HERCULES OFFSHORE, INC.
Form 10-K
March 10, 2011

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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, 2010
Commission file number: 0-51582

Hercules Offshore, Inc.
(Exact name of registrant as specified in its charter)

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 of the Act. Yes o 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 o

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

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

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 o	Accelerated filer þ	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

The aggregate market value of the registrant s common stock held by non-affiliates as of June 30, 2010, based on the closing price on the NASDAQ Global Select Market on such date, was approximately $270 million. (As of such date, the registrant s directors and executive officers and LR Hercules Holdings, LP and its affiliates were considered affiliates of the registrant for this purpose.)

As of March 3, 2011, there were 115,032,964 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 10, 2011 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

Hercules Offshore, Inc. is 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 16, 2011, we owned a fleet of 30 jackup rigs, 17 barge rigs, three submersible rigs, one platform rig, a fleet of marine support vessels and 60 liftboat vessels. In addition, we operate five liftboat vessels owned by a third party. We own two retired jackup rigs, *Hercules 190* and *Hercules 254*, located in the U.S. Gulf of Mexico, for which we have an agreement to sell and we expect to close in the first quarter of 2011. 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 six business segments, which as of February 16, 2011, included the following:

Domestic Offshore includes 22 jackup rigs and three submersible rigs in the U.S. Gulf of Mexico that can drill in maximum water depths ranging from 85 to 350 feet. Ten of the jackup rigs are either working on short-term contracts or available for contracts, one is in the shipyard and eleven are cold-stacked. All three 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 working offshore in each of India and Saudi Arabia. We have one jackup rig contracted offshore in Malaysia, one jackup rig contracted in Angola and one platform rig under contract in Mexico. In addition, we have one jackup rig warm-stacked and one jackup rig cold-stacked in Bahrain.

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 41 liftboats in the U.S. Gulf of Mexico. Thirty-eight are operating or available for contracts and three are cold-stacked.

International Liftboats includes 24 liftboats. Twenty-one are operating or available for contracts offshore West Africa, including five liftboats owned by a third party, one is cold-stacked offshore West Africa and two are operating or available for contracts in the Middle East region.

Delta Towing our Delta Towing business operates a fleet of 29 inland tugs, 10 offshore tugs, 34 crew boats, 46 deck barges, 16 shale barges and five spud barges along and in the U.S. Gulf of Mexico and from time to time along the Southeastern coast and in Mexico. Of these vessels, 26 crew boats, 11 inland tugs, three offshore tugs, one deck barge and one spud barge are cold-stacked, and the remaining are working, being repaired or available for contracts.

In December 2009, we entered into an agreement with First Energy Bank B.S.C. (MENAdrill) whereby we would market, manage and operate two Friede & Goldman Super M2 design new-build jackup drilling rigs, *Hull 109* and *Hull 110* (also known as *MENAdrill Hercules 1* and *2*, respectively), each with a maximum water depth of 300 feet. We received a notice of termination from MENAdrill with respect to *Hull 109* in December 2010, and MENAdrill paid us a termination fee of $250,000 due under the contract on the date of termination. It is our understanding that *Hull 110* has independently secured a contract in Mexico and we therefore, expect to receive an additional termination fee of $250,000.

In January 2011, we entered into an agreement with China Oilfield Services Limited (COSL) whereby we will market and operate a Friede & Goldman JU2000E jackup drilling rig with a maximum water depth of 400 feet. The agreement is limited to a specified opportunity in Angola.

Investment

In January 2011, we paid $10 million to purchase 5.0 million shares, an 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 (the Rigs). 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 (See Part II, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations *Recent Developments*).

Asset Purchase Agreement

In February 2011, we entered into an asset purchase agreement (the Asset Purchase Agreement) with Seahawk Drilling, Inc. and certain of its subsidiaries (Seahawk), pursuant to which Seahawk agreed to sell to us 20 jackup rigs and related assets**,** accounts receivable and cash and certain Seahawk liabilities for total consideration of approximately $105 million (the Consideration), as valued at the date of the Asset Purchase Agreement, preliminarily consisting of $25.0 million in cash plus 22.3 million shares of our common stock, par value $0.01 per share (the Stock Consideration), subject to adjustment (See Part II, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations *Recent Developments*).

Credit Agreement Amendment

In March 2011, we amended our Credit Agreement for our term loan and revolving credit facility (See the information set forth under the caption Cash Requirements and Contractual Obligations in Part II, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations *Liquidity and Capital Resources*).

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.

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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. Twenty-one of our jackup rigs are mat-supported and nine are independent leg rigs.

Twenty-three 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. Seven 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.

As of February 16, 2011, 14 of our jackup rigs were operating under contracts ranging in duration from well-to-well to three years, at an average contract dayrate of approximately $71,643. 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 16, 2011.

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 152	MC	1980	150/22	20,000	U.S. GOM	Cold Stacked
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	Angola	Contracted
Hercules 200	MC	1979	200/23	20,000	U.S. GOM	Contracted
Hercules 201	MC	1981	200/23	20,000	U.S. GOM	Ready Stacked
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	Shipyard
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	Malaysia	Contracted
Hercules 211	MC	1980	200/23	18,000(e)	U.S. GOM	Cold Stacked
Hercules 250	MS	1974	250/24	20,000	U.S. GOM	Cold Stacked
Hercules 251	MS	1978	250/24	20,000	U.S. GOM	Ready Stacked
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	India	Contracted
Hercules 260	ILC	1979/2008	250/12	20,000	India	Contracted
Hercules 261	ILC	1979/2008	250/12	20,000	Saudi Arabia	Contracted
Hercules 262	ILC	1982/2008	250/12	20,000	Saudi Arabia	Contracted
Hercules 350	ILC	1982	350/16	25,000	U.S. GOM	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 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.

(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 regulatory 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. Our three submersible rigs are upgradeable for deep gas drilling.

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. We have one platform drilling rig.

In the following table, Sub means a submersible rig and Plat means a platform drilling rig. The following table contains information regarding our other drilling rig fleet as of February 16, 2011.

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
Hercules 78	Sub	1985/2007	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. Several of our barge drilling rigs are upgradeable for deep gas drilling.

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The following table contains information regarding our barge drilling rig fleet as of February 16, 2011.

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	Contracted
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.

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 3,500 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 16, 2011, we owned 41 liftboats operating in the U.S. Gulf of Mexico, 17 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 16, 2011.

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	En route to Gabon	777
Swordfish(3)	2000	190	4,000	700,000	U.S. GOM	189
Mako(3)	2003	175	5,074	654,000	Nigeria	168
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
Starfish(3)	1978	140	2,266	150,000	U.S. GOM	99
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

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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
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
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 *Palometa, Wolffish, Skipfish* and *Croaker* 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.

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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 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, which may better enable them 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,		
	2010	2009	2008
Oil and Natural Gas Corporation Limited(a)	20%	16%	8%
Chevron Corporation(b)	17	14	12
Saudi Aramco(a)	14	13	
PEMEX Exploración y Producción (PEMEX)(a)	3	10	8

(a) Revenue included in our International Offshore segment.

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

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 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.

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 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 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, weather 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 16, 2011:

		For the Years Ending December 31,				
	Total	**2011**	**2012**	**2013**	**2014**	**Thereafter**
			(In thousands)			
Domestic Offshore	$ 29,081	$ 29,081	$	$	$	$
International Offshore	167,554	121,646	21,737	21,677	2,494	
Inland	914	914				
International Liftboats	14,566	14,566				
Total	$ 212,115	$ 166,207	$ 21,737	$ 21,677	$ 2,494	$

Employees

As of December 31, 2010, we had approximately 2,200 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 $2.1 billion. 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 $100.0 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 $50 million primary covering liability 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 as well as a separate underlying marine package for our Delta Towing business. Our policy related to all but our Delta Towing business, which we renew annually, expires in April 2011. Our policy related to our Delta Towing business, which we also renew annually, expires in August 2011.

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. 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.

Regulation

Our operations are affected in varying degrees by governmental laws and regulations. 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 also subject to the jurisdiction of the U.S. Coast Guard, the National Transportation Safety Board, the U.S. Customs and Border Protection Service, the Department of Interior and the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), as well as private industry organizations 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 U.S. Customs Service is authorized to inspect vessels at will. Coast Guard regulations also require annual inspections and periodic drydock inspections or special examinations of our vessels.

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, regulations applicable to our operations include regulations that require us to obtain and maintain specified permits or governmental approvals, control the discharge of materials into the environment, require 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 units 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 or related to those operations. Laws and regulations protecting the environment have become more stringent 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 which were in compliance with all applicable laws at the time they were performed. The application of these requirements or the adoption of new or more stringent 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, 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 exploration activities occur. Offshore facilities must also prepare plans addressing spill prevention control and countermeasures. Historically, the discharge of ballast water and other substances incidental to the normal operation of vessels visiting U.S. ports was exempted from the Clean Water Act permitting requirements. Challenges arising largely out of foreign invasive species contained in discharges of ballast water resulted in a 2006 court order that vacated, as of September 30, 2008, an exemption from Clean Water Act discharge permit requirements for discharges incidental to normal operation of a vessel. The district court later delayed the vacation until February 6, 2009. Pursuant to the court s ruling and recent legislation, the EPA adopted a Vessel General Permit that became effective on December 19, 2008. The regulated community was required to comply with the terms of the Vessel General Permit as of February 6, 2009. We have obtained the necessary Vessel General Permit for all of our vessels to which this regulation applies. In addition to this federal development, some states have begun regulating ballast water discharges. Violations of monitoring, reporting and permitting requirements can result in the imposition of civil and criminal penalties. We have incurred and will continue to incur certain costs associated with the requirements under the Vessel General Permit and other requirements that may be adopted. However, we believe that any financial impacts resulting from the imposition of the permitting exemption and the implementation of federal and possible state regulation of ballast water discharges will not be material.

The U.S. Oil Pollution Act of 1990 (OPA) and related regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. Few defenses exist to the liability imposed by OPA, and the liability could be substantial. Failure to comply with ongoing requirements or inadequate cooperation in the event of a spill could subject a responsible party to civil or criminal enforcement action. OPA also requires owners and operators of all vessels over 300 gross tons to establish and maintain with the U.S. Coast Guard evidence of financial responsibility sufficient to meet their potential liabilities under OPA. The 2006 amendments to OPA require evidence of financial responsibility for a vessel over 300 gross tons in the amount that is the greater of $950 per gross ton or $800,000. Under OPA, an owner or operator of a fleet of vessels is required only to demonstrate evidence of financial responsibility in an amount sufficient to cover the vessel in the fleet having the greatest maximum liability under OPA. Vessel owners and operators may evidence their financial responsibility by showing proof of insurance, surety bond, self-insurance or guarantee. We have obtained the necessary OPA financial assurance certifications for each of our vessels subject to such requirements. Amendments to OPA are currently being considered by Congress that would, if enacted, increase liability of responsible parties and the limits on liability relating to oil spill and pollution events.

The U.S. Outer Continental Shelf Lands Act authorizes regulations relating to safety and environmental protection applicable to lessees and permittees operating on the outer continental shelf. 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 outer continental shelf 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, also known as CERCLA or the Superfund law, imposes liability without regard to fault or the legality of the original conduct on some 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 companies 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.

In recent years, a variety of initiatives intended to enhance vessel security were adopted to address terrorism risks, including the U.S. 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 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 165 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 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. The United States has not yet ratified Annex VI. Any vessels we operate internationally are, however, 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 incurring significant costs to comply with Annex VI in the near term. If the United States does elect to ratify Annex VI in the future, we could be required to incur potentially significant costs to bring certain of our vessels into compliance with these requirements.

In response to the Macondo well blowout incident in April 2010, the Department of Interior, through the BOEMRE, has undertaken an aggressive overhaul of the offshore oil and natural gas regulatory process that has significantly impacted oil and gas development in the United States Gulf of Mexico (the GOM). From time to time, new rules, regulations and requirements have been proposed and implemented by the BOEMRE and the United States Congress that materially limit or prohibit, and increase the cost of, offshore drilling in the GOM. 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 GOM, the adoption of new safety requirements and policies relating to the approval of drilling permits in the GOM, restrictions on oil and gas development and production activities in the GOM, and the promulgation of numerous Notices to Lessees (NTLs) that have impacted and may continue to impact our operations. In addition to these newly-implemented 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 GOM, 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.

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 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 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 United States Gulf of Mexico.

In response to the Macondo well blowout incident in the United States Gulf of Mexico in April 2010, the U.S. federal government has promulgated new laws, regulations and requirements that impose additional safety and environmental requirements on offshore drilling companies and oil and gas companies operating in the United States Gulf of Mexico. We have significant operations that are either ongoing or scheduled to commence in the Gulf of Mexico. The requirements set forth in these new laws, regulations and requirements may continue to delay our operations and cause us to incur additional expenses in order for our rigs and operations in the 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 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 adversely impact our revenue and profitability.

In addition to the recently implemented laws, regulations and requirements, the federal government is considering additional new laws, regulations and requirements, including those that impose 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 implementation of some of the currently proposed 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 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 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 United States 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 United States Gulf of Mexico, which could likewise have an adverse impact on our business and financial results.

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. In particular, changes in the price of natural gas materially affect our operations because drilling in the shallow-water U.S. Gulf of Mexico is primarily focused on developing and producing natural gas reserves. 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 March 3, 2011, the closing price of natural gas at the Henry Hub was $3.75 per MMBtu. The spot price for West Texas intermediate 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 $101.91 per barrel as of March 3, 2011. 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;
- imports of liquefied natural gas;
- advances in 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, 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 is currently experiencing 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, such as we are currently experiencing, intensify the competition in the industry and often result in rigs or liftboats being idle for long periods of time. While economic conditions have recently begun to improve, 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 are currently experiencing.

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, 2010, we had total outstanding debt of approximately $858.1 million. This debt represented approximately 50% of our total book capitalization. As of December 31, 2010, we had $163.5 million of available capacity under our revolving credit facility, after the commitment of $11.5 million for standby letters of credit issued under it. However, our available capacity under our revolving credit facility, as of and as amended on March 3, 2011, was $129.1 million after the commitment of $10.9 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 55 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 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 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, 2010, 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.

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 current 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 re-activated.

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.

While conditions have recently improved, 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 and, to a lesser extent, natural gas prices have recently 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.

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 March 3, 2011, 56 jackup rigs (excludes 10 rigs that have been indefinitely suspended) were under construction or on order 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. Under U.S. Coast Guard guidelines, the liftboats cannot return to work until the weather improves and seas are less than five feet. 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 16, 2011, our total contract drilling backlog for our Domestic Offshore, International Offshore, International Liftboats and Inland segments was approximately $212.1 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 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.

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 suffered extensive damage from several hurricanes. As a result, over the past five 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

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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.

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, including Nigeria, and in the Middle East. We also operate drilling rigs in India, 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 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.

In 2010, the level of political unrest, acts of terrorism, and organized criminality in Nigeria increased as a part of efforts of militant groups in the country to disrupt the presidential election, which has been postponed until April 2011. The level of political unrest, terrorism, organized criminality and piracy in Nigeria is expected to continue until and after the presidential election. In the past, many of our customers in Nigeria, including Chevron Corporation, have interrupted their activities during these episodes of increased terrorism, piracy and armed conflict. These interruptions in activity can be prolonged, during which time we may not receive dayrates for our liftboats.

In early 2011, political and civil unrest escalated in the Middle East and North Africa, including in Egypt and Libya. We operate drilling rigs and liftboats in the Middle East and could be impacted by the instability in the region. While we do not operate in the countries that are experiencing this instability and our operations have not been impacted by such instability, our customers who operate drilling rigs and liftboats in the affected countries could mobilize their assets to the countries in which we operate, which could lead to increased competition for us in these countries, potentially resulting in lower utilization and lower dayrates for our drilling rigs and liftboats in the region. In addition, if the unrest spreads to other oil and natural gas producing countries in the region, including those in which we operate, our operations could be delayed, hindered, or indefinitely postponed. The occurrence of any of these contingencies could have an adverse impact on our business and financial results.

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.

We derive a significant amount of our revenue from a few energy companies. Oil and Natural Gas Corporation Limited, Chevron Corporation and Saudi Aramco accounted for 20%, 17% and 14% of our revenue for the year ended December 31, 2010, respectively. In addition, 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 any 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, 21 of our 30 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

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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;

- 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.

Closing of the February 2011 Asset Purchase Agreement with Seahawk is subject to bankruptcy court approval, as well as regulatory approvals and other customary conditions. Our 2011 Credit Amendment included a modification to, among other things, allow for the use of cash to purchase assets from Seahawk, to the extent set forth in our Asset Purchase Agreement and 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.

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.

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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 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 United States Coast Guard, the National Transportation Safety Board, the United States Customs and Border Protection Service, the Department of Interior and the Bureau of Ocean Energy Management, Regulation and Enforcement, 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 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 can be costly and could limit our operations.

Our operations are subject to 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. 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.

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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 size of our revolving credit facility was reduced by the 2009 Credit Amendment from $250 million

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to $175 million and by the 2011 Credit Amendment from $175 million to $140 million. The availability under the 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. No amounts were outstanding under the revolving credit facility as of December 31, 2010, although $11.5 million in stand-by letters of credit had been issued under it. The remaining availability under the revolving credit facility is $163.5 million at December 31, 2010. As of March 3, 2011, the effective date of the 2011 Credit Amendment, there were no amounts outstanding and $10.9 million in standby letters of credit issued leaving remaining availability of $129.1 million under the revolving credit facility.

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 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, including payments on our convertible notes. 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, stockholder rights plan or Delaware law may inhibit a takeover, which could adversely affect the value of our common stock.

Our certificate of incorporation, bylaws, stockholder rights plan 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, marine support vessels, 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 Agreement 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, Nigeria, India, Malaysia, Saudi Arabia, Qatar, Bahrain and the Cayman Islands. 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.

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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 have been filed in the Circuit Courts of the State of Mississippi involving 768 persons that allege personal injury or whose heirs claim their deaths arose out of asbestos exposure in the course of their employment by the defendants between 1965 and 2002. The complaints name as defendants, among others, certain of TODCO s subsidiaries and certain subsidiaries of TODCO s former parent to whom TODCO may owe indemnity and other unaffiliated defendant companies, including companies that allegedly manufactured drilling related products containing asbestos that are the subject of the complaints. The number of unaffiliated defendant companies involved in each complaint ranges from approximately 20 to 70. The complaints allege that the defendant drilling contractors used asbestos-containing products in offshore drilling operations, land based drilling operations and in drilling structures, drilling rigs, vessels and other equipment and assert claims based on, among other things, negligence and strict liability, and claims authorized under the Jones Act. The plaintiffs seek, among other things, awards of unspecified compensatory and punitive damages. All of these cases were assigned to a special master who has approved a form of questionnaire to be completed by plaintiffs so that claims made would be properly served against specific defendants. Approximately 700 questionnaires were returned and the remaining plaintiffs, who did not submit a questionnaire reply, have had their suits dismissed without prejudice. Of the respondents, approximately 100 shared periods of employment by TODCO and its former parent which could lead to claims against either company, even though many of these plaintiffs did not state in their questionnaire answers that the employment actually involved exposure to asbestos. After providing the questionnaire, each plaintiff was further required to file a separate and individual amended complaint naming only those defendants against whom they had a direct claim as identified in the questionnaire answers. Defendants not identified in the amended complaints were dismissed from the plaintiffs litigation. To date, three plaintiffs named TODCO as a defendant in their amended complaints. It is possible that some of the plaintiffs who have filed amended complaints and have not named TODCO as a defendant may attempt to add TODCO as a defendant in the future when case discovery begins and greater attention is given to each individual plaintiff s employment background. We have not determined which entity would be responsible for such claims under the Master Separation Agreement between TODCO and its former parent. More than three 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. 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.

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. ***Reserved***

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 March 3, 2011, there were 96 stockholders of record. On March 3, 2011, the closing price of our common

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stock as reported by NASDAQ was $5.85 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
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

	Price	
	High	Low
2009		
Fourth Quarter	$ 6.60	$ 4.21
Third Quarter	7.28	3.02
Second Quarter	5.64	1.54
First Quarter	5.92	1.07

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, 2010	653	$ 2.56	N/A	N/A

November 1 - 30, 2010	133	2.93	N/A	N/A
December 1 - 31, 2010			N/A	N/A
Total	786	2.63	N/A	N/A

(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 2010, 2009 or 2008, 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, 2010 and 2009 and for the years ended December 31, 2010, 2009 and 2008 from our audited consolidated financial statements included in Item 8 of this annual report. 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. The condensed consolidated financial information as of December 31, 2007 and for the year ended December 31, 2006 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 on September 23, 2009. The condensed consolidated financial information as of December 31, 2006 was derived from our audited consolidated financial statements included in Item 8 of our annual report on Form 10-K, as amended, for the year ended December 31, 2006.

We were formed in July 2004 and commenced operations in August 2004. From our formation to December 31, 2010, we completed the 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 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, 2010(a)	Year Ended December 31, 2009(b)	Year Ended December 31, 2008(c)	Year Ended December 31, 2007	Year Ended December 31, 2006
	(In thousands, except per share data)				
Statement of Operations Data:					
Revenue	$ 657,480	$ 742,851	$ 1,111,807	$ 726,278	$ 344,312
Operating income (loss)	(145,160)	(92,146)	(1,120,913)	225,642	158,057
Income (loss) from continuing operations	(134,594)	(90,149)	(1,081,870)	136,012	119,050
Earnings (loss) per share from continuing operations:					
Basic	$ (1.17)	$ (0.93)	$ (12.25)	$ 2.31	$ 3.80
Diluted	(1.17)	(0.93)	(12.25)	2.28	3.70
Balance Sheet Data (as of end of period):					
Cash and cash equivalents	$ 136,666	$ 140,828	$ 106,455	$ 212,452	$ 72,772
Working capital	182,276	144,813	224,785	367,117	110,897
Total assets	1,995,309	2,277,476	2,590,895	3,643,948	605,581
Long-term debt, net of current portion	853,166	856,755	1,015,764	890,013	91,850
Total stockholders equity	853,132	978,512	925,315	2,011,433	394,851

Cash dividends per share

(a) Includes $125.1 million ($81.3 million, net of taxes or $0.71 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 the *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 $950.3 million ($950.3 million, net of taxes or $10.76 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, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008	Year Ended December 31, 2007	Year Ended December 31, 2006
			(In thousands)		
Other Financial Data:					
Net cash provided by (used in):					
Operating activities	$ 24,420	$ 137,861	$ 269,727	$ 175,741	$ 124,241
Investing activities	(21,306)	(60,510)	(515,787)	(825,007)	(149,983)
Financing activities	(7,276)	(42,978)	140,063	788,946	50,939
Capital expenditures	22,018	76,141	585,084(a)	155,390	204,456
Deferred drydocking expenditures	15,040	15,646	17,269	20,772	12,544

(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, 2010 and 2009 and for the years ended December 31, 2010, 2009 and 2008 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 16, 2011, we owned a fleet of 30 jackup rigs, 17 barge rigs, three submersible rigs, one platform rig, a fleet of marine support vessels and 60 liftboat vessels. In addition, we operate five liftboat vessels owned by a third party. We own two retired jackup rigs, *Hercules 190* and *Hercules 254*, located in the U.S. Gulf of Mexico, for which we have an agreement to sell and we expect to close in the first quarter of 2011. 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 six business segments, which as of February 16, 2011, included the following:

Domestic Offshore includes 22 jackup rigs and three submersible rigs in the U.S. Gulf of Mexico that can drill in maximum water depths ranging from 85 to 350 feet. Ten of the jackup rigs are either working on short-term contracts or available for contracts, one is in the shipyard and eleven are cold-stacked. All three 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 working offshore in each of India and Saudi Arabia. We have one jackup rig contracted offshore in Malaysia, one jackup rig contracted in Angola and one platform rig under contract in Mexico. In addition, we have one jackup rig warm-stacked and one jackup rig cold-stacked in Bahrain.

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 41 liftboats in the U.S. Gulf of Mexico. Thirty-eight are operating or available for contracts and three are cold-stacked.

International Liftboats includes 24 liftboats. Twenty-one are operating or available for contracts offshore West Africa, including five liftboats owned by a third party, one is cold-stacked offshore West Africa and two are operating or available for contracts in the Middle East region.

Delta Towing our Delta Towing business operates a fleet of 29 inland tugs, 10 offshore tugs, 34 crew boats, 46 deck barges, 16 shale barges and five spud barges along and in the U.S. Gulf of Mexico and from time to time along the Southeastern coast and in Mexico. Of these vessels, 26 crew boats, 11 inland tugs, three offshore tugs, one deck barge and one spud barge are cold-stacked, and the remaining are working, being repaired or available for contracts.

In December 2009, we entered into an agreement with First Energy Bank B.S.C. (MENAdrill) whereby we would market, manage and operate two Friede & Goldman Super M2 design new-build jackup drilling rigs, *Hull 109* and *Hull 110* (also known as *MENAdrill Hercules 1* and *2*, respectively), each with a maximum water depth of 300 feet. We received a notice of termination from MENAdrill with respect to *Hull 109* in December 2010, and MENAdrill paid us a termination fee of $250,000 due under the contract on the date of termination. It is our understanding that *Hull 110* has independently secured a contract in Mexico and we therefore, expect to receive an additional termination fee of $250,000.

Our jackup and submersible rigs and our 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.

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. 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 and 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 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.

RECENT DEVELOPMENTS

Investment

In January 2011, we paid $10 million to purchase 5.0 million shares, an 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 (the Rigs). The Rigs, Keppel FELS Super A design, are being constructed by Keppel FELS in its Singapore shipyard and have a maximum water depth rating of 400 feet, two million pound hook load capacity, and are capable of drilling up to 35,000 feet deep. The two Rigs are expected to be delivered in the second and fourth quarter of 2013, respectively. Discovery Offshore also holds options to purchase two additional rigs of the same specifications, which must be exercised by the third and fourth quarter of 2011, with delivery dates expected in the second quarter and fourth quarter of 2014, respectively.

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 Agreement, 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 Agreement, 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 Agreement, 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 equivalent to $2.00 which is exercisable in the event that the Discovery stock price reaches an average equal to or higher than 23 Norwegian Kroner per share, which approximated $4.00 per share as of March 3, 2011, for 30 consecutive trading days. 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.

Alliance Agreement

In January 2011, we entered into an agreement with China Oilfield Services Limited (COSL) whereby we will market and operate a Friede & Goldman JU2000E jackup drilling rig with a maximum water depth of 400 feet. The agreement is limited to a specified opportunity in Angola.

Asset Purchase Agreement

In February 2011, we entered into an asset purchase agreement (the Asset Purchase Agreement) with Seahawk Drilling, Inc. and certain of its subsidiaries (Seahawk), pursuant to which Seahawk agreed to sell us 20 jackup rigs and related assets, accounts receivable and cash and certain Seahawk liabilities in a transaction pursuant to Section 363 of the U.S. Bankruptcy Code. In connection with the Asset Purchase Agreement, Seahawk filed voluntary Chapter 11 petitions before the U.S. Bankruptcy Court for the Southern District of Texas, Corpus Christi Division.

The purchase consideration is approximately $105 million (the Consideration), as valued at the date of the Asset Purchase Agreement, preliminarily consisting of $25.0 million in cash plus 22.3 million shares of our common stock, par value $0.01 per share (the Stock Consideration), subject to adjustment as further described. The cash consideration is subject to increase at the request of Seahawk up to an additional $20.0 million, if required for the purpose of paying Seahawk s debt, and if the cash consideration is increased, the number of shares comprising the Stock Consideration shall be reduced by an amount equal to such increase, divided by $3.36. In addition, the Consideration is subject to certain other adjustments, including a working capital adjustment.

Our Board of Directors, and our lenders through the 2011 Credit Amendment, have approved the transaction. Closing of the transaction remains subject to bankruptcy court approval as well as regulatory approvals and other customary conditions. Assuming such conditions are achieved, the transaction is expected to close during the second quarter of 2011.

Credit Agreement Amendment

In March 2011, we amended our Credit Agreement for our term loan and revolving credit facility (See the information set forth under the caption Cash Requirements and Contractual Obligations in Part II, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations *Liquidity and Capital Resources*).

RESULTS OF OPERATIONS

Generally, domestic drilling industry conditions were mixed in 2010. While first half 2010 activity levels rebounded from the lows experienced in late 2009, second half 2010 activity was negatively impacted by the new regulations in the wake of the Macondo well blowout incident for offshore drilling imposed by BOEMRE, which resulted in our customers experiencing significant delays in obtaining necessary permits to operate in the U.S. Gulf of Mexico. Conversely, our Domestic Liftboat and Delta Towing segments realized increased activity levels due to our response to the clean up efforts related to the Macondo well blowout incident.

From an international perspective, our International Offshore segment experienced lower demand and increased jackup supply in 2010 as compared to 2009, which contributed to fewer operating days in 2010. However, our International Liftboats segment benefited from increased dayrates and significantly higher operating days in 2010 as compared to 2009.

Our domestic liftboat operations generally are affected by the seasonal weather patterns in the U.S. Gulf of Mexico. These seasonal patterns may result in increased operations in the spring, summer and fall periods and a decrease in the winter months. The rainy weather, tropical storms, hurricanes and other storms prevalent in the U.S. Gulf of Mexico during the year affect our domestic liftboat operations. During such severe storms, our liftboats typically leave location and cease to earn a full dayrate. Under U.S. Coast Guard guidelines, the liftboats cannot return to work until the weather improves and seas are less than five feet. 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.

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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, 2010	2009	2008
	(Dollars in thousands)		
Domestic Offshore:			
Number of rigs (as of end of period)	25	24	27
Revenue	$ 124,063	$ 140,889	$ 382,358
Operating expenses	147,715	175,473	227,884
Impairment of goodwill			507,194
Impairment of property and equipment	84,744		174,613
Depreciation and amortization expense	68,335	60,775	66,850
General and administrative expenses	5,663	6,496	4,673
Operating loss	$ (182,394)	$ (101,855)	$ (598,856)
International Offshore:			
Number of rigs (as of end of period)	9	10	12
Revenue	$ 291,516	$ 393,797	$ 327,983
Operating expenses	130,460	169,418	147,899
Impairment of goodwill			150,886
Impairment of property and equipment	37,973	26,882	
Depreciation and amortization expense	58,275	63,808	37,865
General and administrative expenses	7,930	35,694	2,980
Operating income (loss)	$ 56,878	$ 97,995	$ (11,647)
Inland:			
Number of barges (as of end of period)	17	17	27
Revenue	$ 21,922	$ 19,794	$ 162,487
Operating expenses	27,702	44,593	125,656
Impairment of goodwill			205,474
Impairment of property and equipment			202,055
Depreciation and amortization expense	23,516	32,465	43,107
General and administrative expenses	(1,420)	1,831	8,347
Operating loss	$ (27,876)	$ (59,095)	$ (422,152)
Domestic Liftboats:			
Number of liftboats (as of end of period)	41	41	45
Revenue	$ 70,710	$ 75,584	$ 94,755
Operating expenses	42,073	48,738	54,474
Depreciation and amortization expense	14,698	20,267	21,317
General and administrative expenses	1,850	2,039	2,386
Operating income	$ 12,089	$ 4,540	$ 16,578

International Liftboats:			
Number of liftboats (as of end of period)	24	24	20
Revenue	$ 116,616	$ 88,537	$ 85,896
Operating expenses	55,879	48,240	39,122
Depreciation and amortization expense	17,711	12,880	9,912
General and administrative expenses	5,815	4,990	5,990
Operating income	$ 37,211	$ 22,427	$ 30,872

	Year Ended December 31, 2010	2009	2008
	(Dollars in thousands)		
Delta Towing:			
Revenue	$ 32,653	$ 24,250	$ 58,328
Operating expenses	25,101	27,674	36,676
Impairment of goodwill			86,733
Impairment of property and equipment	2,419		
Depreciation and amortization expense	5,471	7,917	10,926
General and administrative expenses	1,395	1,336	4,058
Operating loss	$ (1,733)	$ (12,677)	$ (80,065)
Total Company:			
Revenue	$ 657,480	$ 742,851	$ 1,111,807
Operating expenses	428,930	514,136	631,711
Impairment of goodwill			950,287
Impairment of property and equipment	125,136	26,882	376,668
Depreciation and amortization expense	191,183	201,421	192,894
General and administrative expenses	57,391	92,558	81,160
Operating loss	(145,160)	(92,146)	(1,120,913)
Interest expense	(82,941)	(77,986)	(63,778)
Expense of credit agreement fees		(15,073)	
Gain on early retirement of debt, net		12,157	26,345
Other, net	3,885	3,967	3,315
Loss before income taxes	(224,216)	(169,081)	(1,155,031)
Income tax benefit	89,622	78,932	73,161
Loss from continuing operations	(134,594)	(90,149)	(1,081,870)
Loss from discontinued operation, net of taxes		(1,585)	(1,520)
Net loss	$ (134,594)	$ (91,734)	$ (1,083,390)

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

	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

	Year Ended December 31, 2008				
	Operating Days	Available Days	Utilization(1)	Average Revenue per Day(2)	Average Operating Expense per Day(3)
Domestic Offshore	5,907	8,166	72.3%	$ 64,730	$ 27,906
International Offshore	2,753	3,005	91.6%	119,137	49,218
Inland	4,048	5,885	68.8%	40,140	21,352
Domestic Liftboats	10,343	15,785	65.5%	9,161	3,451
International Liftboats	5,028	6,501	77.3%	17,084	6,018

(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. Included in International Offshore revenue is a total of $14.7 million, $16.3 million and $11.6 million related to amortization of deferred mobilization revenue and contract specific capital expenditures reimbursed by the customer for the years ended December 31, 2010, 2009 and 2008, respectively.

(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.

2010 Compared to 2009

Revenue

Consolidated. Total revenue for 2010 was $657.5 million compared with $742.9 million for 2009, a decrease of $85.4 million, or 11%. 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.

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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.

Delta Towing. Revenue for our Delta Towing segment was $32.7 million for 2010 compared with $24.3 million for 2009, an increase of $8.4 million, or 35%. An increase in operating days during 2010 as compared to 2009, due in part to activity associated with the Macondo well blowout incident remediation efforts, 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.

Operating Expenses

Consolidated. Total operating expenses for 2010 were $428.9 million compared with $514.1 million in 2009, a decrease of $85.2 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.

Delta Towing. Operating expenses for our Delta Towing segment were $25.1 million in 2010 compared with $27.7 million in 2009, a decrease of $2.6 million, or 9%. This decrease is primarily due to lower labor expenses during 2010 as compared to 2009 due to the cold stacking of vessels. These decreases are partially offset by costs associated with increased activity due to the Macondo well blowout incident remediation efforts.

Impairment of Property and Equipment

In the year ended December 31, 2010, we incurred $125.1 million of impairment charges related to certain property and equipment on our Domestic Offshore, International Offshore and Delta Towing segments, the impact of which by segment was $84.7 million, $38.0 million and $2.4 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.

Depreciation and Amortization

Depreciation and amortization expense in 2010 was $191.2 million compared with $201.4 million in 2009, a decrease of $10.2 million, or 5%. This decrease resulted primarily from lower amortization of our international contract values and drydocking costs, which contributed a decrease of $3.4 million and $3.2 million, respectively, as well as reduced depreciation due to asset sales and certain assets being fully depreciated, which contributed a decrease of approximately $12 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 $57.4 million compared with $92.6 million in 2009, a decrease of $35.2 million, or 38%. 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 $5.0 million, or 6%. 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 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 $89.6 million on pre-tax loss of $224.2 million during 2010, compared to a benefit of $78.9 million on pre-tax loss of $169.1 million for 2009. The effective tax rate decreased to a tax benefit of 40.0% during 2010 as compared to a tax benefit of 46.7% 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.

2009 Compared to 2008

Revenue

Consolidated. Total revenue for 2009 was $742.9 million compared with $1,111.8 million for 2008, a decrease of $369.0 million, or 33.2%. This decrease is further described below.

Domestic Offshore. Revenue for our Domestic Offshore segment was $140.9 million for 2009 compared with $382.4 million for 2008, a decrease of $241.5 million, or 63.2%. This decline resulted from decreased operating days from 5,907 in 2008 to 2,676 in 2009 primarily due to an overall decrease in demand and our cold stacking of rigs, which contributed $170.1 million of the decrease, and lower average dayrates which contributed $71.4 million of the decrease. Average utilization was 58.9% in 2009 compared with 72.3% in 2008.

International Offshore. Revenue for our International Offshore segment was $393.8 million for 2009 compared with $328.0 million for 2008, an increase of $65.8 million, or 20.1%. Approximately $154 million of this increase was due to increased operating days as a result of the commencement of the *Hercules 260* in late April 2008, *Hercules 258* in June 2008, *Hercules 208* in August 2008, *Hercules 261* in December 2008 and *Hercules 262* in January 2009. These favorable increases were partially offset by a decrease of approximately $76 million related to the *Hercules 156* and *Hercules 170* being in warm stack, *Hercules 206* being transferred to Domestic Offshore for cold stack in the fourth quarter of 2009 and *Hercules 110* in cold stack during 2009 until the date of sale, and a lower average dayrate realized on *Hercules 205*. In addition, the *Hercules 185* contributed to an approximate $14 million decrease as it was in the shipyard for an upgrade for a portion of 2009. Average revenue per rig per day increased to $127,031 in 2009 from $119,137 in 2008 due primarily to higher average dayrates earned on *Hercules 261* and *Hercules 208* for a more significant portion of 2009 as well as the commencement of the *Hercules 262* in January 2009, partially offset by lower average dayrates earned on *Hercules 205* and *Hercules 206,* and *Hercules 156* in warm stack a majority of the year as well as *Hercules 185* which operated at a higher dayrate, but for fewer operating days.

Inland. Revenue for our Inland segment was $19.8 million for 2009 compared with $162.5 million for 2008, a decrease of $142.7 million, or 87.8% as a result of an industry-wide decline in drilling in the transition zones. This decrease resulted primarily from decreased operating days, 651 in 2009 compared to 4,048 in 2008, an 83.9% decrease. Available days declined 73.2% during 2009 as compared to 2008 due to our cold stacking plan. Furthermore, average utilization was 41.3% on fewer available days in 2009 compared with 68.8% in 2008 as demand in the segment declined.

Domestic Liftboats. Revenue for our Domestic Liftboats segment was $75.6 million for 2009 compared with $94.8 million in 2008, a decrease of $19.2 million, or 20.2%. This decrease resulted primarily from lower average dayrates, which contributed $12.8 million of the decrease, as well as a $6.4 million decrease due to fewer operating days in 2009. Average revenue per vessel per day was $7,927 in 2009 compared with $9,161 in 2008, a decrease of $1,234 per day due primarily to lower dayrates in all vessel classes with a slight decrease due to mix of vessel class.

International Liftboats. Revenue for our International Liftboats segment was $88.5 million for 2009 compared with $85.9 million in 2008, an increase of $2.6 million, or 3.1%. This increase resulted from higher average dayrates, which contributed $17.8 million of the increase, significantly offset by fewer operating days, which contributed a $15.2 million decrease. The higher average dayrate was due to increased operating days on our larger class vessels, which have higher dayrates and lower utilization on the smaller class vessels which have lower dayrates.

Delta Towing. Revenue for our Delta Towing segment was $24.3 million for 2009 compared with $58.3 million for 2008, a decrease of $34.1 million, or 58.4%, due to decreased activity both offshore and in the transition zone.

Operating Expenses

Consolidated. Total operating expenses for 2009 were $514.1 million compared with $631.7 million in 2008, a decrease of $117.6 million, or 18.6%. This decrease is further described below.

Domestic Offshore. Operating expenses for our Domestic Offshore segment were $175.5 million in 2009 compared with $227.9 million in 2008, a decrease of $52.4 million, or 23.0%. The decrease was driven primarily by lower labor, catering, repairs and maintenance, and insurance expenses primarily as a result of our cold stacking of rigs. Available days decreased to 4,544 in 2009 from 8,166 in 2008 due to our cold stacking of rigs. Average operating expenses per rig per day were $38,616 in 2009 compared with $27,906 in 2008 due in part to shore based support and cold stacked rig costs being allocated over fewer available days.

International Offshore. Operating expenses for our International Offshore segment were $169.4 million in 2009 compared with $147.9 million in 2008, an increase of $21.5 million, or 14.5%. Available days increased to 3,714 in 2009 from 3,005 in 2008. Average operating expenses per rig per day were $45,616 in 2009 compared with $49,218 in 2008. This decrease related primarily to the *Hercules 156* and *Hercules 170* being in warm stack during a portion of

2009 and the initial start-up costs incurred during 2008 related to our India and Malaysia operations, partially offset by an increase due to the commencement of *Hercules 261* and *Hercules 262* in December 2008 and January 2009, respectively.

Inland. Operating expenses for our Inland segment were $44.6 million in 2009 compared with $125.7 million in 2008, a decrease of $81.1 million, or 64.5%. By mid 2009, fourteen of our seventeen barges were cold stacked which significantly reduced the segment s variable operating costs. Average operating expenses per rig per day were $28,259 in 2009 compared with $21,352 in 2008. The increase in cost per day was driven primarily by costs associated with shore based support and cold stacked barges being allocated over fewer available days.

Domestic Liftboats. Operating expenses for our Domestic Liftboats segment were $48.7 million in 2009 compared with $54.5 million in 2008, a decrease of $5.7 million, or 10.5% due primarily to lower labor expense, fuel and oil and insurance costs. Available days decreased to 14,804 in 2009 from 15,785 in 2008 due to four vessels that were transferred to our International Liftboats Segment, these four vessels were not marketed during the third quarter 2009 in preparation of their mobilization to our International Liftboats Segment in the fourth quarter of 2009, and due to the cold stacking of several liftboats during 2009 that were available in 2008. Average operating expenses per vessel per day had a slight decrease to $3,292 per day during 2009 from $3,451 per day during 2008.

International Liftboats. Operating expenses for our International Liftboats segment were $48.2 million for 2009 compared with $39.1 million in 2008, an increase of $9.1 million, or 23.3%. Available days increased to 7,209 in 2009 from 6,501 in 2008 largely related to the current year availability of the *Whale Shark* and *Amberjack*, which were transferred to our International Liftboats segment from the Domestic Liftboats segment during 2008. Average operating expenses per liftboat per day were $6,692 in 2009 compared with $6,018 in 2008 due to higher repairs and maintenance expenses and costs associated with transferring and preparing the four domestic vessels to work in West Africa.

Delta Towing. Operating expenses for our Delta Towing segment were $27.7 million in 2009 compared with $36.7 million in 2008, a decrease of $9.0 million, or 24.5%. Due to the decline in activity in both offshore and the transition zone, we cold stacked certain assets in our fleet which resulted in lower labor, repairs and maintenance and fuel and oil expenses during 2009.

Impairment of Property and Equipment

Impairment of property and equipment in 2009 was $26.9 million compared with $376.7 million in 2008. The 2008 impairment charges of $376.7 million related to certain property and equipment on our Domestic Offshore and Inland segments in 2008. 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.

Depreciation and Amortization

Depreciation and amortization expense in 2009 was $201.4 million compared with $192.9 million in 2008, an increase of $8.5 million, or 4.4%. This increase resulted primarily from additional depreciation related to the commencement of *Hercules 260* in late April 2008, *Hercules 350* in June 2008, *Hercules 208* in August 2008, *Hercules 261* in December 2008 and *Hercules 262* in January 2009. These increases are partially offset by reduced depreciation due to the impairment of certain rigs, barges and related equipment in the fourth quarter of 2008 and lower amortization of our international contract values.

General and Administrative Expenses

General and administrative expenses in 2009 were $92.6 million compared with $81.2 million in 2008, an increase of $11.4 million, or 14.0%. This increase relates primarily to an allowance for doubtful accounts receivable of $30.8 million, net, of which approximately $26.8 million as of December 31, 2009, related to a customer in its International Offshore segment, partially offset by the cost reduction initiatives implemented in late 2008 and in 2009 in response to the significant decline in activity in several of our business segments. In addition, 2008 included $7.5 million in executive severance related costs.

Interest Expense

Interest expense increased $14.2 million, or 22.3%. This increase was primarily related to the higher interest capitalized in 2008 and interest expense incurred on our 10.5% Senior Secured Notes issued in October 2009. In addition, the increase in interest rates after the 2009 Credit Amendment were offset by lower debt balances due to the early retirement of a portion of our term loan.

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 (Loss) on Early Retirement of Debt, Net

Gain on early retirement of debt, net was $12.2 million in 2009 compared with $26.3 million in 2008, a decrease of $14.2 million or 53.9%. 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. In 2008, the gain on early retirement of debt in the amount of $26.3 million related to the December 2008 redemption of $73.2 million accreted principal amount ($88.2 million aggregate principal amount) of the 3.375% Convertible Senior Notes for a cost of $44.8 million, net of the related write off of $2.1 million of unamortized issuance costs.

Other Income

Other income in 2009 was $4.0 million compared with $3.3 million in 2008, an increase of $0.7 million or 19.7%. This increase is primarily due to foreign currency exchange gains, partially offset by lower interest income.

Income Tax Benefit

Income tax benefit was $78.9 million on pre-tax loss of $169.1 million during 2009, compared to a benefit of $73.2 million on pre-tax loss of $1,155.0 million for 2008. The effective tax rate changed to a tax benefit of 46.7% in 2009 from a tax benefit of 6.3% in 2008. The change in the effective tax rate is due to the non-deductible goodwill impairment in 2008 as well as a state tax benefit of $14.1 million based on prior year state tax audits concluded in the fourth quarter of 2009 and a federal tax benefit of $2.5 million based on recent court cases related to alternative minimum tax positions.

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

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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,		
	2010	2009	2008
Operating Loss	$ (145,160)	$ (92,146)	$ (1,120,913)
Adjustments:			
Property and equipment impairment	125,136	26,882	376,668
Goodwill impairment			950,287
Executive separation and benefit related charges			7,468
Total adjustments	125,136	26,882	1,334,423
Adjusted Operating Income (Loss)	$ (20,024)	$ (65,264)	$ 213,510
Loss from Continuing Operations	$ (134,594)	$ (90,149)	$ (1,081,870)
Adjustments:			
Property and equipment impairment	125,136	26,882	376,668
Goodwill impairment			950,287
Executive separation and benefit related charges			7,468
Gain on early retirement of debt, net		(12,157)	(26,345)
Expense of credit agreement fees		15,073	
Tax impact of adjustments	(43,883)	(14,799)	(133,331)
Total adjustments	81,253	14,999	1,174,747
Adjusted Income (Loss) from Continuing Operations	$ (53,341)	$ (75,150)	$ 92,877
Diluted Loss per Share from Continuing Operations	$ (1.17)	$ (0.93)	$ (12.25)
Adjustments:			
Property and equipment impairment	1.09	0.28	4.26
Goodwill impairment			10.76
Executive separation and benefit related charges			0.08
Gain on early retirement of debt, net		(0.13)	(0.30)
Expense of credit agreement fees		0.16	
Tax impact of adjustments	(0.38)	(0.15)	(1.51)
Total adjustments	0.71	0.16	13.29
Adjusted Diluted Earnings (Loss) per Share from Continuing Operations	$ (0.46)	$ (0.77)	$ 1.04
Loss from Continuing Operations	$ (134,594)	$ (90,149)	$ (1,081,870)
Interest expense	82,941	77,986	63,778

Income tax benefit	(89,622)	(78,932)	(73,161)
Depreciation and amortization	191,183	201,421	192,894
EBITDA	49,908	110,326	(898,359)
Adjustments:			
Property and equipment impairment	125,136	26,882	376,668
Goodwill impairment			950,287
Executive separation and benefit related charges			7,468
Gain on early retirement of debt, net		(12,157)	(26,345)
Expense of credit agreement fees		15,073	
Total adjustments	125,136	29,798	1,308,078
Adjusted EBITDA	$ 175,044	$ 140,124	$ 409,719

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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 1 to our consolidated financial statements. We believe that our more critical accounting policies include those related to property and equipment, revenue recognition, income tax, allowance for doubtful accounts, deferred charges, stock-based compensation, cash and cash equivalents and intangible assets. 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.

Property and Equipment

Property and equipment represents 82% of our total assets as of December 31, 2010. 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

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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.

During the fourth quarter 2008, demand for our domestic drilling assets declined dramatically, significantly beyond our expectations. Demand in these segments is driven by underlying commodity prices which fell to levels lower than those seen in several years. The deterioration in these industry conditions in the fourth quarter of 2008 negatively impacted our outlook for 2009 and we responded by cold stacking several additional rigs in 2009. We considered these factors and our change in our outlook as an indicator of impairment and assessed the rig assets of the Inland and Domestic Offshore segments for impairment. Based on an undiscounted cash flow analysis, it was determined that the non-marketable rigs for both segments were impaired. We estimated the value of the discounted cash flows for each segment s non-marketable rigs and we recorded an impairment charge of $376.7 million for the year ended December 31, 2008. In addition, we analyzed our other segments for impairment as of December 31, 2008 and noted that each segment had adequate undiscounted cash flows to recover their property and equipment carrying values.

In 2009 we entered into an agreement to sell *Hercules 110* and we realized approximately $26.9 million ($13.1 million, net of tax) of impairment charges related to the write-down of the rig to fair value less costs to sell during the second quarter 2009. The sale was completed in August 2009.

During the fourth quarter 2010, we considered the continued 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 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 current estimate of reactivation costs associated with these assets which, based on current and forecasted near-term dayrates and utilization levels, are economically prohibitive, and the sustained lack of visibility in the issuance of offshore drilling permits in the U.S. Gulf of Mexico.

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. 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.

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 and reimbursement for contract specific capital expenditures, which are recognized as services are performed over the term of the related contract.

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, the Company effectively reached a compromise settlement of all issues for 2004 through 2007. The Company paid $11.6 million and reversed (i) previously provided reserves and (ii) an associated tax benefit in the year which totaled $5.8 million.

Certain of our international rigs 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 7.2% of our total assets and 43.7% of our current assets as of December 31, 2010. 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, 2010 and 2009, there was $29.8 million and $38.5 million in allowance for doubtful accounts, respectively.

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, 2010 and 2009, our net deferred charges related to regulatory inspection costs totaled $5.4 million and $4.8 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) Codification Topic 718, *Compensation Stock Compensation* and in accordance with such we record the grant date fair value of share-based payments awarded as compensation expense using a straight-line method over the service period. The fair value of our restricted stock grants is based on the closing price of our common stock on the date of grant. 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 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). We also estimate future forfeitures and related tax effects.

We are estimating that the cost relating to stock options granted through December 31, 2010 will be $2.6 million over the remaining vesting period of 1.4 years and the cost relating to restricted stock granted through December 31, 2010 will be $2.3 million over the remaining vesting period of 1.2 years; however, due to the uncertainty of the level of share-based payments to be granted in the future, 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. Demand in the shallow water U.S. Gulf of Mexico is particularly driven by natural gas prices, while international demand is typically driven by prices for crude oil.

Drilling activity levels in the shallow water U.S. Gulf of Mexico are typically dependent on natural gas prices, and to a lesser extent crude oil prices, as well as our customers ability to obtain necessary drilling permits to operate in the region. As of March 3, 2011, the spot price for Henry Hub natural gas was $3.75 per MMbtu, with the twelve month strip, or average of the next twelve months futures contracts, at $4.22 per MMbtu. We expect natural gas to continue to account for the majority of hydrocarbon production in the shallow water U.S. Gulf of Mexico and the performance of our Domestic Offshore segment will remain dependent on natural gas prices. Additionally, in the wake of the Macondo well blowout incident, new regulations for offshore drilling were imposed by BOEMRE, which 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, it is likely that our customers will continue to experience some degree of delay in obtaining drilling permits into 2011.

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, as 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 has declined from 63 rigs in late 2008 to 51 rigs as of March 3, 2011. Although we are encouraged by the reduction in the marketed supply of jackup rigs in the region, which has helped to partially offset the reduction in demand for drilling rigs, we remain cautious about the outlook for improved demand and dayrates in Domestic Offshore given the permit delays and market expectations for a prolonged period of relatively low natural gas prices. Furthermore, 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.

Demand for our rigs in our International Offshore segment is primarily dependent on crude oil prices. Strong crude oil prices during 2010 and market expectations of continued strength through 2011, 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 2011. Our expectation for greater international rig demand is tempered by the current number of idle jackup rigs and the anticipated growth in supply. As of March 3, 2011, there were 350 jackup rigs marketed in international regions, of which 54 rigs were uncontracted. Further, there were 56 new jackup rigs (excludes 10 rigs that have been indefinitely suspended) either under construction or on order for delivery through 2014, of which 40 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, and we have entered into 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.

Five of our international rigs will complete three year contracts during 2011 and current market rates for comparable rigs in the various international regions where we operate are substantially below our existing contracted rates. There is no guarantee we will be able to secure new contracts for these rigs. If we are successful in securing new contracts, we expect the new dayrates will be substantially below current contract rates. Further, as our international customers typically have longer term investment programs, and tend to enter into multi-year contracts for our services, new international contracts could expose our International Offshore segment to much lower rates over the next several years.

Activity for inland barge drilling in the U.S. generally follows the same drivers as drilling in the U.S. Gulf of Mexico, 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 appear to have stabilized in 2010, but remain depressed relative to historical levels. As of February 28, 2011, there were 24 marketed barge rigs, of which 18 were contracted. We expect industry activity levels in 2011 to remain relatively flat with such levels, barring a significant increase in commodity prices.

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.

Domestic Liftboat segment demand was positively impacted by clean up efforts related to the Macondo well blowout incident throughout mid-2010, with a peak of 12 out of our 38 marketed liftboats dedicated to this activity. Such demand effectively concluded by the end of the third quarter of 2010, and we do not expect this source of revenue to recur. 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. These new federal regulations require E&P operators to perform such services, and we expect liftboat demand in support of these services will increase over an extended period of time, in particular demand for the larger class liftboats. However, the magnitude of demand growth for plugging, abandonment and decommissioning services, and the related increase in demand for liftboats, is uncertain. Further, barring any exogenous industry event, it is also uncertain whether such an increase in liftboat demand stemming from these new regulations will be adequate to fully offset the absence of clean up related business that we benefited from in 2010.

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. In recent years, international liftboat utilization has lagged the U.S. We believe that this is due in part to competitive pressures and curtailment of capital spending by various customers in wake of the 2008 financial crisis. During late 2010 and continuing into 2011, we have seen some signs of improvement in liftboat demand from various international customers. 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 our expectation of increased competition in our international markets.

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

Sources and uses of cash for 2010 and 2009 are as follows (in millions):

	2010	**2009**
Net Cash Provided by Operating Activities	$ 24.4	$ 137.9
Net Cash Provided by (Used in) Investing Activities:		
Additions of Property and Equipment	(22.0)	(76.1)
Deferred Drydocking Expenditures	(15.0)	(15.6)
Proceeds from Sale of Assets, Net	23.2	25.8
Insurance Proceeds Received		9.1
Increase in Restricted Cash	(7.5)	(3.7)
Total	(21.3)	(60.5)
Net Cash Provided by (Used in) Financing Activities:		
Short-term Debt Repayments, Net		(2.5)
Long-term Debt Borrowings		292.1
Long-term Debt Repayments	(7.7)	(403.6)
Redemption of 3.375% Convertible Senior Notes		(6.1)
Common Stock Issuance		89.6
Excess Tax Benefit from Stock-Based Arrangements	0.4	5.6
Payment of Debt Issuance Costs		(18.1)
Total	(7.3)	(43.0)

Net Increase (Decrease) in Cash and Cash Equivalents	$ (4.2)	$ 34.4

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 $475.2 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 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, 2010, 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 $464.1 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 to 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 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 the term loan facility, the 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 July 2007, we terminated all prior facilities and entered into a $1,050.0 million credit facility with a syndicate of financial institutions, consisting of a $900.0 million term loan and a $150.0 million revolving credit facility which is governed by the Credit Agreement. In April 2008, we entered into an agreement to increase the revolving credit facility to $250.0 million and in each of July 2009 and March 2011, the terms of the Credit Agreement were amended. The substantial changes to the terms of the Credit Agreement related to the July 2009 and March 2011 amendments are further described:

July 2009 Credit Amendment

On July 27, 2009, we amended the Credit Agreement (the 2009 Credit Amendment). A fee of 0.50% was paid to lenders consenting to the 2009 Credit Amendment, based on their total commitment, which approximated $4.8 million.

The 2009 Credit Amendment reduced the revolving credit facility by $75.0 million to $175.0 million. The commitment fee on the revolving credit facility increased from 0.375% to 1.00% and the letter of credit fee with respect to the undrawn amount of each letter of credit issued under the revolving credit facility increased from 1.75% to 4.00% per annum. Additionally, the 2009 Credit Amendment established a minimum London Interbank Offered Rate (LIBOR) of 2.00% for Eurodollar Loans, a minimum rate of 3.00% with respect to Alternative Base Rate (ABR) Loans, and increased the margin applicable to Eurodollar Loans and

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ABR Loans, subject to a grid based on the aggregate principal amount of the term loans outstanding as follows ($ in millions):

Principal Amount Outstanding		**Margin Applicable to:**	
Less than or equal to:	**Greater than:**	**Eurodollar Loans**	**ABR Loans**
$ 882.00	$ 684.25	6.50%	5.50%
684.25	484.25	5.00%	4.00%
484.25		4.00%	3.00%

The 2009 Credit Amendment also modified certain provisions of the Credit Agreement to, among other things:

Eliminate the requirement that we comply with the total leverage ratio financial covenant for the nine month period commencing October 1, 2009 and ending on June 30, 2010.

Amend the maximum total leverage ratio that we must comply with. The total leverage ratio for any test period is 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.

Require us to maintain a minimum level of liquidity, measured as the amount of unrestricted cash and cash equivalents we have on hand and availability under the revolving credit facility, of (i) $100.0 million for the period between October 1, 2009 through December 31, 2010, (ii) $75.0 million during calendar year 2011 and (iii) $50.0 million thereafter. As of December 31, 2010, as calculated pursuant to our Credit Agreement, our total liquidity was $300.2 million.

Revise the consolidated fixed charge coverage ratio definition and reduce the minimum fixed charge coverage ratio that we must maintain 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, 2010, our fixed charge coverage ratio was 1.66 to 1.00.

Require mandatory prepayments of debt outstanding under the Credit Agreement with 100% of excess cash flow as defined in the Credit Agreement for the fiscal year ending December 31, 2009 and 50% of excess cash flow as defined in the Credit Agreement for the fiscal years ending December 31, 2010, 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.

March 2011 Credit Amendment

On March 3, 2011, we amended our Credit Agreement (2011 Credit Amendment) to, among other things:

Allow for the use of cash to purchase assets from Seahawk Drilling, Inc. (Seahawk), to the extent set forth in our previously disclosed Asset Purchase Agreement with Seahawk;

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 to $50 million from $25 million; and

Revise the covenant threshold levels of the Total Leverage Ratio, as defined in the Credit Agreement, to the following schedule:

Test Date	**Previous Total Leverage Ratio**	**Amended Total Leverage Ratio (if Seahawk Acquisition has been consummated during or prior to the relevant Test Period)**	**Amended Total Leverage Ratio (if Seahawk Acquisition has not been consummated during or prior to the relevant Test Period)**
September 30, 2010	8.00 to 1.00	No Change	No Change
December 31, 2010	7.50 to 1.00	No Change	No Change
March 31, 2011	7.00 to 1.00	No Change	No Change
June 30, 2011	6.75 to 1.00	No Change	No Change
September 30, 2011	6.00 to 1.00	7.50 to 1.00	7.50 to 1.00
December 31, 2011	5.50 to 1.00	7.75 to 1.00	7.75 to 1.00
March 31, 2012	5.25 to 1.00	7.50 to 1.00	7.75 to 1.00
June 30, 2012	5.00 to 1.00	7.25 to 1.00	7.50 to 1.00
September 30, 2012	4.75 to 1.00	6.75 to 1.00	7.00 to 1.00
December 31, 2012	4.50 to 1.00	6.25 to 1.00	6.50 to 1.00
March 31, 2013	4.25 to 1.00	6.00 to 1.00	6.25 to 1.00
June 30, 2013	4.00 to 1.00	5.75 to 1.00	6.00 to 1.00

At December 31, 2010, our total leverage ratio was 5.06 to 1.00.

In addition, the interest rates on borrowings under the Credit Facility will increase to 5.50% plus LIBOR for Eurodollar Loans and 4.50% plus the Alternate Base Rate for ABR Loans, compared to prior rates of 4.00% plus LIBOR for Eurodollar Loans and 3.00% plus the Alternate Base Rate for ABR Loans. The minimum LIBOR of 2.00% for Eurodollar Loans, or a minimum base rate of 3.00% with respect to ABR Loans, which was established with the 2009 Credit Amendment, remains. We also 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 is approximately $2.0 million. Total commitments on the revolving credit facility, which is currently unfunded, will be reduced to

$140.0 million from $175.0 million.

At December 31, 2010, the credit facility consisted of a $475.2 million term loan which matures on July 11, 2013 and a $175.0 million revolving credit facility that matures on July 11, 2012, under which the remaining availability was $163.5 million as $11.5 million in standby letters of credit had been issued under it. As of March 3, 2011, the effective date of the 2011 Credit Amendment, the credit facility consisted of a $475.2 million term loan and a $140.0 million revolving credit facility, which had remaining availability of $129.1 million as $10.9 million in standby letters of credit were outstanding under it. The availability under the revolving credit facility must be used for working capital, capital expenditures and other general corporate purposes and cannot be used to prepay our term loan. Other than the required prepayments as outlined previously, the principal amount of the term loan amortizes in equal quarterly installments of approximately $1.2 million, with the balance due on July 11, 2013. 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 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, 2010, $475.2 million was outstanding on the term loan facility and the interest rate was 6.00%. The annualized effective interest rate was 8.29% for the year ended December 31, 2010 after giving consideration to revolver fees and derivative activity.

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.

In July 2007, we entered into a zero cost LIBOR collar on $300.0 million of term loan principal with a final settlement date of October 1, 2010 (which was settled on October 1, 2010 per the agreement with a cash payment of $3.4 million) with a ceiling of 5.75% and a floor of 4.99%. The counterparty was obligated to pay us in any quarter that actual LIBOR reset above 5.75% and we paid the counterparty in any quarter that actual LIBOR reset below 4.99%. The terms and settlement dates of the collar matched those of the term loan through July 27, 2009, the date of the 2009 Credit Amendment.

As a result of the inclusion of a LIBOR floor in the Credit Agreement, we determined, as of July 27, 2009 and on an ongoing basis, that the interest rate collar (which was settled on October 1, 2010) will not be highly effective in achieving offsetting changes in cash flows attributable to the hedged interest rate risk during the period that the hedge was designated. As such, we discontinued cash flow hedge accounting for the interest rate collar as of July 27, 2009. Because cash flow hedge accounting was not applied to this instrument, changes in fair value related to the interest rate collar subsequent to July 27, 2009 have been recorded in earnings. As a result of discontinuing the cash flow hedging relationship, 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 as Interest Expense in our Consolidated Statements of Operations for the years ended December 31, 2010 and 2009, respectively. We did not recognize a gain or loss due to hedge ineffectiveness in the Consolidated Statements of Operations for the year ended December 31, 2008 related to interest rate derivative instruments. The change in the fair value of our hedging instruments resulted in a decrease in derivative liabilities of $10.3 million during the year ended December 31, 2010. We had net unrealized gains on hedge transactions of $5.8 million, net of tax of $3.1 million and $9.2 million, net of tax of $4.9 million for the years ended December 31, 2010 and 2009, respectively, and net unrealized losses on hedge transactions of $6.8 million, net of tax of $3.7 million for the year ended December 31, 2008. Overall, our interest expense was increased by $9.1 million, $18.3 and $7.7 million during the years ended December 31, 2010, 2009 and 2008, respectively, as a result of our interest rate derivative instruments.

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, which commenced on April 15, 2010, 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, 2010, $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

$292.9 million at December 31, 2010.

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.

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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, 2010, $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 $86.5 million at December 31, 2010.

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, 2010, 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 December 2008 and April 2009, we repurchased $88.2 million and $20.0 million aggregate principal amount of the 3.375% Convertible Senior Notes, respectively, for a cost of $44.8 million and $6.1 million, respectively. In addition, during December 2008 and April 2009 we recognized a gain of $28.4 million and $10.7 million, respectively and expensed $2.1 million and $0.4 million of unamortized issuance costs, respectively, in connection with the retirements. 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, 2010		December 31, 2009	
	Carrying	**Fair**	**Carrying**	**Fair**

	Value	Value	Value	Value
		(In millions)		
Term Loan Facility, due July 2013	$ 475.2	$ 443.7	$ 482.9	$ 468.4
10.5% Senior Secured Notes, due October 2017	292.9	245.1	292.3	315.8
3.375% Convertible Senior Notes, due June 2038	86.5	69.1	83.1	76.8
7.375% Senior Notes, due April 2018	3.5	2.2	3.5	3.0

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In April 2010, 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 $2.1 billion. 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 $100.0 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 $50 million primary covering liability 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 as well as a separate underlying marine package for our Delta Towing business.

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. 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.

In 2010, in connection with the renewal of certain of our insurance policies, we entered into agreements to finance a portion of our annual insurance premiums. Approximately $25.9 million was financed through these arrangements, and $6.0 million was outstanding at December 31, 2010. The interest rate on the $24.1 million note is 3.79% and the note is scheduled to mature in March 2011. The interest rate on the $1.8 million note is 3.54% and the note is scheduled to mature in July 2011. There was $5.5 million outstanding in insurance notes payable at December 31, 2009 which were fully paid during 2010.

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.

Common Stock Offering

In September 2009, we raised approximately $82.3 million in net proceeds from an underwritten public offering of 17,500,000 shares of our Common Stock. In addition, in October 2009, we sold an additional 1,313,590 shares of our Common Stock pursuant to the partial exercise of the underwriters over-allotment option and raised an additional $6.3 million in net proceeds. We used a portion of the net proceeds from these sales of Common Stock to repay a portion of our outstanding indebtedness under our term loan facility.

Capital Expenditures

We expect to spend approximately $60 million on capital expenditures and drydocking during 2011. Planned capital expenditures are generally maintenance and regulatory in nature and do not include refurbishment or upgrades to our rigs, liftboats, and other marine vessels. Should we elect to reactivate cold stacked rigs or upgrade and refurbish 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 acquisition), 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 the ongoing capital expenditures for our company 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, 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, 2010:

Contractual Obligations and Contingent Commitments	Payments due by Period Less than 1 Year	1-3 Years	4-5 Years	After 5 Years	Total
			(In thousands)		
Recorded Obligations:					
Long-term debt obligations	$ 4,924	$ 566,155	$	$ 303,508	$ 874,587
Insurance notes payable	5,984				5,984
Interest on debt and notes payable(c)	6,974				6,974
Purchase obligations(a)	5,388				5,388
Other	2,756				2,756
Unrecorded Obligations(b):					
Interest on debt and notes payable(c)	59,012	111,945	63,518	63,647	298,122
Bank guarantees	966				966
Letters of credit	11,568				11,568
Surety bonds	31,414				31,414
Management compensation obligations	3,538	6,808			10,346
Purchase obligations(a)	1,945				1,945
Operating lease obligations	4,174	4,503	4,120	4,266	17,063
Total contractual obligations	$ 138,643	$ 689,411	$ 67,638	$ 371,421	$ 1,267,113

(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 $6.4 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 $475.2 million outstanding under our Term Loan Facility as of December 31, 2010 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. In March 2011, we amended our credit agreement for our Term Loan Facility and Revolving Credit Facility. The portion of the estimated unrecorded interest for our Term Loan Facility in the previous table does not incorporate any changes related to the March 2011 amendment. The total estimated additional interest would be approximately $16.5 million over the remaining life of the debt based on 3 month LIBOR reset quarterly and extrapolated from the forward curve as of March 3, 2011.

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, 2010, we had $44.0 million of bank guarantees, letters of credit and surety bonds outstanding, consisting of a $1.0 million unsecured bank guarantee, a $0.1 million unsecured outstanding letter of credit, $11.5 million in standby letters of credit outstanding under our revolver and $31.4 million outstanding in surety bonds that guarantee our performance as it relates to our drilling contracts and other obligations primarily in Mexico and the U.S. If the beneficiaries called the bank guarantee, 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, 2010 we have restricted cash of $11.1 million to support surety bonds primarily related to the Company s Mexico and U.S. operations.

Accounting Pronouncements

In January 2010, the FASB issued Accounting Standards Update (ASU) No. 2010-06, *Improving Disclosures about Fair Value Measurements* (ASU 2010-06), which requires additional disclosures about the various classes of assets and liabilities measured at fair value, the valuation techniques and inputs used, the activity in Level 3 fair value measurements and the transfers between Levels 1, 2, and 3. The disclosures are effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the roll forward of activity in Level 3 fair value measurements, which are effective for interim and annual reporting periods beginning after December 15, 2010. We adopted the required portions of ASU 2010-06 as of January 1, 2010 with no material impact to our consolidated financial statements and will adopt the remaining portions on January 1, 2011 with no expected material impact on 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 long-term international contracts, or enter into new contracts, at current dayrates 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 cost cutting measures and plans to dispose of certain assets;

expected completion times for our refurbishment and upgrade projects;

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- 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, 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;
- 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 in view of recent reductions in our personnel;

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 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. As of December 31, 2010, we have no derivative financial instruments outstanding. 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, 2010, 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, $86.5 million, and $292.9 million, respectively.

As of December 31, 2010 the interest rate for the $475.2 million outstanding under the term loan was 6.0%. If the interest rate averages 1% more for 2011 than the rates as of December 31, 2010, annual interest expense would increase by approximately $4.8 million. This sensitivity analysis assumes there are no changes in our financial structure and excludes the impact of our interest rate derivatives, if any.

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, 2010		December 31, 2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Term Loan Facility, due July 2013	$ 475.2	$ 443.7	$ 482.9	$ 468.4
10.5% Senior Secured Notes, due October 2017	292.9	245.1	292.3	315.8
3.375% Convertible Senior Notes, due June 2038	86.5	69.1	83.1	76.8
7.375% Senior Notes, due April 2018	3.5	2.2	3.5	3.0

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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, 2010 and 2009, and the related consolidated statements of operations, stockholders equity, comprehensive loss and cash flows for each of the three years in the period ended December 31, 2010. 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, 2010 and 2009, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, 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.

As discussed in Note 1 to the consolidated financial statements, on January 1, 2009, the Company adopted Financial Accounting Standards Board (FASB) Staff Position No. APB 14-1, Accounting for Convertible Debt Instruments that May Be Settled in Cash upon Conversion (Including Partial Cash Settlement) (codified in FASB ASC Topic 470 Debt) and, as required, the consolidated financial statements have been adjusted for retrospective application.

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, 2010, 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 9, 2011 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 9, 2011

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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, 2010, 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, 2010, 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, 2010 and 2009, and the related consolidated statements of operations, stockholders equity, comprehensive loss and cash flows for each of the three years in the period ended December 31, 2010 of Hercules Offshore, Inc. and subsidiaries, and our report dated March 9, 2011, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas

March 9, 2011

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2010	December 31, 2009
	(In thousands, except par value)	
ASSETS		
Current Assets:		
Cash and Cash Equivalents	$ 136,666	$ 140,828
Restricted Cash	11,128	3,658
Accounts Receivable, Net of Allowance for Doubtful Accounts of $29,798 and $38,522 as of December 31, 2010 and 2009, respectively	143,796	133,662
Prepaids	17,142	13,706
Current Deferred Tax Asset	8,488	22,885
Other	11,794	6,675
	329,014	321,414
Property and Equipment, Net	1,634,542	1,923,603
Other Assets, Net	31,753	32,459
	$ 1,995,309	$ 2,277,476
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Short-term Debt and Current Portion of Long-term Debt	$ 4,924	$ 4,952
Insurance Notes Payable	5,984	5,484
Accounts Payable	52,279	51,868
Accrued Liabilities	59,861	67,773
Interest Payable	6,974	6,624
Taxes Payable		5,671
Other Current Liabilities	16,716	34,229
	146,738	176,601
Long-term Debt, Net of Current Portion	853,166	856,755
Other Liabilities	6,716	19,809
Deferred Income Taxes	135,557	245,799
Commitments and Contingencies		
Stockholders Equity:		
Common Stock, $0.01 Par Value; 200,000 Shares Authorized; 116,336 and 116,154 Shares Issued, Respectively; 114,784 and 114,650 Shares Outstanding, Respectively	1,163	1,162
Capital in Excess of Par Value	1,924,659	1,921,037
Treasury Stock, at Cost, 1,552 Shares and 1,504 Shares, Respectively	(50,333)	(50,151)
Accumulated Other Comprehensive Loss		(5,773)

Retained Deficit	(1,022,357)	(887,763)
	853,132	978,512
	$ 1,995,309	$ 2,277,476

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

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2010	2009	2008
	(In thousands, except per share data)		
Revenue	$ 657,480	$ 742,851	$ 1,111,807
Costs and Expenses:			
Operating Expenses	428,930	514,136	631,711
Impairment of Goodwill			950,287
Impairment of Property and Equipment	125,136	26,882	376,668
Depreciation and Amortization	191,183	201,421	192,894
General and Administrative	57,391	92,558	81,160
	802,640	834,997	2,232,720
Operating Loss	(145,160)	(92,146)	(1,120,913)
Other Income (Expense):			
Interest Expense	(82,941)	(77,986)	(63,778)
Expense of Credit Agreement Fees		(15,073)	
Gain on Early Retirement of Debt, Net		12,157	26,345
Other, Net	3,885	3,967	3,315
Loss Before Income Taxes	(224,216)	(169,081)	(1,155,031)
Income Tax Benefit	89,622	78,932	73,161
Loss from Continuing Operations	(134,594)	(90,149)	(1,081,870)
Loss from Discontinued Operation, Net of Taxes		(1,585)	(1,520)
Net Loss	$ (134,594)	$ (91,734)	$ (1,083,390)
Basic Loss Per Share:			
Loss from Continuing Operations	$ (1.17)	$ (0.93)	$ (12.25)
Loss from Discontinued Operation		(0.01)	(0.01)
Net Loss	$ (1.17)	$ (0.94)	$ (12.26)
Diluted Loss Per Share:			
Loss from Continuing Operations	$ (1.17)	$ (0.93)	$ (12.25)
Loss from Discontinued Operation		(0.01)	(0.01)
Net Loss	$ (1.17)	$ (0.94)	$ (12.26)
Weighted Average Shares Outstanding:			
Basic	114,753	97,114	88,351

Diluted	114,753	97,114	88,351

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

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

	December 31, 2010		December 31, 2009		December 31, 2008	
	Shares	Amount	Shares	Amount	Shares	Amount
			(In thousands)			
Common Stock:						
Balance at Beginning of Period	116,154	$ 1,162	89,459	$ 895	88,876	$ 889
Exercise of Stock Options	11				478	5
Issuance of Common Stock, Net			26,569	266		
Issuance of Restricted Stock	171	1	126	1	105	1
Balance at End of Period	116,336	1,163	116,154	1,162	89,459	895
Capital in Excess of Par Value:						
Balance at Beginning of Period		1,921,037		1,785,462		1,731,882
Exercise of Stock Options		18				5,122
Issuance of Common Stock, Net				122,762		
Issuance of Restricted Stock		(1)		(1)		(1)
Compensation Expense Recognized		4,431		8,257		12,535
Adjustment due to Convertible Debt Accounting Change (See Note 1)						30,070
Excess Tax Benefit (Deficit) From Stock-Based Arrangements, Net		(826)		4,571		5,860
Other				(14)		(6)
Balance at End of Period		1,924,659		1,921,037		1,785,462
Treasury Stock:						
Balance at Beginning of Period	(1,504)	(50,151)	(1,483)	(50,081)	(19)	(582)
Repurchase of Common Stock	(48)	(182)	(21)	(70)	(1,464)	(49,499)

Balance at End of Period	(1,552)	(50,333)	(1,504)	(50,151)	(1,483)	(50,081)
Accumulated Other Comprehensive Loss:						
Balance at Beginning of Period		(5,773)		(14,932)		(8,117)
Change in Unrealized Gain (Loss) on Hedge Transactions, Net of Tax of $(3,108), $(4,932) and $3,669, Respectively		5,773		9,159		(6,815)
Balance at End of Period, Net of Tax of $0, $3,108 and $8,040, Respectively				(5,773)		(14,932)
Retained Deficit:						
Balance at Beginning of Period		(887,763)		(796,029)		287,361
Net Loss		(134,594)		(91,734)		(1,083,390)
Balance at End of Period		(1,022,357)		(887,763)		(796,029)
Total Stockholders Equity	114,784	$ 853,132	114,650	$ 978,512	87,976	$ 925,315

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

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

	Year Ended December 31,		
	2010	2009	2008
	(In thousands)		
Net Loss	$ (134,594)	$ (91,734)	$ (1,083,390)
Other Comprehensive Income (Loss):			
Changes Related to Hedge Transactions	5,773	9,159	(6,815)
Comprehensive Loss	$ (128,821)	$ (82,575)	$ (1,090,205)

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

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2010	2009	2008
		(In thousands)	
Cash Flows from Operating Activities:			
Net Loss	$ (134,594)	$ (91,734)	$ (1,083,390)
Adjustments to Reconcile Net Loss to Net Cash Provided by Operating Activities:			
Depreciation and Amortization	191,183	201,421	192,918
Stock-Based Compensation Expense	4,431	8,257	12,535
Deferred Income Taxes	(98,468)	(89,295)	(118,685)
Provision for Doubtful Accounts Receivable	182	32,912	6,167
Amortization of Original Issue Discount	4,078	4,120	4,292
Amortization of Deferred Financing Fees	3,302	3,594	4,036
Non-Cash Loss on Derivatives		1,429	
Gain on Insurance Settlement		(8,700)	
Gain on Disposal of Assets	(14,345)	(970)	(3,029)
Expense of Credit Agreement Fees		15,073	
Gain on Early Retirement of Debt, Net		(12,157)	(26,345)
Impairment of Goodwill			950,287
Impairment of Property and Equipment	125,136	26,882	376,668
Excess Tax Benefit from Stock-Based Arrangements	(401)	(5,629)	(6,081)
(Increase) Decrease in Operating Assets -			
Accounts Receivable	(10,316)	126,515	(78,510)
Prepaid Expenses and Other	22,193	39,487	52,795
Increase (Decrease) in Operating Liabilities -			
Accounts Payable	411	(37,256)	(5,482)
Insurance Notes Payable	(25,438)	(28,966)	(45,173)
Other Current Liabilities	(28,994)	(35,281)	17,125
Other Liabilities	(13,940)	(11,841)	19,599
Net Cash Provided by Operating Activities	24,420	137,861	269,727
Cash Flows from Investing Activities:			
Acquisition of Assets			(320,839)
Additions of Property and Equipment	(22,018)	(76,141)	(264,245)
Deferred Drydocking Expenditures	(15,040)	(15,646)	(17,269)
Proceeds from Sale of Marketable Securities			39,300
Insurance Proceeds Received		9,168	30,221
Proceeds from Sale of Assets, Net	23,222	25,767	17,045
Increase in Restricted Cash	(7,470)	(3,658)	
Net Cash Used in Investing Activities	(21,306)	(60,510)	(515,787)
Cash Flows from Financing Activities:			
Short-term Debt Borrowings (Repayments), Net		(2,455)	2,455

Long-term Debt Borrowings		292,149	350,000
Long-term Debt Repayments	(7,695)	(403,648)	(121,427)
Redemption of 3.375% Convertible Senior Notes		(6,099)	(44,848)
Common Stock Issuance (Repurchase)		89,600	(49,228)
Excess Tax Benefit from Stock-Based Arrangements	401	5,629	6,081
Payment of Debt Issuance Costs		(18,143)	(8,097)
Other	18	(11)	5,127
Net Cash Provided by (Used in) Financing Activities	(7,276)	(42,978)	140,063
Net Increase (Decrease) in Cash and Cash Equivalents	(4,162)	34,373	(105,997)
Cash and Cash Equivalents at Beginning of Period	140,828	106,455	212,452
Cash and Cash Equivalents at End of Period	$ 136,666	$ 140,828	$ 106,455

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

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Nature of Business and Significant Accounting Policies

Organization

Hercules Offshore, Inc., a Delaware corporation, and its majority owned subsidiaries (the Company) provide shallow-water drilling and marine services to the oil and natural gas exploration and production industry globally through its Domestic Offshore, International Offshore, Inland, Domestic Liftboats, International Liftboats and Delta Towing segments (See Note 17). At December 31, 2010, the Company owned a fleet of 30 jackup rigs, 17 barge rigs, three submersible rigs, one platform rig, a fleet of marine support vessels operated through Delta Towing, a wholly owned subsidiary, and 60 liftboat vessels and operated an additional five liftboat vessels owned by a third party. In addition, the Company currently owns two retired jackup rigs, *Hercules 190* and *Hercules 254*, both located in the U.S. Gulf of Mexico, for which the Company has an agreement to sell and expects to close in the first quarter of 2011 (See Notes 5 and 17). The Company s 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.

In December 2009, the Company entered into an agreement with First Energy Bank B.S.C. (MENAdrill) whereby it would market, manage and operate two Friede & Goldman Super M2 design new-build jackup drilling rigs, *Hull 109* and *Hull 110* (also known as *MENAdrill Hercules 1* and *2*, respectively), each with a maximum water depth of 300 feet. The Company received a notice of termination from MENAdrill with respect to *Hull 109* in December 2010, and MENAdrill paid the Company a termination fee of $250,000 due under the contract on the date of termination. It is the Company s understanding that *Hull 110* has independently secured a contract in Mexico and the Company therefore, expects to receive an additional termination fee of $250,000.

Adjustment for Retrospective Application of FSP APB 14-1, Primarily Codified into Financial Accounting Standards Board s (FASB) Codification Topic 470-20, Debt Debt with Conversion and Other Options

The Company has adjusted the financial statements as of and for the year ended December 31, 2008 to reflect its adoption of the FASB Codification Topic 470-20, *Debt Debt with Conversion and Other Options*, which clarifies the accounting for convertible debt instruments that may be settled in cash (including partial cash settlement) upon conversion. It requires issuers to account separately for the liability and equity components of certain convertible debt instruments in a manner that reflects the issuer s nonconvertible debt (unsecured debt) borrowing rate when interest cost is recognized. It also requires bifurcation of a component of the debt, classification of that component in equity and the accretion of the resulting discount on the debt to be recognized as part of interest expense in the Company s consolidated statement of operations. The standard became effective as of January 1, 2009 and it required retrospective application to the terms of instruments as they existed for all periods presented. This adoption affects the accounting for the Company s 3.375 percent Convertible Senior Notes due 2038 issued in 2008 (3.375% Convertible Senior Notes).

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. All intercompany account balances and transactions have been eliminated.

Common Stock Offering

In September 2009, the Company raised approximately $82.3 million in net proceeds from an underwritten public offering of 17,500,000 shares of its common stock. In addition, in October 2009, the Company sold an additional 1,313,590 shares of its common stock pursuant to the partial exercise of the underwriters over-allotment option and raised an additional $6.3 million in net proceeds. The Company used a portion of the net

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

proceeds from these sales of common stock to repay a portion of its outstanding indebtedness under its term loan facility.

Reclassifications

Certain reclassifications have been made to conform prior year financial information to the current period presentation.

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.

Restricted Cash

At December 31, 2010 and 2009, the Company had restricted cash of $11.1 million and $3.7 million, respectively, to support surety bonds primarily related to the Company s Mexico and U.S. operations.

Revenue Recognition

Revenue generated from the Company s contracts is recognized as services are performed, as long as collectability is reasonably assured. For certain contracts, the Company may receive lump-sum fees for the mobilization of equipment and personnel. Mobilization fees received and costs incurred to mobilize a rig from one market to another under contracts longer than ninety days are recognized as services are performed over the term of the related drilling contract. Amounts related to mobilization fees are summarized below (in thousands):

	Year Ended December 31,		
	2010	2009	2008
Mobilization revenue deferred	$ 600	$ 12,180	$ 33,727
Mobilization expense deferred		3,468	7,490
Mobilization revenue recognized	15,343	16,491	11,860
Mobilization expense recognized(a)	1,979	6,514	5,550

(a) Includes a $2.6 million write-off of deferred mobilization costs in 2009 due to an impairment related to an international contract.

For certain contracts, the Company may receive fees from its customers for capital improvements to its rigs. Such fees are deferred and recognized as services are performed over the term of the related contract. The Company capitalizes such capital improvements and depreciates them over the useful life of the asset.

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The balances related to the Company s Deferred Mobilization and Contract Preparation Costs and Deferred Mobilization Revenue are as follows (in thousands):

	Balance Sheet Classification	As of December 31, 2010	2009
Assets:			
Deferred Operating Expenses-Current Portion	Other	$ 1,824	$ 1,092
Deferred Operating Expenses-Non-Current Portion	Other Assets, Net	3,172	1,651
Liabilities:			
Deferred Revenue-Current Portion	Other Current Liabilities	12,628	19,406
Deferred Revenue-Non-Current Portion	Other Liabilities		12,628

Stock-Based Compensation

The Company recognizes compensation cost for all share-based payments awarded in accordance with FASB Codification Topic 718, *Compensation Stock Compensation* and in accordance with such records the grant date fair value of share-based payments awarded as compensation expense using a straight-line method over the service period. The fair value of the Company s restricted stock grants is based on the closing price of our common stock on the date of grant. The Company s 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. The Company estimates 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 Company also estimates future forfeitures and related tax effects.

The Company estimates the cost relating to stock options granted through December 31, 2010 will be $2.6 million over the remaining vesting period of 1.4 years and the cost relating to restricted stock granted through December 31, 2010 will be $2.3 million over the remaining vesting period of 1.2 years; however, due to the uncertainty of the level of share-based payments to be granted in the future, these amounts are estimates and subject to change.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are stated at the historical carrying amount net of write-offs and allowance for doubtful accounts. Management of the Company monitors the accounts receivable from its customers for 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. The Company had an allowance of $29.8 million and $38.5 million at December 31, 2010 and 2009, respectively.

Prepaid Expenses

Prepaid expenses consist of prepaid insurance, prepaid income tax and other prepayments. At December 31, 2010 and 2009, prepaid insurance totaled $12.4 million and $11.7 million, respectively. At December 31, 2010, prepaid taxes totaled $2.4 million. There were no prepaid taxes at December 31, 2009.

Property and Equipment

Property and equipment are stated at cost, less accumulated depreciation. Expenditures for property and equipment and items that substantially increase the useful lives of existing assets are capitalized at cost and depreciated. Expenditures for drydocking the Company s liftboats are capitalized at cost in Other Assets, Net

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

on the Consolidated Balance Sheets and amortized on the straight-line method over a period of 12 months. Routine expenditures for repairs and maintenance are expensed as incurred.

Depreciation is computed using the straight-line method, after allowing for salvage value where applicable, over the useful lives of the assets. Depreciation of leasehold improvements is computed utilizing the straight-line method over the lease term or life of the asset, whichever is shorter.

The useful lives of property and equipment for the purposes of computing depreciation are as follows:

	Years
Drilling rigs and marine equipment (salvage value of 10%)	15
Drilling machinery and equipment	3 12
Furniture and fixtures	3
Computer equipment	3 7
Automobiles and trucks	3

The carrying value of long-lived assets, principally property and equipment and excluding goodwill, is reviewed for potential impairment when events or changes in circumstances indicate that the carrying amount of such assets 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 upon the estimated undiscounted future net cash flows of the related asset or group of assets being evaluated. Actual impairment charges are recorded using an estimate of discounted future cash flows. This evaluation requires the Company 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 the Company s 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 the Company s ability to contract its rigs and vessels at economical rates. During periods of an oversupply, it is not uncommon for the Company to have rigs or vessels idled for extended periods of time, which could indicate that an asset group may be impaired. The Company s rigs and vessels are mobile units, equipped to operate in geographic regions throughout the world and, consequently, the Company 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, the Company s rigs and vessels are considered to be interchangeable within classes or asset groups and accordingly, the Company performs its impairment evaluation by asset group.

The Company s estimates, assumptions and judgments used in the application of its 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 the Company s 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 the Company s 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. The Company evaluates

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the remaining useful lives of its rigs and vessels when certain events occur that directly impact its assessment of the remaining useful lives of the rigs and vessels and include changes in operating condition, functional capability and market and economic factors. The Company also considers 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 its assets for impairment, the Company separates its 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 its non-marketable assets, those assets that have been cold stacked for an extended period of time or those assets that the Company currently does not reasonably expect to market in the foreseeable future.

During the fourth quarter 2008, demand for the Company s domestic drilling assets declined dramatically, significantly beyond expectations. Demand in these segments is driven by underlying commodity prices which fell to levels lower than those seen in several years. The deterioration in these industry conditions in the fourth quarter of 2008 negatively impacted the Company s outlook for 2009 and the Company responded by cold stacking several additional rigs. The Company considered these factors and its change in outlook as an indicator of impairment and assessed the rig assets of the Inland and Domestic Offshore segments for impairment. Based on an undiscounted cash flow analysis, it was determined that the non-marketable rigs for both segments were impaired. The Company estimated the value of the discounted cash flows for each segment s non-marketable rigs and recorded an impairment charge of $376.7 million for the year ended December 31, 2008. In addition, the Company analyzed its other segments for impairment as of December 31, 2008 and noted that each segment had adequate undiscounted cash flows to recover its property and equipment carrying values.

In 2009 the Company entered into an agreement to sell *Hercules 110* and realized approximately $26.9 million of impairment charges related to the write-down of the rig to fair value less costs to sell during the second quarter 2009 (See Notes 5 and 12). The sale was completed in August 2009.

During the fourth quarter 2010, the Company considered the continued downturn in the drilling industry as an indicator of impairment and assessed its segments for impairment as of December 31, 2010. When analyzing its Domestic Offshore, International Offshore and Delta segments for impairment, the Company determined five of its domestic jackup rigs, one of its international jackup rigs and several of its 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 the Company s current estimate of reactivation costs associated with these assets which, based on current and forecasted near-term dayrates and utilization levels, are economically prohibitive, and the sustained lack of visibility in the issuance of offshore drilling permits in the U.S. Gulf of Mexico. Based on an undiscounted cash flow analysis, it was determined that the non-marketable assets were impaired. The Company 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. The Company analyzed its other segments and its 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.

Goodwill

Goodwill represents the excess of the cost of business acquired over the fair value of the net assets acquired at the date of acquisition. These assets are not amortized but rather tested for impairment at least annually by applying a fair-value based test. The Company determined its reporting units to be the same as its operating segments. The Company performed a preliminary annual impairment assessment as of October 1, 2008. However, during the fourth quarter of 2008, the Company s market capitalization continued to decline

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

significantly, therefore, the Company completed its analysis as of December 31, 2008. As of December 31, 2008, the Company s market capitalization was significantly below its book value. The Company compared the fair value of each reporting unit to its carrying value and determined that each reporting unit was impaired. Upon completion of step two of the impairment test, the Company recorded a goodwill impairment of $950.3 million, which represented all of the Company s goodwill as of December 31, 2008 (See Note 17).

Other Assets

Other assets consist of drydocking costs for marine vessels, other intangible assets, deferred operating expenses, financing fees, investments and deposits. Drydock costs are capitalized at cost and amortized on the straight-line method over a period of 12 months. Drydocking costs, net of accumulated amortization, at December 31, 2010 and 2009 were $5.9 million and $4.9 million, respectively. Amortization expense for drydocking costs was $14.0 million, $17.2 million and $19.0 million for the years ended December 31, 2010, 2009 and 2008, respectively.

Financing fees are deferred and amortized over the life of the applicable debt instrument. However, in the event of an early repayment of debt or certain debt amendments, the related unamortized deferred financing fees are expensed in connection with the repayment or amendment (See Note 10). Unamortized deferred financing fees at December 31, 2010 and 2009 were $11.4 million and $14.7 million, respectively. Amortization expense for financing fees was $3.3 million, $3.6 million and $4.0 million for the years ended December 31, 2010, 2009 and 2008, respectively, and is included in Interest Expense on the Consolidated Statements of Operations.

Income Taxes

We use the liability method for determining our income taxes. The Company s income tax provision is based upon the tax laws and rates in effect in the countries in which the Company s operations are conducted and income is earned. The income tax rates imposed and methods of computing taxable income in these jurisdictions vary substantially. The Company s effective tax rate is expected to fluctuate from year to year as operations are conducted in different taxing jurisdictions and the amount of pre-tax income fluctuates. Current income tax expense reflects an estimate of the Company s income tax liability for the current year, withholding taxes, changes in prior year tax estimates as returns are filed, or from tax audit adjustments, while the net deferred tax expense or benefit represents the changes in the balance of deferred tax assets and liabilities as reported on the balance sheet.

Valuation allowances are established to reduce deferred tax assets when it is more likely than not that some portion or all of the deferred tax assets will not be realized in the future. The Company currently does not have any valuation allowances related to the tax assets. While the Company has considered estimated future taxable income and ongoing prudent and feasible tax planning strategies in assessing the need for the valuation allowances, changes in these estimates and assumptions, as well as changes in tax laws, could require the Company to adjust the valuation allowances for deferred tax assets. These adjustments to the valuation allowance would impact the Company s income tax provision in the period in which such adjustments are identified and recorded.

Certain of the Company s international rigs and liftboats are owned or operated, directly or indirectly, by the Company s wholly owned Cayman Islands subsidiaries. Most of the earnings from these subsidiaries are reinvested internationally and remittance to the United States is indefinitely postponed. In certain circumstances, management expects that, due to the changing demands of the offshore drilling and liftboat markets and the ability to redeploy the Company s offshore units, certain of such units will not reside in a location long enough to give rise to future tax consequences in that location. As a result, no deferred tax asset or liability has been recognized in these circumstances. Should management s expectations change regarding the

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

length of time an offshore drilling unit will be used in a given location, the Company would adjust deferred taxes accordingly.

Use of Estimates

In preparing financial statements in conformity with accounting principles generally accepted in the United States, management makes estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements, as well as the reported amounts of revenue and expenses during the reporting period. On an ongoing basis, the Company evaluates its estimates, including those related to bad debts, investments, intangible assets, property and equipment, income taxes, insurance, employment benefits and contingent liabilities. The Company bases its 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.

Fair Value of Financial Instruments

The carrying amounts of the Company s financial instruments, which include cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities, approximate fair values because of the short-term nature of the instruments.

The fair value of the Company s 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 the Company s 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, 2010		December 31, 2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Term Loan Facility, due July 2013	$ 475.2	$ 443.7	$ 482.9	$ 468.4
10.5% Senior Secured Notes, due October 2017	292.9	245.1	292.3	315.8
3.375% Convertible Senior Notes, due June 2038	86.5	69.1	83.1	76.8
7.375% Senior Notes, due April 2018	3.5	2.2	3.5	3.0

Accounting Pronouncements

In January 2010, the FASB issued Accounting Standards Update (ASU) No. 2010-06, *Improving Disclosures about Fair Value Measurements* (ASU 2010-06), which requires additional disclosures about the various classes of assets and liabilities measured at fair value, the valuation techniques and inputs used, the activity in Level 3 fair value measurements and the transfers between Levels 1, 2, and 3. The disclosures are effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the roll forward of activity in Level 3 fair value measurements, which are effective for interim and annual reporting periods beginning after December 15, 2010. The Company adopted the required portions of ASU 2010-06 as of January 1, 2010 with no material impact to its consolidated financial statements and will adopt the remaining portions on January 1, 2011 with no expected material impact on its consolidated financial statements (See Note 12).

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Property and Equipment, Net

The following is a summary of property and equipment, at cost, less accumulated depreciation (in thousands):

	December 31,	
	2010	2009
Drilling rigs and marine equipment	$ 2,048,243	$ 2,224,799
Drilling machinery and equipment	74,762	80,185
Leasehold improvements	10,555	11,209
Automobiles and trucks	2,614	2,540
Computer equipment	13,943	17,787
Furniture and fixtures	990	1,553
Total property and equipment, at cost	2,151,107	2,338,073
Less accumulated depreciation	(516,565)	(414,470)
Total property and equipment, net	$ 1,634,542	$ 1,923,603

Depreciation expense was $175.6 million, $179.2 million and $166.3 million for the years ended December 31, 2010, 2009 and 2008, respectively. Additionally, the decrease in drilling rigs and marine equipment relates primarily to the impairment of property and equipment in 2010 (See Notes 1 and 12).

3. Earnings Per Share

The Company calculates basic earnings per share by dividing net income by the weighted average number of shares outstanding. Diluted earnings per share is computed by dividing net income by the weighted average number of shares outstanding during the period as adjusted for the dilutive effect of the Company s stock option and restricted stock awards. The effect of stock option and restricted stock awards is not included in the computation for periods in which a net loss occurs, because to do so would be anti-dilutive. Stock equivalents of 6,282,625, 4,587,868 and 3,009,099 were anti-dilutive and are excluded from the calculation of the dilutive effect of stock equivalents for the diluted earnings per share calculations for the years ended December 31, 2010, 2009 and 2008, respectively.

4. Asset Acquisitions

In February 2008, the Company entered into a definitive agreement to purchase three jackup drilling rigs and related equipment for $320.0 million. The Company completed the purchase of the *Hercules 350* and the *Hercules 261* and related equipment during March 2008, while the purchase of the *Hercules 262* and related equipment was completed in May 2008.

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Dispositions

From time to time the Company enters into agreements to sell assets. The following table provides information related to the sale of several of the Company s jackup rigs and barges during the years ended December 31, 2010, 2009 and 2008 (in thousands):

	Rig	Segment	Period of Sale	Proceeds	Gain/(Loss)
2010:					
	Various(a)	Inland	March 2010	$ 2,200	$ 1,753
	Various(a)	Inland	April 2010	800	410
	Hercules 191	Domestic Offshore	April 2010	5,000	3,067
	Hercules 255	Domestic Offshore	September 2010	5,000	3,180
	Hercules 155	Domestic Offshore	December 2010	4,800	3,969
				$ 17,800	$ 12,379
2009:					
	Hercules 100	Domestic Offshore	August 2009	$ 2,000	$ 295
	Hercules 110(b)	International Offshore	August 2009	10,000	
	Hercules 20	Inland	September 2009	200	139
	Hercules 21	Inland	November 2009	400	432
				$ 12,600	$ 866
2008:					
	Hercules 256	Domestic Offshore	May 2008	$ 8,500	$

(a) The Company entered into an agreement to sell six of its retired barges for $3.0 million. The sale of 3 barges closed in each of March and April 2010.

(b) The Company realized approximately $26.9 million ($13.1 million, net of tax) of impairment charges related to the write-down of the *Hercules 110* to fair value less costs to sell during the second quarter of 2009 (See Note 12).

In November 2010, the Company entered into an agreement to sell its retired jackups *Hercules 190* and *Hercules 254* for a total of $4.0 million for both jackups, which is expected to close in the first quarter of 2011. The financial information for *Hercules 190* and *Hercules 254* has been reported as part of the Domestic Offshore segment (See Note 17).

6. Discontinued Operation

The Company sold its nine land rigs and related equipment in the fourth quarter of 2007. The results of operations of the land rig operations are reflected in the Consolidated Statements of Operations for the years ended December 31, 2009 and 2008 as a discontinued operation. There was no discontinued operation in the year ended December 31, 2010.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Operating results and wind down costs of the land rigs were as follows (in thousands):

	Year Ended December 31, 2009	2008
Revenue	$ 240	$ 1,818
Loss Before Income Taxes	$ (2,440)	$ (2,341)
Income Tax Benefit	855	821
Loss from Discontinued Operation, Net of Taxes	$ (1,585)	$ (1,520)

7. Long-Term Incentive Awards

Stock-based Compensation

The company recognizes compensation cost for all share-based payments awarded in accordance with FASB Codification Topic 718, *Compensation Stock Compensation* and in accordance with such records the grant date fair value of share-based payments awarded as compensation expense using a straight-line method over the service period. In addition it is required that the excess tax benefit (the amount of the realized tax benefit related to deductible compensation cost in excess of the cumulative compensation cost recognized for financial reporting) be reported as cash flows from financing activities. The Company classified $0.4 million, $5.6 million, and $6.1 million in excess tax benefits as a financing cash inflow for the years ended December 31, 2010, 2009 and 2008, respectively.

The Company s 2004 Long-Term Incentive Plan (the 2004 Plan) provides for the granting of stock options, restricted stock, performance stock awards and other stock-based awards to selected employees and non-employee directors of the Company. At December 31, 2010, approximately 2.4 million shares were available for grant or award under the 2004 Plan. The Compensation Committee of the Company s Board of Directors selects participants from time to time and, subject to the terms and conditions of the 2004 Plan, determines all terms and conditions of awards. Most of the option and restricted stock grants issued are subject to a three year vesting period with some vesting one-third on each anniversary of the grant date and others vesting on the third anniversary of the grant date. The options when granted have a maximum contractual term of 10 years. The Company issues originally issued shares upon exercise of stock options and for restricted stock grants. The fair value of restricted stock grants was calculated based on the average of the high and low trading price of the Company s stock on the day of grant for grants prior to 2008. The fair value of restricted stock grants in 2008 and after was calculated based on the closing price of the Company s stock on the day of grant.

The unrecognized compensation cost related to the Company s unvested stock options and restricted stock grants as of December 31, 2010 was $2.6 million and $2.3 million, respectively, and is expected to be recognized over a weighted-average period of 1.4 years and 1.2 years, respectively.

Cash received from stock option exercises was eighteen thousand dollars and $5.1 million during the years ended December 31, 2010 and 2008, respectively. There were no stock option exercises in 2009.

The Company recognized $4.4 million, $8.3 million and $12.5 million in employee stock-based compensation expense during the years ended December 31, 2010, 2009 and 2008, respectively. The related income tax benefit recognized for the years ended December 31, 2010, 2009 and 2008 was $1.6 million, $2.9 million and $4.4 million, respectively.

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The fair value of the options granted under the 2004 Plan was estimated on the date of grant using the Trinomial Lattice option pricing model with the following assumptions used:

	2010	2009	2008
Dividend yield			
Expected price volatility	45.8%	45.0%	40.8%
Risk-free interest rate	2.7%	2.1%	2.9%
Expected life of options (in years)	6.0	6.0	6.0
Weighted-average fair value of options granted	$ 1.67	$ 0.75	$ 6.35

The Company currently uses the historical volatility of its common stock to estimate volatility and it uses the simplified method to estimate the expected life of the options granted.

The following table summarizes stock option activity under the 2004 Plan as of December 31, 2010 and changes during the year then ended:

Options	Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value (In thousands)
Outstanding at January 1, 2010	4,452,321	$ 11.36	6.58	$ 6,145
Granted	1,375,000	3.75		
Exercised	(11,051)	1.65		
Forfeited	(102,000)	5.29		
Expired	(114,298)	18.21		
Outstanding at December 31, 2010	5,599,972	9.48	6.44	3,393
Vested or Expected to Vest at December 31, 2010	5,410,499	9.16	6.40	3,330
Exercisable at December 31, 2010	2,909,706	14.39	4.51	1,285

The intrinsic value of options exercised during 2010 and 2008 was twenty thousand dollars and $11.7 million, respectively. There were no options exercised in 2009.

The following table summarizes information about restricted stock outstanding as of December 31, 2010 and changes during the year then ended:

Weighted-

	Restricted Stock	Average Grant Date Fair Value
Non-Vested at January 1, 2010	349,077	$ 25.15
Granted	782,532	3.79
Vested	(170,010)	26.01
Forfeited	(58,352)	7.17
Non-Vested at December 31, 2010	903,247	8.03

The weighted-average grant date fair value of restricted stock granted during the years ended 2010, 2009 and 2008 was $3.79, $4.82 and $26.12, respectively. The total fair value of restricted stock vested during the years ended 2010, 2009 and 2008 was $0.7 million, $0.4 million and $2.6 million, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Liability Retention Awards

In December 2010, the Compensation Committee of the Company s Board of Directors approved retention and incentive arrangements for the Company s Chief Executive Officer, consisting of three separate awards.

Vesting under each award is conditioned upon continuous employment with the Company from the date of grant until the earlier of a specified vesting date or a change in control of the Company. Subject to the satisfaction of all vesting requirements, awards are payable in cash based on the product of the number of shares of Common Stock specified in the award, the percentage of that number of shares that vest under the award and the average price of the Common Stock for the 90 days prior to the date of vesting (Average Share Price).

The grant date of each of the three awards is January 1, 2011. Vesting of any award and the amount payable under any vested award do not affect vesting or the amount payable under any of the other awards. Subject to vesting, all awards are payable in cash within thirty days of vesting. No shares of common stock are issuable under any of the awards. These awards will be accounted for under stock-compensation principles of accounting as liability instruments. The fair value of these awards will be remeasured based on the awards estimated fair value at the end of each reporting period and will be recorded to expense over the vesting period.

The first award is a Special Retention Agreement (the Agreement), which provides for a cash payment based on 500,000 shares of the Company s common stock, subject to vesting. Upon satisfaction of vesting requirements, 100% of the amount under the Agreement becomes vested on December 31, 2013 and the payout will equal the product of 500,000 and the lesser of the Average Share Price and $10.00. If all of the requirements necessary for vesting of this award are not met, no amounts become vested and no amount is payable.

The second and third awards are performance awards under the 2004 Plan (Performance Awards). Each Performance Award provides for a cash payment, subject to vesting, based on 250,000 shares of the Company s common stock. Upon satisfaction of vesting requirements, 100% of the first Performance Award will vest on December 31, 2013, and 100% of the second Performance Award will vest on March 31, 2014. Under each Performance Award, vesting is subject to the further requirement that the Average Share Price is at least $5.00. Subject to the satisfaction of the vesting requirements, the payout of each Performance Award shall be equal to the product of (1) 250,000, (2) the Average Share Price or $10.00, whichever is less, divided by $10.00, and (3) the lesser of the Average Share Price or $10.00. If the requirements necessary for vesting of a Performance Award are met, the amount payable in cash under each of the Performance Awards shall be not less than $625,000 and not more than $2,500,000.

8. Accrued Liabilities

Accrued liabilities are comprised of the following (in thousands):

	December 31,	
	2010	2009
Accrued Liabilities:		
Taxes other than Income	$ 15,548	$ 9,435
Accrued Payroll and Employee Benefits	25,068	29,283

Accrued Self-Insurance Claims	19,106	28,768
Other	139	287
	$ 59,861	$ 67,773

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. Benefit Plans

The Company currently has two 401(k) plans in which substantially all U.S. employees are eligible to participate. Under the Hercules plan and Delta Towing plan prior to April 1, 2009, the Company matched participant contributions equal to 100% of the first 6% of a participant s eligible compensation. However, under the Hercules plan, the Company match was reduced to 100% of the first 3% of participant eligible compensation on April 1, 2009 and subsequently eliminated on August 1, 2009. In addition, under the Delta Towing plan, the Company match was reduced to 100% of the first 3% of participant eligible compensation on April 1, 2009 and subsequently eliminated on October 1, 2009. The Company made total matching contributions of $3.4 million and $8.6 million for the years ended December 31, 2009 and 2008, respectively. The Company made no matching contributions in the year ended December 31, 2010.

10. Debt

Debt is comprised of the following (in thousands):

	December 31, 2010	December 31, 2009
Term Loan Facility, due July 2013	$ 475,156	$ 482,852
10.5% Senior Secured Notes, due October 2017	292,935	292,272
3.375% Convertible Senior Notes, due June 2038	86,488	83,071
7.375% Senior Notes, due April 2018	3,511	3,512
Total Debt	858,090	861,707
Less Short-term Debt and Current Portion of Long-term Debt	4,924	4,952
Total Long-term Debt, Net of Current Portion	$ 853,166	$ 856,755

The following is a summary of scheduled long-term debt maturities by year (in thousands):

2011	$ 4,924
2012	4,924
2013	551,796
2014	
2015	
Thereafter	296,446
	$ 858,090

Senior secured Credit Agreement

In connection with the July 2007 acquisition of TODCO, the Company 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 which is governed by the credit agreement (Credit Agreement). The proceeds from the term loan were used, together with cash on hand, to finance the cash portion of the Company s acquisition of TODCO, to repay amounts under TODCO s senior secured credit facility outstanding at the closing of the facility and to make certain other payments in connection with the Company s acquisition of TODCO. In connection with the term loan facility, the Company entered into derivative instruments with the purpose of hedging future interest payments (See Note 11). In April 2008, the Company entered into an agreement to increase the revolving credit facility to $250.0 million and in each of July 2009 and March 2011, the terms of the Credit Agreement were amended.

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The substantial changes to the terms of the Credit Agreement related to the July 2009 and March 2011 amendments are further described:

July 2009 Credit Amendment

On July 27, 2009 the Company amended its Credit Agreement (2009 Credit Amendment) in order to revise its covenants to be more favorable to the Company. A fee of 0.50%, which approximated $4.8 million, was paid to lenders consenting to the 2009 Credit Amendment based on their total commitment. The Company 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. The 2009 Credit Amendment reduced the revolving credit facility by $75.0 million to $175.0 million. The commitment fee on the revolving credit facility increased from 0.375% to 1.00% and the letter of credit fee with respect to the undrawn amount of each letter of credit issued under the revolving credit facility increased from 1.75% to 4.00% per annum. The availability under the $175.0 million revolving credit facility must be used for working capital, capital expenditures and other general corporate purposes and cannot be used to prepay the term loan. Additionally, the 2009 Credit Amendment established a minimum London Interbank Offered Rate (LIBOR) of 2.00% for Eurodollar Loans, a minimum rate of 3.00% with respect to Alternative Base Rate (ABR) Loans, and increased the margin applicable to Eurodollar Loans and ABR Loans, subject to a grid based on the aggregate principal amount of the term loans outstanding as follows ($ in millions):

Principal Amount Outstanding		Margin Applicable to:	
Less than or equal to:	**Greater than:**	**Eurodollar Loans**	**ABR Loans**
$882.00	$ 684.25	6.50%	5.50%
684.25	484.25	5.00%	4.00%
484.25		4.00%	3.00%

The 2009 Credit Amendment also modified certain provisions of the Credit Agreement to, among other things:

Eliminate the requirement that the Company comply with the total leverage ratio financial covenant for the nine month period commencing October 1, 2009 and ending on June 30, 2010.

Amend the maximum total leverage ratio that the Company must comply with. The total leverage ratio for any test period is 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.

Require the Company to 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) $100.0 million for the period between October 1, 2009 through December 31, 2010, (ii) $75.0 million during calendar year 2011 and (iii) $50.0 million thereafter. As of December 31, 2010, as calculated pursuant to the Credit Agreement, the Company s total liquidity was $300.2 million.

Revise the consolidated fixed charge coverage ratio definition and reduce the minimum fixed charge coverage ratio that the Company must maintain 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

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2010, the Company s fixed charge coverage ratio was 1.66 to 1.00.

Require mandatory prepayments of debt outstanding under the Credit Agreement with 100% of excess cash flow as defined in the Credit Agreement for the fiscal year ending December 31, 2009 and 50% of excess cash flow as defined in the Credit Agreement for the fiscal years ending December 31, 2010, 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 the Company has achieved a specified leverage ratio, 50% of proceeds from equity issuances, excluding those for permitted acquisitions or to meet the minimum liquidity requirements.

March 2011 Credit Amendment

On March 3, 2011, the Company amended its Credit Agreement (2011 Credit Amendment) to, among other things:

Allow for the use of cash to purchase assets from Seahawk Drilling, Inc. (Seahawk), to the extent set forth in the Company s previously disclosed Asset Purchase Agreement with Seahawk;

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 the Company s investment basket to $50 million from $25 million; and

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Revise the covenant threshold levels of the Total Leverage Ratio, as defined in the Credit Agreement, to the following schedule:

Test Date	Previous Total Leverage Ratio	Amended Total Leverage Ratio (If Seahawk Acquisition has been consummated during or prior to the relevant Test Period)	Amended Total Leverage Ratio (If Seahawk Acquisition has not been consummated during or prior to the relevant Test Period)
September 30, 2010	8.00 to 1.00	No Change	No Change
December 31, 2010	7.50 to 1.00	No Change	No Change
March 31, 2011	7.00 to 1.00	No Change	No Change
June 30, 2011	6.75 to 1.00	No Change	No Change
September 30, 2011	6.00 to 1.00	7.50 to 1.00	7.50 to 1.00
December 31, 2011	5.50 to 1.00	7.75 to 1.00	7.75 to 1.00
March 31, 2012	5.25 to 1.00	7.50 to 1.00	7.75 to 1.00
June 30, 2012	5.00 to 1.00	7.25 to 1.00	7.50 to 1.00
September 30, 2012	4.75 to 1.00	6.75 to 1.00	7.00 to 1.00
December 31, 2012	4.50 to 1.00	6.25 to 1.00	6.50 to 1.00
March 31, 2013	4.25 to 1.00	6.00 to 1.00	6.25 to 1.00
June 30, 2013	4.00 to 1.00	5.75 to 1.00	6.00 to 1.00

At December 31, 2010, the Company s total leverage ratio was 5.06 to 1.00.

In addition, the interest rates on borrowings under the Credit Facility will increase to 5.50% plus LIBOR for Eurodollar Loans and 4.50% plus the Alternate Base Rate for ABR Loans, compared to prior rates of 4.00% plus LIBOR for Eurodollar Loans and 3.00% plus the Alternate Base Rate for ABR Loans. The minimum LIBOR of 2.00% for Eurodollar Loans, or a minimum base rate of 3.00% with respect to ABR Loans, which was established with the 2009 Credit Amendment, remains. The Company also 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 the Company s total cost is approximately $2.0 million. Total commitments on the revolving credit facility, which is currently unfunded, will be reduced to $140.0 million from $175.0 million.

Other Terms and Conditions

The Company s obligations under the Credit Agreement are secured by liens on a majority of its vessels and substantially all of its other personal property. Substantially all of the Company s domestic subsidiaries, and several of its 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 the Company s Credit Agreement.

The Credit Agreement requires that the Company meet certain financial ratios and tests, which it met as of December 31, 2010. The Company s failure to comply with such covenants would result in an event of default under the Credit Agreement. Additionally, in order to maintain compliance with 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 the

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Company from borrowing under the revolving credit facility, which would in turn have a material adverse effect on the Company s available liquidity. Furthermore, an event of default could result in the Company having to immediately repay all amounts outstanding under the credit facility, the 10.5% Senior Secured Notes and the 3.375% Convertible Senior Notes and in the foreclosure of liens on its assets.

Other than the required prepayments as outlined previously, the principal amount of the term loan amortizes in equal quarterly installments of approximately $1.2 million, with the balance due on July 11, 2013. All borrowings under the revolving credit facility mature on July 11, 2012. 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 its scheduled payments, during the fourth quarter of 2009, the Company 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 the Company s term loan facility. In connection with the early retirement, the Company recorded a pretax charge of $1.6 million, $1.0 million, net of tax, related to the write off of unamortized issuance costs (See Note 1).

As of December 31, 2010, no amounts were outstanding and $11.5 million in standby letters of credit had been issued under the revolving credit facility, therefore the remaining availability under this revolving credit facility was $163.5 million. As of December 31, 2010, $475.2 million was outstanding on the term loan facility and the interest rate was 6.00%. The annualized effective rate of interest was 8.29% for the year ended December 31, 2010 after giving consideration to revolver fees and derivative activity. As of March 3, 2011, the effective date of the 2011 Credit Amendment, the credit facility consisted of a $475.2 million term loan and a $140.0 million revolving credit facility, which had remaining availability of $129.1 million as $10.9 million in a standby letters of credit were outstanding under it.

10.5% senior secured notes due 2017

On October 20, 2009, the Company 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, which commenced on April 15, 2010, 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. The Company used the net proceeds of approximately $284.4 million from the offering to repay a portion of the indebtedness outstanding under its term loan facility. The notional amount of the 10.5% Senior Secured Notes, its unamortized discount and its net carrying amount was $300.0 million, $7.1 million and $292.9 million, respectively, as of December 31, 2010 and $300.0 million, $7.7 million and $292.3 million, respectively, as of December 31, 2009. The unamortized discount is being amortized to interest expense over the life of the 10.5% Senior Secured Notes which ends in October 2017. During the year ended December 31, 2010, the Company recognized $32.1 million, $20.8 million, net of tax, in interest expense, or $0.18 per diluted share, at an effective rate of 11%, of which $31.4 million related to the coupon rate of 10.5% and $0.7 million related to discount amortization. During the year ended December 31, 2009, the Company recognized $6.4 million, $4.2 million, net of tax, in interest expense, or $0.04 per diluted share, at an effective rate of 11%, of which $6.3 million related to the coupon rate of 10.5% and $0.1 million related to discount amortization.

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

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

All the liens securing the notes may be released if the Company s secured indebtedness, other than these notes, does not exceed the lesser of $375.0 million and 15.0% of our consolidated tangible assets. The Company refers 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 the Company s secured indebtedness, other than these notes, exceeds the greater of $375.0 million and 15.0% of its 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 the Company s ability and the ability of its 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 its affiliates; and
- consolidate, merge or transfer all or substantially all of its assets.

The indenture governing the notes also contains a provision under which an event of default by the Company 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, the Company 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) the Company makes such redemption not more than 90 days after the consummation of such equity offering. In addition, prior to October 15, 2013, the Company 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, the Company 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 the Company experiences a change of control, as defined, it 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, the Company 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.

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3.375% convertible senior notes due 2038

On June 3, 2008, the Company 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. 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. The Company 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 the Company s 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 the Company s election, shares of Common Stock, cash or a combination of cash and shares of Common Stock. At December 31, 2010, the number of conversion shares potentially issuable in relation to the 3.375% Convertible Senior Notes was 1.9 million. The Company may redeem the notes at its option beginning June 6, 2013, and holders of the notes will have the right to require the Company to repurchase the notes on June 1, 2013 and certain dates thereafter or on the occurrence of a fundamental change. Net proceeds of $243.5 million were used to purchase approximately 1.45 million shares, or $49.2 million, of the Company s common stock, to repay outstanding borrowings under its senior secured revolving credit facility which totaled $100.0 million at the time of the offering and for other general corporate purposes.

The indenture governing the 3.375% Convertible Senior Notes contains a provision under which an event of default by the Company 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.

As of January 1, 2009, the Company was required to adopt the provisions of FASB Codification Topic 470-20, *Debt Debt with Conversion and Other Options*, with retrospective application to the terms of the 3.375% Convertible Senior Notes as they existed for all periods presented (See Note 1). The Consolidated Statements of Operations for the year ended December 31, 2008 has been restated to reflect the adoption. The restatement of the Consolidated Statements of Operations for the year ended December 31, 2008 resulted in the Company recognizing $4.3 million, $2.8 million, net of tax, in interest expense, or $0.03 per diluted share, related to discount amortization as well as $15.0 million, $9.7 million, net of tax, or $0.11 per diluted share, to reduce the gain on early retirement of debt associated with the December 2008 redemption.

The carrying amount of the equity component of the 3.375% Convertible Senior Notes was $30.1 million at both December 31, 2010 and December 31, 2009. The principal amount of the liability component of the 3.375% Convertible Senior Notes, its unamortized discount and its net carrying amount was $95.9 million, $9.4 million and $86.5 million, respectively, as of December 31, 2010 and $95.9 million, $12.8 million and $83.1 million, respectively, as of December 31, 2009. The unamortized discount is being amortized to interest expense over the expected life of the 3.375% Convertible Senior Notes which ends June 1, 2013. During the year ended December 31, 2010, the Company recognized $6.7 million, $4.3 million, net of tax, in interest expense, or $0.04 per diluted share, at an effective rate of 7.93%, of which $3.3 million related to the coupon rate of 3.375% and $3.4 million related to discount amortization. During the year ended December 31, 2009, the Company recognized $8.2 million, $5.3 million, net of tax, in interest expense, or $0.05 per diluted share, at an effective rate of 7.93%, of which $4.2 million related to the coupon rate of 3.375% and $4.0 million related to discount amortization.

The Company determined that upon maturity or redemption, it has the intent and ability to settle the principal amount of its 3.375% Convertible Senior Notes in cash, and any additional conversion consideration spread (the excess of conversion value over face value) in shares of the Company s Common Stock. There were no stock equivalents to exclude from the calculation of the dilutive effect of stock equivalents for the

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

diluted earnings per share calculations for the years ended December 31, 2010, 2009 and 2008 related to the assumed conversion of the 3.375% Convertible Senior Notes under the if-converted method as there was no excess of conversion value over face value in any period.

During December 2008, the Company redeemed $73.2 million accreted principal amount, or $88.2 million aggregate principal amount of the 3.375% Convertible Senior Notes for a cost of $44.8 million resulting in a gain of $28.4 million. In addition, the Company expensed $2.1 million of unamortized issuance costs in connection with the redemption. In April 2009, the Company 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, the Company expensed $0.4 million of unamortized issuance costs in connection with the retirement. In June 2009, the Company retired $45.8 million aggregate principal amount of its 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, the Company expensed $1.0 million of unamortized issuance costs in connection with the retirement. In accordance with FASB Codification Topic 470-20 *Debt Debt with Conversion and Other Options*, 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.

Other debt

In connection with the TODCO acquisition in July 2007, one of our domestic subsidiaries assumed approximately $3.5 million of 7.375% Senior Notes due in April 2018. There are no financial or operating covenants associated with these notes.

11. Derivative Instruments and Hedging

The Company is required to recognize all of its derivative instruments as either assets or liabilities in the statement of financial position at fair value. The accounting for changes in the fair value of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and further, on the type of hedging relationship. For those derivative instruments that are designated and qualify as hedging instruments, a company must designate the hedging instrument, based upon the exposure being hedged, as a fair value hedge, cash flow hedge, or a hedge of a net investment in a foreign operation.

The Company periodically uses derivative instruments to manage its exposure to interest rate risk, including interest rate swap agreements to effectively fix the interest rate on variable rate debt and interest rate collars to limit the interest rate range on variable rate debt. These hedge transactions have historically been accounted for as cash flow hedges.

For derivative instruments that are designated and qualify as a cash flow hedge, the effective portion of the gain or loss on the derivative instrument is reported as a component of other comprehensive income and reclassified into earnings in the same line item associated with the forecasted transaction and in the period or periods during which the hedged transaction affects earnings. The effective portion of the interest rate swaps and collar hedging the exposure to variability in expected future cash flows due to changes in interest rates is reclassified into interest expense. The remaining gain or loss on the derivative instrument in excess of the cumulative change in the present value of future cash flows of the hedged item, if any, or hedged components excluded from the assessment of effectiveness, is recognized in interest expense.

In July 2007, the Company entered into a zero cost LIBOR collar on $300.0 million of term loan principal with a final settlement date of October 1, 2010, which was settled on October 1, 2010 per the

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

agreement with a cash payment of $3.4 million, with a ceiling of 5.75% and a floor of 4.99%. The counterparty was obligated to pay the Company in any quarter that actual LIBOR reset above 5.75% and the Company paid the counterparty in any quarter that actual LIBOR reset below 4.99%. The terms and settlement dates of the collar matched those of the term loan through July 27, 2009, the date of the 2009 Credit Amendment.

As a result of the inclusion of a LIBOR floor in the Credit Agreement, the Company determined, as of July 27, 2009 and on an ongoing basis, that the interest rate collar (which was settled on October 1, 2010) will not be highly effective in achieving offsetting changes in cash flows attributable to the hedged interest rate risk during the period that the hedge was designated. As such, the Company discontinued cash flow hedge accounting for the interest rate collar as of July 27, 2009. Because cash flow hedge accounting was not applied to this instrument, changes in fair value related to the interest rate collar subsequent to July 27, 2009 were recorded in earnings. As a result of discontinuing the cash flow hedging relationship, the Company recognized a decrease in fair value of $0.3 million and $1.7 million related to the hedge ineffectiveness of its interest rate collar as Interest Expense in its Consolidated Statements of Operations for the years ended December 31, 2010 and 2009, respectively.

The following table provides the fair values of the Company s interest rate derivatives (in thousands):

	December 31, 2009 Balance Sheet Classification	Fair Value
Derivatives(a):		
Interest rate contracts:		
Other		$
Total Asset Derivatives		$
Other Current Liabilities		$ 10,312
Other Liabilities		
Total Liability Derivatives		$ 10,312

(a) These interest rate contracts were designated as cash flow hedges through July 27, 2009.

The following table provides the effect of the Company s interest rate derivatives on the Consolidated Statements of Operations (in thousands):

					Year Ended December 31,						
	2010	2009	2008		2010	2009	2008			2010	20
s(a)		I.		II.		III.			IV.		V.

e

$	$ (1,654)	$ (11,849)	Interest Expense	$ (8,881)	$ (16,636)	$ (7,745)	Interest Expense	$ (264)	$ (1,

(a) These interest rate contracts were designated as cash flow hedges through July 27, 2009.

I. Amount of Gain (Loss), Net of Taxes Recognized in Other Comprehensive Income (Loss) on Derivative (Effective Portion)

II. Classification of Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) into Income (Loss) (Effective Portion)

III. Amount of Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) into Income (Loss) (Effective Portion)

IV. Classification of Gain (Loss) Recognized in Income (Loss) on Derivative

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

V. Amount of Gain (Loss) Recognized in Income (Loss) on Derivative

A summary of the changes in Accumulated Other Comprehensive Loss (in thousands):

Cumulative unrealized loss, net of tax of $4,371 as of December 31, 2007	$	(8,117)
Reclassification of losses into net income, net of tax of $2,711		5,034
Other comprehensive losses, net of tax of $6,380		(11,849)
Cumulative unrealized loss, net of tax of $8,040, as of December 31, 2008	$	(14,932)
Reclassification of losses into net income, net of tax of $5,823		10,813
Other comprehensive losses, net of tax of $891		(1,654)
Cumulative unrealized loss, net of tax of $3,108, as of December 31, 2009	$	(5,773)
Reclassification of losses into net income, net of tax of $3,108		5,773
Cumulative unrealized loss, net of tax, as of December 31, 2010	$	

12. Fair Value Measurements

FASB ASC Topic 820-10, *Fair Value Measurements and Disclosures* defines fair value, establishes a framework for measuring fair value under generally accepted accounting principles and expands disclosures about fair value measurements; however, it does not require any new fair value measurements, rather, its application is made pursuant to other accounting pronouncements that require or permit fair value measurements.

Fair value measurements are generally based upon observable and unobservable inputs. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect our view of market assumptions in the absence of observable market information. The Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. FASB ASC Topic 820-10, *Fair Value Measurements and Disclosures* includes a fair value hierarchy that is intended to increase consistency and comparability in fair value measurements and related disclosures. The fair value hierarchy consists of the following three levels:

Level 1 Inputs are quoted prices in active markets for identical assets or liabilities.

Level 2 Inputs are quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable and market-corroborated inputs which are derived principally from or corroborated by observable market data.

Level 3 Inputs are derived from valuation techniques in which one or more significant inputs or value drivers are unobservable.

As of January 1, 2010, the Company adopted the FASB ASU 2010-06 which requires additional disclosures about the various classes of assets and liabilities measured at fair value, the valuation techniques and inputs used, the activity in

Level 3 fair value measurements and the transfers between Levels 1, 2, and 3. The requirement for disclosures about purchases, sales, issuances and settlements in the roll forward of activity in Level 3 fair value measurements are effective for interim and annual reporting periods beginning after December 15, 2010 and will be adopted by the Company on January 1, 2011 (See Note 1).

As of December 31, 2009 the fair value of the Company s interest rate derivative was in a liability position in the amount of $10.3 million. The fair value of the interest rate derivative was determined based on a discontinued cash flow approach using market observable inputs.

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table represents our derivative liabilities measured at fair value on a recurring basis as of December 31, 2009 (in thousands):

	Total Fair Value Measurement December 31, 2009	Quoted Prices in Active Markets for Identical Asset or Liability (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Interest Rate Contracts	$ 10,312	$	$ 10,312	$

There were no derivative liabilities outstanding at December 31, 2010.

The following tables represent our assets measured at fair value on a non-recurring basis for which an impairment measurement was made as of December 31, 2010 and 2009 (in thousands):

	Total Fair Value Measurement December 31, 2010	Quoted Prices in Active Markets for Identical Asset or Liability (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Gain (Loss)
Property and Equipment, Net	$ 27,848	$	$	$ 27,848	$ (125,136)

The Company incurred $125.1 million ($81.3 million, net of tax) in impairment of property and equipment charges related to certain of its assets (See Note 1). The property, plant and equipment was valued based on the discounted cash flows associated with the assets which included management s estimate of sales proceeds less costs to sell.

	Total Fair Value Measurement December 31, 2009	Quoted Prices in Active Markets for Identical Asset or Liability (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Gain (Loss)

Assets Held for Sale	$	$	$	$	$ (26,882)

Long-lived assets held for sale at December 31, 2008 were written down to their fair value less costs to sell of $9.8 million in the second quarter of 2009, resulting in an impairment charge of approximately $26.9 million ($13.1 million, net of tax) related to *Hercules 110.* The sale of *Hercules 110* was completed in August 2009 (See Note 5).

13. Supplemental Cash Flow Information

	Year Ended December 31,		
	2010	2009	2008
		(In thousands)	
Cash paid during the period for:			
Interest, net of capitalized interest	$ 76,993	$ 62,297	$ 55,865
Income taxes	22,092	26,942	42,854

During 2009 and 2008, the Company capitalized interest of $0.3 million and $8.8 million, respectively. The Company did not capitalize interest in 2010.

The Company had non-cash financing activities related to its June 2009 retirement of $45.8 million aggregate principal amount of its 3.375% Convertible Senior Notes in exchange for the issuance of 7,755,440 shares of Common Stock valued at $4.38 per share ($34.0 million) and payment of accrued interest, resulting in a gain of $4.4 million (See Note 10).

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

14. Concentration of Credit Risk

The Company maintains its cash in bank deposit accounts at high credit quality financial institutions or in highly rated money market funds as permitted by its Credit Agreement. The balances, at many times, exceed federally insured limits.

The Company provides services to a diversified group of customers in the oil and natural gas exploration and production industry. Credit is extended based on an evaluation of each customer s financial condition. The Company maintains an allowance for doubtful accounts receivable based on expected collectability and establishes a reserve when payment is unlikely to occur.

15. Sales to Major Customers

The Company s 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 the Company s total revenue are as follows:

	Year Ended December 31,		
	2010	2009	2008
Oil and Natural Gas Corporation Limited(a)	20%	16%	8%
Chevron Corporation(b)	17	14	12
Saudi Aramco(a)	14	13	
PEMEX Exploración y Producción (PEMEX)(a)	3	10	8

(a) Revenue included in the Company s International Offshore segment.

(b) Revenue included in the Company s Domestic Offshore, Domestic Liftboats and International Liftboats segments.

16. Income Taxes

Income (loss) before income taxes consisted of the following (in thousands):

	Year Ended December 31,		
	2010	2009	2008
United States	$ (318,476)	$ (271,879)	$ (1,267,606)
Foreign	94,260	102,798	112,575
Total	$ (224,216)	$ (169,081)	$ (1,155,031)

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The income tax (benefit) provision consisted of the following (in thousands):

	Year Ended December 31, 2010	2009	2008
Current-United States	$	$ (16,335)	$ 11,733
Current-foreign	8,752	35,144	31,103
Current-state	94	(9,302)	1,867
Current income tax provision	8,846	9,507	44,703
Deferred-United States	(102,033)	(80,458)	(103,077)
Deferred-foreign	3,748	61	(5,683)
Deferred-state	(183)	(8,042)	(9,104)
Deferred income tax benefit	(98,468)	(88,439)	(117,864)
Total income tax benefit	$ (89,622)	$ (78,932)	$ (73,161)

The components of and changes in the net deferred taxes were as follows (in thousands):

	December 31, 2010	2009
Deferred tax assets:		
Net operating loss carryforward (Federal, State & Foreign)	$ 144,720	$ 108,307
Credit carryforwards	14,711	14,677
Accrued expenses	11,530	14,329
Unearned income	1,296	3,417
Intangibles	9,030	5,440
Stock-Based Compensation	7,155	7,046
Other		12,622
Deferred tax assets	188,442	165,838
Deferred tax liabilities:		
Fixed assets	(290,749)	(369,639)
Convertible Notes	(7,586)	(7,018)
Deferred expenses	(9,148)	(7,602)
Other	(8,028)	(4,493)
Deferred tax liabilities	(315,511)	(388,752)

Net deferred tax liabilities	$ (127,069)	$ (222,914)

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A reconciliation of statutory and effective income tax rates is as shown below:

	Year Ended December 31,		
	2010	2009	2008
Statutory rate	35.0%	35.0%	35.0%
Effect of:			
Impairment of Goodwill			(29.3)
State income taxes	0.1	8.7	0.7
Taxes on foreign earnings at greater (lesser) than the U.S. statutory rate	7.6	3.8	(0.4)
Uncertain Tax Positions	2.2	(2.8)	0.3
Deemed Repatriation of foreign earnings	(3.6)		
Other	(1.3)	2.0	
Effective rate	40.0%	46.7%	6.3%

The amount of consolidated U.S. net operating losses (NOLs) available as of December 31, 2010 is approximately $413.5 million. These NOLs will expire in the years 2017 through 2030. Because of the TODCO acquisition, the Company s ability to utilize certain of its tax benefits is subject to an annual limitation, in addition to certain additional limitations resulting from TODCO s prior transactions. However, the Company believes that, in light of the amount of the annual limitations, it should not have a material effect on the Company s ability to utilize its tax benefits for the foreseeable future and the Company has not recorded any valuation allowance related to the tax assets. In addition, the Company has $14.7 million of non-expiring alternative minimum tax credits.

The Company has not recorded deferred income taxes on the remaining undistributed earnings of its foreign subsidiaries because of management s intent to permanently reinvest such earnings. At December 31, 2010, the aggregate amount of undistributed earnings of the foreign subsidiaries was $153.8 million. Upon distribution of these earnings in the form of dividends or otherwise, the Company may be subject to U.S. income taxes and foreign withholding taxes. It is not practical, however, to estimate the amount of taxes that may be payable on the remittance of these earnings.

Effective January 1, 2007, the Company adopted the provisions of FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes,* codified in FASB ASC Topic 740, *Income Taxes*. Its adoption did not have a material impact on the Company s financial statements. The Company did not derecognize any tax benefits, nor recognize any interest expense or penalties on unrecognized tax benefits as of the date of adoption. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. The Company recorded interest and penalties of $0.4 million, $6.3 million and $3.1 million through the Consolidated Statement of Operations for the years ended December 31, 2010, 2009 and 2008, respectively. In addition, in 2008 the Company recorded interest and penalties of $6.3 million as a component of goodwill related to the TODCO acquisition.

The Company, directly or through its subsidiaries, files income tax returns in the United States, and multiple state and foreign jurisdictions. The Company s tax returns for 2005 through 2009 remain open for examination by the taxing authorities in the respective jurisdictions where those returns were filed. In addition, certain tax returns filed by

TODCO and its subsidiaries are open for years prior to 2004, however TODCO tax obligations from periods prior to its initial public offering in 2004 are indemnified by Transocean under the tax sharing agreement, except for the Trinidad and Tobago jurisdiction. The Company s Trinidadian tax returns are open for examination for the years 2004 through 2009.

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table presents the reconciliation of the total amounts of unrecognized tax benefits (in thousands):

	Years Ended December 31, 2010	2009	2008
Balance, beginning of period	$ 13,529	13,476	
Gross increases tax positions in prior periods			8,009
Gross decreases tax positions in prior periods	(1,499)		
Gross increases current period tax positions		141	5,467
Settlements	(7,921)	(88)	
Balance, end of period	$ 4,109	$ 13,529	$ 13,476

From time to time, our tax returns are subject to review and examination by various tax authorities within the jurisdictions in which we operate or have operated. We are currently contesting tax assessments in Mexico and Venezuela, and may contest future assessments where we believe the assessments are meritless.

In December 2002, TODCO received an assessment from SENIAT, the national Venezuelan tax authority, relating to calendar years 1998 through 2001. After a series of partial payments and appeals, in July 2009, the Company settled the remaining tax and interest portion of the assessment. Residual penalties of $0.8 million (based on the official exchange rate at December 31, 2010) remain in dispute. The Company, as successor to TODCO, is fully indemnified by TODCO s former parent, Transocean Ltd. for this issue. The Company does not expect the ultimate resolution of this assessment and settlement to have a material impact on its consolidated financial statements. In January 2008, SENIAT commenced an audit for the 2003 calendar year, which was completed in the fourth quarter of 2008. The Company has not yet received any proposed adjustments from SENIAT for that year.

In March 2007, a subsidiary of the Company received an assessment from the Mexican tax authorities related to its operations for the 2004 tax year. This assessment contested the Company s right to certain deductions and also claimed it did not remit withholding tax due on certain of these deductions. In accordance with local statutory requirements, we provided a surety bond for an amount equal to approximately $13 million, which was released in July 2010, to contest these assessments. In 2008, the Mexican tax authorities commenced an audit for the 2005 tax year. During 2010, the Company effectively reached a compromise settlement of all issues for 2004 through 2007. The Company paid $11.6 million and reversed (i) previously provided reserves and (ii) an associated tax benefit in the year which totaled $5.8 million.

As of December 31, 2010, the Company had Taxes Receivable of $5.6 million which is included in Other on the Consolidated Balance Sheets.

As of December 31, 2010, the Company has $4.1 million unrecognized tax benefits that, if recognized, would impact the effective income tax rate.

17. Segments

The Company reports its business activities in six business segments: (1) Domestic Offshore, (2) International Offshore, (3) Inland, (4) Domestic Liftboats, (5) International Liftboats and (6) Delta Towing. The financial information of the Company s discontinued operation is not included in the financial information presented for the Company s reporting segments. The Company eliminates inter-segment revenue and expenses, if any.

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following describes the Company s reporting segments as of December 31, 2010:

Domestic Offshore includes 22 jackup rigs and three submersible rigs in the U.S. Gulf of Mexico that can drill in maximum water depths ranging from 85 to 350 feet. Eleven of the jackup rigs are either working on short-term contracts or available for contracts and eleven are cold-stacked. All three submersibles are cold-stacked.

International Offshore includes eight jackup rigs and one platform rig outside of the U.S. Gulf of Mexico. The Company has two jackup rigs working offshore in each of India and Saudi Arabia, one jackup rig contracted offshore in Malaysia and one platform rig under contract in Mexico. In addition, the Company has one jackup rig warm-stacked and one jackup rig cold-stacked in Bahrain as well as one jackup rig contracted to a customer in Angola, however the rig was on stand-by in Gabon preparing for a new contract.

Inland includes a fleet of 6 conventional and 11 posted barge rigs that operate inland in marshes, rivers, lakes and shallow bay or coastal waterways along the U.S. Gulf Coast. Three of the Company s inland barges are either operating on short-term contracts or available and 14 are cold-stacked.

Domestic Liftboats includes 41 liftboats in the U.S. Gulf of Mexico. Thirty-eight are operating or available and three are cold-stacked.

International Liftboats includes 24 liftboats. Twenty-one are operating or available offshore West Africa, including five liftboats owned by a third party, one is cold-stacked offshore West Africa and two are operating or available in the Middle East region.

Delta Towing the Company s Delta Towing business operates a fleet of 29 inland tugs, 10 offshore tugs, 34 crew boats, 46 deck barges, 16 shale barges and five spud barges along and in the U.S. Gulf of Mexico and from time to time along the Southeastern coast and in Mexico. Of these vessels, 26 crew boats, 11 inland tugs, three offshore tugs, one deck barge and one spud barge are cold-stacked, and the remaining are working, being repaired or available for contracts.

The Company s jackup rigs, submersible rigs and platform rigs are used primarily for exploration and development drilling in shallow waters. The Company s 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.

Information regarding reportable segments is as follows (in thousands):

	Year Ended December 31, 2010			Year Ended December 31, 2009		
	Revenue	Income (Loss) from Operations	Depreciation and Amortization	Revenue	Income (Loss) from Operations	Depreciation and Amortization
Domestic Offshore(a)	$ 124,063	$ (182,394)	$ 68,335	$ 140,889	$ (101,855)	$ 60,775
International Offshore(b)	291,516	56,878	58,275	393,797	97,995	63,808

Inland	21,922	(27,876)	23,516	19,794	(59,095)	32,465
Domestic Liftboats	70,710	12,089	14,698	75,584	4,540	20,267
International Liftboats	116,616	37,211	17,711	88,537	22,427	12,880
Delta Towing(c)	32,653	(1,733)	5,471	24,250	(12,677)	7,917
	$ 657,480	$ (105,825)	$ 188,006	$ 742,851	$ (48,665)	$ 198,112
Corporate		(39,335)	3,177		(43,481)	3,309
Total Company	$ 657,480	$ (145,160)	$ 191,183	$ 742,851	$ (92,146)	$ 201,421

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(a) 2010 Income (Loss) from Operations includes an impairment of property and equipment charge of $84.7 million.

(b) 2010 Income (Loss) from Operations includes an impairment of property and equipment charge of $38.0 million. 2009 Income (Loss) from Operations includes an impairment of property and equipment charge of $26.9 million as well as an allowance for doubtful accounts receivable of approximately $26.8 million, related to a customer in West Africa that was contracted to utilize one rig in its 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) 2010 Income (Loss) from Operations includes an impairment of property and equipment charge of $2.4 million.

	Year Ended December 31, 2008		
	Revenue	Income (Loss) from Operations	Depreciation and Amortization
Domestic Offshore(a)	$ 382,358	$ (598,856)	$ 66,850
International Offshore(b)	327,983	(11,647)	37,865
Inland(c)	162,487	(422,152)	43,107
Domestic Liftboats	94,755	16,578	21,317
International Liftboats	85,896	30,872	9,912
Delta Towing(d)	58,328	(80,065)	10,926
	$ 1,111,807	$ (1,065,270)	$ 189,977
Corporate		(55,643)	2,917
Total Company	$ 1,111,807	$ (1,120,913)	$ 192,894

(a) 2008 Income (Loss) from Operations includes $507.2 million and $174.6 million in impairment of goodwill and impairment of property and equipment charges, respectively.

(b) 2008 Income (Loss) from Operations includes an impairment of goodwill charge of $150.9 million.

(c) 2008 Income (Loss) from Operations includes $205.5 million and $202.1 million in impairment of goodwill and impairment of property and equipment charges, respectively.

(d) 2008 Income (Loss) from Operations includes an impairment of goodwill charge of $86.7 million.

Total Assets

	December 31, 2010	December 31, 2009
Domestic Offshore	$ 772,950	$ 870,723
International Offshore	712,988	860,252
Inland	136,229	160,354
Domestic Liftboats	86,013	88,942
International Liftboats	167,561	164,221
Delta Towing	56,631	62,563
Corporate	62,937	70,421
Total Company	$ 1,995,309	$ 2,277,476

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Year Ended December 31,		
	2010	2009	2008(a)
Capital Expenditures and Deferred Drydocking Expenditures:			
Domestic Offshore	$ 11,133	$ 8,665	$ 139,893
International Offshore	6,469	46,246	390,732
Inland	758	9,886	39,739
Domestic Liftboats	9,987	11,025	12,362
International Liftboats	7,470	15,717	8,302
Delta Towing	927	248	4,125
Corporate	314		7,200
Total Company	$ 37,058	$ 91,787	$ 602,353

(a) Includes the purchase of *Hercules 350*, *Hercules 262* and *Hercules 261* as well as related equipment (See Note 4).

A substantial portion of our assets are mobile. Asset locations at the end of the period are not necessarily indicative of the geographic distribution of the revenue generated by such assets during the periods. The following tables present revenue and long-lived assets by country based on the location of the service provided (in thousands):

	Year Ended December 31,		
	2010	2009	2008
Operating Revenue:			
United States	$ 248,234	$ 258,868	$ 697,930
Saudi Arabia	103,712	109,256	371
India	130,533	122,016	93,544
Mexico	21,240	77,245	90,815
Nigeria	97,163	75,016	83,141
Malaysia	47,071	47,006	17,367
Other(a)	9,527	53,444	128,639
Total	$ 657,480	$ 742,851	$ 1,111,807

	As of December 31,	
	2010	2009
Long-Lived Assets:		

United States	$ 971,640	$ 1,122,294
Saudi Arabia	289,125	311,365
India	136,495	147,497
Mexico	9,365	50,728
Nigeria	106,565	115,656
Malaysia	53,678	58,965
Other(a)	99,427	149,557
Total	$ 1,666,295	$ 1,956,062

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(a) Other represents countries in which we operate that individually had operating revenue or long-lived assets representing less than 4% of total operating revenue or total long-lived assets.

18. Commitments and Contingencies

Operating Leases

The Company has non-cancellable operating lease commitments that expire at various dates through 2017. As of December 31, 2010, future minimum lease payments related to non-cancellable operating leases were as follows (in thousands):

Years Ended December 31,	
2011	$ 4,174
2012	2,404
2013	2,099
2014	2,042
2015	2,078
Thereafter	4,266
Total	$ 17,063

Rental expense for all operating leases was $13.2 million, $15.3 million and $13.3 million for the years ended December 31, 2010, 2009 and 2008, respectively.

Legal Proceedings

The Company is involved in various claims and lawsuits in the normal course of business. As of December 31, 2010, management did not believe any accruals were necessary in accordance with FASB Codification Topic 450-20, *Contingencies Loss Contingencies*.

In connection with the July 2007 acquisition of TODCO, the Company assumed certain 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 the Company s review of its internal records to date, the Company disputes the Company s designation as a potentially responsible party and does not expect that the ultimate outcome of this case will have a material adverse effect on its consolidated results of operations, financial position or cash flows. The Company continues 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 have been filed in the Circuit Courts of the State of Mississippi involving 768 persons that allege personal injury or whose heirs claim their deaths arose out of asbestos exposure in the course of their employment by the defendants between 1965 and 2002. The complaints name as defendants, among others, certain of TODCO s subsidiaries and certain subsidiaries of TODCO s former parent to whom TODCO may owe indemnity and other unaffiliated defendant companies, including companies that allegedly manufactured drilling related products containing asbestos that are the subject of the complaints. The number of unaffiliated defendant companies involved in each complaint ranges from approximately 20 to 70. The complaints allege that the defendant drilling contractors used asbestos-containing products in offshore drilling operations, land based drilling operations and in drilling structures, drilling rigs, vessels and other equipment and assert claims based on, among other things,

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

negligence and strict liability, and claims authorized under the Jones Act. The plaintiffs seek, among other things, awards of unspecified compensatory and punitive damages. All of these cases were assigned to a special master who has approved a form of questionnaire to be completed by plaintiffs so that claims made would be properly served against specific defendants. Approximately 700 questionnaires were returned and the remaining plaintiffs, who did not submit a questionnaire reply, have had their suits dismissed without prejudice. Of the respondents, approximately 100 shared periods of employment by TODCO and its former parent which could lead to claims against either company, even though many of these plaintiffs did not state in their questionnaire answers that the employment actually involved exposure to asbestos. After providing the questionnaire, each plaintiff was further required to file a separate and individual amended complaint naming only those defendants against whom they had a direct claim as identified in the questionnaire answers. Defendants not identified in the amended complaints were dismissed from the plaintiffs litigation. To date, three plaintiffs named TODCO as a defendant in their amended complaints. It is possible that some of the plaintiffs who have filed amended complaints and have not named TODCO as a defendant may attempt to add TODCO as a defendant in the future when case discovery begins and greater attention is given to each individual plaintiff s employment background. The Company has not determined which entity would be responsible for such claims under the Master Separation Agreement between TODCO and its former parent. More than three 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 Company intends to defend vigorously and does not expect the ultimate outcome of these lawsuits to have a material adverse effect on its consolidated results of operations, financial position or cash flows.

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

The Company 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 the Company s 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 management s current estimates.

Insurance

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

The Company maintains 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 2010, the Company completed the annual renewal of all of its key insurance policies. The Company s primary marine package provides for hull and machinery coverage for substantially all of the Company s rigs and liftboats up to a scheduled value of each asset. The total maximum amount of coverage for these assets is $2.1 billion. 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

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 $100.0 million for property damage and removal of wreck liability coverage. The Company 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 the Company s 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. The Company carries a contractor s extra expense policy with $50 million primary covering liability 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, the Company has 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 as well as a separate underlying marine package for its Delta Towing business.

The Company s drilling contracts provide for varying levels of indemnification from its customers and in most cases, may require the Company to indemnify its customers for certain liabilities. Under the Company s drilling contracts, liability with respect to personnel and property is customarily assigned on a knock-for-knock basis, which means that the Company and its customers assume liability for the Company s respective personnel and property, regardless of how the loss or damage to the personnel and property may be caused. The Company s customers typically assume responsibility for and agree to indemnify the Company 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. The Company generally indemnifies the customer for the consequences of spills of industrial waste or other liquids originating solely above the surface of the water and emanating from its rigs or vessels.

In 2010, in connection with the renewal of certain of its insurance policies, the Company entered into agreements to finance a portion of its annual insurance premiums. Approximately $25.9 million was financed through these arrangements, and $6.0 million was outstanding at December 31, 2010. The interest rate on the $24.1 million note is 3.79% and the note is scheduled to mature in March 2011. The interest rate on the $1.8 million note is 3.54% and the note is scheduled to mature in July 2011. There was $5.5 million outstanding in insurance notes payable at December 31, 2009 which were fully paid during 2010. The amounts financed, related interest rates and maturity dates in connection with the prior year renewals were $21.4 million at 4.15% which matured in March 2010 and $1.9 million at 3.75% which matured in July 2010.

Surety Bonds, Bank Guarantees and Unsecured Letters of Credit

The Company had $31.4 million outstanding related to surety bonds at December 31, 2010. The surety bonds guarantee our performance as it relates to the Company s drilling contracts, and other obligations in

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

various jurisdictions. These obligations could be called at any time prior to the expiration dates. The obligations that are the subject of the surety bonds are geographically concentrated primarily in Mexico and the U.S.

The Company had a $1.0 million unsecured bank guarantee and a $0.1 million unsecured letter of credit outstanding at December 31, 2010.

Sales Tax Audits

Certain of the Company s legal entities obtained in the TODCO acquisition are under audit by various taxing authorities for several prior-year periods. These audits are ongoing and the Company is working to resolve all relevant issues, however, the Company has accrued approximately $5.9 million as of December 31, 2010 while the Company provides additional information and responds to auditor requests.

19. Unaudited Interim Financial Data

Unaudited interim financial information for the years ended December 31, 2010 and 2009 is as follows (in thousands, except per share amounts):

	Quarter Ended			
	March 31	**June 30**	**September 30**	**December 31(a)**
2010				
Revenue	$ 150,849	$ 165,895	$ 168,484	$ 172,252
Operating Loss	(20,344)	(5,574)	(1,412)	(117,830)
Net Loss	$ (15,956)	$ (18,984)	$ (15,061)	$ (84,593)
Net Loss Per Share:				
Basic	$ (0.14)	$ (0.17)	$ (0.13)	$ (0.74)
Diluted	(0.14)	(0.17)	(0.13)	(0.74)

(a) Includes $125.1 million in impairment of property and equipment charges (See Notes 1 and 12).

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	Quarter Ended			
	March 31	**June 30(a)**	**September 30**	**December 31(b)**
2009				
Revenue	$ 223,491	$ 183,691	$ 159,262	$ 176,407
Operating Income (Loss)	9,109	(25,829)	(32,712)	(42,714)
Loss from Continuing Operations	(4,511)	(11,787)	(46,970)	(26,881)
Income (Loss) from Discontinued Operation, Net of Taxes	(433)	(242)	(1,290)	380
Net Loss	$ (4,944)	$ (12,029)	$ (48,260)	$ (26,501)
Basic Loss Per Share:				
Loss from Continuing Operations	$ (0.05)	$ (0.13)	$ (0.48)	$ (0.23)
Income (Loss) from Discontinued Operation	(0.01)	(0.01)	(0.02)	
Net Loss	$ (0.06)	$ (0.14)	$ (0.50)	$ (0.23)
Diluted Loss Per Share:				
Loss from Continuing Operations	$ (0.05)	$ (0.13)	$ (0.48)	$ (0.23)
Income (Loss) from Discontinued Operation	(0.01)	(0.01)	(0.02)	
Net Loss	$ (0.06)	$ (0.14)	$ (0.50)	$ (0.23)

(a) Includes approximately $26.9 million of impairment charges related to the write-down of *Hercules 110* to fair value less costs to sell during the second quarter of 2009 (See Notes 5 and 12). The sale was completed in August 2009.

(b) Includes an allowance for doubtful accounts receivable of approximately $26.8 million as of December 31, 2009, related to a customer in West Africa that was contracted to utilize one rig in the Company s 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.

20. Related Parties

The Company engages in transactions in the ordinary course of business with entities with whom certain of our directors or members of management have a relationship. The Company has determined that these transactions were carried out on an arm s-length basis and are not material individually or in the aggregate. All of these transactions were approved in accordance with the Company s Policy on Covered Transactions with Related Persons. The following provides a brief description of these relationships.

The Company s Chairman of the Board of Directors is a Senior Advisor to Lime Rock Partners, who owns a controlling interest in IDM Group, Ltd. (Cyprus) who purchased Louisiana Electric Rig Services, Inc., an equipment manufacturing and service company, and Southwest Oilfield Products, Inc., an oilfield equipment manufacturing company, in December 2008 and June 2008, respectively, and who holds an investment interest in Allis-Chalmers Energy Inc., an oilfield equipment and services company, and Tesco Corporation, an oilfield equipment and services company. In addition, the Chairman was a member of the Board of Directors for T-3 Energy Services, Inc., an oil field equipment and services company.

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Another member of the Company s Board of Directors serves on the Board of Directors for Peregrine Oil & Gas LP, an exploration and production company, and is the Chairman of the Board for Carrizo Oil & Gas, Inc., an exploration and production company. In addition, another of the Company s directors serves on the Board of Directors for Carrizo Oil & Gas, Inc.

Another member of the Company s Board of Directors serves as Chief Executive Officer and Chairman of Technip, a project management, engineering and construction company.

A member of the Company s Board of Directors is a member of the Board of Directors of HCC Insurance Holdings, a specialty insurance group.

The Company holds a three percent investment in each of Hall-Houston Exploration II, L.P. and Hall-Houston Exploration III, L.P., exploration and production funds.

In January 2011, the Company paid $10 million to purchase 5.0 million shares, an investment in approximately eight percent of the total outstanding equity of a new entity incorporated in Luxembourg, Discovery Offshore S.A. (Discovery Offshore). Two of the Company s officers are on the Board of Directors of Discovery Offshore.

21. Subsequent Events

Investment

In January 2011, the Company paid $10 million to purchase 5.0 million shares, an 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 (the Rigs). The Rigs, Keppel FELS Super A design, are being constructed by Keppel FELS in its Singapore shipyard and have a maximum water depth rating of 400 feet, two million pound hook load capacity, and are capable of drilling up to 35,000 feet deep. The two Rigs are expected to be delivered in the second and fourth quarter of 2013, respectively. Discovery Offshore also holds options to purchase two additional rigs of the same specifications, which must be exercised by the third and fourth quarter of 2011, with delivery dates expected in the second quarter and fourth quarter of 2014, respectively.

The Company 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 Agreement, the Company 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 Agreement, the Company 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 Agreement, Discovery Offshore will be responsible for operational and capital expenses for the Rigs. The Company is 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, the Company received 500,000 additional shares worth $1.0 million to cover its costs incurred and efforts expended in forming Discovery Offshore. The Company was issued warrants to purchase up to 5.0 million additional shares of Discovery Offshore stock at a strike price equivalent to $2.00 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, which approximated $4.00 per share as of March 3, 2011, for 30 consecutive trading days. The Company has no other financial obligations or

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

commitments with respect to the Rigs or its ownership in Discovery Offshore. Two of the Company s officers are on the Board of Directors of Discovery Offshore.

Alliance Agreement

In January 2011, the Company entered into an agreement with China Oilfield Services Limited (COSL) whereby it will market and operate a Friede & Goldman JU2000E jackup drilling rig with a maximum water depth of 400 feet. The agreement is limited to a specified opportunity in Angola.

Asset Purchase Agreement

In February 2011, the Company entered into an asset purchase agreement (the Asset Purchase Agreement) with Seahawk Drilling, Inc. and certain of its subsidiaries, pursuant to which Seahawk agreed to sell the Company 20 jackup rigs and related assets, accounts receivable and cash and certain Seahawk liabilities in a transaction pursuant to Section 363 of the U.S. Bankruptcy Code. In connection with the Asset Purchase Agreement, Seahawk filed voluntary Chapter 11 petitions before the U.S. Bankruptcy Court for the Southern District of Texas, Corpus Christi Division.

The purchase consideration is approximately $105 million (the Consideration), as valued at the date of the Asset Purchase Agreement, preliminarily consisting of $25.0 million in cash plus 22.3 million shares of the Company s common stock, par value $0.01 per share (the Stock Consideration), subject to adjustment as further described. The cash consideration is subject to increase at the request of Seahawk up to an additional $20.0 million, if required for the purpose of paying Seahawk s debt, and if the cash consideration is increased, the number of shares comprising the Stock Consideration shall be reduced by an amount equal to such increase, divided by $3.36. In addition, the Consideration is subject to certain other adjustments, including a working capital adjustment.

The Company s Board of Directors, and its lenders through the 2011 Credit Amendment, have approved the transaction. Closing of the transaction remains subject to bankruptcy court approval as well as regulatory approvals and other customary conditions. Assuming such conditions are achieved, the transaction is expected to close during the second quarter of 2011.

Credit Agreement Amendment

In March 2011, the Company amended its Credit Agreement for its term loan and revolving credit facility (See Note 10).

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

None.

Item 9A. *Controls and Procedures*

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our chief executive officer and our chief financial officer, evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Our chief executive officer and chief financial officer evaluated whether our disclosure controls and procedures as of the end of the period covered by this report were designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is (1) recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms and (2) accumulated and communicated to our management, including our chief executive officer and our chief financial officer, as appropriate to allow timely decisions regarding required disclosure. Based on their evaluation, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures were effective to achieve the foregoing objectives as of the end of the period covered by this report.

There were no changes in our internal control over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management s Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) under the U.S. Securities Exchange Act of 1934. Our 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. 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.

Our management assessed the effectiveness of the Company s internal control over financial reporting as of December 31, 2010. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control Integrated Framework. Based on our assessment, we have concluded that, as of December 31, 2010, our internal control over financial reporting is effective based on those criteria.

Our independent registered public accounting firm has audited our internal control over financial reporting as of December 31, 2010, as stated in their report entitled Report of Independent Registered Public Accounting Firm which appears herein.

Item 9B. *Other Information*

None.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

The information required by this item is incorporated by reference to our definitive proxy statement, which is to be filed with the SEC pursuant to the Securities Exchange Act of 1934 within 120 days after the end of our fiscal year on December 31, 2010.

Code of Business Conduct and Ethical Practices

We have adopted a Code of Business Conduct and Ethics, which applies to, among others, our principal executive officer, principal financial officer, principal accounting officer and persons performing similar functions. We have posted a copy of the code in the Corporate Governance section of our internet website at *www.herculesoffshore.com.* Copies of the code may be obtained free of charge on our website or by requesting a copy in writing from our Corporate Secretary at 9 Greenway Plaza, Suite 2200, Houston, Texas 77046. Any waivers of the code must be approved by our board of directors or a designated board committee. Any amendments to, or waivers from, the code that apply to our executive officers and directors will be posted in the Corporate Governance section of our internet website at *www.herculesoffshore.com*.

Item 11. *Executive Compensation*

The information required by this item is incorporated by reference to our definitive proxy statement, which is to be filed with the SEC pursuant to the Exchange Act within 120 days after the end of our fiscal year on December 31, 2010.

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

The information required by this item is incorporated by reference to our definitive proxy statement, which is to be filed with the SEC pursuant to the Exchange Act within 120 days after the end of our fiscal year on December 31, 2010.

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

The information required by this item is incorporated by reference to our definitive proxy statement, which is to be filed with the SEC pursuant to the Exchange Act within 120 days after the end of our fiscal year on December 31, 2010.

Item 14. *Principal Accountant Fees and Services*

The information required by this item is incorporated by reference to our definitive proxy statement, which is to be filed with the SEC pursuant to the Exchange Act within 120 days after the end of our fiscal year on December 31, 2010.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

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

(1) *Financial Statements*

(2) *Consolidated Financial Statement Schedule on page 119 of this Report.*

(3) *The Exhibits of the Company listed below in Item 15(b)*

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(b) *Exhibits*

Exhibit Number	Description
1.1	Underwriting Agreement, dated September 24, 2009, by and between Hercules Offshore, Inc. and Morgan Stanley & Co. Incorporated and UBS Securities LLC, as representatives of the underwriters named in Schedule A thereto (incorporated by reference to Exhibit 1.1 to Hercules Current Report on Form 8-K dated September 30, 2009).
2.1	Asset Purchase Agreement, dated February 11, 2011, by and between Hercules Offshore, Inc., SD Drilling LLC and Seahawk Drilling, Inc., Seahawk Global Holdings LLC, Seahawk Mexico Holdings LLC, Seahawk Drilling Management LLC, Seahawk Drilling LLC, Seahawk Offshore Management LLC, Energy Supply International LLC and Seahawk Drilling USA, LLC (incorporated by reference to Exhibit 2.1 to Hercules Current Report on Form 8-K dated February 15, 2011 (File No. 0-51582)).
2.2	Plan of Conversion (incorporated by reference to Exhibit 2.1 to Hercules Registration Statement on Form S-1 (Registration No. 333-126457), as amended (the S-1 Registration Statement), originally filed on July 8, 2005).
2.3	Amended and Restated Agreement and Plan of Merger, dated effective as of March 18, 2007, by and among Hercules, THE Hercules Offshore Drilling Company LLC and TODCO (incorporated by reference to Annex A to the Joint Proxy/Statement Prospectus included in Part I of Hercules Registration Statement on Form S-4 (Registration No. 333-142314), as amended (the S-4 Registration Statement), originally filed April 24, 2007).
3.1	Certificate of Incorporation of Hercules (incorporated by reference to Exhibit 3.1 to Hercules Current Report on Form 8-K dated November 1, 2005 (File No. 0-51582) (the 2005 Form 8-K)).
3.2	Amended and Restated Bylaws (effective December 31, 2009) (incorporated by reference to Exhibit 3.1 to Hercules Current Report on Form 8-K dated December 8, 2009).
4.1	Form of specimen common stock certificate (incorporated by reference to Exhibit 4.1 to the S-1 Registration Statement).
4.2	Rights Agreement, dated as of October 31, 2005, between Hercules and American Stock Transfer & Trust Company, as rights agent (incorporated by reference to Exhibit 4.1 to the 2005 Form 8-K).
4.3	Amendment No. 1 to Rights Agreement, dated as of February 1, 2008, between Hercules and American Stock Transfer & Trust Company, as rights agent.
4.4	Certificate of Designations of Series A Junior Participating Preferred Stock (incorporated by reference to Exhibit 4.2 to the 2005 Form 8-K).
4.5	Credit Agreement dated as of July 11, 2007 among Hercules, as borrower, its subsidiaries party thereto, as guarantors, UBS AG, Stamford Branch, as issuing bank, administrative agent and collateral agent, Amegy Bank National Association and Comerica Bank, as co-syndication agents, Deutsche Bank AG Cayman Islands Branch and Jefferies Finance LLC, as co-documentation agents, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K dated July 11, 2007 (File No. 0-51582)). Hercules and its subsidiaries are parties to several debt instruments that have not been filed with the SEC under which the total amount of securities authorized does not exceed 10% of the total assets of Hercules and its subsidiaries on a consolidated basis. Pursuant to paragraph 4(iii)(A) of Item 601(b) of Regulation S-K, Hercules agrees to furnish a copy of such instruments to the SEC upon request.
4.6	Indenture, dated as of June 3, 2008, by and between the Company and the Trustee (incorporated by reference to Exhibit 4.1 to Hercules Current Report on Form 8-K dated June 3, 2008 (File No. 0-51582)).

4.7	Form of Note (included in Exhibit 4.6).
4.8	Amendment No. 2 dated as of July 23, 2009, to the Credit Agreement dated July 11, 2007, among Hercules Offshore, Inc., as borrower, its subsidiaries party thereto, as guarantors, and UBS AG, Stamford Branch, as issuing bank, administrative agent and collateral agent, and the lenders party thereto (incorporated by reference to Exhibit 4.1 to Hercules Quarterly Report on Form 10-Q dated July 29, 2009).

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Exhibit Number	Description
4.9	Indenture dated as of October 20, 2009, by and among Hercules Offshore, Inc., the Guarantors named therein and U.S. Bank National Association as Trustee and Collateral Agent (incorporated by reference to Exhibit 4.1 to Hercules Current Report on Form 8-K dated October 26, 2009).
4.10	Form of 10.50% Senior Secured Note due 2017 (included in Exhibit 4.9).
4.11	Security Agreement dated as of October 20, 2009, by and among Hercules Offshore, Inc. and the Guarantors party thereto and U.S. Bank National Association as Collateral Agent (incorporated by reference to Exhibit 4.3 to Hercules Current Report on Form 8-K dated October 26, 2009).
4.12	Registration Rights Agreement dated as of October 20, 2009, by and among Hercules Offshore, Inc., the Guarantors named therein and the Initial Purchasers party thereto (incorporated by reference to Exhibit 4.4 to Hercules Current Report on Form 8-K dated October 26, 2009).
4.13	Form of Indenture between Hercules and the trustee thereunder (the Senior Trustee) in respect of senior debt securities (incorporated by reference to Exhibit 4.7 to Hercules Registration Statement on Form S-3 filed December 3, 2010).
4.14	Form of Indenture between Hercules and the trustee thereunder (the Subordinated Trustee) in respect of subordinated debt securities (incorporated by reference to Exhibit 4.8 to Hercules Registration Statement on Form S-3 filed December 3, 2010).
4.15	Amendment No. 3 to Credit Agreement, dated as of March 3, 2011, by and among the Company, as borrower, its subsidiaries party thereto, as guarantors, the Issuing Banks (as defined in the Credit Agreement) party thereto, and UBS AG, Stamford Branch, as administrative agent for the Lenders and as collateral agent and instructing beneficiary under the Mortgage Trust Agreement (as defined in the Credit Agreement) for the Secured Parties (as defined in the Credit Agreement) (incorporated by reference to Exhibit 10.1 to Hercules Current Report on Form 8-K dated March 8, 2011) (File No. 0-51582).
10.1	Executive Employment Agreement dated as of December 15, 2008, between Hercules and John T. Rynd (incorporated by reference to Exhibit 10.2 to the 2008 Form 8-K).
10.2	Executive Employment Agreement dated as of June 20, 2008, between Hercules Offshore, Inc. and John T. Rynd (incorporated by reference to Exhibit 10.2 to Hercules Current Report on Form 8-K dated June 23, 2008 (File No. 0-51582)).
10.3	Employment Agreement, dated as of December 15, 2008, by and between Hercules and Lisa W. Rodriguez (incorporated by reference to Exhibit 10.3 to the 2008 Form 8-K).
10.4	Executive Employment Agreement, dated December 15, 2008, between Hercules and James W. Noe (incorporated by reference to Exhibit 10.4 to the 2008 Form 8-K).
10.5	Executive Employment Agreement, dated December 15, 2008, between Hercules and Terrell L. Carr (incorporated by reference to Exhibit 10.5 to the 2008 Form 8-K).
10.6	Executive Employment Agreement, dated December 15, 2008, between Hercules and Todd Pellegrin (incorporated by reference to Exhibit 10.6 to the 2008 Form 8-K).
10.7	Executive Employment Agreement, dated December 15, 2008, between Hercules and Troy L. Carson (incorporated by reference to Exhibit 10.7 to the 2008 Form 8-K).
10.8	Executive Employment Agreement, dated December 15, 2008, between Hercules and Stephen M. Butz (incorporated by reference to Exhibit 10.1 to Hercules Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 (File No. 0-51582)).
10.9	Amendment to Executive Employment Agreement for Lisa W. Rodriguez, dated May 7, 2010 (incorporated by reference to Exhibit 10.2 to Hercules Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 (File No. 0-51582)).
10.10	

	Amendment to Executive Employment Agreement for Stephen M. Butz, dated May 7, 2010 (incorporated by reference to Exhibit 10.3 to Hercules Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 (File No. 0-51582)).
10.11	Amendment to Executive Employment Agreement for Troy L. Carson, dated May 7, 2010 (incorporated by reference to Exhibit 10.4 to Hercules Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 (File No. 0-51582)).

Exhibit Number	Description
10.12	Expatriate Employment Agreement, dated November 1, 2006, between Hercules and Don P. Rodney (incorporated by reference to Exhibit 10.2 to Hercules Current Report on Form 8-K dated October 31, 2006 (File No. 0-51582)).
10.13	Extension Letter between Hercules and Don P. Rodney, dated December 31, 2008 (incorporated by reference to Exhibit 10.1 to Hercules Current Report on Form 8-K dated January 6, 2009 (File No. 0-51582)).
* 10.14	Extension Letter between Hercules and Don P. Rodney, dated November 1, 2010.
10.15	Waiver of Executive Employment Agreement between the Company and John T. Rynd, dated April 27, 2009 (incorporated by reference to Exhibit 10.1 to Hercules Current Report on Form 8-K dated April 28, 2009).
10.16	Waiver of Executive Employment Agreement between the Company and Lisa W. Rodriguez, dated April 27, 2009 (incorporated by reference to Exhibit 10.2 to Hercules Current Report on Form 8-K dated April 28, 2009).
10.17	Waiver of Executive Employment Agreement between the Company and James W. Noe, dated April 27, 2009 (incorporated by reference to Exhibit 10.3 to Hercules Current Report on Form 8-K dated April 28, 2009).
10.18	Waiver of Executive Employment Agreement between the Company and Terrell L. Carr, dated April 27, 2009 (incorporated by reference to Exhibit 10.4 to Hercules Current Report on Form 8-K dated April 28, 2009).
10.19	Waiver of Executive Employment Agreement between the Company and Todd A. Pellegrin, dated April 27, 2009 (incorporated by reference to Exhibit 10.5 to Hercules Current Report on Form 8-K dated April 28, 2009).
10.20	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.1 to Hercules Current Report on Form 8-K dated April 7, 2006 (File No. 0-51582)).
10.21	Amended and Restated Hercules Offshore 2004 Long-Term Incentive Plan (incorporated by reference to Annex E to the Joint Proxy Statement/Prospectus included in Part I of the S-4 Registration Statement).
10.22	First Amendment to Hercules Offshore Inc. Amended and Restated 2004 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.4 to Hercules Quarterly Report on Form 10-Q for the quarter ended June 30, 2008 (File No. 0-51582)).
10.23	Form of Stock Option Award Agreement (incorporated by reference to Exhibit 10.1 to Hercules Current Report on Form 8-K dated March 3, 2009).
10.24	Form of Stock Option Agreement.
10.25	Form of Restricted Stock Agreement for Employees and Consultants.
10.26	Form of Restricted Stock Agreement for Directors (incorporated by reference to Exhibit 10.14 to Hercules Annual Report on Form 10-K for the year ended December 31, 2006 (File No. 0-51582)).
* 10.27	Performance Award Agreement, dated January 1, 2011, between Hercules and John T. Rynd.
* 10.28	Performance Award Agreement, dated January 1, 2011, between Hercules and John T. Rynd.
* 10.29	Special Retention Award Agreement, dated January 1, 2011, between Hercules and John T. Rynd.
10.30	Hercules Offshore, Inc. Amended and Restated Deferred Compensation Plan.
10.31	Registration Rights Agreement, dated as of July 8, 2005, between Hercules and the holders listed on the signature page thereto (incorporated by reference to Exhibit 10.9 to Hercules Annual Report on Form 10-K for the year ended December 31, 2005 (File No. 0-51582)).
10.32	Increase Joinder, dated as of April 28, 2008, among Hercules, as borrower, its subsidiaries party thereto, the incremental lenders and other lenders party thereto, and UBS AG Stamford Branch, as

administrative agent for the lenders party thereto (incorporated by reference to Exhibit 10.1 to Hercules Current Report on Form 8-K dated April 30, 2008 (File No. 0-51582)).

Exhibit Number	Description
10.33	Purchase Agreement, dated May 28, 2008, by and between the Company and Goldman, Sachs & Co., Banc of America Securities LLC and UBS Securities LLC, as representatives of the Initial Purchasers (incorporated by reference to Exhibit 10.1 to Hercules Current Report on Form 8-K dated June 3, 2008 (File No. 0-51582)).
10.34	Asset Purchase Agreement, dated April 3, 2006, by and between Hercules Liftboat Company, LLC and Laborde Marine Lifts, Inc. (incorporated by reference to Exhibit 10.1 to Hercules Current Report on Form 8-K dated April 3, 2006 (File No. 0-51582)).
10.35	Asset Purchase Agreement, dated as of August 23, 2006, by and among Hercules International Holdings, Ltd., Halliburton West Africa Ltd. and Halliburton Energy Services Nigeria Limited (incorporated by reference to Exhibit 10.1 to Hercules Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 0-51582)).
10.36	First Amendment to Asset Purchase Agreement, dated as of November 1, 2006, by and among Hercules International Holdings, Ltd., Hercules Oilfield Services Ltd., Halliburton West Africa Ltd. and Halliburton Energy Services Nigeria Limited (incorporated by reference to Exhibit 10.2 to Hercules Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 0-51582)).
10.37	Earnout Agreement, dated November 7, 2006, by and among Hercules Oilfield Services, Ltd., Halliburton West Africa Ltd. and Halliburton Energy Services Nigeria Limited (incorporated by reference to Exhibit 10.3 to Hercules Current Report on Form 8-K dated November 7, 2006 (File No. 0-51582)).
10.38	Basic Form of Exchange Agreement between the Company and certain holders of our 3.375% Convertible Senior Notes due 2038 (incorporated by reference to Exhibit 10.1 to Hercules Current Report on Form 8-K dated June 18, 2009).
10.39	Purchase Agreement, dated October 8, 2009, by and among Hercules Offshore, Inc., the guarantors party thereto, UBS Securities LLC, Banc of America Securities LLC, Deutsche Bank Securities Inc. and Morgan Stanley & Co. Incorporated, as representatives of the initial purchasers named in Schedule I thereto (incorporated by reference to Exhibit 10.1 to Hercules Current Report on Form 8-K dated October 14, 2009).
10.40	Intercreditor Agreement dated as of October 20, 2009, among Hercules Offshore, Inc., the subsidiaries party thereto as guarantors, UBS AG, Stamford Branch, as Bank Collateral Agent and U.S. Bank National Association, as Notes Collateral Agent (incorporated by reference to Exhibit 10.1 to Hercules Current Report on Form 8-K dated October 26, 2009).
*21.1	Subsidiaries of Hercules.
*23.1	Consent of Ernst & Young LLP.
*31.1	Certification of Chief Executive Officer of Hercules pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of Chief Financial Officer of Hercules pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification of the Chief Executive Officer and the Chief Financial Officer of Hercules pursuant to Section 901 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.

Compensatory plan, contract or arrangement.

(c) *Financial Statement Schedules*

(1) *Valuation and Qualifying Accounts and Allowances*

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SCHEDULE II
HERCULES OFFSHORE, INC. AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS AND ALLOWANCES
FOR THE THREE YEARS ENDED DECEMBER 31, 2010

Description	Balance at Beginning of Period	Additions Charged to Expense, Net	Adjustments	Deductions	Balance at End of Period
			(In thousands)		
Year Ended December 31, 2010:					
Allowance for uncollectible accounts receivable	$ 38,522	$ 182	$	$ (8,906)	$ 29,798
Year Ended December 31, 2009:					
Allowance for uncollectible accounts receivable	$ 7,756	$ 32,912	$ 78	$ (2,224)	$ 38,522
Year Ended December 31, 2008:					
Allowance for uncollectible accounts receivable	$ 634	$ 6,167	$ 965	$ (10)	$ 7,756

All other financial statement schedules have been omitted because they are not applicable or not required, or the information required thereby is included in the consolidated financial statements or the notes thereto included in this annual report.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Houston, State of Texas, on March 9, 2011.

HERCULES OFFSHORE, INC.

By: /s/ JOHN T. RYND

John T. Rynd

Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on March 9, 2011.

Signatures	Title
/s/ John T. Rynd **John T. Rynd**	Chief Executive Officer and President (Principal Executive Officer)
/s/ Stephen M. Butz **Stephen M. Butz**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ Troy L. Carson **Troy L. Carson**	Chief Accounting Officer (Principal Accounting Officer)
/s/ Thomas R. Bates, Jr. **Thomas R. Bates, Jr.**	Chairman of the Board
/s/ Thomas N. Amonett **Thomas N. Amonett**	Director
/s/ Suzanne V. Baer **Suzanne V. Baer**	Director
/s/ Thomas M Hamilton **Thomas M Hamilton**	Director
/s/ Thomas J. Madonna	Director

Thomas J. Madonna	
/s/ F. Gardner Parker	Director
F. Gardner Parker	
/s/ Thierry Pilenko	Director
Thierry Pilenko	
/s/ Steven A. Webster	Director
Steven A. Webster	