HERCULES OFFSHORE, INC.
Form 10-K
March 01, 2012
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)

OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2011

Commission file number: 0-51582

Hercules Offshore, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**56-2542838**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
9 Greenway Plaza, Suite 2200 Houston, Texas	**77046**
(Address of principal executive offices)	*(Zip Code)*

Registrant s telephone number, including area code:

(713) 350-5100

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

Title of Each Class	Name of Exchange on Which Registered
Common Stock, $0.01 par value per share	NASDAQ Global Select Market
Rights to Purchase Preferred Stock	NASDAQ Global Select Market

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 þ

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

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 þ 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 (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) 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 þ	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 þ

The aggregate market value of the registrant s common stock held by non-affiliates as of June 30, 2011, based on the closing price on the NASDAQ Global Select Market on such date, was approximately $630 million. As of such date, the registrant s directors and executive officers and Seahawk Drilling, Inc. were considered affiliates of the registrant for this purpose.

As of February 24, 2012, there were 138,160,365 shares of the registrant s common stock, par value $0.01 per share, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant s definitive proxy statement for the Annual Meeting of Stockholders to be held on May 15, 2012 are incorporated by reference into Part III of this report.

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PART I

Item 1. Business

In this Annual Report on Form 10-K, we refer to Hercules Offshore, Inc. and its subsidiaries as we, the Company or Hercules Offshore, unless the context clearly indicates otherwise. Hercules Offshore, Inc. is a Delaware corporation formed in July 2004, with its principal executive offices located at 9 Greenway Plaza, Suite 2200, Houston, Texas 77046. Hercules Offshore s telephone number at such address is (713) 350-5100 and our Internet address is www.herculesoffshore.com.

Overview

We are a leading provider of shallow-water drilling and marine services to the oil and natural gas exploration and production industry globally. We provide these services to national oil and gas companies, major integrated energy companies and independent oil and natural gas operators. As of February 23, 2012, we owned a fleet of 42 jackup rigs, seventeen barge rigs, two submersible rigs, one platform rig, 58 liftboat vessels and operate an additional five liftboat vessels owned by a third party. Our diverse fleet is capable of providing services such as oil and gas exploration and development drilling, well service, platform inspection, maintenance and decommissioning operations in several key shallow-water provinces around the world.

We report our business activities in five business segments, which as of February 23, 2012, included the following:

Domestic Offshore includes 34 jackup rigs and two submersible rigs in the U.S. Gulf of Mexico that can drill in maximum water depths ranging from 85 to 350 feet. Eighteen of the jackup rigs are either working on short-term contracts or available for contracts and sixteen are cold stacked. Both submersibles are cold stacked.

International Offshore includes eight jackup rigs and one platform rig outside of the U.S. Gulf of Mexico. We have two jackup rigs contracted offshore Saudi Arabia, one jackup rig preparing for a contract in Indonesia, one jackup rig contracted offshore in the Democratic Republic of Congo and one platform rig contracted offshore in Mexico. In addition, we have one jackup rig warm stacked and one jackup rig cold stacked in Bahrain, one jackup rig warm stacked in Malaysia as well as one jackup rig contracted in Angola, however, it is currently in a shipyard in Mississippi undergoing repairs and is estimated to be out of service through the first quarter of 2012. In addition to owning and operating our own rigs, we have the Construction Management Agreement and the Services Agreement with Discovery Offshore with respect to each of its Rigs.

Inland includes a fleet of six conventional and eleven posted barge rigs that operate inland in marshes, rivers, lakes and shallow bay or coastal waterways along the U.S. Gulf Coast. Three of our inland barges are either operating on short-term contracts or available and fourteen are cold stacked.

Domestic Liftboats includes 40 liftboats in the U.S. Gulf of Mexico. Thirty-four are operating or available for contracts and six are cold stacked.

International Liftboats includes 23 liftboats. Eighteen are operating or available for contracts offshore West Africa, including five liftboats owned by a third party, three are cold stacked offshore West Africa and two are operating or available for contracts in the Middle East region.

Asset Purchase

On April 27, 2011, we completed our acquisition of 20 jackup rigs and related assets, accounts receivable, accounts payable and certain contractual rights from Seahawk Drilling, Inc. and certain of its subsidiaries (Seahawk) (Seahawk Transaction) for total consideration of approximately $150.3 million consisting of $25.0 million of cash and 22.1 million shares of Hercules common stock, net of a working capital adjustment. The fair value of the shares issued was determined using the closing price of our common stock of $5.68 on April 27, 2011. The results of Seahawk are included in our results from the date of acquisition.

Asset Dispositions

In May 2011, we completed the sale of substantially all of Delta Towing s assets and certain liabilities for aggregate consideration of $30 million in cash and recognized a loss on the sale of approximately $13 million.

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In addition, we retained the working capital of our Delta Towing business which was approximately $6 million at the date of sale. The results of operations of the Delta Towing segment are reflected in the Consolidated Statements of Operations for all periods presented as discontinued operations.

We also sold various rigs and other miscellaneous assets during the year ended December 31, 2011.

Investment

In January 2011, we paid $10 million to purchase 5.0 million shares, an initial investment in approximately eight percent of the total outstanding equity of a new entity incorporated in Luxembourg, Discovery Offshore S.A. (Discovery Offshore), which investment was used by Discovery Offshore towards funding the down payments on two new-build ultra high specification harsh environment jackup drilling rigs (collectively the Rigs or individually Rig). The two Rigs are expected to be delivered in the second and fourth quarter of 2013, respectively. Discovery Offshore also held options to purchase two additional rigs of the same specifications that expired in the fourth quarter of 2011.

We also executed a construction management agreement (the Construction Management Agreement) and a services agreement (the Services Agreement) with Discovery Offshore with respect to each of the Rigs. Under the Construction Management Agreements, we will plan, supervise and manage the construction and commissioning of the Rigs in exchange for a fixed fee of $7.0 million per Rig, which we received in February 2011. Pursuant to the terms of the Services Agreements, we will market, manage, crew and operate the Rigs and any other rigs that Discovery Offshore subsequently acquires or controls, in exchange for a fixed daily fee of $6,000 per Rig plus five percent of Rig-based EBITDA (EBITDA excluding SG&A expense) generated per day per Rig, which commences once the Rigs are completed and operating. Under the Services Agreements, Discovery Offshore will be responsible for operational and capital expenses for the Rigs. We are entitled to a minimum fee of $5 million per Rig in the event Discovery Offshore terminates a Services Agreement in the absence of a breach of contract by Hercules Offshore.

In addition to the $10 million investment, we received 500,000 additional shares worth $1.0 million to cover our costs incurred and efforts expended in forming Discovery Offshore. We were issued warrants to purchase up to 5.0 million additional shares of Discovery Offshore stock at a strike price of 11.5 Norwegian Kroner per share which is exercisable in the event that the Discovery Offshore stock price reaches an average equal to or higher than 23 Norwegian Kroner per share for 30 consecutive trading days. The warrants were issued to additionally compensate us for our costs incurred and efforts expended in forming Discovery Offshore. As of December 31, 2011, Discovery Offshore s stock price was 8.50 Norwegian Kroner per share. We have no other financial obligations or commitments with respect to the Rigs or our ownership in Discovery Offshore. Two of our officers are on the Board of Directors of Discovery Offshore.

Investigations

On April 4, 2011, we received a subpoena issued by the Securities and Exchange Commission (SEC) requesting the delivery of certain documents to the SEC in connection with its investigation into possible violations of the securities laws, including possible violations of the Foreign Corrupt Practices Act (FCPA) in certain international jurisdictions where we conduct operations. We were also notified by the Department of Justice (DOJ) on April 5, 2011, that certain of our activities are under review by the DOJ.

We, through the Audit Committee of the Board of Directors, have engaged an outside law firm with significant experience in FCPA-related matters to conduct an internal review, and intend to continue to cooperate with the SEC and DOJ in their investigations. At this time, it is not possible to predict the outcome of the investigations, the expenses we will incur associated with these matters, or the impact on the price of our common stock or other securities as a result of these investigations.

Our Fleet

Our jackup rigs, submersible rigs and barge rigs are used primarily for exploration and development drilling in shallow waters. Under most of our contracts, we are paid a fixed daily rental rate called a dayrate, and we are required to pay all costs associated with our own crews as well as the upkeep and insurance of the rig and equipment. Dayrate drilling contracts typically provide for higher rates while the unit is operating and lower rates or a lump sum payment for periods of mobilization or when operations are interrupted or restricted by equipment breakdowns, adverse weather conditions or other factors.

Our liftboats are self-propelled, self-elevating vessels with a large open deck space, which provides a versatile, mobile and stable platform to support a broad range of offshore maintenance and construction services throughout the life of an oil or natural gas well. A liftboat contract generally is based on a flat dayrate for the vessel and crew. Our liftboat dayrates are determined by prevailing market rates, vessel availability and historical rates paid by the specific customer. Under most of our liftboat contracts, we receive a variable rate for reimbursement of costs such as catering, fuel, oil, rental equipment, crane overtime and other items. Liftboat contracts generally are for shorter terms than are drilling contracts, although international liftboat contracts may have terms of greater than one year.

Jackup Drilling Rigs

Jackup rigs are mobile, self-elevating drilling platforms equipped with legs that can be lowered to the ocean floor until a foundation is established to support the drilling platform. Once a foundation is established, the drilling platform is jacked further up the legs so that the platform is above the highest expected waves. The rig hull includes the drilling rig, jackup system, crew quarters, loading and unloading facilities, storage areas for bulk and liquid materials, helicopter landing deck and other related equipment.

Jackup rig legs may operate independently or have a lower hull referred to as a mat attached to the lower portion of the legs in order to provide a more stable foundation in soft bottom areas, similar to those encountered in certain of the shallow-water areas of the U.S. Gulf of Mexico or U.S. GOM . Mat-supported rigs generally are able to more quickly position themselves on the worksite and more easily move on and off location than independent leg rigs. Thirty-three of our jackup rigs are mat-supported and nine are independent leg rigs.

Thirty-two of our rigs have a cantilever design that permits the drilling platform to be extended out from the hull to perform drilling or workover operations over some types of pre-existing platforms or structures. Ten rigs have a slot-type design, which requires drilling operations to take place through a slot in the hull. Slot-type rigs are usually used for exploratory drilling rather than development drilling, in that their configuration makes them difficult to position over existing platforms or structures. Historically, jackup rigs with a cantilever design have maintained higher levels of utilization than rigs with a slot-type design.

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As of February 23, 2012, twenty-three of our jackup rigs were under contract ranging in duration from well-to-well to three years, at an average contract dayrate of approximately $63,000. In the following table, ILS means an independent leg slot-type jackup rig, MC means a mat-supported cantilevered jackup rig, ILC means an independent leg cantilevered jackup rig and MS means a mat-supported slot-type jackup rig.

The following table contains information regarding our jackup rig fleet as of February 23, 2012.

Rig Name	Type	Year Built/ Upgraded(c)	Maximum/ Minimum Water Depth Rating (Feet)	Rated Drilling Depth(a) (Feet)	Location	Status(b)
Hercules 85	ILS	1982	85/9	20,000	U.S. GOM	Cold Stacked
Hercules 101	MC	1980	100/20	20,000	U.S. GOM	Cold Stacked
Hercules 120	MC	1958	120/22	18,000	U.S. GOM	Contracted
Hercules 150	ILC	1979	150/10	20,000	U.S. GOM	Contracted
Hercules 153	MC	1980/2007	150/22	25,000	U.S. GOM	Cold Stacked
Hercules 156	ILC	1983	150/14	20,000	Bahrain	Cold Stacked
Hercules 170	ILC	1981/2006	170/16	16,000	Bahrain	Warm Stacked
Hercules 173	MC	1971	173/22	15,000	U.S. GOM	Contracted
Hercules 185	ILC	1982/2009	150/20	20,000	Mississippi	Shipyard
Hercules 200	MC	1979	200/23	20,000	U.S. GOM	Contracted
Hercules 201	MC	1981	200/23	20,000	U.S. GOM	Contracted
Hercules 202	MC	1981	200/23	20,000	U.S. GOM	Contracted
Hercules 203	MC	1982	200/23	20,000	U.S. GOM	Cold Stacked
Hercules 204	MC	1981	200/23	20,000	U.S. GOM	Contracted
Hercules 205	MC	1979/2003	200/23	20,000	U.S. GOM	Contracted
Hercules 206	MC	1980/2003	200/23	20,000	U.S. GOM	Cold Stacked
Hercules 207	MC	1981	200/23	20,000	U.S. GOM	Cold Stacked
Hercules 208(d)	MC	1980/2008	200/22	20,000	Vietnam	Ready Stacked
Hercules 209	MC	1981/2002	200/23	20,000	U.S. GOM	Cold Stacked
Hercules 211	MC	1980	200/23	18,000(e)	U.S. GOM	Cold Stacked
Hercules 212	MC	1982	200/23	20,000	U.S. GOM	Contracted
Hercules 213	MC	1981/2002	200/23	20,000	U.S. GOM	Contracted
Hercules 214	MC	1982	200/23	20,000	U.S. GOM	Shipyard
Hercules 250	MS	1974	250/24	20,000	U.S. GOM	Cold Stacked
Hercules 251	MS	1978	250/24	20,000	U.S. GOM	Contracted
Hercules 252	MS	1978	250/24	20,000	U.S. GOM	Cold Stacked
Hercules 253	MS	1982	250/24	20,000	U.S. GOM	Contracted
Hercules 257	MS	1979	250/24	20,000	U.S. GOM	Cold Stacked
Hercules 258	MS	1979/2008	250/24	20,000	Malaysia	Warm Stacked
Hercules 259	MS	1975/2002	250/24	20,000	U.S. GOM	Cold Stacked
Hercules 260	ILC	1979/2008	250/12	20,000	Democratic Republic of Congo	Contracted
Hercules 261	ILC	1979/2008	250/12	20,000	Bahrain	Shipyard
Hercules 262	ILC	1982/2008	250/12	20,000	Saudi Arabia	En route to Shipyard
Hercules 263	MC	1982/2002	250/23	20,000	U.S. GOM	Contracted
Hercules 264	MC	1976/1999	250/23	25,000	U.S. GOM	Contracted
Hercules 265	MC	1982	250/25	20,000	U.S. GOM	Contracted
Hercules 300	MC	1974/1999	300/25	25,000	U.S. GOM	Contracted

Hercules 350	ILC	1982	350/16	25,000	U.S. GOM	Ready Stacked
Hercules 2002	MC	1982	200/23	20,000	U.S. GOM	Cold Stacked
Hercules 2003	MC	1981	200/23	20,000	U.S. GOM	Cold Stacked
Hercules 2500	MS	1981/1996	250/24	20,000	U.S. GOM	Cold Stacked
Hercules 2501	MS	1975/2002	250/24	20,000	U.S. GOM	Cold Stacked

(a) Rated drilling depth means drilling depth stated by the manufacturer of the rig. Depending on deck space and other factors, a rig may not have the actual capacity to drill at the rated drilling depth.

(b) Rigs designated as Contracted are under contract while rigs described as Ready Stacked are not under contract but generally are ready for service. Rigs described as Warm Stacked may have a reduced number of crew, but only require a full crew to be ready for service. Rigs described as Cold Stacked are not actively marketed, normally require the hiring of an entire crew and require a maintenance review and refurbishment before they can function as a drilling rig. Rigs described as Shipyard are undergoing maintenance, repairs or upgrades and may or may not be actively marketed depending on the length of stay in the shipyard.

(c) Dates shown are the original date the rig was built and the date of the most recent upgrade and/or major refurbishment, if any.

(d) This rig is currently unable to operate in the U.S. Gulf of Mexico due to the United States Department of Transportation Maritime Administration (MARAD) restrictions.

(e) Rated workover depth. *Hercules 211* is currently configured for workover activity, which includes maintenance and repair or modification of wells that have already been drilled and completed to enhance or resume the well s production.

Other Drilling Rigs

A submersible rig is a mobile drilling platform that is towed to the well site where it is submerged by flooding its lower hull tanks until it rests on the sea floor, with the upper hull above the water surface. After completion of the drilling operation, the rig is refloated by pumping the water out of the lower hull, so that it can be towed to another location. Submersible rigs typically operate in water depths of 14 to 85 feet.

A platform drilling rig is placed on a production platform and is similar to a modular land rig. The production platform s crane is capable of lifting the modularized rig crane that subsequently sets the rig modules. The assembled rig has all the drilling, housing and support facilities necessary for drilling multiple production wells. Most platform drilling rig contracts are for multiple wells and extended periods of time on the same platform. Once work has been completed on a particular platform, the rig can be redeployed to another platform for further work.

In the following table, Sub means a submersible rig and Plat means a platform drilling rig. The following table contains information regarding our other offshore drilling rig fleet as of February 23, 2012.

Rig Name	Type	Year Built/ Upgraded(c)	Maximum/ Minimum Water Depth Rating (Feet)	Rated Drilling Depth(a) (Feet)	Location	Status(b)
Hercules 75	Sub	1983	85/14	25,000	U.S. GOM	Cold Stacked
Hercules 77	Sub	1982/2007	85/14	30,000	U.S. GOM	Cold Stacked
Platform 3	Plat	1993	N/A	25,000	Mexico	Contracted

(a) Rated drilling depth means drilling depth stated by the manufacturer of the rig. Depending on deck space and other factors, a rig may not have the actual capacity to drill at the rated drilling depth.

(b) Rigs described as Cold Stacked are not actively marketed, normally require the hiring of an entire crew and require a maintenance review and refurbishment before they can function as a drilling rig while rigs described as Contracted are under contract.

(c) Dates shown are the original date the rig was built and the date of the most recent upgrade and/or major refurbishment, if any.

Barge Drilling Rigs

Barge drilling rigs are mobile drilling platforms that are submersible and are built to work in seven to 20 feet of water. They are towed by tugboats to the drill site with the derrick lying down. The lower hull is then submerged by flooding compartments until it rests on the river or sea floor. The derrick is then raised and drilling operations are conducted with the barge resting on the bottom. Our barge drilling fleet consists of 17 conventional and posted barge rigs. A posted barge is identical to a conventional barge except that the hull and superstructure are separated by 10 to 14 foot columns, which increases the water depth capabilities of the rig.

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The following table contains information regarding our barge drilling rig fleet as of February 23, 2012.

Rig Name	Type	Year Built/ Upgraded(c)	Horsepower Rating	Rated Drilling Depth(a) (Feet)	Location	Status(b)
1	Conv.	1980	2,000	20,000	U.S. GOM	Cold Stacked
9	Posted	1981	2,000	25,000	U.S. GOM	Cold Stacked
11	Conv.	1982	3,000	30,000	U.S. GOM	Cold Stacked
15	Conv.	1981	2,000	25,000	U.S. GOM	Cold Stacked
17	Posted	1981	3,000	30,000	U.S. GOM	Ready Stacked
19	Conv.	1974	1,000	14,000	U.S. GOM	Cold Stacked
27	Posted	1979/2008	3,000	30,000	U.S. GOM	Cold Stacked
28	Conv.	1980	3,000	30,000	U.S. GOM	Cold Stacked
29	Conv.	1981	3,000	30,000	U.S. GOM	Cold Stacked
41	Posted	1981	3,000	30,000	U.S. GOM	Ready Stacked
46	Posted	1979	3,000	30,000	U.S. GOM	Cold Stacked
48	Posted	1982	3,000	30,000	U.S. GOM	Cold Stacked
49	Posted	1980	3,000	30,000	U.S. GOM	Contracted
52	Posted	1981	2,000	25,000	U.S. GOM	Cold Stacked
55	Posted	1981	3,000	30,000	U.S. GOM	Cold Stacked
57	Posted	1975	2,000	25,000	U.S. GOM	Cold Stacked
64	Posted	1979	3,000	30,000	U.S. GOM	Cold Stacked

(a) Rated drilling depth means drilling depth stated by the manufacturer of the rig. Depending on deck space and other factors, a rig may not have the actual capacity to drill at the rated drilling depth.

(b) Rigs designated as Contracted are under contract. Rigs described as Ready Stacked are not under contract but generally are ready for service. Rigs described as Cold Stacked are not actively marketed, normally require the hiring of an entire crew and require a maintenance review and refurbishment before they can function as a drilling rig.

(c) Dates shown are the original date the rig was built and the date of the most recent upgrade and/or major refurbishment, if any.

Liftboats

Unlike larger and more costly alternatives, such as jackup rigs or construction barges, our liftboats are self-propelled and can quickly reposition at a worksite or move to another location without third-party assistance. Once a liftboat is in position, typically adjacent to an offshore production platform or well, third-party service providers perform:

- production platform construction, inspection, maintenance and removal;
- well intervention and workover;
- well plug and abandonment; and

pipeline installation and maintenance.

Our liftboats are ideal working platforms to support platform and pipeline inspection and maintenance tasks because of their ability to maneuver efficiently and support multiple activities at different working heights. Diving operations may also be performed from our liftboats in connection with underwater inspections and repair. In addition, our liftboats provide an effective platform from which to perform well-servicing activities such as mechanical wireline, electrical wireline and coiled tubing operations. Technological advances, such as coiled tubing, allow more well-servicing procedures to be conducted from liftboats. Moreover, during both platform construction and removal, smaller platform components can be installed and removed more efficiently and at a lower cost using a liftboat crane and liftboat-based personnel than with a specialized construction barge or jackup rig.

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The length of the legs is the principal measure of capability for a liftboat, as it determines the maximum water depth in which the liftboat can operate. Our liftboats in the U.S. Gulf of Mexico range in leg lengths up to 229 feet, which allows us to service approximately 83% of the approximately 3,200 existing production platforms in the U.S. Gulf of Mexico. Liftboats are typically moved to a port during severe weather to avoid the winds and waves they would be exposed to in open water.

As of February 23, 2012, we owned 40 liftboats operating in the U.S. Gulf of Mexico, sixteen liftboats operating in West Africa, and two liftboats operating in the Middle East. In addition, we operated five liftboats owned by a third party in West Africa. The following table contains information regarding the liftboats we operate as of February 23, 2012.

Liftboat Name(1)	Year Built/ Upgraded(5)	Leg Length (Feet)	Deck Area (Square feet)	Maximum Deck Load (Pounds)	Location	Gross Tonnage
Whale Shark(4)	2005/2009	260	8,170	729,000	U.A.E.	1,142
Tiger Shark(3)	2001	230	5,300	1,000,000	Nigeria	469
Kingfish(3)	1996	229	5,000	500,000	U.S. GOM	188
Man-O-War(3)	1996	229	5,000	500,000	U.S. GOM	188
Wahoo(3)	1981	215	4,525	500,000	U.S. GOM	491
Blue Shark(4)	1981	215	3,800	400,000	Nigeria	1,182
Amberjack(4)	1981	205	3,800	500,000	U.A.E.	417
Bullshark(3)	1998	200	7,000	1,000,000	U.S. GOM	859
Creole Fish(3)	2001	200	5,000	798,000	Nigeria	192
Cutlassfish(3)	2006	200	5,000	798,000	Nigeria	183
Black Jack(4)	1997/2008	200	4,000	480,000	Nigeria	777
Swordfish(3)	2000	190	4,000	700,000	U.S. GOM	189
Leatherjack(3)	1998	175	3,215	575,850	U.S. GOM	168
Oilfish(4)	1996	170	3,200	590,000	Nigeria	495
Manta Ray(3)	1981	150	2,400	200,000	U.S. GOM	194
Seabass(3)	1983	150	2,600	200,000	U.S. GOM	186
F.J. Leleux(2)	1981	150	2,600	200,000	Nigeria	407
Black Marlin(4)	1984	150	2,600	200,000	Nigeria	407
Hammerhead(3)	1980	145	1,648	150,000	U.S. GOM	178
Pilotfish(4)	1990	145	2,400	175,000	Nigeria	292
Rudderfish(4)	1991	145	3,000	100,000	Nigeria	309
Blue Runner(3)	1980	140	3,400	300,000	U.S. GOM	174
Rainbow Runner(3)	1981	140	3,400	300,000	U.S. GOM	174
Pompano(3)	1981	130	1,864	100,000	U.S. GOM	196
Sandshark(3)	1982	130	1,940	150,000	U.S. GOM	196
Stingray(3)	1979	130	2,266	150,000	U.S. GOM	99
Albacore(3)	1985	130	1,764	150,000	U.S. GOM	171
Moray(3)	1980	130	1,824	130,000	U.S. GOM	178
Skipfish(3)	1985	130	1,116	110,000	U.S. GOM	91
Sailfish(3)	1982	130	1,764	137,500	U.S. GOM	179
Mahi Mahi(3)	1980	130	1,710	142,000	U.S. GOM	99
Triggerfish(3)	2001	130	2,400	150,000	U.S. GOM	195
Scamp(4)	1984	130	2,400	150,000	Nigeria	195
Rockfish(3)	1981	125	1,728	150,000	U.S. GOM	192
Gar(3)	1978	120	2,100	150,000	U.S. GOM	98

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Liftboat Name(1)	Year Built/ Upgraded(5)	Leg Length (Feet)	Deck Area (Square feet)	Maximum Deck Load (Pounds)	Location	Gross Tonnage
Grouper(3)	1979	120	2,100	150,000	U.S. GOM	97
Sea Robin(3)	1984	120	1,507	110,000	U.S. GOM	98
Tilapia(3)	1976	120	1,280	110,000	U.S. GOM	97
Charlie Cobb(2)	1980	120	2,000	100,000	Nigeria	229
Durwood Speed(2)	1979	120	2,000	100,000	Nigeria	210
James Choat(2)	1980	120	2,000	100,000	Nigeria	210
Solefish(4)	1978	120	2,000	100,000	Nigeria	229
Tigerfish(4)	1980	120	2,000	100,000	Nigeria	210
Zoal Albrecht(2)	1982	120	2,000	100,000	Nigeria	213
Barracuda(3)	1979	105	1,648	110,000	U.S. GOM	93
Carp(3)	1978	105	1,648	110,000	U.S. GOM	98
Cobia (3)	1978	105	1,648	110,000	U.S. GOM	94
Dolphin (3)	1980	105	1,648	110,000	U.S. GOM	97
Herring(3)	1979	105	1,648	110,000	U.S. GOM	97
Marlin(3)	1979	105	1,648	110,000	U.S. GOM	97
Corina(3)	1974	105	953	100,000	U.S. GOM	98
Pike(3)	1980	105	1,360	130,000	U.S. GOM	92
Remora(3)	1976	105	1,179	100,000	U.S. GOM	94
Wolffish(3)	1977	105	1,044	100,000	U.S. GOM	99
Seabream(3)	1980	105	1,140	100,000	U.S. GOM	92
Sea Trout(3)	1978	105	1,500	100,000	U.S. GOM	97
Tarpon(3)	1979	105	1,648	110,000	U.S. GOM	97
Palometa(3)	1972	105	780	100,000	U.S. GOM	99
Jackfish(3)	1978	105	1,648	110,000	U.S. GOM	99
Bonefish(4)	1978	105	1,344	90,000	Nigeria	97
Croaker(4)	1976	105	1,344	72,000	Nigeria	82
Gemfish(4)	1978	105	2,000	100,000	Nigeria	223
Tapertail(4)	1979	105	1,392	110,000	Nigeria	100

(1) The *Skipfish, Mahi Mahi, Corina, Remora, Wolffish, Palometa, Bonefish, Croaker* and *Gemfish* are currently cold stacked. All other liftboats are either available or operating.

(2) We operate these vessels; however, they are owned by a third party.

(3) Pursuant to U.S. Coast Guard documentation. International regulatory bodies or non-U.S. Flag states may calculate gross tonnage differently than the U.S. Coast Guard.

(4) Pursuant to the registry documents issued by the Republic of Panama.

(5) Dates shown are the original date the vessel was built and the date of the most recent upgrade and/or major refurbishment, if any.

Competition

The shallow-water businesses in which we operate are highly competitive. Domestic drilling and liftboat contracts are traditionally short term in nature, whereas international drilling and liftboat contracts are longer term in nature. The contracts are typically awarded on a competitive bid basis. Pricing is often the primary factor in determining which qualified contractor is awarded a job, although technical capability of service and

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equipment, unit availability, unit location, safety record and crew quality may also be considered. Certain of our competitors in the shallow-water business may have greater financial and other resources than we have. As a result, these competitors may have a better ability to withstand periods of low utilization, compete more effectively on the basis of price, build new rigs, acquire existing rigs, and make technological improvements to existing equipment or replace equipment that becomes obsolete. Competition for offshore rigs is usually on a global basis, as drilling rigs are highly mobile and may be moved, at a cost that is sometimes substantial, from one region to another in response to demand. However, our mat-supported jackup rigs are less capable than independent leg jackup rigs of managing variable sea floor conditions found in most areas outside the Gulf of Mexico. As a result, our ability to move our mat-supported jackup rigs to certain regions in response to changes in market conditions is limited. Additionally, a number of our competitors have independent leg jackup rigs with generally higher specifications and capabilities than the independent leg rigs that we currently operate in the Gulf of Mexico. Particularly during market downturns when there is decreased rig demand, higher specification rigs may be more likely to obtain contracts than lower specification rigs.

Customers

Our customers primarily include major integrated energy companies, independent oil and natural gas operators and national oil companies. Sales to customers exceeding 10 percent or more of our total revenue are as follows:

	Year Ended December 31,		
	2011	**2010**	**2009**
Chevron Corporation (a)	25%	17%	14%
Saudi Aramco (b)	13	14	13
Oil and Natural Gas Corporation Limited (b)	9	20	16
PEMEX Exploración y Producción (PEMEX) (b)	3	3	10

(a) Revenue included in our Domestic Offshore, International Offshore, Domestic Liftboats and International Liftboats segments.

(b) Revenue included in our International Offshore segment.

Contracts

Our contracts to provide services are individually negotiated and vary in their terms and provisions. Currently, all of our drilling contracts are on a dayrate basis. Dayrate drilling contracts typically provide for payment on a dayrate basis, with higher rates while the unit is operating and lower rates or a lump sum payment for periods of mobilization or when operations are interrupted or restricted by equipment breakdowns, adverse weather conditions or other factors.

A dayrate drilling contract generally extends over a period of time covering the drilling of a single well or group of wells or covering a stated term. These contracts typically can be terminated by the customer under various circumstances such as the loss or destruction of the drilling unit or the suspension of drilling operations for a specified period of time as a result of a breakdown of major equipment or due to events beyond the control of either party. In addition, customers in some instances have the right to terminate our contracts with little or no prior notice, and without penalty or early termination payments. The contract term in some instances may be extended by the customers exercising options for the drilling of additional wells or for an additional term, or by exercising a right of first refusal. To date, most of our contracts in the U.S. Gulf of Mexico have been on a short-term basis of less than six months. Our contracts in international locations have historically been longer-term, with contract terms of up to three years. For contracts over six months in term we may have the right to pass through certain cost escalations. Our customers may have the right to terminate, or may seek to renegotiate, existing contracts if we experience downtime or operational problems above a contractual limit, if the rig is a total loss, or in other specified circumstances. A customer is more likely to seek to cancel or renegotiate its contract during periods of depressed market conditions. We could be required to pay penalties if some of our contracts with our customers are canceled due to downtime or operational problems. Suspension of drilling contracts results in the reduction in or loss of dayrates for the period of the suspension.

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A liftboat contract generally is based on a flat dayrate for the vessel and crew. Our liftboat dayrates are determined by prevailing market rates, vessel availability and historical rates paid by the specific customer. Under most of our liftboat contracts, we receive a variable rate for reimbursement of costs such as catering, fuel, oil, rental equipment, crane overtime and other items. Liftboat contracts generally are for shorter terms than are drilling contracts.

On larger contracts, particularly outside the United States, we may be required to arrange for the issuance of a variety of bank guarantees, performance bonds or letters of credit. The issuance of such guarantees may be a condition of the bidding process imposed by our customers for work outside the United States. The customer would have the right to call on the guarantee, bond or letter of credit in the event we default in the performance of the services. The guarantees, bonds and letters of credit would typically expire after we complete the services.

Contract Backlog

We calculate our contract revenue backlog, or future contracted revenue, as the contract dayrate multiplied by the number of days remaining on the contract, assuming full utilization. Backlog excludes revenue for management agreements, mobilization, demobilization, contract preparation and customer reimbursables. The amount of actual revenue earned and the actual periods during which revenue is earned will be different than the backlog disclosed or expected due to various factors. Downtime due to various operational factors, including unscheduled repairs, maintenance, operational delays, health, safety and environmental incidents, weather events in the Gulf of Mexico and elsewhere and other factors (some of which are beyond our control), may result in lower dayrates than the full contractual operating dayrate. In some of the contracts, our customer has the right to terminate the contract without penalty and in certain instances, with little or no notice. The following table reflects the amount of our contract backlog by year as of February 23, 2012:

		For the Years Ending December 31,				
	Total	**2012**	**2013**	**2014**	**2015**	**Thereafter**
			(in thousands)			
Domestic Offshore	$ 152,417	$ 152,417	$	$	$	$
International Offshore	276,022	95,381	99,568	68,373	12,700	
Inland	3,647	3,647				
Total	$ 432,086	$ 251,445	$ 99,568	$ 68,373	$ 12,700	$

Employees

As of December 31, 2011, we had approximately 2,300 employees. We require skilled personnel to operate and provide technical services and support for our rigs, barges and liftboats. As a result, we conduct extensive personnel training and safety programs.

Certain of our employees in West Africa are working under collective bargaining agreements. Additionally, efforts have been made from time to time to unionize portions of the offshore workforce in the U.S. Gulf of Mexico and Mexico. We believe that our employee relations are good.

Insurance

We maintain insurance coverage that includes coverage for physical damage, third party liability, workers compensation and employer s liability, general liability, vessel pollution and other coverages.

Our primary marine package provides for hull and machinery coverage for substantially all of our rigs and liftboats up to a scheduled value of each asset. The total maximum amount of coverage for these assets is $1.6 billion, including the newly acquired Seahawk units. The marine package includes protection and indemnity and maritime employer s liability coverage for marine crew personal injury and death and certain operational liabilities, with primary coverage (or self-insured retention for maritime employer s liability coverage) of $5.0 million per occurrence with excess liability coverage up to $200.0 million. The marine package policy also includes coverage for personal injury and death of third parties with primary and excess coverage of $25 million per occurrence with additional excess liability coverage up to $200 million, subject to a $250,000 per-occurrence deductible. The marine package also provides coverage for cargo and charterer s legal liability. The marine package includes limitations for coverage for losses caused in U.S. Gulf of Mexico named windstorms, including an annual aggregate limit of liability of $75.0 million for property damage and removal of wreck liability coverage. We also procured an additional $75.0 million excess policy for removal of wreck and certain third-party liabilities incurred in U.S. Gulf of Mexico named windstorms. Deductibles for events that are not caused by a U.S. Gulf of Mexico named windstorm are 12.5% of the insured drilling rig values per occurrence, subject to a minimum of $1.0 million, and $1.0 million per occurrence for liftboats. The deductible for drilling rigs and liftboats in a U.S. Gulf of Mexico named windstorm event is $25.0 million. Vessel pollution is covered under a Water Quality Insurance Syndicate policy (WQIS Policy) providing limits as required by applicable law, including the Oil Pollution Act of 1990. The WQIS Policy covers pollution emanating from our vessels and drilling rigs, with primary limits of $5 million (inclusive of a $3.0 million per-occurrence deductible) and excess liability coverage up to $200 million.

Control-of-well events generally include an unintended flow from the well that cannot be contained by equipment on site (e.g., a blow-out preventer), by increasing the weight of the drilling fluid, or that does not naturally close itself off through what is typically described as bridging over. We carry a contractor s extra expense policy with $25.0 million primary liability coverage for well control costs, expenses incurred to redrill wild or lost wells and pollution, with excess liability coverage up to $200 million for pollution liability that is covered in the primary policy. The policies are subject to exclusions, limitations, deductibles, self-insured retention and other conditions. In addition to the marine package, we have separate policies providing coverage for onshore foreign and domestic general liability, employer s liability, auto liability and non-owned aircraft liability, with customary deductibles and coverage. Our policy, which we renew annually, expires in April 2012.

Our drilling contracts provide for varying levels of indemnification from our customers and in most cases, may require us to indemnify our customers for certain liabilities. 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, regardless of how the loss or damage to the personnel and property may be caused. Our customers typically assume responsibility for and agree to indemnify us from any loss or liability resulting from pollution or contamination, including clean-up and removal and third-party damages arising from operations under the contract and originating below the surface of the water, including as a result of blow-outs or cratering of the well (Blowout Liability). The customer s assumption for Blowout Liability may, in certain circumstances, be limited or could be determined to be unenforceable in the event of our gross negligence, willful misconduct or other egregious conduct. We generally indemnify the customer for the consequences of spills of industrial waste or other liquids originating solely above the surface of the water and emanating from our rigs or vessels.

We are self-insured for the deductible portion of our insurance coverage. Management believes adequate accruals have been made on known and estimated exposures up to the deductible portion of our insurance coverage. Management believes that claims and liabilities in excess of the amounts accrued are adequately insured. However, our insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect us against liability from all potential consequences. In addition, there is no assurance of renewal or the ability to obtain coverage acceptable to us.

Insurance Claims

In September 2011, we were conducting a required annual spud can inspection on the *Hercules 185* in protected waters offshore Angola. While conducting the inspection, it was determined that the spud can on the starboard leg had detached from the leg. While preparing the rig for heavy-lift transport to a shipyard in Pascagoula, Mississippi to conduct the spud can repairs, additional leg damage was identified. The rig is currently in the shipyard at Pascagoula, Mississippi undergoing the repairs necessary to return the rig to service. We currently estimate that the rig will be out of service through the first quarter of 2012. During this period, the rig will be at zero dayrate pursuant to its contract with Cabinda Gulf Oil Company (Cabinda Gulf). We have discussed the expected downtime of the rig with Cabinda Gulf and Cabinda Gulf has indicated that it intends to accept the rig after the completion of the repairs and to continue the contract, although Cabinda Gulf may have the right to terminate the contract and be paid $1.0 million by us for liquidated damages. We expect to be insured for damage to the rig up to the insured value of $35.0 million, subject to a $3.5 million deductible and other

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customary limitations and exclusions. We have recorded expenses up to the deductible amount of $3.5 million during the year ended December 31, 2011 related to rig repairs, inspections and other costs and have recorded an insurance claims receivable of $6.4 million for costs incurred through December 31, 2011 in excess of the deductible, which is included in Other on the Consolidated Balance Sheet at December 31, 2011. In addition, the rig had a net book value of $50.0 million as of December 31, 2011.

In September 2011, the *Starfish*, a 140 class liftboat, was en route to a project in the Gulf of Mexico in Ship Shoal Block 116 when it was hit by a series of waterspouts and capsized. The vessel has been salvaged and our underwriters have determined that the vessel is a constructive total loss and, therefore, we will receive the full insured value of $2.5 million. We carry removal of wreck insurance adequately covering the salvage operation, subject to a $250,000 deductible. Additionally, we carry pollution insurance, subject to a $3 million deductible and other customary limitations. We have recorded an insurance claims receivable of $3.1 million for the net book value of the vessel as well as any costs incurred through December 31, 2011 in excess of the deductible, which is included in Other on the Consolidated Balance Sheet at December 31, 2011. In addition, the vessel had a net book value of $0.7 million as of December 31, 2011.

In January 2012, the *Mako*, a 175 class liftboat in Nigeria, was engulfed by a fire that originated on a third-party rig, the *KS Endeavor*. Our underwriters have determined that the vessel is considered to be a constructive total loss and, therefore, we will receive the full insured value of $8.0 million which we believe approximates the fair market value for the vessel. We carry removal of wreck insurance adequately covering the salvage operation, subject to a $250,000 deductible. Additionally, we carry pollution insurance, subject to a $3 million deductible and other customary limitations. The vessel had a net book value of $6.4 million as of December 31, 2011.

Regulation

Our operations are affected in varying degrees by federal, state, local and foreign and/or international governmental laws and regulations regarding the discharge of materials into the environment or otherwise relating to environmental protection. Our industry is dependent on demand for services from the oil and natural gas industry and, accordingly, is also affected by changing tax and other laws relating to the energy business generally. In the United States, we are subject to the jurisdiction of the U.S. Coast Guard (Coast Guard), the National Transportation Safety Board, the U.S. Customs and Border Protection (CBP), the Department of Interior, the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE), as well as classification societies such as the American Bureau of Shipping. The Coast Guard and the National Transportation Safety Board set safety standards and are authorized to investigate vessel accidents and recommend improved safety standards, and the CBP is authorized to inspect vessels at will. Coast Guard regulations also require annual inspections and periodic drydock inspections or special examinations of our vessels.

For instance, the Coast Guard issued a Policy Letter in July 2011 that provides for more frequent inspections of foreign flagged Mobile Offshore Drilling Units (MODUs) that operate on the U.S. Outer Continental Shelf (OCS). The Coast Guard will make determinations to conduct more frequent inspections of foreign flagged MODUs in accordance with its newly-implemented Mobile Offshore Drilling Unit Safety and Environmental Protection Compliance Targeting Matrix. We may be subject to increased costs and potential downtime for certain of our rigs operating on the OCS if such rigs are determined by the Coast Guard to need additional oversight and inspection under this new Policy Letter.

In addition to this new Coast Guard Policy Letter, in November 2011, the BSEE announced a change in its enforcement policies in the aftermath of the Macondo well blowout in April 2010, pursuant to which the agency has extended its regulatory enforcement reach to include contractors as well as offshore lease operators. Consequently, the BSEE may elect to hold contractors, including drilling contractors, liable for alleged violations of law arising in the BSEE s jurisdictional area. Implementation of this announced change in enforcement policy by the BSEE could subject us to added liabilities, including sanctions and penalties, as well as increased costs arising from contractual arrangements in master services agreements that failed to take into account such change in enforcement policy with respect to our operations in the U.S. Gulf of Mexico, which may have an adverse effect on our business and results of operations.

The shorelines and shallow-water areas of the U.S. Gulf of Mexico are ecologically sensitive. Heightened environmental concerns in these areas have led to higher drilling costs and a more difficult and lengthy well permitting process and, in general, have adversely affected drilling decisions of oil and natural gas companies. In the United States, our operations are subject to federal and state laws and regulations that require us to obtain and maintain specified permits or governmental approvals; control the discharge of materials into the environment; remove and cleanup materials that may harm the environment; or otherwise comply with the protection of the environment. For example, as an operator of mobile offshore units in navigable U.S. waters including the OCS, and some offshore areas, we may be liable for damages and costs incurred in connection with oil spills or other unauthorized discharges of chemicals or wastes resulting from or related to those operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions restricting some or all of our activities in the affected areas.

Laws and regulations protecting the environment have become more stringent over time and may in some cases impose strict liability, rendering a person liable for environmental damage without regard to negligence or fault on the part of such person. Some of these laws and regulations may expose us to liability for the conduct of or conditions caused by others or for acts that were in compliance with all applicable laws at the time they were performed. The application of these legal requirements or the adoption of new or more stringent legal requirements could have a material adverse effect on our financial condition and results of operations.

The U.S. Federal Water Pollution Control Act of 1972, as amended, commonly referred to as the Clean Water Act, prohibits the discharge of pollutants into the navigable waters of the United States without a permit. The regulations implementing the Clean Water Act require permits to be obtained by an operator before specified discharge activities occur. Offshore facilities must also prepare plans addressing spill prevention, control and countermeasures. In addition, while operators of vessels visiting U.S. ports historically have been excluded from obtaining permits for the discharge of ballast water and other substances incidental to the normal operation of the vessels because of an exemption under the Clean Water Act, that exemption was vacated, effective February 6, 2009. In place of the former Clean Water Act exemption, the EPA adopted a Vessel General Permit, effective December 19, 2008, that required subject vessel operators, including us, to obtain a Vessel General Permit for all of our covered vessels by February 6, 2009. We have obtained the necessary Vessel General Permit for all of our vessels to which this permitting program applies. In addition to the EPA s issuance of the Vessel General Permit, some states are, and other states are considering, regulating ballast water discharges. Violations of monitoring, reporting and permitting requirements associated with applicable ballast water discharge permitting programs or other regulatory initiatives may result in the imposition of civil and criminal penalties. Moreover, we have incurred added costs to comply with legal requirements under the Vessel General Permit and may continue to incur further costs as other legal requirements under federal and state ballast water discharge permit programs are adopted and implemented, but we do not believe that such compliance efforts will have a material adverse effect on our results of operations or financial position.

The U.S. Oil Pollution Act of 1990 (OPA), as amended, and related regulations impose a variety of requirements on responsible parties related to the prevention and/or reporting of oil spills and liability for damages resulting from such spills in waters off the U.S. A responsible party includes the owner or operator of an onshore facility, pipeline or vessel or the lessee or permittee of the area in which an offshore facility is located. OPA assigns liability to each responsible party for oil removal costs and a variety of public and private damages. Under OPA, as amended by the Coast Guard and Maritime Transportation Act of 2006, tank vessels of over 3,000 gross tons that carry oil or other hazardous materials in bulk as cargo, are subject to liability limits of (i) for a single-hulled vessel, the greater of $3,200 per gross ton or $23.5 million or (ii) for a tank vessel other than a single-hulled vessel, the greater of $2,000 per gross ton or $17.1 million. Tank vessels of 3,000 gross tons or less are subject to liability limits of (i) for a single-hulled vessel, the greater of $3,200 per gross ton or $6.4 million or (ii) for a tank vessel other than a single-hulled vessel, the greater of $2,000 per gross ton or $4.3 million. For any vessels other than tank vessels that are subject to OPA, the liability limits are the greater of $1,000 per gross ton or $854,400. Few defenses exist to the liability imposed by OPA and the liability could be substantial. Moreover, a party 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

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party fails to report a spill or to cooperate fully in the cleanup, the liability limits likewise do not apply and certain defenses may not be available. In addition, OPA imposes on responsible parties the need for proof of financial responsibility to cover at least some costs in a potential spill. As required, we have provided satisfactory evidence of financial responsibility to the Coast Guard for all of our vessels subject to such requirements.

The U.S. Outer Continental Shelf Lands Act, as amended, authorizes regulations relating to safety and environmental protection applicable to lessees and permittees operating on the OCS. Included among these are regulations that require the preparation of spill contingency plans and establish air quality standards for certain pollutants, including particulate matter, volatile organic compounds, sulfur dioxide, carbon monoxide and nitrogen oxides. Specific design and operational standards may apply to OCS vessels, rigs, platforms, vehicles and structures. Violations of lease conditions or regulations related to the environment issued pursuant to the Outer Continental Shelf Lands Act can result in substantial civil and criminal penalties, as well as potential court injunctions curtailing operations and canceling leases. Such enforcement liabilities can result from either governmental or citizen prosecution.

The U.S. Comprehensive Environmental Response, Compensation, and Liability Act, as amended, also known as CERCLA or the Superfund law, imposes liability without regard to fault or the legality of the original conduct on certain classes of persons that are considered to have contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of a facility where a release occurred, the owner or operator of a vessel from which there is a release, and entities that disposed or arranged for the disposal of the hazardous substances found at a particular site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the cost of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. Prior owners and operators are also subject to liability under CERCLA. It is also not uncommon for third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We generate wastes in the course of our routine operations that may be classified as hazardous substances.

The U.S. Resource Conservation and Recovery Act, as amended, regulates the generation, transportation, storage, treatment and disposal of onshore hazardous and non-hazardous wastes and requires states to develop programs to ensure the safe disposal of wastes. We generate nonhazardous wastes and small quantities of hazardous wastes in connection with routine operations. We believe that all of the wastes that we generate are handled in compliance in all material respects with the Resource Conservation and Recovery Act and analogous state laws.

In recent years, a variety of initiatives intended to enhance vessel security were adopted to address terrorism risks, including the Coast Guard regulations implementing the Maritime Transportation and Security Act of 2002. These regulations required, among other things, the development of vessel security plans and on-board installation of automatic information systems, or AIS, to enhance vessel-to-vessel and vessel-to-shore communications. We believe that our vessels are in substantial compliance with all vessel security regulations.

Some of our operations are conducted in the U.S. domestic trade, which is governed by the coastwise laws of the United States. The U.S. coastwise laws reserve marine transportation, including liftboat services, between points in the United States to vessels built in and documented under the laws of the United States and owned and manned by U.S. citizens. Generally, an entity is deemed a U.S. citizen for these purposes so long as:

- it is organized under the laws of the United States or a state;
- each of its president or other chief executive officer and the chairman of its board of directors is a U.S. citizen;
- no more than a minority of the number of its directors necessary to constitute a quorum for the transaction of business are non-U.S. citizens; and
- at least 75% of the interest and voting power in the corporation is held by U.S. citizens free of any trust, fiduciary arrangement or other agreement, arrangement or understanding whereby voting power may be exercised directly or indirectly by non-U.S. citizens.

Because we could lose our privilege of operating our liftboats in the U.S. coastwise trade if non-U.S. citizens were to own or control in excess of 25% of our outstanding interests, our certificate of incorporation restricts foreign ownership and control of our common stock to not more than 20% of our outstanding interests. One of our liftboats relies on an exemption from coastwise laws in order to operate in the U.S. Gulf of Mexico. If this liftboat were to lose this exemption, we would be unable to use it in the U.S. Gulf of Mexico and would be forced to seek opportunities for it in international locations.

The United States is one of approximately 170 member countries to the International Maritime Organization (IMO), a specialized agency of the United Nations that is responsible for developing measures to improve the safety and security of international shipping and to prevent marine pollution from ships. Among the various international conventions negotiated by the IMO is the International Convention for the Prevention of Pollution from Ships (MARPOL). MARPOL imposes environmental standards on the shipping industry relating to oil spills, management of garbage, the handling and disposal of noxious liquids, harmful substances in packaged forms, sewage and air emissions.

Annex VI to MARPOL sets limits on sulfur dioxide and nitrogen oxide emissions from ship exhausts and prohibits deliberate emissions of ozone depleting substances. Annex VI entered into force on May 19, 2005, and applies to all ships, fixed and floating drilling rigs and other floating platforms. Annex VI also imposes a global cap on the sulfur content of fuel oil and allows for specialized areas to be established internationally with more stringent controls on sulfur emissions. For vessels 400 gross tons and greater, platforms and drilling rigs, Annex VI imposes various survey and certification requirements. For this purpose, gross tonnage is based on the International Tonnage Certificate for the vessel, which may vary from the standard U.S. gross tonnage for the vessel reflected in our liftboat table previously. Annex VI came into force in the United States on January 8, 2009. Moreover, on July 1, 2010, amendments to Annex VI to the MARPOL Convention took effect requiring the imposition of progressively stricter limitations on sulfur emissions from ships. As a result, limitations imposed on sulfur emissions will require that fuels of vessels in covered Emission Control Areas (ECAs) contain no more than 1% sulfur. In August 2012, the North American ECA will become enforceable. The North American ECA includes areas subject to the exclusive sovereignty of the United States and extends up to 200 nautical miles from the coasts of the United States, which area includes parts of the U.S. Gulf of Mexico. Consequently, beginning on January 1, 2012, limits on marine fuel used to power ships in non-ECA areas are capped at 3.5% sulfur and, in August 2012, when the North American ECA becomes effective, the sulfur limit in marine fuel will be capped at 1%, which is the capped amount for all other ECA areas since July 1, 2010. These capped amounts will then decrease progressively until they reach 0.5% by January 1, 2020 for non-ECA areas and 0.1% by January 1, 2015 for ECA areas, including the North American ECA. The amendments also establish new tiers of stringent nitrogen oxide emissions standards for new marine engines, depending on their date of installation. Our operation of vessels in international waters, outside of the North American ECA, are subject to the requirements of Annex VI in those countries that have implemented its provisions. We believe the rigs we currently offer for international projects are generally exempt from the more costly compliance requirements of Annex VI and the liftboats we currently offer for international projects are generally exempt from or otherwise substantially comply with those requirements. Accordingly, we do not anticipate that compliance with MARPOL or Annex VI to MARPOL, whether within the North American ECA or beyond, will have a material adverse effect on our results of operations or financial position.

In response to the Macondo well blowout incident in April 2010, the U.S. Department of Interior, initially through the U.S. Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) and, upon dissolution of the BOEMRE effective October 1, 2011, through the BOEM and BSEE, has undertaken an aggressive overhaul of the offshore oil and natural gas regulatory process that has significantly impacted oil and gas development in the U.S. Gulf of Mexico. From time to time, new rules, regulations and requirements have been proposed and implemented by BOEM, BSEE or the United States Congress that materially limit or prohibit, and increase the cost of, offshore drilling in the U.S. Gulf of Mexico. These new rules, regulations and requirements include the moratorium on shallow-water drilling that was lifted in May 2010, but which has resulted in a significant delay in permits being issued in the U.S. Gulf of Mexico, the adoption of new safety requirements and policies relating to the approval of drilling permits in the U.S. Gulf of Mexico, restrictions on oil and gas development and production activities in the U.S. Gulf of Mexico, and the promulgation of numerous

Notices to Lessees that have impacted and may continue to impact our operations. In addition to these rules, regulations and requirements, the federal government is considering new legislation that could impose additional equipment and safety requirements on operators and drilling contractors in the U.S. Gulf of Mexico, as well as regulations relating to the protection of the environment, all of which could materially adversely affect our financial condition and results of operations.

Greenhouse gas emissions have increasingly become the subject of international, national, regional, state and local attention. Cap and trade initiatives to limit greenhouse gas emissions have been introduced in the European Union. Similarly, numerous bills related to climate change have been introduced in the U.S. Congress, which could adversely impact most industries. In addition, future regulation of greenhouse gas could occur pursuant to future treaty obligations, statutory or regulatory changes or new climate change legislation in the jurisdictions in which we operate. It is uncertain whether any of these initiatives will be implemented. However, based on published media reports, we believe that it is not reasonably likely that recently considered federal legislative initiatives in the U.S. will be adopted and implemented without substantial modification. Restrictions on greenhouse gas emissions or other related legislative or regulatory enactments could have an effect in those industries that use significant amounts of petroleum products, which could potentially result in a reduction in demand for petroleum products and, consequently and indirectly, our offshore support services. We are currently unable to predict the manner or extent of any such effect. Furthermore, one of the asserted long-term physical effects of climate change may be an increase in the severity and frequency of adverse weather conditions, such as hurricanes, which may increase our insurance costs or risk retention, limit insurance availability or reduce the areas in which, or the number of days during which, our customers would contract for our vessels in general and in the U.S. Gulf of Mexico in particular. We are currently unable to predict the manner or extent of any such effect.

Our non-U.S. operations are subject to other laws and regulations in countries in which we operate, including laws and regulations relating to the importation of and operation of rigs and liftboats, currency conversions and repatriation, oil and natural gas exploration and development, environmental protection, taxation of offshore earnings and earnings of expatriate personnel, the use of local employees and suppliers by foreign contractors and duties on the importation and exportation of rigs, liftboats and other equipment. Governments in some foreign countries have become increasingly active in regulating and controlling the ownership of concessions and companies holding concessions, the exploration for oil and natural gas and other aspects of the oil and natural gas industries in their countries. In some areas of the world, this governmental activity has adversely affected the amount of exploration and development work done by major oil and natural gas companies and may continue to do so. Operations in less developed countries can be subject to legal systems that are not as mature or predictable as those in more developed countries, which can lead to greater uncertainty in legal matters and proceedings.

Although significant capital expenditures may be required to comply with these governmental laws and regulations, such compliance has not materially adversely affected our earnings or competitive position. We believe that we are currently in compliance in all material respects with the environmental regulations to which we are subject.

Available Information

General information about us, including our corporate governance policies, can be found on our Internet website at *www.herculesoffshore.com*. On our website we make available, free of charge, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file or furnish them to the SEC. These filings also are available at the SEC s Internet website at *www.sec.gov*. Information contained on our website is not part of this annual report.

Segment and Geographic Information

Information with respect to revenue, operating income and total assets attributable to our segments and revenue and long-lived assets by geographic areas of operations is presented in Note 17 of our Notes to

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Consolidated Financial Statements included in Item 8 of this annual report. Additional information about our segments, as well as information with respect to the impact of seasonal weather patterns on domestic operations, is presented in Management s Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this annual report.

Item 1A. ***Risk Factors***

New and proposed laws, regulations and legal requirements arising out of the Macondo well blowout incident could prevent or cause delays for our customers in obtaining approval to conduct drilling operations and lead to increased potential liability and costs for us and our customers, which could adversely impact our operations and profitability in the U.S. Gulf of Mexico.

In response to the Macondo well blowout incident in the U.S. Gulf of Mexico in April 2010, the Obama Administration and regulatory agencies with jurisdiction over oil and gas exploration, including the U.S. Department of the Interior (DOI) imposed temporary moratoria on drilling operations, required operators to reapply for exploration plans and drilling permits which had previously been approved, and adopted numerous new regulations and new interpretations of existing regulations regarding operations in the U.S. Gulf of Mexico that are applicable to our oil and gas exploration and production customers and with which their new applications for exploration plans and drilling permits must prove compliant. We have significant operations that are either ongoing or scheduled to commence in the U.S. Gulf of Mexico. The requirements set forth in these new laws, regulations and requirements may delay our operations and cause us to incur additional expenses in order for our rigs and operations in the U.S. Gulf of Mexico to be compliant with the new laws, regulations and requirements. These new laws, regulations and requirements and other potential changes in laws and regulations applicable to the offshore drilling industry in the U.S. Gulf of Mexico may also continue to prevent our customers from obtaining new drilling permits and approvals in a timely manner, if at all, which could materially adversely impact our business, financial position or results of operations. Since early 2011, there has been gradual improvement in the number of approved permits per month, however, it is possible that the improvement of this pace could slow or reverse as a result of uncertainties with respect to implementation and interpretation of Notices to Lessees and other regulatory initiatives issued by the DOI and/or the BOEMRE, BSEE and BOEM, as to the ability of the BSEE to timely review submits and issue drilling permits or because of potential third party challenges to industry drilling operations in the U.S Gulf of Mexico.

In addition to the recently implemented laws, regulations and requirements since the Macondo incident, the federal government has considered additional new laws, regulations and requirements, including those that would have imposed additional equipment requirements and that relate to the protection of the environment, which would be applicable to the offshore drilling industry in the Gulf of Mexico. The federal government may again consider implementing new, more restrictive laws, regulations and requirements. In particular, the commission appointed by President Obama to study the causes of the Macondo well blowout incident released its report and has recommended certain legislative and regulatory measures that should be taken to minimize the possibility of a reoccurrence of a disastrous spill. The implementation of new laws and regulations could lead to substantially increased potential liability and operating costs for us and our customers, which could cause our customers to discontinue or delay operating in the U.S. Gulf of Mexico and/or redeploy capital to international locations. These actions, if taken by any of our customers, could result in underutilization of our U.S. Gulf of Mexico assets and have an adverse impact on our revenue, profitability and financial position. The regulatory and legal environment in the Gulf of Mexico remains uncertain and is currently in a state of flux. Accordingly, we cannot predict at this time the impact that any potential changes in laws and regulations relating to offshore oil and gas exploration and development activity in the U.S. Gulf of Mexico may have on our operations or contracts, the extent to which the issuance of drilling permits will continue to be delayed, the effect on the cost or availability of insurance, or the impact on our customers and the demand for our services in the U.S. Gulf of Mexico. Future legislation or regulations may impose new equipment and environmental requirements on us and our customers that could delay or hinder our operations and those of our customers in the U.S. Gulf of Mexico, which could likewise have an adverse impact on our business and financial results.

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Our business depends on the level of activity in the oil and natural gas industry, which is significantly affected by volatile oil and natural gas prices.

Our business depends on the level of activity of oil and natural gas exploration, development and production in the U.S. Gulf of Mexico and internationally, and in particular, the level of exploration, development and production expenditures of our customers. Demand for our drilling services is adversely affected by declines associated with depressed oil and natural gas prices. Even the perceived risk of a decline in oil or natural gas prices often causes oil and gas companies to reduce spending on exploration, development and production. Reductions in capital expenditures of our customers reduce rig utilization and day rates. Crude oil and condensates are representing a larger proportion of overall production in the U.S. GOM, however, a majority of production remains natural gas. However, higher prices do not necessarily translate into increased drilling activity since our clients expectations about future commodity prices typically drive demand for our services. Oil and natural gas prices are extremely volatile. On July 2, 2008 natural gas prices were $13.31 per million British thermal unit, or MMBtu, at the Henry Hub. They subsequently declined sharply, reaching a low of $1.88 per MMBtu at the Henry Hub on September 4, 2009. As of February 23, 2012, the closing price of natural gas at the Henry Hub was $2.68 per MMBtu. The spot price for West Texas intermediate (WTI) crude has recently ranged from a high of $145.29 per barrel as of July 3, 2008, to a low of $31.41 per barrel as of December 22, 2008, with a closing price of $107.49 per barrel as of February 23, 2012. Additionally, the spot price for Louisiana Light Sweet (LLS) was $127.79 per barrel as of February 23, 2012. It is our understanding that much of the crude oil produced from the U.S. GOM is sold at LLS posted prices, which trades at a premium to other crude benchmarks, such as WTI. Commodity prices are affected by numerous factors, including the following:

- the demand for oil and natural gas in the United States and elsewhere;
- the cost of exploring for, developing, producing and delivering oil and natural gas, and the relative cost of onshore production or importation of natural gas;
- political, economic and weather conditions in the United States and elsewhere;
- advances in drilling, exploration, development and production technology;
- the ability of the Organization of Petroleum Exporting Countries, commonly called OPEC, to set and maintain oil production levels and pricing;
- the level of production in non-OPEC countries;
- domestic and international tax policies and governmental regulations;
- the development and exploitation of alternative fuels, and the competitive, social and political position of natural gas as a source of energy compared with other energy sources;
- the policies of various governments regarding exploration and development of their oil and natural gas reserves;
- the worldwide military and political environment and uncertainty or instability resulting from an escalation or additional outbreak of armed hostilities or other crises in the Middle East (including the recent tensions between the international community and Iran), North Africa, West Africa and other significant oil and natural gas producing regions; and

- acts of terrorism or piracy that affect oil and natural gas producing regions, especially in Nigeria, where armed conflict, civil unrest and acts of terrorism have recently increased.

While economic conditions have improved, reduced demand for drilling and liftboat services has materially eroded dayrates and utilization rates for our units, adversely affecting our financial condition and results of operations. Continued hostilities in the Middle East, North Africa, and West Africa and the occurrence or threat of terrorist attacks against the United States or other countries could negatively impact the economies of the United States and other countries where we operate. Another decline in the economy could result in a decrease in energy consumption, which in turn would cause our revenue and margins to further decline and limit our future growth prospects.

The offshore service industry is highly cyclical and experiences periods of low demand and low dayrates. The volatility of the industry, coupled with our short-term contracts, has resulted and could continue to result in sharp declines in our profitability.

Historically, the offshore service industry has been highly cyclical, with periods of high demand and high dayrates often followed by periods of low demand and low dayrates. Periods of low demand or increasing supply intensify the competition in the industry and often result in rigs or liftboats being idle for long periods of time. While economic conditions have been improving over the past 24 months, in response to the economic downturn that commenced in late 2008, we stacked additional rigs and liftboats and entered into lower dayrate contracts. As a result of the cyclicality of our industry, we expect our results of operations to be volatile and to decrease during market declines such as we recently experienced.

We have a significant level of debt, and could incur additional debt in the future. Our debt could have significant consequences for our business and future prospects.

As of December 31, 2011, we had total outstanding debt of approximately $840.3 million. This debt represented approximately 48% of our total book capitalization. As of December 31, 2011, we had $137.1 million of available capacity under our revolving credit facility, after the commitment of $2.9 million for standby letters of credit issued under it. We may borrow under our revolving credit facility to fund working capital or other needs in the near term up to the remaining availability subject to our compliance with financial covenants. Our debt and the limitations imposed on us by our existing or future debt agreements could have significant consequences for our business and future prospects, including the following:

- we may not be able to obtain necessary financing in the future for working capital, capital expenditures, acquisitions, debt service requirements or other purposes and we may be required under the terms of our credit facility, as amended, to use the proceeds of any financing we obtain to repay or prepay existing debt;

- we will be required to dedicate a substantial portion of our cash flow from operations to payments of principal and interest on our debt;

- we may be exposed to risks inherent in interest rate fluctuations because 54 percent of our borrowings are at variable rates of interest, which will result in higher interest expense to the extent that we do not hedge such risk in the event of increases in interest rates;

- we could be more vulnerable during downturns in our business and be less able to take advantage of significant business opportunities and to react to changes in our business and in market or industry conditions; and

- we may have a competitive disadvantage relative to our competitors that have less debt.

Our ability to make payments on and to refinance our indebtedness, including the term loan issued in July 2007, the convertible notes issued by us in June 2008 and the senior secured notes issued by us in October 2009, and to fund planned capital expenditures will depend on our ability to generate cash in the future, which is subject to general economic, financial, competitive, legislative, regulatory and other factors that are beyond our control. Our future cash flows may be insufficient to meet all of our debt obligations and other commitments, and any insufficiency could negatively impact our business. To the extent we are unable to repay our indebtedness as it becomes due or at maturity with cash on hand, we will need to refinance our debt, sell assets or repay the debt with the proceeds from equity offerings. Additional indebtedness or equity financing may not be available to us in the future for the refinancing or repayment of existing indebtedness, and we may not be able to complete asset sales in a timely manner sufficient to make such repayments.

If we are unable to comply with the restrictions and covenants in our credit agreement, there could be a default, which could result in an acceleration of repayment of funds that we have borrowed.

Our Credit Agreement (Credit Agreement) requires that we meet certain financial ratios and tests. Effective July 27, 2009, we entered into an amendment of our Credit Agreement (2009 Credit Amendment) to provide additional flexibility in certain financial covenants. Furthermore, the 2009 Credit Amendment also

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imposes other covenants and restrictions, including the imposition of a requirement to maintain a minimum level of liquidity at all times. Effective March 3, 2011, we entered into another amendment to our Credit Facility (2011 Credit Amendment) to, among other things, allow for the use of cash to purchase certain assets from Seahawk Drilling, Inc., exempt the pro forma treatment of historical results from the Seahawk assets with respect to the calculation of the financial covenants in the Credit Agreement, increase our investment basket and provide additional flexibility in a certain financial covenant. However, there can be no assurance that we will be able to comply with the modified financial covenants. Our ability to comply with these financial covenants and restrictions can be affected by events beyond our control. Continued reduced activity levels in the oil and natural gas industry could adversely impact our ability to comply with such covenants in the future. Our failure to comply with such covenants would result in an event of default under the Credit Agreement. An event of default could prevent us from borrowing under our revolving credit facility, which could in turn have a material adverse effect on our available liquidity. In addition, an event of default could result in our having to immediately repay all amounts outstanding under the term loan facility, the revolving credit facility, the 3.375% Convertible Senior Notes due 2038 (3.375% Convertible Senior Notes), the 10.5% Senior Secured Notes due 2017 (10.5% Senior Secured Notes) and in foreclosure of liens on our assets. As of December 31, 2011, we were in compliance with all of our financial covenants under the Credit Agreement.

Our Credit Agreement imposes significant additional costs and operating and financial restrictions on us, which may prevent us from capitalizing on business opportunities and taking certain actions.

Our Credit Agreement imposes significant additional costs and operating and financial restrictions on us. These restrictions limit our ability to, among other things:

- make certain types of loans and investments;
- pay dividends, redeem or repurchase stock, prepay, redeem or repurchase other debt or make other restricted payments;
- incur or guarantee additional indebtedness;
- use proceeds from asset sales, new indebtedness or equity issuances for general corporate purposes or investment into our current business;
- invest in certain new joint ventures;
- create or incur liens;
- place restrictions on our subsidiaries ability to make dividends or other payments to us;
- sell our assets or consolidate or merge with or into other companies;
- engage in transactions with affiliates; and
- enter into new lines of business.

In addition, under our Credit Agreement, as amended, we are required to prepay our term loan with 50% of our excess cash flow through the fiscal year ending December 31, 2012. Our term loan must also be prepaid using the proceeds from unsecured debt issuances (with the exception of refinancing), secured debt issuances and sales of assets in excess of $25 million annually, casualty events not used to repair damaged property as well as 50% of proceeds from equity issuances (excluding those for permitted acquisitions or to meet the minimum liquidity requirements) unless we have achieved a specified leverage ratio. Our Credit Agreement also imposes significant financial and operating restrictions on us. These restrictions limit our ability to acquire assets, except in cases in which the consideration is equity or the net cash proceeds of an issuance thereof (with the exception of the Seahawk acquisition), unless we are in compliance with more restrictive financial covenants than what we are normally required to meet in each respective period as defined in the 2011 Credit Amendment. Our compliance with these provisions may materially adversely affect our ability to react to changes in market conditions, take advantage of business opportunities we believe to be desirable, obtain future financing, fund needed capital expenditures, finance our acquisitions, equipment purchases and development expenditures, or withstand the present or any future downturn in our business.

The maturity dates on our revolving credit facility and term loan facility are coming due and we may need to refinance our debt through the issuance of new debt or equity. We cannot guarantee that we will be able to access the capital markets at times and on terms that we would prefer.

Any outstanding balances on our revolving credit facility and our term loan facility mature and become due in full on July 11, 2012 and July 11, 2013, respectively. As of December 31, 2011, we had no amounts outstanding and $2.9 million in standby letters of credit issued under our revolving credit facility and $452.9 million outstanding under our term loan facility. We intend to refinance our revolving credit facility and term loan facility before the revolving credit facility matures and may attempt to do so at any time in the future. We may not be able to refinance this debt on favorable terms or at all prior to the maturity date on the revolving credit facility, which could lead to a higher cost of borrowing, having to issue additional equity, complete asset sales or use cash on hand to pay down debt, or any combination of the foregoing.

Maintaining idle assets or the sale of assets below their then carrying value may cause us to experience losses and may result in impairment charges.

Prolonged periods of low utilization and dayrates, the cold stacking of idle assets or the sale of assets below their then carrying value may cause us to experience losses. These events may also result in the recognition of impairment charges on certain of our assets if future cash flow estimates, based upon information available to management at the time, indicate that their carrying value may not be recoverable or if we sell assets at below their then carrying value.

Our industry is highly competitive, with intense price competition. Our inability to compete successfully may reduce our profitability.

Our industry is highly competitive. Our contracts are traditionally awarded on a competitive bid basis. Pricing is often the primary factor in determining which qualified contractor is awarded a job, although rig and liftboat availability, location and technical capability and each contractor s safety performance record and reputation for quality also can be key factors in the determination. Dayrates also depend on the supply of rigs and vessels. Generally, excess capacity puts downward pressure on dayrates, and we have recently experienced declines in utilized days and dayrates. Excess capacity can occur when newly constructed rigs and vessels enter service, when rigs and vessels are mobilized between geographic areas and when non-marketed rigs and vessels are reactivated.

Several of our competitors also are incorporated in other jurisdictions outside the United States, which provides them with significant tax advantages that are not available to us as a U.S. company, which may materially impair our ability to compete with them for many projects that would be beneficial to our company.

The continuing worldwide economic problems have materially reduced our revenue, profitability and cash flows.

The worldwide economic problems that commenced in late 2008 led to a reduction in the availability of liquidity and credit to fund business operations worldwide, and adversely affected our customers, suppliers and lenders. The economic decline caused a reduction in worldwide demand for energy and resulted in lower oil and natural gas prices. While oil prices have rebounded, demand for our services depends on oil and natural gas industry activity and capital expenditure levels that are directly affected by trends in oil and natural gas prices. Any prolonged reduction in oil and natural gas prices will further depress the current levels of exploration, development and production activity. Perceptions of longer-term lower oil and natural gas prices by oil and gas companies can similarly reduce or defer major expenditures. Lower levels of activity result in a corresponding decline in the demand for our services, which could have a material adverse effect on our revenue and profitability.

Global financial and economic circumstances may have impacts on our business and financial condition that we cannot predict, and may limit our ability to finance our business and refinance our debt at a reasonable cost of capital.

We may face challenges if conditions in the financial markets are inadequate to finance our activities and refinance our debt as it comes due at a reasonable cost of capital. Continuing concerns over the worldwide economic outlook, the availability and costs of credit, and the sovereign debt crisis have contributed to increased volatility in the global financial markets and commodity prices and diminished expectations for the global economy. These conditions could make it more difficult for us to access capital on reasonable terms and to refinance our debt at reasonable costs.

We may require additional capital in the future, which may not be available to us or may be at a cost which reduces our cash flow and profitability.

Our business is capital intensive and, to the extent we do not generate sufficient cash from operations, we may need to raise additional funds through public or private debt (which would increase our interest costs) or equity financings to execute our business strategy, to fund capital expenditures or to meet our covenants under the Credit Agreement. Adequate sources of capital funding may not be available when needed or may not be available on acceptable terms and, under the terms of our Credit Agreement, we may be required to use the proceeds of any capital that we raise to repay existing indebtedness. If we raise additional funds by issuing additional equity securities, existing stockholders may experience dilution. If funding is insufficient at any time in the future, we may be unable to fund maintenance of our assets, take advantage of business opportunities or respond to competitive pressures, any of which could harm our business.

Asset sales are currently an important component of our business strategy for the purpose of reducing our debt. We may be unable to identify appropriate buyers with access to financing or to complete any sales on acceptable terms.

We are currently considering sales or other dispositions of certain of our assets, and any such disposition could be significant and could significantly affect the results of operations of one or more of our business segments. In the current economic environment, asset sales may occur on less favorable terms than terms that might be available at other times in the business cycle. At any given time, discussions with one or more potential buyers may be at different stages. However, any such discussions may or may not result in the consummation of an asset sale. We may not be able to identify buyers with access to financing or complete any sales on acceptable terms.

Our contracts are generally short term, and we will experience reduced profitability if our customers reduce activity levels or terminate or seek to renegotiate our drilling or liftboat contracts or if we experience downtime, operational difficulties, or safety-related issues.

Currently, all of our drilling contracts with major customers are dayrate contracts, where we charge a fixed charge per day regardless of the number of days needed to drill the well. Likewise, under our current liftboat contracts, we charge a fixed fee per day regardless of the success of the operations that are being conducted by our customer utilizing our liftboat. During depressed market conditions, a customer may no longer need a rig or liftboat that is currently under contract or may be able to obtain a comparable rig or liftboat at a lower daily rate. As a result, customers may seek to renegotiate the terms of their existing drilling contracts or avoid their obligations under those contracts. In addition, our customers may have the right to terminate, or may seek to renegotiate, existing contracts if we experience downtime, operational problems above the contractual limit or safety-related issues, if the rig or liftboat is a total loss, if the rig or liftboat is not delivered to the customer within the period specified in the contract or in other specified circumstances, which include events beyond the control of either party.

In the U.S. Gulf of Mexico, contracts are generally short term, and oil and natural gas companies tend to reduce activity levels quickly in response to downward changes in oil and natural gas prices. Due to the short-term nature of most of our contracts, a decline in market conditions can quickly affect our business if customers reduce their levels of operations.

Some of our contracts with our customers include terms allowing them to terminate the contracts without cause, with little or no prior notice and without penalty or early termination payments. In addition, we could be required to pay penalties if some of our contracts with our customers are terminated due to downtime, operational problems or failure to deliver. Some of our other contracts with customers may be cancelable at the option of the customer upon payment of a penalty, which may not fully compensate us for the loss of the contract. Early termination of a contract may result in a rig or liftboat 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. If our customers cancel or require us to renegotiate some of our significant contracts, if we are unable to secure new contracts on substantially similar terms, especially those contracts in our International Offshore segment, or if contracts are suspended for an extended period of time, our revenue and profitability would be materially reduced.

An increase in supply of rigs or liftboats could adversely affect our financial condition and results of operations.

Reactivation of non-marketed rigs or liftboats, mobilization of rigs or liftboats back to the U.S. Gulf of Mexico or new construction of rigs or liftboats could result in excess supply in the region, and our dayrates and utilization could be reduced.

Construction of rigs could result in excess supply in international regions, which could reduce our ability to secure new contracts for our stacked rigs and could reduce our ability to renew, or extend or obtain new contracts for working rigs at the end of their contract term. The excess supply would also impact the dayrates on future contracts.

If market conditions improve, inactive rigs and liftboats that are not currently being marketed could be reactivated to meet an increase in demand. Improved market conditions in the U.S. Gulf of Mexico, particularly relative to other regions, could also lead to jackup rigs, other mobile offshore drilling units and liftboats being moved into the U.S. Gulf of Mexico. Improved market conditions in any region worldwide could lead to increased construction and upgrade programs by our competitors. Some of our competitors have already announced plans to upgrade existing equipment or build additional jackup rigs with higher specifications than our rigs. According to ODS-Petrodata, as of February 24, 2012, 79 jackup rigs were under construction or on order globally by industry participants, national oil companies and financial investors for delivery through 2014. Many of the rigs currently under construction have not been contracted for future work, which may intensify price competition as scheduled delivery dates occur. A significant increase in the supply of jackup rigs, other mobile offshore drilling units or liftboats could adversely affect both our utilization and dayrates.

Our business involves numerous operating hazards and exposure to extreme weather and climate risks, and our insurance may not be adequate to cover our losses.

Our operations are subject to the usual hazards inherent in the drilling and operation of oil and natural gas wells, such as blowouts, reservoir damage, loss of production, loss of well control, punchthroughs, craterings, fires and pollution. The occurrence of these events could result in the suspension of drilling or production operations, claims by the operator, severe damage to or destruction of the property and equipment involved, injury or death to rig or liftboat personnel, and environmental damage. We may also be subject to personal injury and other claims of rig or liftboat personnel as a result of our drilling and liftboat operations. Operations also may be suspended because of machinery breakdowns, abnormal operating conditions, failure of subcontractors to perform or supply goods or services and personnel shortages.

In addition, our drilling and liftboat operations are subject to perils of marine operations, including capsizing, grounding, collision and loss or damage from severe weather. Tropical storms, hurricanes and other severe weather prevalent in the U.S. Gulf of Mexico could have a material adverse effect on our operations. During such severe weather conditions, our liftboats typically leave location and cease to earn a full dayrate. The liftboats cannot return to the location until the weather improves and the seas are less than U.S. Coast Guard approved limits. In addition, damage to our rigs, liftboats, shorebases and corporate infrastructure caused by high winds, turbulent seas, or unstable sea bottom conditions could potentially cause us to curtail operations for significant periods of time until the damages can be repaired. In addition, we cold stack a number of rigs in certain locations offshore. This concentration of rigs in specific locations could expose us to increased liability from a catastrophic event and could cause an increase in our insurance costs.

Damage to the environment could result from our operations, particularly through oil spillage or extensive uncontrolled fires. We may also be subject to property, environmental and other damage claims by oil and natural gas companies and other businesses operating offshore and in coastal areas. Our insurance policies and contractual rights to indemnity may not adequately cover losses, and we may not have insurance coverage or rights to indemnity for all risks. Moreover, pollution and environmental risks generally are subject to significant deductibles and are not totally insurable. Risks from extreme weather and marine hazards may increase in the event of ongoing patterns of adverse changes in weather or climate.

A significant portion of our business is conducted in shallow-water areas of the U.S. Gulf of Mexico. The mature nature of this region could result in less drilling activity in the area, thereby reducing demand for our services.

The U.S. Gulf of Mexico, and in particular the shallow-water region of the U.S. Gulf of Mexico, is a mature oil and natural gas production region that has experienced substantial seismic survey and exploration activity for many years. Because a large number of oil and natural gas prospects in this region have already been drilled, additional prospects of sufficient size and quality could be more difficult to identify. According to the U.S. Energy Information Administration, the average size of the U.S. Gulf of Mexico discoveries has declined significantly since the early 1990s. In addition, the amount of natural gas production in the shallow-water U.S. Gulf of Mexico has declined over the last decade. Moreover, oil and natural gas companies may be unable to obtain financing necessary to drill prospects in this region. The decrease in the size of oil and natural gas prospects, the decrease in production or the failure to obtain such financing may result in reduced drilling activity in the U.S. Gulf of Mexico and reduced demand for our services.

We can provide no assurance that our current backlog of contract drilling revenue will be ultimately realized.

As of February 23, 2012, our total contract drilling backlog for our Domestic Offshore, International Offshore and Inland segments was approximately $432.1 million. We calculate our contract revenue backlog, or future contracted revenue, as the contract dayrate multiplied by the number of days remaining on the contract, assuming full utilization. Backlog excludes revenue for management agreements, mobilization, demobilization, contract preparation and customer reimbursables. We may not be able to perform under our drilling contracts due to various operational factors, including unscheduled repairs, maintenance, operational delays, health, safety and environmental incidents, weather events in the Gulf of Mexico and elsewhere and other factors (some of which are beyond our control), and our customers may seek to cancel or renegotiate our contracts for various reasons. In some of the contracts, our customer has the right to terminate the contract without penalty and in certain instances, with little or no notice. Our inability or the inability of our customers to perform under our or their contractual obligations may have a material adverse effect on our financial position, results of operations and cash flows.

Our insurance coverage has become more expensive, may become unavailable in the future, and may be inadequate to cover our losses.

Our insurance coverage is subject to certain significant deductibles and levels of self-insurance, does not cover all types of losses and, in some situations, may not provide full coverage for losses or liabilities resulting from our operations. In addition, due to the losses sustained by us and the offshore drilling industry in recent years, primarily as a result of Gulf of Mexico hurricanes, we are likely to continue experiencing increased costs for available insurance coverage, which may impose higher deductibles and limit maximum aggregated recoveries, including for hurricane-related windstorm damage or loss. Insurance costs may increase in the event of ongoing patterns of adverse changes in weather or climate.

Further, we may not be able to obtain windstorm coverage in the future, thus putting us at a greater risk of loss due to severe weather conditions and other hazards. If a significant accident or other event resulting in damage to our rigs or liftboats, including severe weather, terrorist acts, piracy, war, civil disturbances, pollution or environmental damage, occurs and is not fully covered by insurance or a recoverable indemnity from a customer, it could adversely affect our financial condition and results of operations. Moreover, we may not be able to maintain adequate insurance in the future at rates we consider reasonable or be able to obtain insurance against certain risks.

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As a result of a number of recent catastrophic weather related and other events, insurance underwriters increased insurance premiums for many of the coverages historically maintained and issued general notices of cancellation and significant changes for a wide variety of insurance coverages. The oil and natural gas industry has suffered extensive damage from several hurricanes over the past several years. As a result, over the past several years our insurance costs increased significantly, our deductibles increased and our coverage for named windstorm damage was restricted. Any additional severe storm activity in the energy producing areas of the U.S. Gulf of Mexico in the future could cause insurance underwriters to no longer insure U.S. Gulf of Mexico assets against weather-related damage. A number of our customers that produce oil and natural gas have previously maintained business interruption insurance for their production. This insurance is less available and may cease to be available in the future, which could adversely impact our customers business prospects in the U.S. Gulf of Mexico and reduce demand for our services.

Our customers may be unable or unwilling to indemnify us.

Consistent with standard industry practice, our clients generally assume, and indemnify us against, well control and subsurface risks under dayrate contracts. These risks are those associated with the loss of control of a well, such as blowout or cratering, the cost to regain control or redrill the well and associated pollution. There can be no assurance, however, that these clients will necessarily be financially able to indemnify us against all these risks. Also, we may be effectively prevented from enforcing these indemnities because of the nature of our relationship with some of our larger clients. Additionally, from time to time we may not be able to obtain agreement from our customer to indemnify us for such damages and risks.

Any violation of the Foreign Corrupt Practices Act or similar laws and regulations could result in significant expenses, divert management attention, and otherwise have a negative impact on us.

We are subject to the Foreign Corrupt Practices Act (the FCPA), which generally prohibits U.S. companies and their intermediaries from making improper payments to foreign officials for the purpose of obtaining or retaining business, and the anti-bribery laws of other jurisdictions. On April 4, 2011, we received a subpoena from the SEC requesting that we produce documents relating to our compliance with the FCPA. We have also been advised by the Department of Justice that it is conducting a similar investigation. Under the direction of the audit committee, we are conducting an internal investigation regarding these matters. Any determination that we have violated the FCPA or laws of any other jurisdiction could have a material adverse effect on our financial condition.

Our international operations may subject us to political and regulatory risks and uncertainties.

In connection with our international contracts, the transportation of rigs, services and technology across international borders subjects us to extensive trade laws and regulations. Our import and export activities are governed by unique customs laws and regulations in each of the countries where we operate. In each jurisdiction, laws and regulations concerning importation, recordkeeping and reporting, import and export control and financial or economic sanctions are complex and constantly changing. Our business and financial condition may be materially affected by enactment, amendment, enforcement or changing interpretations of these laws and regulations. Rigs and other shipments can be delayed and denied import or export for a variety of reasons, some of which are outside our control and some of which may result in failure to comply with existing laws and regulations and contractual requirements. Shipping delays or denials could cause operational downtime or increased costs, duties, taxes and fees. Any failure to comply with applicable legal and regulatory obligations also could result in criminal and civil penalties and sanctions, such as fines, imprisonment, debarment from government contracts, seizure of goods and loss of import and export privileges.

Our international operations are subject to additional political, economic, and other uncertainties not generally associated with domestic operations.

An element of our business strategy is to continue to expand into international oil and natural gas producing areas such as West Africa, the Middle East and the Asia-Pacific region. We operate liftboats in West Africa,

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including Nigeria, and in the Middle East. We also operate drilling rigs in Southeast Asia, Saudi Arabia, Mexico and West Africa. Our international operations are subject to a number of risks inherent in any business operating in foreign countries, including:

- political, social and economic instability, war and acts of terrorism;
- potential seizure, expropriation or nationalization of assets;
- damage to our equipment or violence directed at our employees, including kidnappings and piracy;
- increased operating costs;
- complications associated with repairing and replacing equipment in remote locations;
- repudiation, modification or renegotiation of contracts, disputes and legal proceedings in international jurisdictions;
- limitations on insurance coverage, such as war risk coverage in certain areas;
- import-export quotas;
- confiscatory taxation;
- work stoppages or strikes, particularly in the West African and Mexican labor environments;
- unexpected changes in regulatory requirements;
- wage and price controls;
- imposition of trade barriers;
- imposition or changes in enforcement of local content laws, particularly in West Africa and Southeast Asia, where the legislatures are active in developing new legislation;
- restrictions on currency or capital repatriations;

- currency fluctuations and devaluations; and

- other forms of government regulation and economic conditions that are beyond our control.

Many governments favor or effectively require that liftboat or drilling contracts be awarded to local contractors or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. These practices may result in inefficiencies or put us at a disadvantage when bidding for contracts against local competitors.

Our non-U.S. contract drilling and liftboat operations are subject to various laws and regulations in countries in which we operate, including laws and regulations relating to the equipment and operation of drilling rigs and liftboats, currency conversions and repatriation, oil and natural gas exploration and development, taxation of offshore earnings and earnings of expatriate personnel, the use of local employees and suppliers by foreign contractors, the ownership of assets by local citizens and companies, and duties on the importation and exportation of units and other equipment. Governments in some foreign countries have become increasingly active in regulating and controlling the ownership of concessions and companies holding concessions, the exploration for oil and natural gas and other aspects of the oil and natural gas industries in their countries. In some areas of the world, this governmental activity has adversely affected the amount of exploration and development work done by major oil and natural gas companies and may continue to do so. Operations in developing countries can be subject to legal systems which are not as predictable as those in more developed countries, which can lead to greater risk and uncertainty in legal matters and proceedings.

Due to our international operations, we may experience currency exchange losses when revenue is received and expenses are paid in nonconvertible currencies or when we do not hedge an exposure to a foreign currency. We may also incur losses as a result of an inability to collect revenue 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.

A small number of customers account for a significant portion of our revenue, and the loss of one or more of these customers could adversely affect our financial condition and results of operations.

In recent years there has been a significant consolidation in our customer base. Therefore, we derive a significant amount of our revenue from a few energy companies. Chevron Corporation and Saudi Aramco accounted for 25% and 13% of our revenue for the year ended December 31, 2011, respectively. Our financial condition and results of operations will be materially adversely affected if these customers interrupt or curtail their activities, terminate their contracts with us, fail to renew their existing contracts or refuse to award new contracts to us and we are unable to enter into contracts with new customers at comparable dayrates. The loss of either of these or any other significant customer could adversely affect our financial condition and results of operations.

Our existing jackup rigs are at a relative disadvantage to higher specification rigs, which may be more likely to obtain contracts than lower specification jackup rigs such as ours.

Many of our competitors have jackup fleets with generally higher specification rigs than those in our jackup fleet. In addition, all of the new rigs under construction are of higher specification than our existing fleet. While Hercules has signed agreements to manage the construction and operations of the two ultra high specification harsh environment jackup drilling rigs on order for Discovery Offshore, 33 of our 42 jackup rigs are mat-supported, which are generally limited to geographic areas with soft bottom conditions like much of the Gulf of Mexico. Most of the rigs under construction are currently without contracts, which may intensify price competition as scheduled delivery dates occur. Particularly in periods in which there is decreased rig demand, such as the current period, higher specification rigs may be more likely to obtain contracts than lower specification jackup rigs such as ours. In the past, lower specification rigs have been stacked earlier in the cycle of decreased rig demand than higher specification rigs and have been reactivated later in the cycle, which may adversely impact our business. In addition, higher specification rigs may be more adaptable to different operating conditions and therefore have greater flexibility to move to areas of demand in response to changes in market conditions. Because a majority of our rigs were designed specifically for drilling in the shallow-water U.S. Gulf of Mexico, our ability to move them to other regions in response to changes in market conditions is limited.

Furthermore, in recent years, an increasing amount of exploration and production expenditures have been concentrated in deepwater drilling programs and deeper formations, including deep natural gas prospects, requiring higher specification jackup rigs, semisubmersible drilling rigs or drillships. This trend is expected to continue and could result in a decline in demand for lower specification jackup rigs like ours, which could have an adverse impact on our financial condition and results of operations. One of our customers, PEMEX, has indicated a shifting focus in drilling rig requirements since the beginning of 2008, with more emphasis placed on newer, higher specification rigs. Demand in Mexico for our jackup rig fleet declined and the future contracting opportunities for such rigs in Mexico could diminish.

We may consider future acquisitions and may be unable to complete and finance future acquisitions on acceptable terms. In addition, we may fail to successfully integrate acquired assets or businesses we acquire or incorrectly predict operating results.

We may consider future acquisitions which could involve the payment by us of a substantial amount of cash, the incurrence of a substantial amount of debt or the issuance of a substantial amount of equity. Unless we have achieved specified financial covenant levels, our Credit Agreement restricts our ability to make acquisitions involving the payment of cash or the incurrence of debt. If we are restricted from using cash or incurring debt to fund a potential acquisition, we may not be able to issue, on terms we find acceptable, sufficient equity that may be required for any such permitted acquisition or investment. In addition, barring any restrictions under the Credit Agreement, we still may not be able to obtain, on terms we find acceptable, sufficient financing or funding that may be required for any such acquisition or investment.

We cannot predict the effect, if any, that any announcement or consummation of an acquisition would have on the trading price of our common stock.

Any future acquisitions could present a number of risks, including:

- the risk of incorrect assumptions regarding the future results of acquired operations or assets or expected cost reductions or other synergies expected to be realized as a result of acquiring operations or assets;

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the risk of failing to integrate the operations or management of any acquired operations or assets successfully and timely; and

the risk of diversion of management s attention from existing operations or other priorities.

If we are unsuccessful in integrating our acquisitions in a timely and cost-effective manner, our financial condition and results of operations could be adversely affected.

Failure to retain or attract skilled workers could hurt our operations.

We require skilled personnel to operate and provide technical services and support for our rigs and liftboats. The shortages of qualified personnel or the inability to obtain and retain qualified personnel could negatively affect the quality and timeliness of our work. In periods of economic crisis or during a recession, we may have difficulty attracting and retaining our skilled workers as these workers may seek employment in less cyclical or volatile industries or employers. In periods of recovery or increasing activity, we may have to increase the wages of our skilled workers, which could negatively impact our operations and financial results.

Although our domestic employees are not covered by a collective bargaining agreement, the marine services industry has been targeted by maritime labor unions in an effort to organize U.S. Gulf of Mexico employees. A significant increase in the wages paid by competing employers or the unionization of our U.S. Gulf of Mexico employees could result in a reduction of our skilled labor force, increases in the wage rates that we must pay, or both. If either of these events were to occur, our capacity and profitability could be diminished and our growth potential could be impaired.

Governmental laws and regulations, including those related to climate change and emissions of greenhouse gases, may add to our costs or limit drilling activity and liftboat operations.

Our operations are affected in varying degrees by governmental laws and regulations. We are also subject to the jurisdiction of the Coast Guard, the National Transportation Safety Board, the CBP, the DOI, the BOEM and the BSEE, as well as private industry organizations such as the American Bureau of Shipping. We may be required to make significant capital expenditures to comply with laws and the applicable regulations and standards of governmental authorities and organizations. Moreover, the cost of compliance could be higher than anticipated. Similarly, our international operations are subject to compliance with the U.S. Foreign Corrupt Practices Act, certain international conventions and the laws, regulations and standards of other foreign countries in which we operate. It is also possible that existing and proposed governmental conventions, laws, regulations and standards, including those related to climate change and emissions of greenhouse gases, may in the future add significantly to our operating costs or limit our activities or the activities and levels of capital spending by our customers.

In addition, as our vessels age, the costs of drydocking the vessels in order to comply with governmental laws and regulations and to maintain their class certifications are expected to increase, which could adversely affect our financial condition and results of operations.

Compliance with or a breach of environmental laws and regulations can be costly and could limit our operations.

Our operations are subject to federal, state, local and foreign and/or international laws and regulations that require us to obtain and maintain specified permits or other governmental approvals, control the discharge of materials into the environment, require the removal and cleanup of materials that may harm the environment or otherwise relate to the protection of the environment. For example, as an operator of mobile offshore drilling units and liftboats in navigable U.S. waters and some offshore areas, we may be liable for damages and costs incurred in connection with oil spills or other unauthorized discharges of chemicals or wastes resulting from those operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions restricting some or all of our activities in the affected areas. Laws and regulations protecting the environment have become more stringent in recent years, and may in some cases impose strict liability, rendering a person liable for environmental damage without regard to negligence or fault on the part of such person. Some of these laws and regulations may expose us to liability for the conduct of or conditions caused by others or for acts that were in compliance with all applicable laws at the time they were performed. The application of these requirements, the modification of existing laws or regulations or the adoption of new requirements, both in U.S. waters and internationally, could have a material adverse effect on our financial condition and results of operations.

We may not be able to maintain or replace our rigs and liftboats as they age.

The capital associated with the repair and maintenance of our fleet increases with age. We may not be able to maintain our fleet by extending the economic life of existing rigs and liftboats, and our financial resources may not be sufficient to enable us to make expenditures necessary for these purposes or to acquire or build replacement units.

Our operating and maintenance costs with respect to our rigs include fixed costs that will not decline in proportion to decreases in dayrates.

We do not expect our operating and maintenance costs with respect to our rigs to necessarily fluctuate in proportion to changes in operating revenue. Operating revenue may fluctuate as a function of changes in dayrate, but costs for operating a rig are generally fixed or only semi-variable regardless of the dayrate being earned. Additionally, if our rigs incur idle time between contracts, we typically do not de-man those rigs because we will use the crew to prepare the rig for its next contract. During times of reduced activity, reductions in costs may not be immediate as portions of the crew may be required to prepare our rigs for stacking, after which time the crew members are assigned to active rigs or dismissed. Moreover, as our rigs are mobilized from one geographic location to another, the labor and other operating and maintenance costs can vary significantly. In general, labor costs increase primarily due to higher salary levels and inflation. Equipment maintenance expenses fluctuate depending upon the type of activity the unit is performing and the age and condition of the equipment. Contract preparation expenses vary based on the scope and length of contract preparation required and the duration of the firm contractual period over which such expenditures are amortized.

Upgrade, refurbishment and repair projects are subject to risks, including delays and cost overruns, which could have an adverse impact on our available cash resources and results of operations.

We make upgrade, refurbishment and repair expenditures for our fleet from time to time, including when we acquire units or when repairs or upgrades are required by law, in response to an inspection by a governmental authority or when a unit is damaged. We also regularly make certain upgrades or modifications to our drilling rigs to meet customer or contract specific requirements. Upgrade, refurbishment and repair projects are subject to the risks of delay or cost overruns inherent in any large construction project, including costs or delays resulting from the following:

- unexpectedly long delivery times for, or shortages of, key equipment, parts and materials;
- shortages of skilled labor and other shipyard personnel necessary to perform the work;
- unforeseen increases in the cost of equipment, labor and raw materials, particularly steel;
- unforeseen design and engineering problems;
- latent damages to or deterioration of hull, equipment and machinery in excess of engineering estimates and assumptions;
- unanticipated actual or purported change orders;
- work stoppages;

failure or delay of third-party service providers and labor disputes;

disputes with shipyards and suppliers;

delays and unexpected costs of incorporating parts and materials needed for the completion of projects;

failure or delay in obtaining acceptance of the rig from our customer;

financial or other difficulties at shipyards;

adverse weather conditions; and

inability or delay in obtaining customer acceptance or flag-state, classification society, certificate of inspection, or regulatory approvals. Significant cost overruns or delays would adversely affect our financial condition and results of operations. Additionally, capital expenditures for rig upgrade and refurbishment projects could exceed our planned capital expenditures. Failure to complete an upgrade, refurbishment or repair project on time may, in some circumstances, result in the delay, renegotiation or cancellation of a drilling or liftboat contract and could put at risk our planned arrangements to commence operations on schedule. We also could be exposed to penalties for failure to complete an upgrade, refurbishment or repair project and commence operations in a timely manner. Our rigs and liftboats undergoing upgrade, refurbishment or repair generally do not earn a dayrate during the period they are out of service.

We are subject to litigation that could have an adverse effect on us.

We are from time to time involved in various litigation matters. The numerous operating hazards inherent in our business increases our exposure to litigation, including personal injury litigation brought against us by our employees that are injured operating our rigs and liftboats. These matters may include, among other things, contract dispute, personal injury, environmental, asbestos and other toxic tort, employment, tax and securities litigation, and litigation that arises in the ordinary course of our business. We have extensive litigation brought against us in federal and state courts located in Louisiana, Mississippi and South Texas, areas that were significantly impacted by hurricanes during the last several years and recently by the Macondo well blowout incident. The jury pools in these areas have become increasingly more hostile to defendants, particularly corporate defendants in the oil and gas industry. We cannot predict with certainty the outcome or effect of any claim or other litigation matter. Litigation may have an adverse effect on us because of potential negative outcomes, the costs associated with defending the lawsuits, the diversion of our management s resources and other factors.

Changes in effective tax rates, taxation of our foreign subsidiaries, limitations on utilization of our net operating losses or adverse outcomes resulting from examination of our tax returns could adversely affect our operating results and financial results.

Our future effective tax rates could be adversely affected by changes in tax laws, both domestically and internationally. From time to time, Congress and foreign, state and local governments consider legislation that could increase our effective tax rates. We cannot determine whether, or in what form, legislation will ultimately be enacted or what the impact of any such legislation would be on our profitability. If these or other changes to tax laws are enacted, our profitability could be negatively impacted.

Our future effective tax rates could also be adversely affected by changes in the valuation of our deferred tax assets and liabilities, the ultimate repatriation of earnings from foreign subsidiaries to the United States, or by changes in tax treaties, regulations, accounting principles or interpretations thereof in one or more countries in which we operate. In addition, we are subject to the potential examination of our income tax returns by the Internal Revenue Service and other tax authorities where we file tax returns. We regularly assess the likelihood of adverse outcomes resulting from these examinations to determine the adequacy of our provision for taxes. There can be no assurance that such examinations will not have an adverse effect on our operating results and financial condition.

Our business would be adversely affected if we failed to comply with the provisions of U.S. law on coastwise trade, or if those provisions were modified, repealed or waived.

We are subject to U.S. federal laws that restrict maritime transportation, including liftboat services, between points in the United States to vessels built and registered in the United States and owned and manned by U.S. citizens. We are responsible for monitoring the ownership of our common stock. If we do not comply with these restrictions, we would be prohibited from operating our liftboats in U.S. coastwise trade, and under certain circumstances we would be deemed to have undertaken an unapproved foreign transfer, resulting in severe penalties, including permanent loss of U.S. coastwise trading rights for our liftboats, fines or forfeiture of the liftboats.

During the past several years, interest groups have lobbied Congress to repeal these restrictions to facilitate foreign flag competition for trades currently reserved for U.S.-flag vessels under the federal laws. We believe that interest groups may continue efforts to modify or repeal these laws currently benefiting U.S.-flag vessels. If these efforts are successful, it could result in increased competition, which could adversely affect our results of operations.

Our liquidity depends upon cash on hand, cash from operations and availability under our revolving credit facility.

Our liquidity depends upon cash on hand, cash from operations and availability under our revolving credit facility. The availability under the $140 million revolving credit facility is to be used for working capital, capital expenditures and other general corporate purposes and cannot be used to prepay outstanding term loans under our credit facility. All borrowings under the revolving credit facility mature on July 11, 2012, and the revolving credit facility requires interest-only payments on a quarterly basis until the maturity date. We intend to refinance the revolving credit facility and term loan before the revolving credit facility matures. No amounts were outstanding under the revolving credit facility as of December 31, 2011, although $2.9 million in stand-by letters of credit had been issued under it. The remaining availability under the revolving credit facility is $137.1 million at December 31, 2011.

We currently maintain a shelf registration statement covering the future issuance from time to time of various types of securities, including debt and equity securities. If we issue any debt securities off the shelf registration statement or otherwise incur debt, we may be required to make payments on our term loan. We currently believe we will have adequate liquidity to fund our operations for the foreseeable future. However, to the extent we do not generate sufficient cash from operations, we may need to raise additional funds through public or private debt or equity offerings to fund operations and under the terms of the amendments to our credit facility, we may be required to use the proceeds of any capital that we raise to repay existing indebtedness. Furthermore, we may need to raise additional funds through public or private debt or equity offerings or asset sales to avoid a breach of our financial covenants in our Credit Facility to refinance our indebtedness, to fund capital expenditures or for general corporate purposes.

We are a holding company, and we are dependent upon cash flow from subsidiaries to meet our obligations.

We currently conduct our operations through, and most of our assets are owned by, both U.S. and foreign subsidiaries, and our operating income and cash flow are generated by our subsidiaries. As a result, cash we obtain from our subsidiaries is the principal source of funds necessary to meet our debt service obligations. Contractual provisions or laws, as well as our subsidiaries financial condition and operating requirements, may limit our ability to obtain cash from our subsidiaries that we require to pay our debt service obligations. Applicable tax laws may also subject such payments to us by our subsidiaries to further taxation.

The inability to transfer cash from our subsidiaries to us may mean that, even though we may have sufficient resources on a consolidated basis to meet our obligations, we may not be permitted to make the necessary transfers from subsidiaries to the parent company in order to provide funds for the payment of the parent company s obligations.

We limit foreign ownership of our company, which may restrict investment in our common stock and could reduce the price of our common stock.

Our certificate of incorporation limits the percentage of outstanding common stock and other classes of capital stock that can be owned by non-United States citizens within the meaning of statutes relating to the ownership of U.S.-flagged vessels. Applying the statutory requirements applicable today, our certificate of incorporation provides that no more than 20% of our outstanding common stock may be owned by non-United States citizens and establishes mechanisms to maintain compliance with these requirements. These restrictions may have an adverse impact on the liquidity or market value of our common stock because holders may be unable to transfer our common stock to non-United States citizens. Any attempted or purported transfer of our common stock in violation of these restrictions will be ineffective to transfer such common stock or any voting, dividend or other rights in respect of such common stock.

Our certificate of incorporation also provides that any transfer, or attempted or purported transfer, of any shares of our capital stock that would result in the ownership or control of in excess of 20% of our outstanding capital stock by one or more persons who are not United States citizens for purposes of U.S. coastwise shipping will be void and ineffective as against us. In addition, if at any time persons other than United States citizens own shares of our capital stock or possess voting power over any shares of our capital stock in excess of 20%, we may withhold payment of dividends, suspend the voting rights attributable to such shares and redeem such shares.

We have no plans to pay regular dividends on our common stock, so investors in our common stock may not receive funds without selling their shares.

We do not intend to declare or pay regular dividends on our common stock in the foreseeable future. Instead, we generally intend to invest any future earnings in our business. Subject to Delaware law, our board of directors will determine the payment of future dividends on our common stock, if any, and the amount of any dividends in light of any applicable contractual restrictions limiting our ability to pay dividends, our earnings and cash flows, our capital requirements, our financial condition, and other factors our board of directors deems relevant. Our Credit Agreement restricts our ability to pay dividends or other distributions on our equity securities. Accordingly, stockholders may have to sell some or all of their common stock in order to generate cash flow from their investment. Stockholders may not receive a gain on their investment when they sell our common stock and may lose the entire amount of their investment.

Provisions in our charter documents or Delaware law may inhibit a takeover, which could adversely affect the value of our common stock.

Our certificate of incorporation, bylaws and Delaware corporate law contain provisions that could delay or prevent a change of control or changes in our management that a stockholder might consider favorable. These provisions will apply even if the offer may be considered beneficial by some of our stockholders. If a change of control or change in management is delayed or prevented, the market price of our common stock could decline.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

Our property consists primarily of jackup rigs, barge rigs, submersible rigs, a platform rig, liftboats and ancillary equipment, substantially all of which we own. The majority of our vessels and substantially all of our other personal property, are pledged to collateralize our credit facility and 10.5% Senior Secured Notes.

We maintain offices, maintenance facilities, yard facilities, warehouses, waterfront docks as well as residential premises in various countries, including the United States, Mexico, Angola, Nigeria, Singapore, Democratic Republic of Congo, India, Malaysia, Saudi Arabia, Qatar and Bahrain. Almost all of these properties are leased. Our leased principal executive offices are located in Houston, Texas.

We incorporate by reference in response to this item the information set forth in Item 1 of this annual report.

Item 3. ***Legal Proceedings***

In connection with our July 2007 acquisition of TODCO, we assumed certain other material legal proceedings from TODCO and its subsidiaries.

In October 2001, TODCO was notified by the U.S. Environmental Protection Agency (EPA) that the EPA had identified a subsidiary of TODCO as a potentially responsible party under CERCLA in connection with the Palmer Barge Line superfund site located in Port Arthur, Jefferson County, Texas. Based upon the information provided by the EPA and our review of our internal records to date, we dispute our designation as a potentially responsible party and do not expect that the ultimate outcome of this case will have a material adverse effect on our consolidated results of operations, financial position or cash flows. We continue to monitor this matter.

Robert E. Aaron et al. vs. Phillips 66 Company et al. Circuit Court, Second Judicial District, Jones County, Mississippi. This is the case name used to refer to several cases that were filed in the Circuit Courts of the State of Mississippi originally involving 768 plaintiffs grouped into 21 suits that alleged personal injury or whose heirs claimed their deaths arose out of exposure to asbestos contained in drilling mud additives, occurring in the course of their employment by the defendants between 1965 and 2002. Each individual was subsequently required to file a separate lawsuit, and the original 21 multi-plaintiff complaints were then dismissed by the Circuit Courts. The amended complaints resulted in one of our subsidiaries being named as a direct defendant in three cases. More than five years has passed since the court ordered that amended complaints be filed by each individual plaintiff, and the original complaints. No additional plaintiffs have attempted to name TODCO as a defendant and such actions may now be time-barred. The complaints generally allege that the defendants used or manufactured drilling mud additives that contained asbestos for use in connection with offshore and land based drilling operations, and have included allegations of negligence, products liability, strict liability and claims allowed under the Jones Act and general maritime law. The plaintiffs generally seek awards of unspecified compensatory and punitive damages. In each of these cases, the complaints have named other unaffiliated defendant companies, including companies that allegedly manufactured the drilling related products that contained asbestos. All of these cases are being governed for discovery and trial setting by a single Case Management Order entered by a Special Master appointed by the Court to preside over all the cases. We intend to defend ourselves vigorously and do not expect the ultimate outcome of these lawsuits to have a material adverse effect on our consolidated results of operations, financial position or cash flows.

Shareholder Derivative Suits

FCPA Litigation

As disclosed in our prior filings, on April 27, 2011, a shareholder derivative action was filed in the District Court of Harris County, Texas, allegedly on behalf of us, naming us as a nominal defendant and certain of our officers and directors as defendants alleging, among other claims, breach of fiduciary duty, abuse of control, waste of corporate assets, and unjust enrichment. The petition alleges that the individual defendants allowed us to violate the U.S. Foreign Corrupt Practices Act (FCPA) and failed to maintain internal controls and accounting systems for compliance with the FCPA. Plaintiffs sought restitution and injunctive and/or equitable relief purportedly on behalf of us, certain corporate actions, and an award of their costs and attorney s fees.

On October 19, 2011, the District Court sustained special exceptions filed by us and the other defendants (collectively Defendants). The special exceptions filed by the Defendants sought the dismissal of the action due to the plaintiff s failure to plead sufficient facts giving rise to a cause of action. The District Court ordered the action would be dismissed with prejudice if the plaintiff failed to amend his petition by November 4, 2011 and plead sufficient facts giving rise to a cause of action against the Defendants. The plaintiff filed an amended petition on November 4, 2011, in response to which we again filed special exceptions seeking dismissal of the action due to the plaintiff s failure again to plead sufficient facts giving rise to a cause of action.

On February 10, 2012, the District Court granted our special exceptions and dismissed the plaintiff s action with prejudice.

Say-on-Pay Litigation

In June, two separate shareholder derivative actions were filed purportedly on our behalf in response to our failure to receive a majority advisory say-on-pay vote in favor of our 2010 executive compensation. On June 8, 2011, the first action was filed in the District Court of Harris County, Texas, and on June 23, 2011, the second action was filed in the United States Court for the District of Delaware. Subsequently, on July 21, 2011, the plaintiff in the Harris County action filed a concurrent action in the United States District Court for the Southern District of Texas. Each action named us as a nominal defendant and certain of our officers and directors, as well as our Compensation Committee s consultant, as defendants. Plaintiffs allege that our directors breached their fiduciary duty by approving excessive executive compensation for 2010, that the Compensation Committee consultant aided and abetted that breach of fiduciary duty, that the officer defendants were unjustly enriched by receiving the allegedly excessive compensation, and that the directors violated the federal securities laws by disseminating a materially false and misleading proxy. The plaintiffs seek damages in an unspecified amount on our behalf from the officer and director defendants, certain corporate governance actions, and an award of their costs and attorney s fees. We and the other defendants have filed motions to dismiss these cases for failure to make demand upon our board and for failing to state a claim. Those motions are pending.

We do not expect the ultimate outcome of any of these shareholder derivative lawsuits to have a material adverse effect on our consolidated results of operation, financial position or cash flows.

We and our subsidiaries are involved in a number of other lawsuits, all of which have arisen in the ordinary course of our business. We do not believe that ultimate liability, if any, resulting from any such other pending litigation will have a material adverse effect on our business or consolidated financial statements.

We cannot predict with certainty the outcome or effect of any of the litigation matters specifically described above or of any other pending litigation. There can be no assurance that our belief or expectations as to the outcome or effect of any lawsuit or other litigation matter will prove correct, and the eventual outcome of these matters could materially differ from our current estimates.

Item 4. ***Mine Safety Disclosures***

Not applicable.

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PART II

Item 5. ***Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***
Quarterly Common Stock Prices and Dividend Policy

Our common stock is traded on the NASDAQ Global Select Market under the symbol HERO. As of February 24, 2012, there were 115 stockholders of record. On February 24, 2012, the closing price of our common stock as reported by NASDAQ was $5.38 per share. The following table sets forth, for the periods indicated, the range of high and low sales prices for our common stock:

	Price	
	High	**Low**
2011		
Fourth Quarter	$ 4.58	$ 2.25
Third Quarter	5.60	2.90
Second Quarter	6.99	4.97
First Quarter	6.72	3.04

	Price	
	High	**Low**
2010		
Fourth Quarter	$ 3.65	$ 2.16
Third Quarter	2.78	2.05
Second Quarter	4.73	2.39
First Quarter	5.85	3.51

We have not paid any cash dividends on our common stock since becoming a publicly held corporation in October 2005, and we do not intend to declare or pay regular dividends on our common stock in the foreseeable future. Instead, we generally intend to invest any future earnings in our business. Subject to Delaware law, our board of directors will determine the payment of future dividends on our common stock, if any, and the amount of any dividends in light of any applicable contractual restrictions limiting our ability to pay dividends, our earnings and cash flows, our capital requirements, our financial condition, and other factors our board of directors deems relevant. Our Credit Agreement and 10.5% Senior Secured Notes restrict our ability to pay dividends or other distributions on our equity securities.

Issuer Purchases of Equity Securities

The following table sets forth for the periods indicated certain information with respect to our purchases of our common stock:

Period	**Total Number of Shares Purchased (1)**	**Average Price Paid per Share**	**Total Number of Shares Purchased as Part of a Publicly Announced Plan (2)**	**Maximum Number of Shares that may yet be Purchased Under the Plan (2)**
October 1 - 31, 2011	441	$ 3.24	N/A	N/A
November 1 - 30, 2011			N/A	N/A
December 1 - 31, 2011	882	4.44	N/A	N/A

Total	1,323	4.04	N/A	N/A

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(1) Represents the surrender of shares of our common stock to satisfy tax withholding obligations in connection with the vesting of restricted stock issued to employees under our stockholder-approved long-term incentive plan.

(2) We did not have at any time during 2011, 2010 or 2009, and currently do not have, a share repurchase program in place.

Item 6. *Selected Financial Data*

We have derived the following condensed consolidated financial information as of December 31, 2011 and 2010 and for the years ended December 31, 2011, 2010 and 2009 from our audited consolidated financial statements included in Item 8 of this report. The condensed consolidated financial information as of December 31, 2009 and for the year ended December 31, 2008 was derived from our audited consolidated financial statements included in Item 8 of our annual report on Form 10-K for the year ended December 31, 2010, as amended by our current report on Form 8-K filed on July 8, 2011. The condensed consolidated financial information as of December 31, 2008 and for the year ended December 31, 2007 was derived from our audited consolidated financial statements included in Item 8 of our annual report on Form 10-K for the year ended December 31, 2009, adjusting the financial information for the year ended December 31, 2007 for the discontinued operations of our Delta Towing segment. The condensed consolidated financial information as of December 31, 2007 was derived from our audited consolidated financial statements included in Item 8 of our annual report on Form 10-K, for the year ended December 31, 2008, as amended by our current report on Form 8-K filed September 23, 2009.

We were formed in July 2004 and commenced operations in August 2004. From our formation to December 31, 2011, we completed the Seahawk Transaction, acquisition of TODCO and several significant asset acquisitions that impact the comparability of our historical financial results. Our financial results reflect the impact of the Seahawk Transaction, TODCO business and the asset acquisitions from the dates of closing.

The selected consolidated financial information below should be read together with Management s Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this annual report and our audited consolidated financial statements and related notes included in Item 8 of this annual report. In addition, the following information may not be deemed indicative of our future operations.

	Year Ended December 31, 2011	Year Ended December 31, 2010(a)	Year Ended December 31, 2009(b)	Year Ended December 31, 2008(c)	Year Ended December 31, 2007
			(In thousands, except per share data)		
Statement of Operations Data:					
Revenue	$ 655,358	$ 624,827	$ 718,601	$ 1,053,479	$ 694,357
Operating income (loss)	(18,749)	(143,427)	(79,469)	(1,040,848)	215,380
Income (loss) from continuing operations	(66,520)	(132,093)	(81,047)	(997,893)	130,537
Earnings (loss) per share from continuing operations:					
Basic	$ (0.51)	$ (1.15)	$ (0.83)	$ (11.29)	$ 2.22
Diluted	(0.51)	(1.15)	(0.83)	(11.29)	2.19
Balance Sheet Data (as of end of period):					
Cash and cash equivalents	$ 134,351	$ 136,666	$ 140,828	$ 106,455	$ 212,452
Working capital	174,598	182,276	144,813	224,785	367,117
Total assets	2,006,704	1,995,309	2,277,476	2,590,895	3,643,948
Long-term debt, net of current portion	818,146	853,166	856,755	1,015,764	890,013
Total stockholders equity	908,553	853,132	978,512	925,315	2,011,433
Cash dividends per share					

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(a) Includes $122.7 million ($79.8 million, net of taxes or $0.69 per diluted share) in impairment of property and equipment charges.

(b) Includes $26.9 million ($13.1 million, net of taxes or $0.13 per diluted share) of impairment charges related to the write-down of *Hercules 110* to fair value less costs to sell during the second quarter of 2009. The sale of the rig was completed in August 2009. In addition, 2009 includes $31.6 million ($20.5 million, net of taxes or $0.21 per diluted share) related to an allowance for doubtful accounts receivable of approximately $26.8 million, associated with a customer in our International Offshore segment, a non-cash charge of approximately $7.3 million to fully impair the related deferred mobilization and contract preparation costs, partially offset by a $2.5 million reduction in previously accrued contract related operating costs that are not expected to be settled if the receivable is not collected.

(c) Includes $863.6 million ($863.6 million, net of taxes or $9.77 per diluted share) and $376.7 million ($236.7 million, net of taxes or $2.68 per diluted share) in impairment of goodwill and impairment of property and equipment charges, respectively.

	Year Ended December 31, 2011	Year Ended December 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008	Year Ended December 31, 2007
			(In thousands)		
Other Financial Data:					
Net cash provided by (used in):					
Operating activities	$ 52,025	$ 24,420	$ 137,861	$ 269,727	$ 175,741
Investing activities	(32,520)	(21,306)	(60,510)	(515,787)	(825,007)
Financing activities	(21,820)	(7,276)	(42,978)	140,063	788,946
Capital expenditures	39,483	22,018	76,141	585,084(a)	155,390
Deferred drydocking expenditures	15,739	15,040	15,646	17,269	20,772

(a) Includes the purchase of *Hercules 350*, *Hercules 262* and *Hercules 261* as well as related equipment.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the accompanying consolidated financial statements as of December 31, 2011 and 2010 and for the years ended December 31, 2011, 2010 and 2009 included in Item 8 of this annual report. The following discussion and analysis contains forward-looking statements that involve risks and uncertainties. Our actual results may differ materially from those anticipated in these forward-looking statements as a result of certain factors, including those set forth under Risk Factors in Item 1A and elsewhere in this annual report. See Forward-Looking Statements .

OVERVIEW

We are a leading provider of shallow-water drilling and marine services to the oil and natural gas exploration and production industry globally. We provide these services to national oil and gas companies, major integrated energy companies and independent oil and natural gas operators. As of February 23, 2012, we owned a fleet of 42 jackup rigs, seventeen barge rigs, two submersible rigs, one platform rig, 58 liftboat vessels, and operate an additional five liftboat vessels owned by a third party. Our diverse fleet is capable of providing services such as oil and gas exploration and development drilling, well service, platform inspection, maintenance and decommissioning operations in several key shallow-water provinces around the world.

Asset Purchase

On April 27, 2011, we completed our acquisition of 20 jackup rigs and related assets, accounts receivable, accounts payable and certain contractual rights from Seahawk Drilling, Inc. and certain of its subsidiaries (Seahawk) (Seahawk Transaction) for total consideration of approximately $150.3 million consisting of

$25.0 million of cash and 22.1 million shares of Hercules common stock, net of a working capital adjustment. The fair value of the shares issued was determined using the closing price of our common stock of $5.68 on April 27, 2011. The results of Seahawk are included in our results from the date of acquisition.

Asset Dispositions

In May 2011, we completed the sale of substantially all of Delta Towing s assets and certain liabilities for aggregate consideration of $30 million in cash (the Delta Towing Sale) and recognized a loss on the sale of approximately $13 million. In addition, we retained the working capital of our Delta Towing business which was approximately $6 million at the date of sale. The results of operations of the Delta Towing segment are reflected in the Consolidated Statements of Operations for all periods presented as discontinued operations.

We also sold various rigs and other miscellaneous assets during the year ended December 31, 2011.

Investment

In January 2011, we paid $10 million to purchase 5.0 million shares, an initial investment in approximately eight percent of the total outstanding equity of a new entity incorporated in Luxembourg, Discovery Offshore S.A. (Discovery Offshore), which investment was used by Discovery Offshore towards funding the down payments on two new-build ultra high specification harsh environment jackup drilling rigs (collectively the Rigs or individually Rig). The two Rigs are expected to be delivered in the second and fourth quarter of 2013, respectively. Discovery Offshore also held options to purchase two additional rigs of the same specifications that expired in the fourth quarter of 2011.

We also executed a construction management agreement (the Construction Management Agreement) and a services agreement (the Services Agreement) with Discovery Offshore with respect to each of the Rigs. Under the Construction Management Agreements, we will plan, supervise and manage the construction and commissioning of the Rigs in exchange for a fixed fee of $7.0 million per Rig, which we received in February 2011. Pursuant to the terms of the Services Agreements, we will market, manage, crew and operate the Rigs and any other rigs that Discovery Offshore subsequently acquires or controls, in exchange for a fixed daily fee of $6,000 per Rig plus five percent of Rig-based EBITDA (EBITDA excluding SG&A expense) generated per day per Rig, which commences once the Rigs are completed and operating. Under the Services Agreements, Discovery Offshore will be responsible for operational and capital expenses for the Rigs. We are entitled to a minimum fee of $5 million per Rig in the event Discovery Offshore terminates a Services Agreement in the absence of a breach of contract by Hercules Offshore.

In addition to the $10 million investment, we received 500,000 additional shares worth $1.0 million to cover our costs incurred and efforts expended in forming Discovery Offshore. We were issued warrants to purchase up to 5.0 million additional shares of Discovery Offshore stock at a strike price of 11.5 Norwegian Kroner per share which is exercisable in the event that the Discovery Offshore stock price reaches an average equal to or higher than 23 Norwegian Kroner per share for 30 consecutive trading days. The warrants were issued to additionally compensate us for our costs incurred and efforts expended in forming Discovery Offshore. As of December 31, 2011, Discovery Offshore s stock price was 8.50 Norwegian Kroner per share. We have no other financial obligations or commitments with respect to the Rigs or our ownership in Discovery Offshore. Two of our officers are on the Board of Directors of Discovery Offshore.

We report our business activities in five business segments, which as of February 23, 2012, included the following:

Domestic Offshore includes 34 jackup rigs and two submersible rigs in the U.S. Gulf of Mexico that can drill in maximum water depths ranging from 85 to 350 feet. Eighteen of the jackup rigs are either working on short-term contracts or available for contracts and sixteen are cold stacked. Both submersibles are cold stacked.

International Offshore includes eight jackup rigs and one platform rig outside of the U.S. Gulf of Mexico. We have two jackup rigs contracted offshore Saudi Arabia, one jackup rig preparing for a contract in Indonesia, one jackup rig contracted offshore in the Democratic Republic of Congo and one platform rig contracted offshore in Mexico. In addition, we have one jackup rig warm stacked and one jackup rig cold stacked in Bahrain, one jackup rig warm stacked in Malaysia, as well as one jackup rig contracted in Angola, however, it is currently in a shipyard in Mississippi undergoing repairs and is estimated to be out of service through the first quarter of 2012. In addition to owning and operating our own rigs, we have the Construction Management Agreement and the Services Agreement with Discovery Offshore with respect to each of its Rigs.

Inland includes a fleet of six conventional and eleven posted barge rigs that operate inland in marshes, rivers, lakes and shallow bay or coastal waterways along the U.S. Gulf Coast. Three of our inland barges are either operating on short-term contracts or available and fourteen are cold stacked.

Domestic Liftboats includes 40 liftboats in the U.S. Gulf of Mexico. Thirty-four are operating or available for contracts and six are cold stacked.

International Liftboats includes 23 liftboats. Eighteen are operating or available for contracts offshore West Africa, including five liftboats owned by a third party, three are cold stacked offshore West Africa and two are operating or available for contracts in the Middle East region.

Our drilling rigs are used primarily for exploration and development drilling in shallow waters. Under most of our contracts, we are paid a fixed daily rental rate called a dayrate, and we are required to pay all costs associated with our own crews as well as the upkeep and insurance of the rig and equipment.

Our liftboats are self-propelled, self-elevating vessels with a large open deck space, which provides a versatile, mobile and stable platform to support a broad range of offshore maintenance and construction services throughout the life of an oil or natural gas well. Under most of our liftboat contracts, we are paid a fixed dayrate for the rental of the vessel, which typically includes the costs of a small crew of four to eight employees, and we also receive a variable rate for reimbursement of other operating costs such as catering, fuel, rental equipment and other items.

Our revenue is affected primarily by dayrates, fleet utilization, the number and type of units in our fleet and mobilization fees received from our customers. Utilization and dayrates, in turn, are influenced principally by the demand for rig and liftboat services from the exploration and production sectors of the oil and natural gas industry. Our contracts in the U.S. Gulf of Mexico tend to be short-term in nature and are heavily influenced by changes in the supply of units relative to the fluctuating expenditures for both drilling and production activity. Most of our international drilling contracts and some of our liftboat contracts in West Africa are longer term in nature.

Our operating costs are primarily a function of fleet configuration and utilization levels. The most significant direct operating costs for our Domestic Offshore, International Offshore and Inland segments are wages paid to crews, maintenance and repairs to the rigs, and insurance. These costs do not vary significantly whether the rig is operating under contract or idle, unless we believe that the rig is unlikely to work for a prolonged period of time, in which case we may decide to cold stack or warm stack the rig. Cold stacking is a common term used to describe a rig that is expected to be idle for a protracted period and typically for which routine maintenance is suspended and the crews are either redeployed or laid-off. When a rig is cold stacked, operating expenses for the rig are significantly reduced because the crew is smaller and maintenance activities are suspended. Placing rigs in service that have been cold stacked typically requires a lengthy reactivation project that can involve significant expenditures and potentially additional regulatory review, particularly if the rig has been cold stacked for a long period of time. Warm stacking is a term used for a rig expected to be idle for a period of time that is not as prolonged as is the case with a cold stacked rig. Maintenance is continued for warm stacked rigs. Crews are reduced but a small crew is retained. Warm stacked rigs generally can be reactivated in three to four weeks.

The most significant costs for our Domestic Liftboats and International Liftboats segments are the wages paid to crews and the amortization of regulatory drydocking costs. Unlike our Domestic Offshore, International Offshore and Inland segments, a significant portion of the expenses incurred with operating each liftboat are paid for or reimbursed by the customer under contractual terms and prices. This includes catering, fuel, oil, rental

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equipment, crane overtime and other items. We record reimbursements from customers as revenue and the related expenses as operating costs. Our liftboats are required to undergo regulatory inspections every year and to be drydocked two times every five years; the drydocking expenses and length of time in drydock vary depending on the condition of the vessel. All costs associated with regulatory inspections, including related drydocking costs, are deferred and amortized over a period of twelve months.

Investigations

On April 4, 2011, we received a subpoena issued by the Securities and Exchange Commission (SEC) requesting the delivery of certain documents to the SEC in connection with its investigation into possible violations of the securities laws, including possible violations of the Foreign Corrupt Practices Act (FCPA) in certain international jurisdictions where we conduct operations. We were also notified by the Department of Justice (DOJ) on April 5, 2011, that certain of our activities are under review by the DOJ.

We, through the Audit Committee of the Board of Directors, have engaged an outside law firm with significant experience in FCPA-related matters to conduct an internal review, and intend to continue to cooperate with the SEC and DOJ in their investigations. At this time, it is not possible to predict the outcome of the investigations, the expenses we will incur associated with these matters, or the impact on the price of our common stock or other securities as a result of these investigations.

RESULTS OF OPERATIONS

Generally, domestic drilling industry conditions improved in 2011, as supply was further diminished and demand increased for jackup rigs. Factors that led to the increase in demand included the high price of crude oil, the shift by operators to liquids-rich drilling activity, and the improvement in our customers ability to obtain necessary drilling permits to operate in the U.S. Gulf of Mexico, which tightened during 2010 due to the new federal regulations in the wake of the Macondo well blowout incident. Furthermore, our Domestic Offshore segment benefited from the addition of rigs from the Seahawk Transaction. Our Domestic Liftboat performance weakened in 2011, primarily because 2010 results benefitted from a significant increase in utilization stemming from coastal restoration efforts related to the Macondo well blowout incident.

Our International Offshore segment experienced weaker results due to contract expiration on the international rig fleet during the year. While the majority of our international rigs were recontracted, market dayrates were significantly below prior contract dayrates. Our International Liftboat operations experienced a decline in operating income due to an increase in operating and administrative expenses in 2011 as compared to 2010. The increase in revenue experienced by increased operating days, was offset by a decline in the revenue per liftboat per day.

Our domestic liftboat operations are generally affected by the seasonal weather patterns in the U.S. Gulf of Mexico. These seasonal patterns may result in increased activity in the spring, summer and fall periods and a decrease in the winter months. High winds, significant rain, tropical storms, hurricanes and other inclement weather conditions prevalent in the U.S. Gulf of Mexico during the year affect our domestic liftboat operations, as these conditions typically require our liftboats to leave work locations and cease to earn a full dayrate. The liftboats cannot return to the location until the weather improves and the seas are less than U.S. Coast Guard approved limits. Demand for our domestic rigs may decline during hurricane season, which is generally considered June 1 through November 30, as our customers may reduce drilling activity. Accordingly, our operating results may vary from quarter to quarter, depending on factors outside of our control.

On April 27, 2011, we completed the Seahawk Transaction. The results of Seahawk are included in our results from the date of acquisition which impacts the comparability of the 2011 period with the corresponding 2010 and 2009 periods.

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The following table sets forth financial information by operating segment and other selected information for the periods indicated:

	Year Ended December 31, 2011	2010	2009
	(Dollars in thousands)		
Domestic Offshore:			
Number of rigs (as of end of period)	38	25	24
Revenue	$ 217,450	$ 124,063	$ 140,889
Operating expenses	186,132	147,715	175,473
Impairment of property and equipment		84,744	
Depreciation and amortization expense	68,146	68,335	60,775
General and administrative expenses	9,275	5,663	6,496
Operating loss	$ (46,103)	$ (182,394)	$ (101,855)
International Offshore:			
Number of rigs (as of end of period)	9	9	10
Revenue	$ 237,047	$ 291,516	$ 393,797
Operating expenses	134,439	130,460	169,418
Impairment of property and equipment		37,973	26,882
Depreciation and amortization expense	52,278	58,275	63,808
General and administrative expenses	(7,512)	7,930	35,694
Operating income	$ 57,842	$ 56,878	$ 97,995
Inland:			
Number of barges (as of end of period)	17	17	17
Revenue	$ 28,180	$ 21,922	$ 19,794
Operating expenses	22,973	27,702	44,593
Depreciation and amortization expense	14,589	23,516	32,465
General and administrative expenses	1,388	(1,420)	1,831
Operating loss	$ (10,770)	$ (27,876)	$ (59,095)
Domestic Liftboats:			
Number of liftboats (as of end of period)	40	41	41
Revenue	$ 56,575	$ 70,710	$ 75,584
Operating expenses	42,381	42,073	48,738
Depreciation and amortization expense	15,329	14,698	20,267
General and administrative expenses	2,190	1,850	2,039
Operating income (loss)	$ (3,325)	$ 12,089	$ 4,540

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	Year Ended December 31, 2011	2010	2009
	(Dollars in thousands)		
International Liftboats:			
Number of liftboats (as of end of period)	24	24	24
Revenue	$ 116,106	$ 116,616	$ 88,537
Operating expenses	58,407	55,879	48,240
Depreciation and amortization expense	19,624	17,711	12,880
General and administrative expenses	7,166	5,815	4,990
Operating income	$ 30,909	$ 37,211	$ 22,427
Total Company:			
Revenue	$ 655,358	$ 624,827	$ 718,601
Operating expenses	444,332	403,829	486,462
Impairment of property and equipment		122,717	26,882
Depreciation and amortization expense	172,571	185,712	193,504
General and administrative expenses	57,204	55,996	91,222
Operating loss	(18,749)	(143,427)	(79,469)
Interest expense	(79,178)	(80,482)	(75,431)
Expense of credit agreement fees	(455)		(15,073)
Gain on early retirement of debt, net			12,157
Other, net	(3,479)	3,876	3,955
Loss before income taxes	(101,861)	(220,033)	(153,861)
Income tax benefit	35,341	87,940	72,814
Loss from continuing operations	(66,520)	(132,093)	(81,047)
Loss from discontinued operations, net of taxes	(9,608)	(2,501)	(10,687)
Net loss	$ (76,128)	$ (134,594)	$ (91,734)

The following table sets forth selected operational data by operating segment for the periods indicated:

Year Ended December 31, 2011	Operating Days	Available Days	Utilization(1)	Average Revenue per Day(2)	Average Operating Expense per Day(3)
Domestic Offshore	4,494	5,755	78.1%	$ 48,387	$ 32,343
International Offshore	2,131	2,828	75.4%	111,237	47,539
Inland	966	1,095	88.2%	29,172	20,980
Domestic Liftboats	7,290	12,983	56.2%	7,761	3,264
International Liftboats	5,310	8,395	63.3%	21,866	6,957

Year Ended December 31, 2010	Operating Days	Available Days	Utilization(1)	Average Revenue per Day(2)	Average Operating Expense per Day(3)
Domestic Offshore	3,321	4,086	81.3%	$ 37,357	$ 36,151

International Offshore	2,106	3,344	63.0%	138,422	39,013
Inland	986	1,095	90.0%	22,233	25,299
Domestic Liftboats	9,641	13,870	69.5%	7,334	3,033
International Liftboats	5,100	8,546	59.7%	22,866	6,539

	Year Ended December 31, 2009				
	Operating Days	Available Days	Utilization(1)	Average Revenue per Day(2)	Average Operating Expense per Day(3)
Domestic Offshore	2,676	4,544	58.9%	$ 52,649	$ 38,616
International Offshore	3,100	3,714	83.5%	127,031	45,616
Inland	651	1,578	41.3%	30,406	28,259
Domestic Liftboats	9,535	14,804	64.4%	7,927	3,292
International Liftboats	4,293	7,209	59.6%	20,624	6,692

(1) Utilization is defined as the total number of days our rigs or liftboats, as applicable, were under contract, known as operating days, in the period as a percentage of the total number of available days in the period. Days during which our rigs and liftboats were undergoing major refurbishments, upgrades or construction, and days during which our rigs and liftboats are cold stacked, are not counted as available days. Days during which our liftboats are in the shipyard undergoing drydocking or inspection are considered available days for the purposes of calculating utilization.

(2) Average revenue per rig or liftboat per day is defined as revenue earned by our rigs or liftboats, as applicable, in the period divided by the total number of operating days for our rigs or liftboats, as applicable, in the period.

(3) Average operating expense per rig or liftboat per day is defined as operating expenses, excluding depreciation and amortization, incurred by our rigs or liftboats, as applicable, in the period divided by the total number of available days in the period. We use available days to calculate average operating expense per rig or liftboat per day rather than operating days, which are used to calculate average revenue per rig or liftboat per day, because we incur operating expenses on our rigs and liftboats even when they are not under contract and earning a dayrate. In addition, the operating expenses we incur on our rigs and liftboats per day when they are not under contract are typically lower than the per day expenses we incur when they are under contract.

2011 Compared to 2010

Revenue

Consolidated. Total revenue for 2011 was $655.4 million compared with $624.8 million for 2010, an increase of $30.5 million, or 5%. This increase is further described below.

Domestic Offshore. Revenue for our Domestic Offshore segment was $217.5 million for 2011 compared with $124.1 million for 2010, an increase of $93.4 million, or 75%, primarily due to revenue of $74.4 million related to the rigs acquired from Seahawk. Excluding the revenue from the rigs acquired from Seahawk, revenue increased $19.0 million for the legacy Hercules rigs due to an increase in average dayrates, $47,000 in 2011 compared to $37,357 in 2010, which contributed to an approximate $32 million increase in revenue. This increase was partially offset by a decline in operating days for the legacy Hercules rigs to 3,043 days during 2011 from 3,321 days during 2010, which contributed to an approximate $13 million decrease in revenue in 2011 as compared to 2010.

International Offshore. Revenue for our International Offshore segment was $237.0 million for 2011 compared with $291.5 million for 2010, a decrease of $54.5 million, or 19%. *Hercules 258* and *Hercules 260* contributed to a reduction of $26.5 million and $29.0 million, respectively, as their contracts matured in June and May 2011, respectively, and subsequently operated at lower dayrates. Additionally, there is no provision of marine services associated with the subsequent contracts. *Hercules 262* and *Hercules 208* contributed to a reduction of $6.9 million and $5.2 million, respectively, primarily due to fewer operating days in 2011 as compared to 2010. These decreases are partially offset by *Hercules 185* operating a large portion of 2011 compared to not meeting revenue recognition criteria in 2010 which contributed to a $15.2 million increase in revenue. Average revenue per rig per day decreased to $111,237 in 2011 from $138,422 in 2010 primarily due to lower average dayrates earned on *Hercules 258* and *Hercules 260*.

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Inland. Revenue for our Inland segment was $28.2 million for 2011 compared with $21.9 million for 2010, an increase of $6.3 million, or 29%. This increase was driven primarily from a 31% increase in average dayrates in 2011 as compared to 2010.

Domestic Liftboats. Revenue for our Domestic Liftboats segment was $56.6 million for 2011 compared with $70.7 million in 2010, a decrease of $14.1 million, or 20%. This decrease resulted primarily from a 24% decline in operating days which contributed to an approximate $18 million decrease in revenue, largely due to activity associated with the Macondo well blowout incident remediation efforts in 2010. This decrease was partially offset by an increase in average revenue per liftboat per day to $7,761 in 2011 compared with $7,334 in 2010, which contributed to an approximate $4 million increase in revenue.

International Liftboats. Revenue for our International Liftboats segment was $116.1 million for 2011 compared with $116.6 million in 2010, a decrease of $0.5 million.

Operating Expenses

Consolidated. Total operating expenses for 2011 were $444.3 million compared with $403.8 million in 2010, an increase of $40.5 million, or 10%. This increase is further described below.

Domestic Offshore. Operating expenses for our Domestic Offshore segment were $186.1 million in 2011 compared with $147.7 million in 2010, an increase of $38.4 million, or 26%, primarily due to operating expenses of approximately $41 million related to the rigs acquired from Seahawk. Excluding the operating expenses related to the rigs acquired from Seahawk, operating expenses decreased approximately $3 million driven by a decrease in labor expense, equipment rentals, insurance, repairs and maintenance and freight costs of $6.6 million, $5.2 million, $3.8 million, $0.9 million and $1.3 million, respectively, offset by an increase in workers compensation expenses of $12.1 million as well as $7.0 million fewer gains on asset sales in 2011 as compared to 2010. Additionally, 2010 included an accrual of approximately $3.0 million related to a multi-year state sales and use tax audit. Average operating expenses per rig per day were $32,343 in 2011 compared with $36,151 in 2010.

International Offshore. Operating expenses for our International Offshore segment were $134.4 million in 2011 compared with $130.5 million in 2010, an increase of $4.0 million, or 3%. The increase was driven by i) increased operating expenses for *Hercules 185* which contributed to a $12.0 million increase in 2011 as compared to 2010, ii) increased operating expenses for *Rig 3* which contributed to a $4.5 million increase in 2011 as compared to 2010 primarily due to permanent importation costs of approximately $8 million, offset by a $1.7 million benefit for a forfeited deposit and a $1.0 million deferral of contract preparation costs as well as iii) increased operating expenses for *Hercules 208* which contributed to a $6.0 million increase in 2011 as compared to 2010 primarily due to $2.3 million in amortization of deferred costs as well as approximately $2.8 million in costs incurred for the planned demobilization of the rig from Vietnam, which was delayed as a result of inclement weather. Partially offsetting these increases i) *Hercules 156* was cold stacked in December 2010 which contributed to a $6.5 million decrease, ii) *Hercules 260* contributed to a $5.0 million decrease primarily due to not providing marine services under its new contract which contributed to an approximate $7 million decrease offset by increased amortization of deferred expenses of $2.9 million in 2011 as compared to 2010 and iii) *Hercules 258* contributed to a $8.4 million decrease primarily due to not providing marine services subsequent to its contract expiration in June 2011. Average operating expenses per rig per day were $47,539 in 2011 compared with $39,013 in 2010.

Inland. Operating expenses for our Inland segment were $23.0 million in 2011 compared with $27.7 million in 2010, a decrease of $4.7 million, or 17%. This decrease is primarily due to an accrual in 2010 of approximately $3.0 million related to a multi-year state sales and use tax audit. In addition, labor costs decreased $1.3 million in 2011 as compared to 2010. Average operating expenses per rig per day were $20,980 in 2011 compared with $25,299 in 2010.

Domestic Liftboats. Operating expenses for our Domestic Liftboats segment were $42.4 million in 2011 compared with $42.1 million in 2010, an increase of $0.3 million, or 1%.

International Liftboats. Operating expenses for our International Liftboats segment were $58.4 million for 2011 compared with $55.9 million in 2010, an increase of $2.5 million, or 5%. The increase is primarily due to increased labor costs in 2011.

Impairment of Property and Equipment

In the year ended December 31, 2010, we incurred $122.7 million of impairment charges related to certain property and equipment in our Domestic Offshore and International Offshore segments, the impact of which by segment was $84.7 million and $38.0 million, respectively.

Depreciation and Amortization

Depreciation and amortization expense in 2011 was $172.6 million compared with $185.7 million in 2010, a decrease of $13.1 million, or 7%. This decrease resulted primarily from reduced depreciation in the Current Period of approximately $26 million due to asset sales and fully depreciated assets as well as asset impairments recorded in the fourth quarter of 2010, partially offset by an approximate $11 million increase in depreciation in the Current Period due to capital additions, including $7.0 million of depreciation related to the addition of the rigs acquired from Seahawk. Additionally, drydock amortization increased $2.2 million.

General and Administrative Expenses

General and administrative expenses in 2011 were $57.2 million compared with $56.0 million in 2010, an increase of $1.2 million, or 2%. The increase is related to an increase in labor costs, including contract labor, of $4.1 million as well as an increase of $10.2 million in legal and professional service fees, of which $3.4 million related to the Seahawk Transaction. These increases were partially offset by a $13.9 million reduction in bad debt expense in 2011 as compared to 2010 due primarily to additional recoveries from one international customer.

Interest Expense

Interest expense decreased $1.3 million, or 2%. This decrease was related primarily to the impact of our interest rate collar outstanding in the Comparable Period, somewhat offset by the increased rate on our term loan.

Expense of Credit Agreement Fees

During 2011, we amended our credit agreement (the Credit Agreement). In doing so, we recorded the write-off of certain deferred debt issuance costs and expensed certain fees directly related to these activities totaling $0.5 million.

Other Expense

Other Expense in the Current Period was $3.5 million compared to Other Income in 2010 of $3.9 million, an increase to expense of $7.4 million, primarily due to the 2011 recording of the fair market value of our Discovery Offshore Warrants of $3.3 million as well as a $3.3 million currency gain in 2010 due to the devaluation of the Venezuelan Bolivar.

Income Tax Benefit

Our income tax benefit was $35.3 million on a pre-tax loss of $101.9 million, for an effective rate of 34.7%, during 2011, compared to a benefit of $87.9 million on a pre-tax loss of $220.0 million, for an effective rate of 40.0%, for 2010. The effective tax rate in 2011 decreased as compared to 2010 due to mix of earnings (losses) from different jurisdictions as well as the prior year benefit of $5.8 million related to the effective compromise settlement with the Mexican tax authorities on certain tax liabilities, partially offset by adjustments for various discrete items, including certain return to provision adjustments in 2010. In some cases our income tax is based on gross revenues or deemed profits under local tax laws rather than income before taxes. In addition, our assets move between taxing jurisdictions and operating structures with differing tax rates. As a result, variations in our effective tax rate from period to period may have limited correlation with pre-tax income or loss.

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Discontinued Operations

We had a loss from our discontinued Delta Towing operations of $9.6 million during 2011 compared to a loss from our discontinued Delta Towing operations of $2.5 million during 2010. The $7.1 million increase in loss was primarily the result of the $13.4 million loss recognized for the Delta Towing Sale in May 2011.

2010 Compared to 2009

Revenue

Consolidated. Total revenue for 2010 was $624.8 million compared with $718.6 million for 2009, a decrease of $93.8 million, or 13%. This decrease is further described below.

Domestic Offshore. Revenue for our Domestic Offshore segment was $124.1 million for 2010 compared with $140.9 million for 2009, a decrease of $16.8 million, or 12%. This decrease resulted primarily from a 29% decline in average dayrates which contributed to an approximate $41 million decrease during 2010 as compared to 2009. Partially offsetting this decrease was an increase in operating days to 3,321 days during 2010 from 2,676 days during 2009, which contributed to an approximate $24 million increase in revenue. Average utilization was 81.3% in 2010 compared with 58.9% in 2009.

International Offshore. Revenue for our International Offshore segment was $291.5 million for 2010 compared with $393.8 million for 2009, a decrease of $102.3 million, or 26%. Approximately $26 million of this decrease related to *Hercules 156* and *Hercules 170*, which did not work in 2010, approximately $55 million was associated with a decline in revenue from mobilizing *Hercules 205* and *Hercules 206* to the U.S. Gulf of Mexico, and approximately $27 million related to *Hercules 185* not meeting revenue recognition criteria in 2010. Partially offsetting these decreases was an approximate $8 million increase for *Hercules 260* primarily due to downtime in 2009 for leg repairs.

Inland. Revenue for our Inland segment was $21.9 million for 2010 compared with $19.8 million for 2009, an increase of $2.1 million, or 11%. This increase resulted from a 51% increase in operating days, 986 in 2010 compared to 651 in 2009, which contributed to an approximate $7 million increase in revenue. Partially offsetting this increase, average dayrates declined 27% which contributed to an approximate $5 million decrease in revenue.

Domestic Liftboats. Revenue for our Domestic Liftboats segment was $70.7 million for 2010 compared with $75.6 million in 2009, a decrease of $4.9 million, or 6%. Approximately $8 million of this decrease resulted from the transfer of four vessels to West Africa in the fourth quarter of 2009, offset in part by increased operating days for the remaining vessels. Operating days increased slightly to 9,641 days during 2010 as compared to 9,535 days during 2009 due in part to increased activity associated with the Macondo well blowout incident remediation efforts, largely offset by the impact of the transfer of four vessels. Average revenue per vessel per day was $7,334 in 2010 compared with $7,927 in 2009, a decrease of $593 per day due to both weaker dayrates on our smaller class vessels and a shift in the mix of vessel class as we mobilized four larger class vessels to West Africa in the fourth quarter of 2009.

International Liftboats. Revenue for our International Liftboats segment was $116.6 million for 2010 compared with $88.5 million in 2009, an increase of $28.1 million, or 32%. Approximately $34 million of this increase resulted from the transfer of four vessels from the U.S. Gulf of Mexico. Average revenue per liftboat per day increased to $22,866 in 2010 compared with $20,624 in 2009 and operating days increased to 5,100 days in 2010 as compared to 4,293 in 2009.

Operating Expenses

Consolidated. Total operating expenses for 2010 were $403.8 million compared with $486.5 million in 2009, a decrease of $82.6 million, or 17%. This decrease is further described below.

Domestic Offshore. Operating expenses for our Domestic Offshore segment were $147.7 million in 2010 compared with $175.5 million in 2009, a decrease of $27.8 million, or 16%. The decrease was driven in part by 458 fewer available days during 2010 as compared to 2009, or a 10% decline, due to our cold stacking of rigs. Our cold stacking resulted in a reduction to our labor, repairs and maintenance, and workers compensation expenses. Additionally, 2010 includes gains totaling $10.2 million for the sale of *Hercules 155*, *Hercules 191* and *Hercules 255*. Partially offsetting these decreases are increases in insurance costs and equipment rentals of $5.1 million, accrued sales and use tax expense of approximately $3.0 million related to a multi-year state sales and use tax audit as well as a gain of $6.3 million in 2009 for an insurance settlement related to hurricane damage. Average operating expenses per rig per day were $36,151 in 2010 compared with $38,616 in 2009.

International Offshore. Operating expenses for our International Offshore segment were $130.5 million in 2010 compared with $169.4 million in 2009, a decrease of $39.0 million, or 23%. *Hercules 170* was in warm stack during all of 2010 which contributed to a decrease of $7.5 million, and *Hercules 205* and *Hercules 206* were transferred to the Domestic Offshore segment in the first quarter of 2010 and fourth quarter of 2009, respectively, which contributed to a decrease of $19.8 million. Additionally, *Hercules 185* was on stand-by in 2010, but operated a portion of 2009 which contributed to a decrease of $8.8 million. In addition, 2009 included a charge of $4.8 million associated with a customer in our International Offshore segment ($7.3 million to fully impair the related deferred mobilization and contract preparation costs, partially offset by a $2.5 million reduction in previously accrued contract related operating costs that are not expected to be settled if the receivable is not collected). Average operating expenses per rig per day were $39,013 in 2010 compared with $45,616 in 2009.

Inland. Operating expenses for our Inland segment were $27.7 million in 2010 compared with $44.6 million in 2009, a decrease of $16.9 million, or 38%. Our cold stacking of barges reduced our available days from 1,578 in 2009 to 1,095 in 2010. This reduction in available days coupled with the reduction in our labor force significantly reduced the segment s variable operating costs. In addition, 2010 includes a $3.1 million gain on the sale of eight of our retired barges, while 2009 includes a $0.6 million gain of the sale of two of our retired barges. These decreases are partially offset by accrued sales and use tax expense of approximately $3.0 million related to a multi-year state sales and use tax audit. Average operating expenses per rig per day were $25,299 in 2010 compared with $28,259 in 2009.

Domestic Liftboats. Operating expenses for our Domestic Liftboats segment were $42.1 million in 2010 compared with $48.7 million in 2009, a decrease of $6.7 million, or 14%. The transfer of four vessels to our International Liftboats segment contributed $3.3 million to this decrease. In addition, labor costs decreased $2.4 million. Available days declined to 13,870 in 2010 from 14,804 in 2009 due to the transfer of four vessels to our International Liftboats segment in the fourth quarter of 2009. Average operating expenses per vessel per day decreased to $3,033 per day during 2010 from $3,292 per day during 2009.

International Liftboats. Operating expenses for our International Liftboats segment were $55.9 million for 2010 compared with $48.2 million in 2009, an increase of $7.6 million, or 16%. The transfer of four vessels from our Domestic Liftboats segment in the fourth quarter of 2009 contributed $4.1 million to this increase. In addition, higher expenses for equipment rentals and certain regulatory fees contributed to an increase of $2.2 million. Available days increased to 8,546 in 2010 from 7,209 in 2009 largely related to the transfer of four vessels. Average operating expenses per vessel per day decreased to $6,539 per day during 2010 from $6,692 per day during 2009.

Impairment of Property and Equipment

In the year ended December 31, 2010, we incurred $122.7 million of impairment charges related to certain property and equipment on our Domestic Offshore and International Offshore segments, the impact of which by segment was $84.7 million and $38.0 million, respectively. In June 2009, we entered into an agreement to sell *Hercules 110*, which was cold stacked in Trinidad, and incurred a $26.9 million impairment charge to write-down the rig to its fair value less costs to sell.

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Depreciation and Amortization

Depreciation and amortization expense in 2010 was $185.7 million compared with $193.5 million in 2009, a decrease of $7.8 million, or 4%. This decrease resulted primarily from lower amortization of our international contract values and drydocking costs, which contributed a decrease of $3.4 million and $2.4 million, respectively, as well as reduced depreciation due to asset sales and certain assets being fully depreciated, which contributed a decrease of approximately $10 million. These decreases were partially offset by the impact of capital additions which contributed to an approximate $8 million increase.

General and Administrative Expenses

General and administrative expenses in 2010 were $56.0 million compared with $91.2 million in 2009, a decrease of $35.2 million, or 39%. This decrease relates primarily to a $26.8 million allowance for doubtful accounts receivable that was recorded in 2009 related to a customer in our International Offshore segment. In addition, labor costs decreased in 2010 as compared to 2009 driven in part by an adjustment of approximately $2.8 million to stock-based compensation expense due to a revision of our estimated forfeiture rate during 2010 as well as the impact of headcount reductions.

Interest Expense

Interest expense increased $5.1 million, or 7%. This increase was related to interest expense incurred on our 10.5% Senior Secured Notes issued in October 2009, partially offset by lower interest on our term loan as the increase in interest rates after the 2009 Credit Amendment (2009 Credit Amendment) were offset by lower debt balances due to the early retirement of a portion of our term loan in the third and fourth quarters of 2009. In addition, interest expense decreased on our 3.375% Convertible Senior Notes due to our second quarter 2009 retirements.

Expense of Credit Agreement Fees

During 2009, we amended our Credit Agreement and repaid and terminated a portion of our credit facility. In doing so, we recorded the write-off of certain deferred debt issuance costs and certain fees directly related to these activities totaling $15.1 million.

Gain on Early Retirement of Debt, Net

Gain on early retirement of debt, net was $12.2 million in 2009. During 2009, we retired a portion of our term loan facility and wrote off $1.6 million in associated unamortized issuance costs. In addition, in 2009 we retired $65.8 million aggregate principal amount of the 3.375% Convertible Senior Notes for cash and equity consideration of approximately $40.1 million, resulting in a gain of $13.7 million, net of an associated write-off of a portion of our unamortized issuance costs.

Income Tax Benefit

Income tax benefit was $87.9 million on pre-tax loss of $220.0 million during 2010, compared to a benefit of $72.8 million on pre-tax loss of $153.9 million for 2009. The effective tax rate decreased to a tax benefit of 40.0% during 2010 as compared to a tax benefit of 47.3% during 2009. The decrease in tax benefit for 2010 results from a higher tax charge associated with a deemed repatriation of foreign earnings and a reduction in state income tax benefits, partially offset by reduced foreign tax cost when compared to 2009.

Discontinued Operations

We had a loss from discontinued operations of $2.5 million during 2010 compared to a loss from discontinued operations of $10.7 million during 2009, a decrease of $8.2 million or 77%. The decrease is primarily related to an increase in revenue of $8.4 million, or 35% for the discontinued operations of our Delta Towing segment. The discontinued operations of our Delta Towing segment had increased operating days during 2010 as compared to 2009, due in part to activity associated with the Macondo well blowout incident remediation efforts, which contributed to an approximate $16 million increase in revenue. This increase was partially offset by the impact of a decrease in average vessel dayrates during 2010 as compared to 2009, which contributed to an approximate $7 million decrease in revenue.

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Non-GAAP Financial Measures

Regulation G, *General Rules Regarding Disclosure of Non-GAAP Financial Measures* and other SEC regulations define and prescribe the conditions for use of certain Non-Generally Accepted Accounting Principles (Non-GAAP) financial measures. We use various Non-GAAP financial measures such as adjusted operating income (loss), adjusted income (loss) from continuing operations, adjusted diluted earnings (loss) per share from continuing operations, EBITDA and Adjusted EBITDA. EBITDA is defined as net income plus interest expense, income taxes, depreciation and amortization. We believe that in addition to GAAP based financial information, Non-GAAP amounts are meaningful disclosures for the following reasons: (i) each are components of the measures used by our board of directors and management team to evaluate and analyze our operating performance and historical trends, (ii) each are components of the measures used by our management team to make day-to-day operating decisions, (iii) the Credit Agreement contains covenants that require us to maintain a total leverage ratio and a consolidated fixed charge coverage ratio, which contain Non-GAAP adjustments as components, (iv) each are components of the measures used by our management to facilitate internal comparisons to competitors results and the shallow-water drilling and marine services industry in general, (v) results excluding certain costs and expenses provide useful information for the understanding of the ongoing operations without the impact of significant special items, and (vi) the payment of certain bonuses to members of our management is contingent upon, among other things, the satisfaction by the Company of financial targets, which may contain Non-GAAP measures as components. We acknowledge that there are limitations when using Non-GAAP measures. The measures below are not recognized terms under GAAP and do not purport to be an alternative to net income as a measure of operating performance or to cash flows from operating activities as a measure of liquidity. EBITDA and Adjusted EBITDA are not intended to be a measure of free cash flow for management s discretionary use, as it does not consider certain cash requirements such as tax payments and debt service requirements. In addition, the EBITDA and Adjusted EBITDA amounts presented in the following table should not be used for covenant compliance purposes as these amounts could differ materially from the amounts ultimately calculated under our Credit Agreement. Because all companies do not use identical calculations, the amounts below may not be comparable to other similarly titled measures of other companies.

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The following tables present a reconciliation of the GAAP financial measures to the corresponding adjusted financial measures (in thousands, except per share amounts):

	For the Years Ended December 31, 2011	2010	2009
Operating Loss	$ (18,749)	$ (143,427)	$ (79,469)
Adjustments:			
Property and equipment impairment		122,717	26,882
Total adjustments		122,717	26,882
Adjusted Operating Loss	$ (18,749)	$ (20,710)	$ (52,587)
Loss from Continuing Operations	$ (66,520)	$ (132,093)	$ (81,047)
Adjustments:			
Property and equipment impairment		122,717	26,882
Gain on early retirement of debt, net			(12,157)
Expense of credit agreement fees			15,073
Tax impact of adjustments		(42,959)	(14,799)
Total adjustments		79,758	14,999
Adjusted Loss from Continuing Operations	$ (66,520)	$ (52,335)	$ (66,048)
Diluted Loss per Share from Continuing Operations	$ (0.51)	$ (1.15)	$ (0.83)
Adjustments:			
Property and equipment impairment		1.07	0.28
Gain on early retirement of debt, net			(0.13)
Expense of credit agreement fees			0.16
Tax impact of adjustments		(0.38)	(0.16)
Total adjustments		0.69	0.15
Adjusted Diluted Loss per Share from Continuing Operations	$ (0.51)	$ (0.46)	$ (0.68)
Loss from Continuing Operations	$ (66,520)	$ (132,093)	$ (81,047)
Interest expense	79,178	80,482	75,431
Income tax benefit	(35,341)	(87,940)	(72,814)
Depreciation and amortization	172,571	185,712	193,504
EBITDA	149,888	46,161	115,074
Adjustments:			
Property and equipment impairment		122,717	26,882
Gain on early retirement of debt, net			(12,157)
Expense of credit agreement fees			15,073
Total adjustments		122,717	29,798
Adjusted EBITDA	$ 149,888	$ 168,878	$ 144,872

Critical Accounting Policies

Critical accounting policies are those that are important to our results of operations, financial condition and cash flows and require management s most difficult, subjective or complex judgments. Different amounts would be reported under alternative assumptions. We have evaluated the accounting policies used in the preparation of the consolidated financial statements and related notes appearing elsewhere in this annual report. We apply those accounting policies that we believe best reflect the underlying business and economic events, consistent with accounting principles generally accepted in the United States. We believe that our policies are generally consistent with those used by other companies in our industry. We base our estimates on historical experience and on various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results could differ from those estimates.

We periodically update the estimates used in the preparation of the financial statements based on our latest assessment of the current and projected business and general economic environment. During recent periods, there has been substantial volatility and a decline in natural gas prices. This decline may adversely impact the business of our customers, and in turn our business. This could result in changes to estimates used in preparing our financial statements, including the assessment of certain of our assets for impairment. Our significant accounting policies are summarized in Note 2 to our consolidated financial statements. We believe that our more critical accounting policies include those related to business combinations, property and equipment, equity investments, derivatives, revenue recognition, percentage-of-completion, income tax, allowance for doubtful accounts, deferred charges, stock-based compensation and cash and cash equivalents. Inherent in such policies are certain key assumptions and estimates.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand, demand deposits with banks and all highly liquid investments with original maturities of three months or less.

Business Combinations

On April 27, 2011, we completed our acquisition of 20 jackup rigs and related assets, accounts receivable, accounts payable and certain contractual rights from Seahawk for total consideration of approximately $150.3 million consisting of $25.0 million of cash and 22.1 million shares of Hercules common stock, net of a working capital adjustment. We accounted for this transaction as a business combination and accordingly the total consideration was allocated to Seahawk s net tangible assets based on their estimated fair values. Certain of our tax positions are being reviewed and the valuation of our deferred taxes specific to the Seahawk Transaction are preliminary and are subject to change, as for income tax purposes, our financial statements have been prepared assuming that this transaction should be characterized as a purchase of assets. Seahawk is currently in a Chapter 11 proceeding in the United States Bankruptcy Court. The resolution of the bankruptcy and future actions taken in the reorganization of Seahawk s operations may require that the transaction is instead treated by us as a reorganization pursuant to IRC §368(a)(1)(G). Any resulting change, which is currently indeterminable, to our financial position would be reflected in our financial statements as a period adjustment to income at that future date.

Property and Equipment

Property and equipment represents 79% of our total assets as of December 31, 2011. Property and equipment is stated at cost, less accumulated depreciation. Expenditures that substantially increase the useful lives of our assets are capitalized and depreciated, while routine expenditures for repairs and maintenance items are expensed as incurred, except for expenditures for drydocking our liftboats. Drydock costs are capitalized at cost as Other Assets, Net on the Consolidated Balance Sheets and amortized on the straight-line method over a period of 12 months (see Deferred Charges). Depreciation is computed using the straight-line method, after allowing for salvage value where applicable, over the useful life of the asset, which is typically 15 years for our rigs and liftboats. We review our property and equipment for potential impairment when events or changes in circumstances indicate that the carrying value of any asset may not be recoverable or when reclassifications are made between property and equipment and assets held for sale. Factors that might indicate a potential impairment may include, but are not limited to, significant decreases in the market value of the long-lived asset, a significant change in the long-lived asset s physical condition, a change in industry conditions or a substantial reduction in cash flows associated with the use of the long-lived asset. For property and equipment held for use, the determination of recoverability is made based on the estimated undiscounted future net cash flows of the related asset or group of assets being reviewed. Any actual impairment charge would be recorded using the estimated discounted value of future cash flows. This evaluation requires us to make judgments regarding long-term forecasts of future revenue and costs. In turn these forecasts are uncertain in that they require assumptions about demand for our services, future market conditions and technological developments. Significant and unanticipated changes to these assumptions could require a provision for impairment in a future period. Given the nature of these evaluations and their application to specific asset groups and specific times, it is not possible to reasonably quantify the impact of changes in these assumptions.

Supply and demand are the key drivers of rig and vessel utilization and our ability to contract our rigs and vessels at economical rates. During periods of an oversupply, it is not uncommon for us to have rigs or vessels idled for extended periods of time, which could indicate that an asset group may be impaired. Our rigs and vessels are mobile units, equipped to operate in geographic regions throughout the world and, consequently, we may move rigs and vessels from an oversupplied region to one that is more lucrative and undersupplied when it is economical to do so. As such, our rigs and vessels are considered to be interchangeable within classes or asset groups and accordingly, we perform our impairment evaluation by asset group.

Our estimates, assumptions and judgments used in the application of our property and equipment accounting policies reflect both historical experience and expectations regarding future industry conditions and operations. Using different estimates, assumptions and judgments, especially those involving the useful lives of our rigs and liftboats and expectations regarding future industry conditions and operations, would result in different carrying values of assets and results of operations. For example, a prolonged downturn in the drilling industry in which utilization and dayrates were significantly reduced could result in an impairment of the carrying value of our assets.

Useful lives of rigs and vessels are difficult to estimate due to a variety of factors, including technological advances that impact the methods or cost of oil and gas exploration and development, changes in market or economic conditions and changes in laws or regulations affecting the drilling industry. We evaluate the remaining useful lives of our rigs and vessels when certain events occur that directly impact our assessment of the remaining useful lives of the rigs and vessels and include changes in operating condition, functional capability and market and economic factors. We also consider major capital upgrades required to perform certain contracts and the long-term impact of those upgrades on the future marketability when assessing the useful lives of individual rigs and vessels.

When analyzing our assets for impairment, we separate our marketable assets, those assets that are actively marketed and can be warm stacked or cold stacked for short periods of time depending on market conditions, from our non-marketable assets, those assets that have been cold stacked for an extended period of time or those assets that we currently do not reasonably expect to market in the foreseeable future.

2010 Impairment

During the fourth quarter 2010, we considered the prolonged downturn in the drilling industry as an indicator of impairment and assessed our segments for impairment as of December 31, 2010. When analyzing our Domestic Offshore, International Offshore and Delta Towing segments for impairment, we determined five of our domestic jackup rigs, one of our international jackup rigs and several of our Delta Towing assets that had previously been considered marketable, would not be marketed in the foreseeable future and were included in the impairment analysis of non-marketable assets. This determination was based on our estimate of reactivation costs associated with these assets which, based on current and forecasted near-term dayrates and utilization levels, were economically prohibitive, and the sustained lack of visibility in the issuance of offshore drilling permits in the U.S. Gulf of Mexico at that time. Based on an undiscounted cash flow analysis, it was determined that the non-marketable assets were impaired. We estimated the value of the discounted cash flows for each segment s non-marketable assets, which included management s estimate of sales proceeds less costs to sell, and recorded an impairment charge of $125.1 million, of which $2.4 million related to our Delta Towing segment and is included in Loss from Discontinued Operations, Net of Taxes in the Consolidated Statements of Operations for the year ended December 31, 2010. We analyzed our other segments and our marketable assets for impairment as of December 31, 2010 and noted that each segment had adequate undiscounted cash flows to recover its property and equipment carrying values.

Equity Investments

Our investment in Discovery Offshore is being accounted for using the equity method of accounting as we have the ability to exert significant influence, but not control, over operating and financial policies. We review our equity investments for impairment whenever there is a loss in value of an investment which is considered to be other than temporary.

Derivatives

As compensation for costs incurred and efforts expended in forming Discovery Offshore, we were issued warrants to purchase up to 5.0 million additional shares of Discovery Offshore stock at a strike price of 11.5 Norwegian Kroner (NOK) per share which is exercisable in the event that the Discovery Offshore stock price reaches an average equal to or higher than 23 Norwegian Kroner per share for 30 consecutive trading days. As of December 31, 2011, Discovery Offshore s stock price was 8.50 Norwegian Kroner per share. The warrants are being accounted for as a derivative instrument as the underlying security is readily convertible to cash. The fair value of the derivative asset of $1.8 million is included in Other Assets, Net on the Consolidated Balance Sheet at December 31, 2011. Subsequent changes in the fair value of the warrants are recognized to other income (expense). We recognized $3.3 million to other expense related to the change in the fair value of the warrants during the year ended December 31, 2011. The fair value of the Discovery Offshore warrants was determined using a Monte Carlo simulation and is a Level 2 measurement within the fair value hierarchy. We used the historical volatility of companies similar to that of Discovery Offshore to estimate volatility. The risk-free interest rate assumption was based on observed interest rates consistent with the approximate life of the warrants. The stock price represents the closing stock price of Discovery Offshore stock at December 31, 2011. The strike price, target price, expected life and number of warrants are all contractual based on the terms of the warrant agreement. Our estimate of fair value requires a number of inputs and changes to those inputs could result in a different valuation.

Revenue Recognition

Revenue generated from our contracts is recognized as services are performed, as long as collectability is reasonably assured. Some of our contracts also allow us to recover additional direct costs, including mobilization and demobilization costs, additional labor and additional catering costs. Additionally, some of our contracts allow us to receive fees for contract specific capital improvements to a rig. Under most of our liftboat contracts, we receive a variable rate for reimbursement of costs such as catering, fuel, oil, rental equipment, crane overtime and other items. Revenue for the recovery or reimbursement of these costs is recognized when the costs are incurred except for mobilization revenue under contracts longer than ninety days and reimbursement for contract specific capital expenditures, which are recognized as services are performed over the term of the related contract.

The initial fair value of the warrants and 500,000 shares issued from Discovery Offshore have been recorded to deferred revenue to be amortized over 30 years, the estimated useful life of the two new-build Discovery Offshore rigs. Additionally, revenue has been deferred related to our construction management agreements with Discovery Offshore.

Percentage-of-Completion

We are using the percentage-of-completion method of accounting for our revenue and related costs associated with our construction management agreements with Discovery Offshore, combining the construction management agreements, based on a cost-to-cost method. Any revisions in revenue, cost or the progress towards completion, will be treated as a change in accounting estimate and will be accounted for using the cumulative catch-up method.

Income Taxes

Our provision for income taxes takes into account the differences between the financial statement treatment and tax treatment of certain transactions. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates is recognized as income or expense in the period that includes the enactment date.

Our net income tax expense or benefit is determined based on the mix of domestic and international pre-tax earnings or losses, respectively, as well as the tax jurisdictions in which we operate. We operate in multiple countries through various legal entities. As a result, we are subject to numerous domestic and foreign tax jurisdictions and are taxed on various bases: income before tax, deemed profits (which is generally determined using a percentage of revenue rather than profits), and withholding taxes based on revenue. The calculation of our tax liabilities involves consideration of uncertainties in the application and interpretation of complex tax regulations in our operating jurisdictions. Changes in tax laws, regulations, agreements and treaties, or our level of operations or profitability in each taxing jurisdiction could have an impact upon the amount of income taxes that we provide during any given year.

In March 2007, one of our subsidiaries received an assessment from the Mexican tax authorities related to our operations for the 2004 tax year. This assessment contested our right to certain deductions and also claimed the subsidiary did not remit withholding tax due on certain of these deductions. During 2010, we effectively reached a compromise settlement of all issues for 2004 through 2007. We paid $11.6 million and reversed (i) previously provided reserves and (ii) an associated tax benefit in the year ended December 31, 2010 which totaled $5.8 million.

Certain of our international rigs and liftboats are owned or operated, directly or indirectly, by our wholly owned Cayman Islands subsidiaries. Most of the earnings from these subsidiaries are reinvested internationally and remittance to the United States is indefinitely postponed.

Allowance for Doubtful Accounts

Accounts receivable represents approximately 7.7% of our total assets and 43.9% of our current assets as of December 31, 2011. We continuously monitor our accounts receivable from our customers to identify any collectability issues. An allowance for doubtful accounts is established based on reviews of individual customer accounts, recent loss experience, current economic conditions and other pertinent factors. Accounts deemed uncollectable are charged to the allowance. We establish an allowance for doubtful accounts based on the actual amount we believe is not collectable. As of December 31, 2011 and 2010, there was $11.5 million and $29.8 million in allowance for doubtful accounts, respectively. The change in our allowance during the year ended December 31, 2011 related primarily to payments received from a customer in our International Offshore segment.

Deferred Charges

All of our U.S. flagged liftboats are required to undergo regulatory inspections on an annual basis and to be drydocked two times every five years to ensure compliance with U.S. Coast Guard regulations for vessel safety and vessel maintenance standards. Costs associated with these inspections, which generally involve setting the vessels on a drydock, are deferred, and the costs are amortized over a period of 12 months. As of December 31, 2011 and 2010, our net deferred charges related to regulatory inspection costs totaled $5.2 million and $5.4 million, respectively. The amortization of the regulatory inspection costs was reported as part of our depreciation and amortization expense.

Stock-Based Compensation

We recognize compensation cost for all share-based payments awarded in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 718, *Compensation Stock*

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Compensation and in accordance with such we record the grant date fair value of stock options and restricted stock awarded as compensation expense using a straight-line method over the requisite service period. We estimate the fair value of the options granted using the Trinomial Lattice option pricing model using the following assumptions: expected dividend yield, expected stock price volatility, risk-free interest rate and employee exercise patterns (expected life of the options). The fair value of our restricted stock grants is based on the closing price of our common stock on the date of grant. Our liability retention awards are recorded at fair value, which is remeasured at the end of each reporting period, over the requisite service period. Our liability retention awards that contain performance conditions are valued using a Monte Carlo simulation, while the service based liability retention award is valued based on the average price of our common stock for the 90 days prior to the end of the quarter or date of vesting. We also estimate future forfeitures and related tax effects. Our estimate of compensation expense requires a number of complex and subjective assumptions and changes to those assumptions could result in different valuations for individual share awards.

We are estimating that the cost relating to stock options granted through December 31, 2011 will be $0.9 million over the remaining vesting period of 0.6 years, the cost relating to restricted stock granted through December 31, 2011 will be $6.1 million over the remaining vesting period of 1.8 years and the cost relating to liability retention awards granted through December 31, 2011 will be $1.9 million over the remaining vesting period of 2.1 years; however, due to the uncertainty in the level of awards to be granted in the future as well as changes in the fair value of the liability retention awards, these amounts are estimates and subject to change.

OUTLOOK

Offshore

Demand for our oilfield services is driven by our Exploration and Production (E&P) customers capital spending, which can experience significant fluctuations depending on current commodity prices and their expectations of future price levels, among other factors.

Drilling activity levels in the shallow-water U.S. Gulf of Mexico is dependent on natural gas and crude oil prices, as well as our customers ability to obtain necessary drilling permits to operate in the region. As of February 23, 2012, the spot price for Henry Hub natural gas was $2.68 per MMbtu, with the twelve month strip, or average of the next twelve months futures contracts, at $3.16 per MMbtu. While we expect natural gas will continue to account for the majority of hydrocarbon production in the region, and the performance of our Domestic Offshore segment will remain dependent on natural gas prices, our customers appear to be increasingly focused on drilling activities that contain greater concentrations of crude oil and condensates. We expect this trend to continue, given the current high price for crude oil. Further, it is our understanding that much of the crude oil produced from the U.S. Gulf of Mexico is sold at Louisiana Light Sweet (LLS) posted prices, which trades at a premium to other crude benchmarks, such as West Texas Intermediate (WTI). As of February 23, 2012, the spot price for LLS crude was $127.79 per barrel, compared to WTI spot price of $107.49 per barrel.

In the wake of the Macondo well blowout incident, new regulations for offshore drilling imposed by the former BOEMRE in June 2010 have resulted in our customers experiencing significant delays in obtaining necessary permits to operate in the U.S. Gulf of Mexico. While we believe that the current state of the permit approval process appears to have improved since the advent of these new regulations, and the number of permits issued by the Bureau of Safety and Environmental Enforcement over the past quarter has increased from prior periods, it is likely that our customers will continue to experience some degree of delay in obtaining drilling permits for the foreseeable future.

The supply of marketed jackup rigs in the U.S. Gulf of Mexico has declined significantly since the financial crisis starting in 2008 and again with imposition of new regulations during 2010. Drilling contractors such as ourselves and some of our competitors have elected to cold stack, or no longer actively market, a number of rigs in the region, while other competitors have mobilized rigs out of the U.S. Gulf of Mexico. As a result, the number of actively marketed jackup rigs in the U.S. Gulf of Mexico, excluding rigs scheduled to move to international locations, has declined from 63 rigs in late 2008 to 42 rigs as of February 24, 2012, of which we estimate that approximately 38 rigs are contracted.

We are encouraged by the reduction in the marketed supply of jackup rigs in the U.S. Gulf of Mexico, the relatively limited supply of uncontracted rigs, and the high price of crude oil, all contributing to a rising dayrate environment. Tempering these positive developments in the U.S. Gulf of Mexico is the continued slow pace of permit approval, and market expectations for a prolonged period of low natural gas prices. Any new regulatory or legislative changes that would affect shallow-water drilling activity in the U.S. Gulf of Mexico could have a material impact on Domestic Offshore s financial results.

Additionally, based on the improved backdrop of drilling activity in the U.S. Gulf of Mexico, as well as robust onshore drilling activity in the U.S., there has been a tightening of skilled labor across the oilfield service industry. These factors, coupled with our reduction of wages during the financial crisis, lead us to believe that labor costs are likely to experience upward pressure in 2012. Further, maintaining a skilled workforce may become harder, particularly if drilling activity worldwide continues to rise and competition intensifies for the pool of experienced offshore labor.

Demand for rigs in our International Offshore segment is primarily dependent on crude oil prices. Strong crude oil prices, capital budget announcements by National and International Oil Companies, as well as what appears to be an increase in the number of international tenders for drilling rigs, leads us to believe that international capital spending and demand for drilling rigs overseas will increase in 2012. Our expectation for greater international rig demand is tempered by the current number of idle jackup rigs and the anticipated growth in supply from newly constructed rigs. As of February 24, 2012, there were 373 jackup rigs actively marketed in international regions, of which 35 rigs were uncontracted. Further, there are 79 new jackup rigs either under construction or on order globally for delivery through 2014, of which 59 were without contracts. All of the jackup rigs under construction have higher specifications than the rigs in our existing fleet. We expect that increased market demand will be sufficient to absorb the increased supply of drilling rigs with higher specifications. We have a 28% equity ownership in, and agreements with Discovery Offshore to manage the construction, marketing and operations of two ultra high specification harsh environment jackup drilling rigs scheduled to be delivered in the second quarter and fourth quarter of 2013, respectively.

Our international drilling fleet consists of eight jackup rigs and one platform rig. Three of our rigs and our platform rig are under long term (multi-year) contracts. One of these jackup rigs, *Hercules 185*, is currently estimated to be out of service through the first quarter of 2012 undergoing repairs. We expect to be insured for damage to the rig up to the insured value of $35.0 million, subject to a $3.5 million deductible and other customary limitations and exclusions. While the *Hercules 185* is contracted through February 2014, the rig will not generate revenue while it is out of service. We believe that the improving fundamentals in the international jackup market will be beneficial as we seek contract work for our idle rigs or rigs that have contract terms scheduled to expire within 2012.

Activity for inland barge drilling in the U.S. generally follows similar drivers as drilling in the U.S. Gulf of Mexico Shelf, with activity following operators expectations of prices for natural gas and crude oil. The predominance of smaller independent operators active in inland waters adds to the volatility of this region. Inland barge drilling activity has slowed dramatically since 2008, as a number of key operators have curtailed or ceased activity in the inland market for various reasons, including lack of funding, lack of drilling success and reallocation of capital to other onshore basins. Inland activity levels stabilized in 2010, but remain depressed relative to historical levels. As of February 27, 2012, we estimate there were 25 marketed barge rigs, of which 17 were contracted. We expect industry activity levels to remain relatively flat into 2012, barring a significant increase in natural gas prices and/or property exchanges to new operators that may spur drilling activity in this region.

Liftboats

Demand for liftboats is typically a function of our customers demand for platform inspection and maintenance, well maintenance, offshore construction, well plugging and abandonment, and other related activities. Although activity levels for liftboats are not as closely correlated to commodity prices as our drilling segments, commodity prices are still a key driver of liftboat demand. In addition, liftboat demand in the U.S. Gulf of Mexico typically experiences seasonal fluctuations, due in large part to the operating limitations of liftboats in rough waters, which tend to occur during the winter months. On occasion, domestic liftboat demand will experience a sharp increase due to the occurrence of exogenous events such as hurricanes or maritime incidents that result in extraordinary damage to offshore infrastructure or require coastal restoration work.

On September 15, 2010, the Department of Interior issued the Notice to Lessees Number 2010-G05, which provides federal guidelines for the plugging and abandonment of wells and decommissioning of offshore platforms in the U.S. Gulf of Mexico. Since the issuance of this mandate, our Domestic Liftboat segment has experienced an increased shift in revenue mix to plugging and abandonment services. Further increases in plugging and abandonment related services are uncertain, although we expect such services will provide a relatively stable base of activity for our domestic liftboats over the next several years.

Our International Liftboat segment is driven by our customers demand for production, platform maintenance and support activities in West Africa and the Middle East. While international rates for liftboats typically exceed those in the U.S., operating costs are also higher, and we expect this dynamic to continue through the foreseeable future. Utilization can and has been negatively impacted by local labor disputes and regional conflicts, particularly in West Africa. Over the long term, we believe that international liftboat demand will benefit from: (i) the aging offshore infrastructure and maturing offshore basins, (ii) desire by our international customers to economically produce from these mature basins and service their infrastructure and (iii) the cost advantages of liftboats to perform these services relative to alternatives. Tempering this demand outlook is (i) our expectation of increased competition from newly constructed liftboats and mobilizations of existing liftboats primarily from the U.S. Gulf of Mexico to international markets, as well as (ii) the risk of recurring political and social unrest, principally in West Africa.

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

Sources and uses of cash for 2011 and 2010 are as follows (in millions):

	2011	2010
Net Cash Provided by Operating Activities	$ 52.0	$ 24.4
Net Cash Provided by (Used in) Investing Activities:		
Acquisition of Assets	(25.0)	
Additions of Property and Equipment	(39.5)	(22.0)
Deferred Drydocking Expenditures	(15.7)	(15.0)
Cash Paid for Equity Investment	(34.2)	
Proceeds from Sale of Assets and Businesses, Net	80.4	23.2
(Increase) Decrease in Restricted Cash	1.5	(7.5)
Total	(32.5)	(21.3)
Net Cash Provided by (Used in) Financing Activities:		
Long-term Debt Repayments	(22.2)	(7.7)
Payment of Debt Issuance Costs	(2.1)	
Other	2.5	0.4
Total	(21.8)	(7.3)
Net Decrease in Cash and Cash Equivalents	$ (2.3)	$ (4.2)

Business Combination

On April 27, 2011, we completed the Seahawk Transaction. The results of Seahawk are included in our results from the date of acquisition.

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Equity Investment and Derivative Asset

Our total equity investment in Discovery Offshore was $34.7 million, or 28% as of December 31, 2011, which includes the initial cash investment of $10.0 million, additional equity interest of $1.0 million related to 500,000 Discovery Offshore shares awarded to us for reimbursement of costs incurred and efforts expended in forming Discovery Offshore, additional purchases of Discovery Offshore shares on the open market totaling $24.2 million, or 12.9 million shares, for the year ended December 31, 2011 as well as our proportionate share of Discovery Offshore s losses of $0.4 million. We were also issued warrants to purchase up to 5.0 million additional shares of Discovery Offshore as additional compensation for our costs incurred and efforts expended in forming Discovery Offshore, which are being accounted for as a derivative asset equal to $1.8 million as of December 31, 2011, that, if exercised, would be recorded as an increase to our equity investment in Discovery Offshore. The initial fair value of the warrants of $5.0 million as well as the $1.0 million related to the 500,000 additional shares have been recorded as deferred revenue to be amortized over 30 years, the estimated useful life of the two new-build Discovery Offshore rigs, of which $0.2 million was recognized for the year ended December 31, 2011. Subsequent changes in the fair value of the warrants are recognized to other income (expense). We recognized $3.3 million to other expense related to the change in the fair value of the warrants during the year ended December 31, 2011.

Percentage-of-Completion

We are using the percentage-of-completion method of accounting for our revenue and related costs associated with our construction management agreements with Discovery Offshore, combining the construction management agreements, based on a cost-to-cost method. Any revisions in revenue, cost or the progress towards completion, will be treated as a change in accounting estimate and will be accounted for using the cumulative catch-up method. During the year ended December 31, 2011, $14.0 million has been recorded as deferred revenue and $11.2 million was outstanding at December 31, 2011. We recognized $2.8 million to revenue during the year ended December 31, 2011 under the percentage-of-completion method of accounting. Additionally, $2.4 million in cost was recognized during the year ended December 31, 2011 under the percentage-of-completion method of accounting related to activities associated with the performance of contract obligations.

Sources of Liquidity and Financing Arrangements

Our liquidity is comprised of cash on hand, cash from operations and availability under our revolving credit facility. We also maintain a shelf registration statement covering the future issuance from time to time of various types of securities, including debt and equity securities. If we issue any debt securities off the shelf or otherwise incur debt, we would generally be required to allocate the proceeds of such debt to repay or refinance existing debt. We currently believe we will have adequate liquidity to meet the minimum liquidity requirement under our Credit Agreement that governs our $452.9 million term loan and $140.0 million revolving credit facility and to fund our operations. However, to the extent we do not generate sufficient cash from operations we may need to raise additional funds through debt, equity offerings or the sale of assets. Furthermore, we may need to raise additional funds through debt or equity offerings or asset sales to meet certain covenants under the Credit Agreement, to refinance existing debt, to fund capital expenditures or for general corporate purposes. In July 2012, our $140.0 million revolving credit facility matures. To the extent we are unsuccessful in extending the maturity or entering into a new revolving credit facility, our liquidity would be negatively impacted. In June 2013, we may be required to settle our 3.375% Convertible Senior Notes. As of December 31, 2011, the notional amount of these notes outstanding was $95.9 million. Additionally, our term loan matures in July 2013 and currently requires a balloon payment of $429.6 million at maturity. We intend to meet these obligations through one or more of the following: cash flow from operations, asset sales, debt refinancing and future debt or equity offerings.

Our Credit Agreement imposes various affirmative and negative covenants, including requirements that we meet certain financial ratios and tests, which we currently meet. Our failure to comply with such covenants would result in an event of default under the Credit Agreement. Additionally, in order to maintain compliance with the our financial covenants, borrowings under our revolving credit facility may be limited to an amount less than the full amount of remaining availability after outstanding letters of credit. An event of default could prevent us from borrowing under the revolving credit facility, which would in turn have a material adverse effect on our available liquidity. Furthermore, an event of default could result in us having to immediately repay all amounts outstanding under our term loan facility, our revolving credit facility, our 10.5% Senior Secured Notes and our 3.375% Convertible Senior Notes and in the foreclosure of liens on our assets.

Cash Requirements and Contractual Obligations

Debt

Our current debt structure is used to fund our business operations.

In connection with the July 2007 acquisition of TODCO, we obtained a $1,050.0 million credit facility, consisting of a $900.0 million term loan facility and a $150.0 million revolving credit facility governed by the credit agreement which, as amended, is the (Credit Agreement). In April 2008, we entered into an agreement to increase the revolving credit facility and in each of July 2009 and March 2011, the terms of the credit agreement were amended. As of December 31, 2011, we have a $592.9 million credit facility, consisting of a $452.9 million term loan facility and a $140.0 million revolving credit facility. The availability under the $140.0 million revolving credit facility must be used for working capital, capital expenditures and other general corporate purposes and cannot be used to prepay the term loan. The interest rates on borrowings under the Credit Facility are 5.50% plus LIBOR for Eurodollar Loans and 4.50% plus the Alternate Base Rate for ABR Loans. The minimum LIBOR is 2.00% for Eurodollar Loans, or a minimum base rate of 3.00% with respect to ABR Loans. Under the Credit Agreement, we must among other things:

Maintain a total leverage ratio for any test period calculated as the ratio of consolidated indebtedness on the test date to consolidated EBITDA for the trailing twelve months, all as defined in the Credit Agreement according to the following schedule:

Test Date	Maximum Total Leverage Ratio
December 31, 2011	7.75 to 1.00
March 31, 2012	7.50 to 1.00
June 30, 2012	7.25 to 1.00
September 30, 2012	6.75 to 1.00
December 31, 2012	6.25 to 1.00
March 31, 2013	6.00 to 1.00
June 30, 2013	5.75 to 1.00

At December 31, 2011, our total leverage ratio was 5.73 to 1.00.

Maintain a minimum level of liquidity, measured as the amount of unrestricted cash and cash equivalents on hand and availability under the revolving credit facility, of i) $75.0 million during calendar year 2011 and ii) $50.0 million thereafter. As of December 31, 2011, as calculated pursuant to the Credit Agreement, our total liquidity was $271.5 million.

Maintain a minimum fixed charge coverage ratio according to the following schedule:

Period		Fixed Charge Coverage Ratio
July 1, 2009	December 31, 2011	1.00 to 1.00
January 1, 2012	March 31, 2012	1.05 to 1.00
April 1, 2012	June 30, 2012	1.10 to 1.00
July 1, 2012 and thereafter		1.15 to 1.00

The consolidated fixed charge coverage ratio for any test period is defined as the sum of consolidated EBITDA for the test period plus an amount that may be added for the purpose of calculating the ratio for such test period, not to exceed $130.0 million in total during the term of the credit facility, to consolidated fixed charges for the test period adjusted by an amount not to exceed $110.0 million during the term of the credit facility to be deducted from capital expenditures, all as defined in the Credit Agreement. As of December 31, 2011, our fixed charge coverage ratio was 1.15 to 1.00.

Make mandatory prepayments of debt outstanding under the Credit Agreement with 50% of excess cash flow as defined in the Credit Agreement for the fiscal years ending December 31, 2011 and 2012, and with proceeds from:

unsecured debt issuances, with the exception of refinancing;

secured debt issuances;

casualty events not used to repair damaged property;

sales of assets in excess of $25 million annually; and

unless we have achieved a specified leverage ratio, 50% of proceeds from equity issuances, excluding those for permitted acquisitions or to meet the minimum liquidity requirements.

Our obligations under the Credit Agreement are secured by liens on a majority of our vessels and substantially all of our other personal property. Substantially all of our domestic subsidiaries, and several of our international subsidiaries, guarantee the obligations under the Credit Agreement and have granted similar liens on the majority of their vessels and substantially all of their other personal property.

Other covenants contained in the Credit Agreement restrict, among other things, asset dispositions, mergers and acquisitions, dividends, stock repurchases and redemptions, other restricted payments, debt issuances, liens, investments, convertible notes repurchases and affiliate transactions. The Credit Agreement also contains a provision under which an event of default on any other indebtedness exceeding $25.0 million would be considered an event of default under our Credit Agreement.

Other than the required prepayments as outlined previously, the principal amount of the term loan amortizes in equal quarterly installments of approximately $1.1 million, with the balance due on July 11, 2013. All borrowings under the revolving credit facility mature on July 11, 2012. We intend to refinance the revolving credit facility and term loan before the revolving credit facility matures. Interest payments on both the revolving and term loan facility are due at least on a quarterly basis and in certain instances, more frequently. In addition to our scheduled payments, during the second quarter of 2011, we used a portion of the net proceeds from the sale of the Delta Towing assets to retire $15.0 million of the outstanding balance on our term loan facility. During the fourth quarter of 2011, we used a portion of the net proceeds from asset sales to retire $2.4 million of the outstanding balance on our term loan facility. In January 2012, we used a portion of the net proceeds from December 2011 asset sales to retire $17.6 million of the outstanding balance on our term loan facility as required under the Credit Agreement. Additionally, during the fourth quarter of 2009, we used the net proceeds from the equity issuance pursuant to the partial exercise of the underwriters over-allotment option and the 10.5% Senior Secured Notes due 2017, which approximated $287.5 million, as well as cash on hand to retire $379.6 million of the outstanding balance on our term loan facility. In connection with the early retirement, we recorded a pretax charge of $1.6 million, $1.0 million, net of tax, related to the write off of unamortized issuance costs.

As of December 31, 2011, no amounts were outstanding and $2.9 million in standby letters of credit had been issued under our revolving credit facility, therefore the remaining availability under this revolving credit facility was $137.1 million. As of December 31, 2011, $452.9 million was outstanding on the term loan facility and the interest rate was 7.5%. The annualized effective rate of interest was 7.67% for the year ended December 31, 2011 after giving consideration to revolver fees.

In connection with the amendment of the Credit Agreement in March 2011 (2011 Credit Amendment), we agreed to pay consenting lenders an upfront fee of 0.25% on their commitment, or approximately $1.4 million. Including agent bank fees and expenses our total cost was approximately $2.0 million. We recognized a pretax charge of $0.5 million, $0.3 million net of tax, related to the write off of certain unamortized issuance costs and the expense of certain fees in connection with the 2011 Credit Amendment. Additionally, in connection with the 2009 Credit Amendment, a fee of 0.50%, which approximated $4.8 million, was paid to lenders consenting to the

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2009 Credit Amendment based on their total commitment. We recognized a pretax charge of $10.8 million, $7.0 million net of tax, related to the write off of unamortized issuance costs in connection with the 2009 Credit Amendment.

We recognized a decrease in fair value of $0.3 million and $1.7 million related to the hedge ineffectiveness of our interest rate collar, settled October 1, 2010 per the contract, as Interest Expense in our Consolidated Statements of Operations for the years ended December 31, 2010 and 2009, respectively. Overall, our interest expense was increased by $9.1 million and $18.3 million during the years ended December 31, 2010 and 2009, respectively as a result of our interest rate derivative instruments. We did not recognize a gain or loss due to hedge ineffectiveness in the Consolidated Statements of Operations for year ended December 31, 2011 as our interest rate collar s final settlement occurred in 2010.

On October 20, 2009, we completed an offering of $300.0 million of senior secured notes at a coupon rate of 10.5% (10.5% Senior Secured Notes) with a maturity in October 2017. The interest on the 10.5% Senior Secured Notes is payable in cash semi-annually in arrears on April 15 and October 15 of each year to holders of record at the close of business on April 1 or October 1. Interest on the notes will be computed on the basis of a 360-day year of twelve 30-day months. The notes were sold at 97.383% of their face amount to yield 11.0% and were recorded at their discounted amount, with the discount to be amortized over the life of the notes. We used the net proceeds of approximately $284.4 million from the offering to repay a portion of the indebtedness outstanding under our term loan facility. As of December 31, 2011, $300.0 million notional amount of the 10.5% Senior Secured Notes was outstanding. The carrying amount of the 10.5% Senior Secured Notes was $293.7 million at December 31, 2011.

The notes are guaranteed by all of our existing and future restricted subsidiaries that incur or guarantee indebtedness under a credit facility, including our existing credit facility. The notes are secured by liens on all collateral that secures our obligations under our secured credit facility, subject to limited exceptions. The liens securing the notes share on an equal and ratable first priority basis with liens securing our credit facility. Under the intercreditor agreement, the collateral agent for the lenders under our secured credit facility is generally entitled to sole control of all decisions and actions.

All the liens securing the notes may be released if our secured indebtedness, other than these notes, does not exceed the lesser of $375.0 million and 15.0% of our consolidated tangible assets. We refer to such a release as a collateral suspension. If a collateral suspension is in effect, the notes and the guarantees will be unsecured, and will effectively rank junior to our secured indebtedness to the extent of the value of the collateral securing such indebtedness. If, after any such release of liens on collateral, the aggregate principal amount of our secured indebtedness, other than these notes, exceeds the greater of $375.0 million and 15.0% of our consolidated tangible assets, as defined in the indenture, then the collateral obligations of the Company and guarantors will be reinstated and must be complied with within 30 days of such event.

The indenture governing the notes contains covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to:

- incur additional indebtedness or issue certain preferred stock;
- pay dividends or make other distributions;
- make other restricted payments or investments;
- sell assets;
- create liens;
- enter into agreements that restrict dividends and other payments by restricted subsidiaries;
- engage in transactions with our affiliates; and

consolidate, merge or transfer all or substantially all of our assets.

The indenture governing the notes also contains a provision under which an event of default by us or by any restricted subsidiary on any other indebtedness exceeding $25.0 million would be considered an event of default under the indenture if such default: a) is caused by failure to pay the principal at final maturity, or b) results in the acceleration of such indebtedness prior to maturity.

Prior to October 15, 2012, we may redeem the notes with the net cash proceeds of certain equity offerings, at a redemption price equal to 110.50% of the aggregate principal amount plus accrued and unpaid interest; provided, that (i) after giving effect to any such redemption, at least 65% of the notes originally issued would remain outstanding immediately after such redemption and (ii) we make such redemption not more than 90 days after the consummation of such equity offering. In addition, prior to October 15, 2013, we may redeem all or part of the notes at a price equal to 100% of the aggregate principal amount of notes to be redeemed, plus the applicable premium, as defined in the indenture, and accrued and unpaid interest.

On or after October 15, 2013, we may redeem the notes, in whole or part, at the redemption prices set forth below, together with accrued and unpaid interest to the redemption date.

Year	Optional Redemption Price
2013	105.2500%
2014	102.6250%
2015	101.3125%
2016 and thereafter	100.0000%

If we experience a change of control, as defined, we must offer to repurchase the notes at an offer price in cash equal to 101% of their principal amount, plus accrued and unpaid interest. Furthermore, following certain asset sales, we may be required to use the proceeds to offer to repurchase the notes at an offer price in cash equal to 100% of their principal amount, plus accrued and unpaid interest.

On June 3, 2008, we completed an offering of $250.0 million convertible senior notes at a coupon rate of 3.375% (3.375% Convertible Senior Notes) with a maturity in June 2038. As of December 31, 2011, $95.9 million notional amount of the $250.0 million 3.375% Convertible Senior Notes was outstanding. The net carrying amount of the 3.375% Convertible Senior Notes was $90.2 million at December 31, 2011.

The interest on the 3.375% Convertible Senior Notes is payable in cash semi-annually in arrears, on June 1 and December 1 of each year until June 1, 2013, after which the principal will accrete at an annual yield to maturity of 3.375% per year. We will also pay contingent interest during any six-month interest period commencing June 1, 2013, for which the trading price of these notes for a specified period of time equals or exceeds 120% of their accreted principal amount. The notes will be convertible under certain circumstances into shares of our common stock (Common Stock) at an initial conversion rate of 19.9695 shares of Common Stock per $1,000 principal amount of notes, which is equal to an initial conversion price of approximately $50.08 per share. Upon conversion of a note, a holder will receive, at our election, shares of Common Stock, cash or a combination of cash and shares of Common Stock. At December 31, 2011, the number of conversion shares potentially issuable in relation to our 3.375% Convertible Senior Notes was 1.9 million. We may redeem the notes at our option beginning June 6, 2013, and holders of the notes will have the right to require us to repurchase the notes on June 1, 2013 and certain dates thereafter or on the occurrence of a fundamental change.

We determined that upon maturity or redemption, we have the intent and ability to settle the principal amount of our 3.375% Convertible Senior Notes in cash, and any additional conversion consideration spread (the excess of conversion value over face value) in shares of our Common Stock.

The indenture governing the 3.375% Convertible Senior Notes contains a provision under which an event of default by us or by any subsidiary on any other indebtedness exceeding $25.0 million would be considered an event of default under the indenture if such default is: a) caused by failure to pay the principal at final maturity, or b) results in the acceleration of such indebtedness prior to maturity.

During April 2009, we repurchased $20.0 million aggregate principal amount of the 3.375% Convertible Senior Notes for a cost of $6.1 million resulting in a gain of $10.7 million. In addition, we expensed $0.4 million of unamortized issuance costs in connection with the retirement. In June 2009, we retired $45.8 million aggregate principal amount of our 3.375% Convertible Senior Notes in exchange for the issuance of 7,755,440 shares of Common Stock valued at $4.38 per share and payment of accrued interest, resulting in a gain of $4.4 million.

In addition, we expensed $1.0 million of unamortized issuance costs in connection with the retirement. The settlement consideration was allocated to the extinguishment of the liability component in an amount equal to the fair value of that component immediately prior to extinguishment, with the difference between this allocation and the net carrying amount of the liability component and unamortized debt issuance costs recognized as a gain or loss on debt extinguishment. If there would have been any remaining settlement consideration, it would have been allocated to the reacquisition of the equity component and recognized as a reduction of Stockholders Equity.

The fair value of our 3.375% Convertible Senior Notes, 10.5% Senior Secured Notes and term loan facility is estimated based on quoted prices in active markets. The fair value of our 7.375% Senior Notes is estimated based on discounted cash flows using inputs from quoted prices in active markets for similar debt instruments. The following table provides the carrying value and fair value of our long-term debt instruments:

	December 31, 2011		December 31, 2010	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(in millions)			
Term Loan Facility, due July 2013	$ 452.9	$ 442.0	$ 475.2	$ 443.7
10.5% Senior Secured Notes, due October 2017	293.7	291.2	292.9	245.1
3.375% Convertible Senior Notes due June 2038	90.2	84.7	86.5	69.1
7.375% Senior Notes, due April 2018	3.5	2.8	3.5	2.2

We maintain insurance coverage that includes coverage for physical damage, third party liability, workers compensation and employer s liability, general liability, vessel pollution and other coverages.

In April 2011, we completed the annual renewal of all of our key insurance policies. Our primary marine package provides for hull and machinery coverage for substantially all of our rigs and liftboats up to a scheduled value of each asset. The total maximum amount of coverage for these assets is $1.6 billion, including the newly acquired Seahawk units. The marine package includes protection and indemnity and maritime employer s liability coverage for marine crew personal injury and death and certain operational liabilities, with primary coverage (or self-insured retention for maritime employer s liability coverage) of $5.0 million per occurrence with excess liability coverage up to $200.0 million. The marine package policy also includes coverage for personal injury and death of third parties with primary and excess coverage of $25 million per occurrence with additional excess liability coverage up to $200 million, subject to a $250,000 per-occurrence deductible. The marine package also provides coverage for cargo and charterer s legal liability. The marine package includes limitations for coverage for losses caused in U.S. Gulf of Mexico named windstorms, including an annual aggregate limit of liability of $75.0 million for property damage and removal of wreck liability coverage. We also procured an additional $75.0 million excess policy for removal of wreck and certain third-party liabilities incurred in U.S. Gulf of Mexico named windstorms. Deductibles for events that are not caused by a U.S. Gulf of Mexico named windstorm are 12.5% of the insured drilling rig values per occurrence, subject to a minimum of $1.0 million, and $1.0 million per occurrence for liftboats. The deductible for drilling rigs and liftboats in a U.S. Gulf of Mexico named windstorm event is $25.0 million. Vessel pollution is covered under a Water Quality Insurance Syndicate policy (WQIS Policy) providing limits as required by applicable law, including the Oil Pollution Act of 1990. The WQIS Policy covers pollution emanating from our vessels and drilling rigs, with primary limits of $5 million (inclusive of a $3.0 million per-occurrence deductible) and excess liability coverage up to $200 million.

Control-of-well events generally include an unintended flow from the well that cannot be contained by equipment on site (e.g., a blow-out preventer), by increasing the weight of the drilling fluid, or that does not naturally close itself off through what is typically described as bridging over. We carry a contractor s extra expense policy with $25.0 million primary liability coverage for well control costs, expenses incurred to redrill wild or lost wells and pollution, with excess liability coverage up to $200 million for pollution liability that is covered in the primary policy. The policies are subject to exclusions, limitations, deductibles, self-insured retention and other conditions. In addition to the marine package, we have separate policies providing coverage for onshore foreign and domestic general liability, employer s liability, auto liability and non-owned aircraft liability, with customary deductibles and coverage.

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Our drilling contracts provide for varying levels of indemnification from our customers and in most cases, may require us to indemnify our customers for certain liabilities. 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, regardless of how the loss or damage to the personnel and property may be caused. Our customers typically assume responsibility for and agree to indemnify us from any loss or liability resulting from pollution or contamination, including clean-up and removal and third-party damages arising from operations under the contract and originating below the surface of the water, including as a result of blow-outs or cratering of the well (Blowout Liability). The customer s assumption for Blowout Liability may, in certain circumstances, be limited or could be determined to be unenforceable in the event of our gross negligence, willful misconduct or other egregious conduct. We generally indemnify the customer for the consequences of spills of industrial waste or other liquids originating solely above the surface of the water and emanating from our rigs or vessels.

We are self-insured for the deductible portion of our insurance coverage. Management believes adequate accruals have been made on known and estimated exposures up to the deductible portion of our insurance coverage. Management believes that claims and liabilities in excess of the amounts accrued are adequately insured. However, our insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect us against liability from all potential consequences. In addition, there is no assurance of renewal or the ability to obtain coverage acceptable to us.

In 2011, in connection with the renewal of certain of our insurance policies, we entered into an agreement to finance a portion of our annual insurance premiums. Approximately $25.8 million was financed through this arrangement, of which $5.2 million was outstanding at December 31, 2011. The interest rate on the note is 3.59% and it is scheduled to mature in March 2012. There was $6.0 million outstanding in insurance notes payable at December 31, 2010 which we fully paid during 2011.

Insurance Claims

In September 2011, we were conducting a required annual spud can inspection on the *Hercules 185* in protected waters offshore Angola. While conducting the inspection, it was determined that the spud can on the starboard leg had detached from the leg. While preparing the rig for heavy-lift transport to a shipyard in Pascagoula, Mississippi to conduct the spud can repairs, additional leg damage was identified. The rig is currently in the shipyard at Pascagoula, Mississippi undergoing the repairs necessary to return the rig to service. We currently estimate that the rig will be out of service through the first quarter of 2012. During this period, the rig will be at zero dayrate pursuant to its contract with Cabinda Gulf Oil Company (Cabinda Gulf). We have discussed the expected downtime of the rig with Cabinda Gulf and Cabinda Gulf has indicated that it intends to accept the rig after the completion of the repairs and to continue the contract, although Cabinda Gulf may have the right to terminate the contract and be paid $1.0 million by us for liquidated damages. We expect to be insured for damage to the rig up to the insured value of $35.0 million, subject to a $3.5 million deductible and other customary limitations and exclusions. We have recorded expenses up to the deductible amount of $3.5 million during the year ended December 31, 2011 related to rig repairs, inspections and other costs and have recorded an insurance claims receivable of $6.4 million for costs incurred through December 31, 2011 in excess of the deductible, which is included in Other on the Consolidated Balance Sheet at December 31, 2011. In addition, the rig had a net book value of $50.0 million as of December 31, 2011.

In September 2011, the *Starfish*, a 140 class liftboat, was en route to a project in the Gulf of Mexico in Ship Shoal Block 116 when it was hit by a series of waterspouts and capsized. The vessel has been salvaged and our underwriters have determined that the vessel is a constructive total loss and, therefore, we will receive the full insured value of $2.5 million. We carry removal of wreck insurance adequately covering the salvage operation, subject to a $250,000 deductible. Additionally, we carry pollution insurance, subject to a $3 million deductible and other customary limitations. We have recorded an insurance claims receivable of $3.1 million for the net book value of the vessel as well as any costs incurred through December 31, 2011 in excess of the deductible, which is included in Other on the Consolidated Balance Sheet at December 31, 2011. In addition, the vessel had a net book value of $0.7 million as of December 31, 2011.

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In January 2012, the *Mako*, a 175 class liftboat in Nigeria, was engulfed by a fire that originated on a third-party rig, the *KS Endeavor*. Our underwriters have determined that the vessel is considered to be a constructive total loss and, therefore, we will receive the full insured value of $8.0 million which we believe approximates the fair market value for the vessel. We carry removal of wreck insurance adequately covering the salvage operation, subject to a $250,000 deductible. Additionally, we carry pollution insurance, subject to a $3 million deductible and other customary limitations. The vessel had a net book value of $6.4 million as of December 31, 2011.

Capital Expenditures

We currently expect capital expenditures and drydocking during 2012 to be approximately $100 million. Planned capital expenditures include items related to general maintenance, regulatory, refurbishment and upgrades to our rigs and liftboats. Planned capital expenditures include contract specific requirements related to various international rigs. Should we elect to reactivate cold stacked rigs or upgrade and refurbish additional selected rigs or liftboats our capital expenditures may increase. Reactivation, upgrades and refurbishments are subject to our discretion and will depend on our view of market conditions and our cash flows.

Costs associated with refurbishment or upgrade activities which substantially extend the useful life or operating capabilities of the asset are capitalized. Refurbishment entails replacing or rebuilding the operating equipment. An upgrade entails increasing the operating capabilities of a rig or liftboat. This can be accomplished by a number of means, including adding new or higher specification equipment to the unit, increasing the water depth capabilities or increasing the capacity of the living quarters, or a combination of each.

We are required to inspect and drydock our liftboats on a periodic basis to meet U.S. Coast Guard requirements. The amount of expenditures is impacted by a number of factors, including, among others, our ongoing maintenance expenditures, adverse weather, changes in regulatory requirements and operating conditions. In addition, from time to time we agree to perform modifications to our rigs and liftboats as part of a contract with a customer. When market conditions allow, we attempt to recover these costs as part of the contract cash flow.

From time to time, we may review possible acquisitions of rigs, liftboats or businesses, joint ventures, mergers or other business combinations, and we may have outstanding from time to time bids to acquire certain assets from other companies. We may not, however, be successful in our acquisition efforts. We are generally restricted by our Credit Agreement from making acquisitions for cash consideration, except to the extent the acquisition is funded by an issuance of our stock or cash proceeds from the issuance of stock (with the exception of the Seahawk Transaction), or unless we are in compliance with more restrictive financial covenants than what we are normally required to meet in each respective period as defined in the 2011 Credit Amendment. If we acquire additional assets, we would expect that our ongoing capital expenditures as a whole would increase in order to maintain our equipment in a competitive condition.

Our ability to fund capital expenditures would be adversely affected if conditions deteriorate in our business.

Contractual Obligations

Our contractual obligations and commitments principally include obligations associated with our outstanding indebtedness, certain income tax liabilities, bank guarantees, surety bonds, letters of credit, future minimum operating lease obligations, purchase commitments and management compensation obligations.

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The following table summarizes our contractual obligations and contingent commitments by period as of December 31, 2011:

Contractual Obligations and Contingent Commitments	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years	Total
	Payments due by Period (In thousands)				
Recorded Obligations:					
Long-term debt obligations	$ 22,130	$ 526,702	$	$ 303,508	$ 852,340
Insurance notes payable	5,218				5,218
Interest on debt and notes payable(c)	9,899				9,899
Purchase obligations(a)	9,363				9,363
Other	2,756				2,756
Unrecorded Obligations(b):					
Interest on debt and notes payable(c)	58,967	81,449	63,518	31,888	235,822
Bank guarantees	995				995
Letters of credit	3,046				3,046
Surety bonds	13,612				13,612
Management compensation obligations	3,243	6,486			9,729
Purchase obligations(a)	6,990				6,990
Operating lease obligations	3,373	4,815	4,170	2,139	14,497
Total contractual obligations	$ 139,592	$ 619,452	$ 67,688	$ 337,535	$ 1,164,267

(a) A purchase obligation is defined as an agreement to purchase goods or services that is enforceable and legally binding on the company and that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transaction. These amounts are primarily comprised of open purchase order commitments to vendors and subcontractors.

(b) Tax liabilities of $7.3 million have been excluded from the table above as a reasonably reliable estimate of the period of cash settlement cannot be made.

(c) Estimated interest on our Term Loan Facility is based on 3 month LIBOR reset quarterly and extrapolated from the forward curve dated as of the balance sheet date. There was $452.9 million outstanding under our Term Loan Facility as of December 31, 2011 and the interest estimates above assume the reduction in principal related to scheduled principal payments. The remaining interest estimates are based on the rates associated with the respective fixed rate instrument.

Off-Balance Sheet Arrangements

Guarantees

Our obligations under the credit facility and 10.5% Senior Secured Notes are secured by liens on a majority of our vessels and substantially all of our other personal property. Substantially all of our domestic subsidiaries, and several of our international subsidiaries, guarantee the obligations under the credit facility and 10.5% Senior Secured Notes and have granted similar liens on the majority of their vessels and substantially all of their other personal property.

Bank Guarantees, Letters of Credit and Surety Bonds

We execute bank guarantees, letters of credit and surety bonds in the normal course of business. While these obligations are not normally called, these obligations could be called by the beneficiaries at any time before the expiration date should we breach certain contractual or payment obligations. As of December 31, 2011, we had $17.6 million of bank guarantees, letters of credit and surety bonds outstanding, consisting of $1.0 million in unsecured bank guarantees, a $0.1 million unsecured outstanding letter of credit, $2.9 million in standby letters of credit outstanding under our revolver and $13.6 million outstanding in surety bonds that guarantee our performance as it relates to our drilling contracts and other obligations in Mexico and the U.S. If the beneficiaries called the bank guarantees, letters of credit and surety bonds, the called amount would become an on-balance sheet liability, and we would be required to settle the liability with cash on hand or through borrowings under our available line of credit. As of December 31, 2011 we have restricted cash of $9.6 million to support surety bonds related to our Mexico and U.S. operations.

Accounting Pronouncements

In May 2011, the FASB issued Accounting Standards Update (ASU) No. 2011-04, *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs* (ASU 2011-04), which changes the wording used to describe many of the requirements in U.S. GAAP for measuring fair value and disclosing information about fair value measurements. Some of the amendments clarify the FASB s intent about the application of existing fair value measurement requirements while other amendments change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. The amendments in this ASU are effective prospectively for interim and annual periods beginning after December 15, 2011, with no early adoption permitted. We do not expect the adoption of this standard to have a material impact on our consolidated financial statements.

In June 2011, the FASB issued ASU No. 2011-05, *Presentation of Comprehensive Income* (ASU 2011-05), which eliminates the option to present components of other comprehensive income as part of the statement of changes in stockholders equity. The amendments in this standard require that an entity present the total of comprehensive income, the components of net income, and the components of other comprehensive income in a single continuous statement of comprehensive income or in two separate but consecutive statements. Under either method, the entity is required to present on the face of the financial statements reclassification adjustments for items that are reclassified from other comprehensive income to net income in the statement(s) where the components of net income and the components of other comprehensive income are presented. However, in December 2011 this ASU was amended by ASU No. 2011-12, *Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05* (ASU 2011-12), which defers the requirement to present on the face of the financial statements the effects of reclassifications out of accumulated other comprehensive income on the components of net income and other comprehensive income. For public entities, the amendments in these ASUs are effective for fiscal years, and interim periods within those years, beginning after December 15, 2011 and are to be applied retrospectively, with early adoption permitted. We adopted both ASU 2011-05 and ASU 2011-12 at December 31, 2011 with no material impact to our consolidated financial statements.

FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical fact, included in this annual report that address outlook, activities, events or developments that we expect, project, believe or anticipate will or may occur in the future are forward-looking statements. These include such matters as:

- our levels of indebtedness, covenant compliance and access to capital under current market conditions;

- our ability to enter into new contracts for our rigs and liftboats and future utilization rates and dayrates for the units;

- our ability to renew or extend our international contracts, or enter into new contracts, when such contracts expire;
- demand for our rigs and our liftboats;
- activity levels of our customers and their expectations of future energy prices and ability to obtain drilling permits;
- sufficiency and availability of funds for required capital expenditures, working capital and debt service;
- levels of reserves for accounts receivable;
- success of our plans to dispose of certain assets;
- expected completion times for our repair, refurbishment and upgrade projects, including the repair project for the *Hercules 185*;
- our plans to increase international operations;
- expected useful lives of our rigs and liftboats;
- future capital expenditures and refurbishment, reactivation, transportation, repair and upgrade costs;
- our ability to effectively reactivate rigs that we have stacked;
- liabilities and restrictions under coastwise and other laws of the United States and regulations protecting the environment;
- expected outcomes of litigation, investigations, claims and disputes and their expected effects on our financial condition and results of operations; and
- expectations regarding offshore drilling activity and dayrates, market conditions, demand for our rigs and liftboats, our earnings, operating revenue, operating and maintenance expense, insurance coverage, insurance expense and deductibles, interest expense, debt levels and other matters with regard to outlook.

We have based these statements on our assumptions and analyses in light of our experience and perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate in the circumstances. Forward-looking statements by their nature involve substantial risks and uncertainties that could significantly affect expected results, and actual future results could differ materially from those described in such statements. Although it is not possible to identify all factors, we continue to face many risks and uncertainties. Among the factors that could cause actual future results to differ materially are the risks and uncertainties described under Risk Factors in Item 1A of this annual report and the following:

the ability of our customers in the U.S. Gulf of Mexico to obtain drilling permits in an efficient manner or at all;

oil and natural gas prices and industry expectations about future prices;

levels of oil and gas exploration and production spending;

demand for and supply of offshore drilling rigs and liftboats;

our ability to enter into and the terms of future contracts;

the worldwide military and political environment, uncertainty or instability resulting from an escalation or additional outbreak of armed hostilities or other crises in the Middle East, North Africa, West Africa and other oil and natural gas producing regions or acts of terrorism or piracy;

the impact of governmental laws and regulations, including new laws and regulations in the U.S. Gulf of Mexico arising out of the Macondo well blowout incident;

the adequacy and costs of sources of credit and liquidity;

uncertainties relating to the level of activity in offshore oil and natural gas exploration, development and production;

competition and market conditions in the contract drilling and liftboat industries;

the availability of skilled personnel and rising cost of labor;

labor relations and work stoppages, particularly in the West African and Mexican labor environments;

operating hazards such as hurricanes, severe weather and seas, fires, cratering, blowouts, war, terrorism and cancellation or unavailability of insurance coverage or insufficient coverage;

the effect of litigation, investigations, and contingencies; and

our inability to achieve our plans or carry out our strategy.

Many of these factors are beyond our ability to control or predict. Any of these factors, or a combination of these factors, could materially affect our future financial condition or results of operations and the ultimate accuracy of the forward-looking statements. These forward-looking statements are not guarantees of our future performance, and our actual results and future developments may differ materially from those projected in the forward-looking statements. Management cautions against putting undue reliance on forward-looking statements or projecting any future results based on such statements or present or prior earnings levels. In addition, each forward-looking statement speaks only as of the date of the particular statement, and we undertake no obligation to publicly update or revise any forward-looking statements except as required by applicable law.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

We are currently exposed to market risk from changes in interest rates. From time to time, we may enter into derivative financial instrument transactions to manage or reduce our market risk, but we do not enter into derivative transactions for speculative purposes. A discussion of our market risk exposure in financial instruments follows.

Interest Rate Exposure

We are subject to interest rate risk on our fixed-interest and variable-interest rate borrowings. Variable rate debt, where the interest rate fluctuates periodically, exposes us to short-term changes in market interest rates. Fixed rate debt, where the interest rate is fixed over the life of the instrument, exposes us to changes in market interest rates reflected in the fair value of the debt and to the risk that we may need to refinance maturing debt with new debt at a higher rate.

As of December 31, 2011, the long-term borrowings that were outstanding subject to fixed interest rate risk consisted of the 7.375% Senior Notes due April 2018, the 3.375% Convertible Senior Notes due June 2038 and the 10.5% Senior Secured Notes due October 2017 with a carrying amount of $3.5 million, $90.2 million, and $293.7 million, respectively.

As of December 31, 2011 the interest rate for the $452.9 million outstanding under the term loan was 7.5%. If the interest rate averages 1% more for 2012 than the rates as of December 31, 2011, annual interest expense would increase by approximately $4.5 million. This sensitivity analysis assumes there are no changes in our financial structure and excludes the impact of our interest rate derivatives, if any.

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The fair value of our 3.375% Convertible Senior Notes, 10.5% Senior Secured Notes and term loan facility is estimated based on quoted prices in active markets. The fair value of our 7.375% Senior Notes is estimated based on discounted cash flows using inputs from quoted prices in active markets for similar debt instruments. The following table provides the carrying value and fair value of our long-term debt instruments:

	December 31, 2011		December 31, 2010	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(in millions)			
Term Loan Facility, due July 2013	$ 452.9	$ 442.0	$ 475.2	$ 443.7
10.5% Senior Secured Notes, due October 2017	293.7	291.2	292.9	245.1
3.375% Convertible Senior Notes, due June 2038	90.2	84.7	86.5	69.1
7.375% Senior Notes, due April 2018	3.5	2.8	3.5	2.2

Fair Value of Warrants and Derivative Asset

At December 31, 2011, the fair value of derivative instruments was $1.8 million. We estimate the fair value of these instruments using a Monte Carlo simulation which takes into account a variety of factors including the strike price, the target price, the stock value, the expected volatility, the risk-free interest rate, the expected life of warrants, and the number of warrants. We are required to revalue this asset each quarter. We believe that the assumption that has the greatest impact on the determination of fair value is the closing price of Discovery Offshore s stock. The following table illustrates the potential effect on the fair value of the derivative asset from changes in the assumptions made:

	Increase/(Decrease) (In thousands)
25% increase in stock price	$ 1,089
50% increase in stock price	2,338
10% increase in assumed volatility	647
25% decrease in stock price	(858)
50% decrease in stock price	(1,446)
10% decrease in assumed volatility	(665)

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Item 8. ***Financial Statements and Supplementary Data***

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and

Stockholders of Hercules Offshore, Inc.:

We have audited the accompanying consolidated balance sheets of Hercules Offshore, Inc. and subsidiaries as of December 31, 2011 and 2010, and the related consolidated statements of operations, comprehensive loss, stockholders equity and cash flows for each of the three years in the period ended December 31, 2011. Our audits also included the financial statement schedule listed in the Index at Item 15(a). These financial statements and schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Hercules Offshore, Inc. and subsidiaries at December 31, 2011 and 2010, and the consolidated results of their operations and their cash flows for each of the three years in the 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 financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Hercules Offshore Inc. and subsidiaries 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 and our report dated March 1, 2012 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas

March 1, 2012

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and

Stockholders of Hercules Offshore, Inc.:

We have audited Hercules Offshore, Inc. and subsidiaries 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 (the COSO criteria). Hercules Offshore, Inc. and subsidiaries management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company s internal control over financial reporting based on our audit.

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

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

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

In our opinion, Hercules Offshore, Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Hercules Offshore, Inc. and subsidiaries as of December 31, 2011 and 2010, and the related consolidated statements of operations, comprehensive loss, stockholders equity and cash flows for each of the three years in the period ended December 31, 2011 of Hercules Offshore, Inc. and subsidiaries, and our report dated March 1, 2012, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas

March 1, 2012

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(In thousands, except par value)

	December 31, 2011	December 31, 2010
ASSETS		
Current Assets:		
Cash and Cash Equivalents	$ 134,351	$ 136,666
Restricted Cash	9,633	11,128
Accounts Receivable, Net of Allowance for Doubtful Accounts of $11,460 and $29,798 as of December 31, 2011 and 2010, Respectively	153,688	143,796
Prepaids	16,352	17,142
Current Deferred Tax Asset	15,543	8,488
Other	20,435	11,794
	350,002	329,014
Property and Equipment, Net	1,591,791	1,634,542
Equity Investment	34,735	
Other Assets, Net	30,176	31,753
	$ 2,006,704	$ 1,995,309
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Short-term Debt and Current Portion of Long-term Debt	$ 22,130	$ 4,924
Accounts Payable	49,370	52,279
Accrued Liabilities	70,421	59,861
Interest Payable	9,899	6,974
Insurance Notes Payable	5,218	5,984
Other Current Liabilities	18,366	16,716
	175,404	146,738
Long-term Debt, Net of Current Portion	818,146	853,166
Other Liabilities	21,098	6,716
Deferred Income Taxes	83,503	135,557
Commitments and Contingencies		
Stockholders Equity:		
Common Stock, $0.01 Par Value; 200,000 Shares Authorized; 139,798 and 116,336 Shares Issued, Respectively; 137,899 and 114,784 Shares Outstanding, Respectively	1,398	1,163
Capital in Excess of Par Value	2,057,824	1,924,659
Treasury Stock, at Cost, 1,899 Shares and 1,552 Shares, Respectively	(52,184)	(50,333)
Retained Deficit	(1,098,485)	(1,022,357)
	908,553	853,132
	$ 2,006,704	$ 1,995,309

The accompanying notes are an integral part of these financial statements.

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)

	Year Ended December 31, 2011	2010	2009	
Revenue	$ 655,358	$ 624,827	$ 718,601	
Costs and Expenses:				
Operating Expenses	444,332	403,829	486,462	
Impairment of Property and Equipment		122,717	26,882	
Depreciation and Amortization	172,571	185,712	193,504	
General and Administrative	57,204	55,996	91,222	
	674,107	768,254	798,070	
Operating Loss	(18,749)	(143,427)	(79,469)	
Other Income (Expense):				
Interest Expense	(79,178)	(80,482)	(75,431)	
Expense of Credit Agreement Fees	(455)		(15,073)	
Gain on Early Retirement of Debt, Net			12,157	
Other, Net	(3,479)	3,876	3,955	
Loss Before Income Taxes	(101,861$ 600,000			$ 1,891,368
Total investments	$ 5,910,573	$ 197,863,943	$ 4,978,195	$ 208,752,711
Receivable for insurance proceeds		$ 1,633,988		$ 1,633,988
Other assets			$ 7,743	$ 7,743
Other Financial Instruments:				
Forward Foreign Currency Contracts		1,658		1,658
Total	$ 5,910,573	$ 199,499,589	$ 4,985,938	$ 210,396,100

See Schedule of Investments for additional detailed categorizations.

LIABILITIES

DESCRIPTION	QUOTED PRICES (LEVEL 1)	OTHER SIGNIFICANT OBSERVABLE INPUTS (LEVEL 2)	SIGNIFICANT UNOBSERVABLE INPUTS (LEVEL 3)	TOTAL
Other Financial Instruments:				
Forward Foreign Currency Contracts		$ 16,201		$ 16,201
Futures Contracts	$ 17,903			17,903
Total	$ 17,903	$ 16,201		$ 34,104

Notes to Schedule of Investments (unaudited) (continued)

The following is a reconciliation of investments in which significant unobservable inputs (Level 3) were used in determining fair value:

	CORPORATE BONDS & NOTES	
INVESTMENTS IN SECURITIES	**INDUSTRIALS**	**ASSET-BACKED SECURITIES**
Balance as of December 31, 2015	$ 2,546,072	$ 2,533,965
Accrued premiums/discounts	4,060	15,240
Realized gain (loss)		(657)
Change in unrealized appreciation (depreciation)[1]	(71,845)	(19,671)
Purchases		
Sales	(399,679)	(379)
Transfers into Level 3[2]	883,973	
Transfers out of Level 3[3]	(1,638,199)	
Balance as of March 31, 2016	$ 1,324,382	$ 2,528,498
Net change in unrealized appreciation (depreciation) for investments in securities still held at March 31, 2016[1]	$ (4,181)	$ (19,671)

	SENIOR LOANS		
INVESTMENTS IN SECURITIES (cont d)	**CONSUMER STAPLES**	**ENERGY**	**UTILITIES**
Balance as of December 31, 2015	$ 176,400	$ 559,900	$ 341,420
Accrued premiums/discounts	186	3,150	250
Realized gain (loss)			19
Change in unrealized appreciation (depreciation)[1]	2,064	15,600	(31,981)
Purchases		168,000	
Sales			(1,075)
Transfers into Level 3[2]			
Transfers out of Level 3[3]	(178,650)		
Balance as of March 31, 2016		$ 746,650	$ 308,633
Net change in unrealized appreciation (depreciation) for investments in securities still held at March 31, 2016[1]		$ 15,600	$ (31,981)

	COMMON STOCKS				
INVESTMENTS IN SECURITIES (cont d)	**HEALTH CARE**	**INDUSTRIALS**	**PREFERRED STOCKS**	**OTHER ASSETS**	**TOTAL**
Balance as of December 31, 2015	$ 157,700	$ 41,368	$	7,743	$ 6,364,568
Accrued premiums/discounts					22,886
Realized gain (loss)	36,853				36,215
Change in unrealized appreciation (depreciation)[1]	19,135	7,008			(79,690)
Purchases	17,418				185,418
Sales	(209,484)				(610,617)
Transfers into Level 3[2]			34	$	884,007
Transfers out of Level 3[3]					(1,816,849)
Balance as of March 31, 2016	21,622	$ 48,376	$ 34	$ 7,743	$ 4,985,938
Net change in unrealized appreciation (depreciation) for investments in securities still held at March 31, 2016[1]	4,204	$ 7,008			$ (29,021)

The Fund s policy is to recognize transfers between levels as of the end of the reporting period.

[1] Change in unrealized appreciation (depreciation) includes net unrealized appreciation (depreciation) resulting from changes in investment values during the reporting period and the reversal of previously recorded unrealized appreciation (depreciation) when gains or losses are realized.

[2] Transferred into Level 3 as a result of the unavailability of a quoted price in an active market for an identical investment or the unavailability of other significant observable inputs.

[3] Transferred out of Level 3 as a result of the availability of a quoted price in an active market for an identical investment or the availability of other significant observable inputs.

Notes to Schedule of Investments (unaudited) (continued)

2. Investments

At March 31, 2016, the aggregate gross unrealized appreciation and depreciation of investments for federal income tax purposes were substantially as follows:

Gross unrealized appreciation	$ 14,713,407
Gross unrealized depreciation	(9,412,286)
Net unrealized appreciation	$ 5,301,121

At March 31, 2016, the Fund had the following open futures contracts:

	Number of Contracts	Expiration Date	Basis Value	Market Value	Unrealized Depreciation
Contracts to Buy:					
U.S. Treasury Ultra Long-Term Bonds	15	6/16	$ 2,605,872	$ 2,587,969	$ (17,903)

At March 31, 2016, the Fund had the following open forward foreign currency contracts:

Currency Purchased		Currency Sold		Counterparty	Settlement Date	Unrealized Appreciation (Depreciation)
EUR	60,000	USD	66,695	Citibank N.A.	5/13/16	$ 1,658
USD	1,977,448	EUR	1,750,000	Citibank N.A.	5/13/16	(16,201)
Total						$ (14,543)

Abbreviations used in this table:

EUR	Euro
USD	United States Dollar

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ITEM 2. CONTROLS AND PROCEDURES.

(a) The registrant s principal executive officer and principal financial officer have concluded that the registrant s disclosure controls and procedures (as defined in Rule 30a- 3(c) under the Investment Company Act of 1940, as amended (the 1940 Act)) are effective as of a date within 90 days of the filing date of this report that includes the disclosure required by this paragraph, based on their evaluation of the disclosure controls and procedures required by Rule 30a-3(b) under the 1940 Act and 15d-15(b) under the Securities Exchange Act of 1934.

(b) There were no changes in the registrant s internal control over financial reporting (as defined in Rule 30a-3(d) under the 1940 Act) that occurred during the registrant s last fiscal quarter that have materially affected, or are likely to materially affect the registrant s internal control over financial reporting.

ITEM 3. EXHIBITS.

Certifications pursuant to Rule 30a-2(a) under the Investment Company Act of 1940, as amended, are attached hereto.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934 and the Investment Company Act of 1940, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Western Asset Premier Bond Fund

By /s/ Jane Trust
Jane Trust
Chief Executive Officer

Date: May 20, 2016

Pursuant to the requirements of the Securities Exchange Act of 1934 and the Investment Company Act of 1940, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

By /s/ Jane Trust
Jane Trust
Chief Executive Officer

Date: May 20, 2016

By /s/ Richard F. Sennett
Richard F. Sennett
Principal Financial Officer

Date: May 20, 2016