in net earnings of subsidiaries	20,797	—	—	(20,797)	—
Change in accounts receivable	34,435	(38,905)	6,126	—	1,656
Change in other assets	(35,604)	906	8,439	—	(26,259)
Change in liabilities	17,203	41,411	(41,883)	—	16,731
Net cash provided by operating activities	41,112	2,952	73,170	(6,361)	110,872
Cash flows from investing activities:					
Capital expenditures	—	(129,281)	(30,773)	—	(160,054)
Proceeds from the sale of assets	—	6,918	2,418	—	9,336
Intercompany dividend payments	—	—	(6,361)	6,361	—
Net cash used in investing activities	—	(122,363)	(34,716)	6,361	(150,718)
Cash flows from financing activities:					
Proceeds from draw on revolver credit facility	4,000	—	—	—	4,000
Paydown on revolver credit facility	(26,000)	—	—	—	(26,000)
Proceeds from stock options exercised	199	—	—	—	199
Excess tax benefit from stock-based compensation	(1,848)	—	—	—	(1,848)
Intercompany advances, net	(70,598)	114,321	(43,723)	—	—
Net cash provided by financing activities	(94,247)	114,321	(43,723)	—	(23,649)
Net increase in cash and cash equivalents	(53,135)	(5,090)	(5,270)	(0)	(63,495)
Cash and cash equivalents at beginning of year	111,324	6,858	54,116	—	172,298
Cash and cash equivalents at end of year	$ 58,189	$ 1,768	$ 48,846	$ (0)	$ 108,803

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Note 17 — Selected Quarterly Financial Data

Year 2011	Quarter First	Second	Third	Fourth	Total
	(Dollars in Thousands Except Per Share Amounts) (Unaudited)				
Revenues	$156,179	$172,812	$176,589	$ 181,066	$686,646
Operating gross margin(2)	$ 21,204	$ 40,797	$ 49,966	$ 44,399	$156,366
Operating income	$ 15,402	$ 33,215	$ 41,959	$(133,215)	$ (42,639)
Net income (loss) attributable to controlling interest	$ 4,827	$ 14,173	$ 20,725	$ (90,176)	$ (50,451)
Basic earnings per share — net income (loss)(1)	$ 0.04	$ 0.12	$ 0.18	$ (0.77)	$ (0.43)
Diluted earnings per share — net income (loss)(1)	$ 0.04	$ 0.12	$ 0.18	$ (0.77)	$ (0.43)

Year 2010	Quarter First	Second	Third	Fourth	Total
	(Dollars in Thousands Except Per Share Amounts) (Unaudited)				
Revenues	$157,605	$156,525	$172,029	$173,316	$659,475
Operating gross margin	$ 15,486	$ 18,538	$ 13,443	$ 25,700	$ 73,167
Operating income (loss)	$ 6,126	$ 13,313	$ 7,555	$ 18,113	$ 45,107
Net income (loss) attributable to controlling interest	$ (2,051)	$ 507	$ 492	$ (13,409)	$ (14,461)
Basic earnings per share — net income (loss)(1)	$ (0.02)	$ —	$ —	$ (0.12)	$ (0.13)
Diluted earnings per share — net income (loss)(1)	$ (0.02)	$ —	$ —	$ (0.12)	$ (0.13)

(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 2011 YTD results.

(2) As the Company modified our reporting segments to be consistent with recent organizational changes to improve our drilling organization, certain human resource related 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 18 — Recent Accounting Pronouncements

Revenue Recognition — On January 1, 2011, we adopted an update issued by the Financial Accounting Standards Board (FASB) to existing guidance on revenue recognition for arrangements with multiple deliverables. This update allows companies to allocate consideration for qualified separate deliverables using estimated selling price for both delivered and undelivered items when vendor-specific objective evidence or third-party evidence is unavailable. It also requires additional disclosures on the nature of multiple element arrangements, the types of deliverables under the arrangements, the general timing of their delivery, and significant factors and estimates used to determine estimated selling prices. The update is effective for fiscal years beginning after June 15, 2010. The adoption of this update did not have a material impact on our financial position, results of operations, cash flows, or disclosures.

Comprehensive Income — In June 2011, the FASB issued Accounting Standards Update 2011-05, "*Presentation of Comprehensive Income.*" This update will increase the prominence of comprehensive income in the financial statements. It gives an entity the option to present the components of net income and comprehensive income in either a single continuous statement or in two separate but consecutive financial statements and eliminates the option to present other comprehensive income in the statement of changes in equity. This update will be effective for us beginning in the first quarter of 2012. This update is not anticipated to have a material impact on our financial position, results of operations, cash flows, or disclosures.

Fair value measurements — Effective January 1, 2012, we will adopt 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. We do not expect that our adoption will have a material effect on the disclosures contained in our notes to the consolidated financial statements.

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 — The Company's management, under the supervision and with the participation of the chief executive officer and chief financial officer, carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act), as of December 31, 2011. In designing and evaluating the disclosure controls and procedures, management recognized that disclosure controls and procedures, no matter how well designed and operated, can provide only reasonable, not absolute, assurance of achieving the desired control objectives, and management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible disclosure controls and procedures. Based on the evaluation, the chief executive officer and chief financial officer have concluded that the disclosure controls and procedures were effective to ensure that information required to be disclosed by us in the reports it files or submits with its periodic filings under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and such information is accumulated and communicated to management as appropriate to allow timely decisions regarding required disclosure.

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, 2011 based on criteria established in Internal Control — Integrated Framework 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, 2011.

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, 2011.

Changes in Internal Control over Financial Reporting — There were no changes in our internal control over financial reporting during the quarter ended December 31, 2011 that have materially affected, or are reasonably likely to materially affect, the Company's 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 2012 Proxy Statement for the Annual Meeting of Stockholders to be held on April 26, 2012. Such information is incorporated herein by reference.

Information with respect to executive officers is shown in Item 1 of this Form 10-K.

Information with respect to our audit committee and audit committee financial expert can be found under the caption “The Audit Committee” of our 2012 Proxy Statement for the Annual Meeting of Stockholders to be held on April 26, 2012 and is incorporated herein by reference.

The information in our 2012 Proxy Statement for the Annual Meeting of Stockholders to be held on April 26, 2012 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,” “2011 Director Compensation Table,” “Option/SAR Grants in 2009 to Non-Employee Directors,” “Compensation Committee Interlocks and Insider Participation” and “Compensation Committee Report” in our 2012 Proxy Statement for the Annual Meeting of Stockholders to be held on April 26, 2012 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 2012 Proxy Statement for the Annual Meeting of Stockholders to be held on April 26, 2012.

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 2012 Proxy Statement for the Annual Meeting of Stockholders to be held on April 26, 2012.

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 2012 Proxy Statement for the Annual Meeting of the Stockholders to be held on April 26, 2012.

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PART IV

ITEM15. ***EXHIBITS AND FINANCIAL STATEMENT SCHEDULES***

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

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

	Page
Report of Independent Registered Public Accounting Firm	55
Consolidated Statement of Operations for the years ended December 31, 2011, 2010 and 2009	56
Consolidated Balance Sheet as of December 31, 2011 and 2010	57
Consolidated Statement of Cash Flows for the years ended December 31, 2011, 2010 and 2009	58
Consolidated Statement of Stockholders' Equity for the years ended December 31, 2011, 2010 and 2009	59
Notes to the Consolidated Financial Statements	60
(2) Financial Statement Schedule:	
Schedule II — Valuation and qualifying accounts	101

(3) Exhibits:

Exhibit Number		Description
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 as of July 5, 2007, among Parker Drilling Company, the guarantors from time to time party thereto and The Bank of New York Trust Company, N.A., with respect to the 2.125% Convertible Senior Notes due 2012 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed on July 5, 2007).
4.2	—	Form of 2.125% Convertible Senior Note due 2012 (included in Exhibit 4.1).
4.3	—	Second Supplemental Indenture, dated as of October 26, 2010, among Parker Drilling Company and The Bank of New York Mellon Trust Company, N.A., as trustee supplementing the indenture dated July 5, 2007 for the 2.125% Convertible Senior Notes due 2012 (incorporated by reference to Exhibit 4.1 to the Company's Quarterly Report on Form 10-Q filed on November 8, 2010).
4.4	—	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).
4.5	—	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).
4.6	—	Registration Rights Agreement, dated March 22, 2010, by and among Parker Drilling Company, the guarantors named therein, Bank of America Securities LLC, RBS Securities Inc., Barclays Capital Inc., Credit Suisse Securities (USA), Inc., Deutsche Bank Securities Inc., HSBC Securities (USA) Inc., Natixis Bleichroeder LLC and Wells Fargo Securities, LLC (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on March 22, 2010).
10.1	—	Credit Agreement, dated as of May 15, 2008, 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, ABN AMRO BANK N.V., as Documentation Agent, and Banc of America Securities LLC and Lehman Brothers Inc., as Joint Lead Arrangers and Book Managers (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 21, 2008).
10.2	—	First Amendment to Credit Agreement, dated as of June 30, 2008, but effective as of May 15, 2008, among Parker Drilling Company, as Borrower, each lender from time to time party to the Credit Agreement, Bank of America, N.A., as Administrative Agent and an L/C Issuer, Lehman Commercial Paper Inc., as Syndication Agent, and ABN AMRO Bank N.V., as Documentation Agent (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed on May 5, 2011).

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Exhibit Number		Description
10.3	—	Consent and Second Amendment to Credit Agreement dated as of January 15, 2010, among Parker Drilling Company, as Borrower, each lender from time to time party to the Credit Agreement, Bank of America, N.A., as Administrative Agent and an L/C Issuer, and ABN AMRO Bank N.V., as Documentation Agent (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed on May 5, 2011).
10.4	—	Third Amendment to Credit Agreement and Joinder dated as of April 1, 2011, among Parker Drilling Company, as Borrower, each lender from time to time party to the Credit Agreement, and Bank of America, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q filed on May 5, 2011).
10.5	—	Amended and Restated Parker Drilling Company Stock Bonus Plan effective as of January 1, 1999 (incorporated by reference to Exhibit 10(a) to the Company's Quarterly Report on Form 10-Q filed on May 14, 1999).*
10.6	—	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).*
10.7	—	Parker Drilling Company Incentive Compensation Plan (as amended and restated effective January 1, 2009) (incorporated by reference to Exhibit 10.4 to the Company's Annual Report on Form 10-K filed on March 1, 2011)*
10.8	—	Parker Drilling Company Third Amended and Restated 1997 Stock Plan effective July 24, 2002 (incorporated by reference to Exhibit 10(e) to the Company's Annual Report on Form 10-K filed on March 20, 2003).*
10.9	—	Form of Stock Option Award Agreement under the Parker Drilling Company Third Amended and Restated 1997 Stock Plan (incorporated by reference to Exhibit 10(m) to the Company's Annual Report on Form 10-K filed on March 16, 2005).*
10.10	—	Form of Stock Grant Award Agreement under the Parker Drilling Company Third Amended and Restated 1997 Stock Plan (incorporated by reference to Exhibit 10(n) to the Company's Annual Report on Form 10-K filed on March 16, 2005).*
10.11	—	Parker Drilling Company 2005 Long Term Incentive Plan 2005 LTIP (incorporated by reference to the Annex E to the Company's Definitive Proxy Statement filed on March 25, 2005).*
10.12	—	Amendment No. 1 to the Parker Drilling Company 2005 LTIP (incorporated by reference to Annex B to the Company's Definitive Proxy Statement filed on March 21, 2008).*
10.13	—	Second Amendment to the Parker Drilling Company 2005 LTIP, dated December 13, 2008 (incorporated by reference to Exhibit 10(j) to the Company's Annual Report on Form 10-K filed on March 2, 2009).*
10.14	—	Form of Parker Drilling Company Restricted Stock Agreement under the 2005 LTIP (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on May 3, 2005).*
10.15	—	Form of Parker Drilling Company Performance Based Restricted Stock Agreement under the 2005 LTIP (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on May 3, 2005).*
10.16	—	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).*
10.17	—	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).*
10.18	—	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).*

Exhibit Number		Description
10.19	—	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).*
10.20	—	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).*
10.21	—	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).*
10.22	—	Employment Agreement, dated as of October 23, 2009, by and between Parker Drilling Company and David C. Mannon (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on October 29, 2009).*
10.23	—	First Amendment dated August 29, 2011 to Employment Agreement between Mr. David C. Mannon and Parker Drilling Company, effective October 23, 2009 (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on August 30, 2011).*
10.24	—	Employment Agreement, dated as of December 29, 2010, by and between Parker Drilling Company and W. Kirk Brassfield (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on January 4, 2011).*
10.25	—	First Amendment dated August 29, 2011 to Employment Agreement between Mr. W. Kirk Brassfield and Parker Drilling Company, effective December 29, 2010 (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on August 30, 2011).*
10.26	—	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).*
10.27	—	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).*
10.28	—	Consulting Agreement between Parker Drilling Company and Robert L. Parker Sr. dated April 12, 2006 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on April 12, 2006).*
10.29	—	Amendment to Consulting Agreement between Parker Drilling Company and Robert L. Parker Sr., effective as of May 1, 2008. (incorporated by reference to Exhibit 10(t) to the Company's Annual Report on Form 10-K filed on March 2, 2009)*
10.30	—	Second Amendment to Consulting Agreement between Parker Drilling Company and Robert L. Parker Sr., dated May 1, 2009 (incorporated by reference to Exhibit 10(n)(3) to the Company's Annual Report on Form 10-K filed on March 3, 2010).*
10.31	—	Third Amendment to Consulting Agreement between Parker Drilling Company and Robert L. Parker Sr. dated May 1, 2010. (incorporated by reference to Exhibit 10.28 to the Company's Annual Report on Form 10-K filed on March 1, 2011)*
10.32	—	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).*
10.33	—	Confirmation of Convertible Bond Hedge Transaction, dated as of June 28, 2007, by and between Parker Drilling Company and Bank of America, N.A (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on July 5, 2007).

Exhibit Number		Description
10.34	—	Confirmation of Convertible Bond Hedge Transaction, dated as of June 28, 2007, by and between Parker Drilling Company and Deutsche Bank AG London (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on July 5, 2007).
10.35	—	Confirmation of Convertible Bond Hedge Transaction, dated as of June 28, 2007, by and between Parker Drilling Company and Lehman Brothers OTC Derivatives Inc. (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on July 5, 2007).
10.36	—	Confirmation of Issuer Warrant Transaction dated as of June 28, 2007, by and between Parker Drilling Company and Bank of America, N.A. (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed on July 5, 2007).
10.37	—	Confirmation of Issuer Warrant Transaction, dated as of June 28, 2007, by and between Parker Drilling Company and Deutsche Bank AG London (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K filed on July 5, 2007).
10.38	—	Confirmation of Issuer Warrant Transaction dated as of June 28, 2007, by and between Parker Drilling Company and Lehman Brothers OTC Derivatives Inc. (incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K filed on July 5, 2007).
10.39	—	Amendment to Confirmation of Issuer Warrant Transaction dated as of June 29, 2007, by and between Parker Drilling Company and Bank of America, N.A. (incorporated by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K filed on July 5, 2007).
10.40	—	Amendment to Confirmation of Issuer Warrant Transaction, dated as of June 29, 2007, by and between Parker Drilling Company and Deutsche Bank AG, London Branch (incorporated by reference to Exhibit 10.8 to the Company's Current Report on Form 8-K filed on July 5, 2007).
10.41	—	Amendment to Confirmation of Issuer Warrant Transaction, dated as of June 29, 2007, by and between Parker Drilling Company Lehman Brothers OTC Derivatives Inc. (incorporated by reference to Exhibit 10.9 to the Company's Current Report on Form 8-K filed on July 5, 2007).
21	—	Subsidiaries of the Registrant.
23.1	—	Consent of KPMG LLP.
31.1	—	David C. Mannon, President and Chief Executive Officer, Rule 13a-14(a)/15d-14(a) Certification.
31.2	—	W. Kirk Brassfield, Senior Vice President and Chief Financial Officer, Rule 13a-14(a)/15d-14(a) Certification.
32.1	—	David C. Mannon, President and Chief Executive Officer, Section 1350 Certification.
32.2	—	W. Kirk Brassfield, Senior Vice President and Chief Financial Officer, Section 1350 Certification.
101.INS	—	XBRL Instance Document.
101.SCH	—	XBRL Taxonomy Schema Document.
101.CAL	—	XBRL Calculation Linkbase Document.
101.LAB	—	XBRL Label Linkbase Document.
101.PRE	—	XBRL Presentation Linkbase Document.
101.DEF	—	XBRL Definition Linkbase Document.

* — Management contract, compensatory plan or agreement.

PARKER DRILLING COMPANY AND SUBSIDIARIES

SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS

Classifications	Balance at beginning of year	Charged to cost and expenses	Charged to other accounts	Deductions	Balance at end of year
			(Dollars in Thousands)		
Year ended December 31, 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
Year ended December 31, 2010					
Allowance for doubtful accounts and notes	$ 4,095	$3,244	$ 211	$ 108	$7,020
Allowance for obsolete rig materials and supplies	$ —	$ 309	$ —	$ —	$ 309
Deferred tax valuation allowance	$ 5,194	$ 338	$ —	$ —	$5,532
Year ended December 31, 2009					
Allowance for doubtful accounts and notes	$ 3,169	$2,246	$ —	$ 1,320	$4,095
Allowance for obsolete rig materials and supplies	$ —	$ —	$ —	$ —	$ —
Deferred tax valuation allowance	$ 4,556	$ 638	$ —	$ —	$5,194

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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/ W. Kirk Brassfield
W. Kirk Brassfield
Senior Vice President and Chief Financial Officer

Date: March 6, 2012

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/ Robert L. Parker Jr. Robert L. Parker Jr.	Executive Chairman and Director	March 6, 2012
By: /s/ David C. Mannon David C. Mannon	President, Chief Executive Officer, and Director (Principal Executive Officer)	March 6, 2012
By: /s/ W. Kirk Brassfield W. Kirk Brassfield	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	March 6, 2012
By: /s/ Philip A. Schlom Philip A. Schlom	Controller (Principal Accounting Officer)	March 6, 2012
By: Jonathan M. Clarkson	Director	March 6, 2012
By: /s/ George J. Donnelly George J. Donnelly	Director	March 6, 2012
By: /s/ John W. Gibson Jr. John W. Gibson Jr.	Director	March 6, 2012
By: /s/ Robert W. Goldman Robert W. Goldman	Director	March 6, 2012
By: /s/ Gary R. King Gary R. King	Director	March 6, 2012
By: /s/ Robert E. McKee III Robert E. McKee III	Director	March 6, 2012
By: Richard D. Paterson	Director	March 6, 2012
By: /s/ Roger B. Plank Roger B. Plank	Director	March 6, 2012
By: R. Rudolph Reinfrank	Director	March 6, 2012

INDEX TO EXHIBITS

Exhibit Number		Description
21	—	Subsidiaries of the Registrant.
23.1	—	Consent of KPMG LLP — Independent Registered Public Accounting Firm.
31.1	—	David C. Mannon, President and Chief Executive Officer, Rule 13a-14(a)/15d-14(a) Certification.
31.2	—	W. Kirk Brassfield, Senior Vice President and Chief Financial Officer, Rule 13a-14(a)/15d-14(a) Certification.
32.1	—	David C. Mannon, President and Chief Executive Officer, Section 1350 Certification.
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101.LAB	—	XBRL Label Linkbase Document.
101.PRE	—	XBRL Presentation Linkbase Document.
101.DEF	—	XBRL Definition Linkbase Document.

EXHIBIT 21

SUBSIDIARIES OF THE REGISTRANT

Consolidated Subsidiaries of the Registrant
(Jurisdiction of incorporation):

Parker Drilling Company of Oklahoma, Incorporated (Oklahoma)	100%
Parker Technology, Inc. (Oklahoma)	100%
Parker Drilling Company Limited LLC (Delaware)	100%
Parker North America Operations, Inc. (Nevada)(3)	100%
Parker Drilling Company (Bolivia) S.A. (Bolivia)	100%
Universal Rig Service LLC (Delaware)	100%
Parker Drilling Arctic Operating Inc.	100%
Parker Drilling Domestic Holding Company LLC(2)	100%
Parker Drilling International Holding Company LLC(1)	100%
Parker Drilling Management Services, Inc.(4)	100%

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

(1) Parker Drilling International Holding Company owns 64.8% of Parker Drilling Eurasia, Inc.

(2) Parker Drilling Domestic Holding Company owns 100% of Choctaw International Rig Corp. (Nevada); Creek International Rig Corp. (Nevada) and Parker Drilling Company of Argentina, Inc. (Nevada). It also owns 74% of Parker Drilling Pacific Rim, Inc. (Delaware).

(3) Parker North America Operations, Inc. owns 100% of Parker Drilling Company North America, Inc. (Nevada); Parker USA Drilling Company (Nevada) and Parker Drilling Offshore Corporation (Nevada).*

* Parker Drilling Offshore Corporation owns 100% of the following entities:

- Mallard Argentine Holdings, Ltd. (Cayman Islands)
- Mallard Drilling of South America, Inc. (Cayman Islands)
- Mallard Drilling of Venezuela, Inc. (Cayman Islands)
- Parker Drilling Offshore International, Inc. (formerly Mallard Drilling International, Inc.)(Cayman Islands), which owns 100% of Parker Drilling (Nigeria) Limited (Nigeria) and 100% of KDN Drilling Limited (Nigeria).
- Parker Drilling Offshore USA, L.L.C. (Oklahoma), which owns 100% of Parker Drilling Company of Mexico, LLC (Nevada), 98% of Parker Drilling de Mexico, SRL (Mexico), 2% of PD Servicios Integrales, SRL (Mexico) and 100% of Parker Enex, LLC (Delaware).
- Parker Technology, L.L.C. (Louisiana)
- Parker Tools, LLC (Oklahoma), which owns 99% of Quail Tools, L.P. (formerly Quail Tools, L.L.P.) (Oklahoma).
- Quail USA, LLC (Oklahoma), which owns 1% of Quail Tools, L.P. (formerly Quail Tools, L.L.P.) (Oklahoma).

SUBSIDIARIES OF THE REGISTRANT ***(continued)***

* Parker Drilling Offshore Corporation owns 98% of PD Servicios Integrales, SRL (Mexico).
* Parker Drilling Offshore Corporation owns 2% of Parker Drilling de Mexico, SRL (Mexico).
* Parker Drilling Offshore Corporation owns 35.2% of Parker Drilling Eurasia, Inc. (Delaware), which owns 100% of Parker Drilling Company International Limited (Nevada), 100% of Parker Drilling Company Eastern Hemisphere, Ltd. Co. (Oklahoma), 100% of Parker Drillserv, LLC (Delaware), 100% of Parker Drilltech, LLC (Delaware) and 99.96% of PD Offshore Holdings C.V. (Netherlands) which owns 100% of Parker 3source, LLC (Delaware) and 99.97% of PD Selective Holdings C.V. (Netherlands) which owns 100% of the following entities:
    - Parker Drillex, LLC (Delaware)
    - Parker Drilling AME Limited (Cayman Islands)
    - Parker Drilling Company of New Guinea, LLC (Delaware)
    - Parker Drilling Company of Sakhalin (Russia)
    - Parker Drilling Company of Singapore, LLC (Delaware)
    - Parker Drilling Netherlands B.V. (Netherlands)
    - Parker Drillsource, LLC (Delaware)
    - PD Labor Services, Ltd. (Cayman Islands).
    - PD Labor Sourcing, Ltd. (Cayman Islands)
    - PD Personnel Services, Ltd. (Cayman Islands) and 99.9% of Parker Drilling Company Kuwait Limited (Bahamas).
    - Parker Singapore Rig Holding Pte. Ltd. (Singapore)
* Parker Drilling Offshore Corporation owns 26% of Parker Drilling Pacific Rim, Inc. (Delaware), which owns 100% of Parker Rigsource, LLC (Delaware) and 99.88% of PD International Holdings C.V. (Netherlands) which owns 100% of Parker 5272, LLC (Delaware) and 99.96% of PD Dutch Holdings C.V. (Netherlands) which owns 100% of the following entities:
    - Parker Drilling (Kazakstan), LLC (Delaware)
    - Parker Drilling Company International, LLC (Delaware)
    - Parker Drilling Company of New Zealand Limited (New Zealand)
    - Parker Drilling Dutch B.V. (Netherlands)
    - Parker Drilling International of New Zealand Limited (New Zealand)

(4) Parker Drilling Management Services, Inc. owns 1% of PD Management Resources, L.P., and 100% of Parker USA Resources, LLC, which owns 99% of PD Management Resources, L.P.

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Board of Directors
Parker Drilling Company:

We consent to the incorporation by reference in the registration statement (No. 333-144111) on Form S-3 and in the registration statements (Nos. 333-167695, 333-158130, 333-124697, 333-59132, 333-57345, 333-41369, 333-84069, 333-99187) on Form S-8 of Parker Drilling Company of our report dated March 6, 2012, with respect to the consolidated balance sheets of Parker Drilling Company as of December 31, 2011 and 2010, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2011, the related financial statement schedules and the effectiveness of internal control over financial reporting as of December 31, 2011, which reports appear in the December 31, 2011 annual report on Form 10-K of Parker Drilling Company.

/S/ KPMG LLP

Houston, Texas
March 6, 2012

EXHIBIT 31.1

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

I, David C. Mannon, certify that:

1. I have reviewed this annual report on Form 10-K for the period ended December 31, 2011, of Parker Drilling Company (the registrant);

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

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

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

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

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

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

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

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

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

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

Date: March 6, 2012

/s/ David C. Mannon
David C. Mannon
President and Chief Executive Officer

EXHIBIT 31.2

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

I, W. Kirk Brassfield, certify that:

1. I have reviewed this annual report on Form 10-K for the period ended December 31, 2011, of Parker Drilling Company (the registrant);

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

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

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

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

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

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

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

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

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

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

Date: March 6, 2012

/s/ W. Kirk Brassfield
W. Kirk Brassfield
Senior Vice President and Chief Financial Officer

EXHIBIT 32.1

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

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

1. The Company's Annual Report on Form 10-K for the year ended December 31, 2011 (the "Report) fully complies with the requirements of section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Dated: March 6, 2012

/s/ David C. Mannon
David C. Mannon
President and Chief Executive Officer

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

EXHIBIT 32.2

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

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

1. The Company's Annual Report on Form 10-K for the year ended December 31, 2011 (the "Report) fully complies with the requirements of section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Dated: March 6, 2012

/s/ W. Kirk Brassfield

W. Kirk Brassfield
Senior Vice President and Chief Financial Officer

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