HERCULES OFFSHORE, INC.
Form 10-K
February 26, 2009

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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, 2008
Commission file number: 0-51582

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

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

Registrant s telephone number, including area code:
(713) 350-5100

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

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes 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 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 þ	Accelerated filer o	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, 2008, based on the closing price on the NASDAQ Global Select Market on such date, was approximately $3.3 billion. (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 February 20, 2009, there were 88,024,585 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 April 23, 2009 are incorporated by reference into Part III of this report.

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PART I

Item 1. *Business*

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

Overview

We provide 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.

We report our business activities in six business segments: (1) Domestic Offshore, (2) International Offshore, (3) Inland, (4) Domestic Liftboats, (5) International Liftboats and (6) Delta Towing.

In January 2009, we reclassified four of our cold-stacked jackup rigs located in the U.S. Gulf of Mexico and 10 of our cold-stacked inland barges as retired. These rigs would require extensive refurbishment and currently are not expected to re-enter active service. As of February 19, 2009, our business segments included the following:

Domestic Offshore operates 20 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. Fourteen of the jackup rigs are either working on short-term contracts or available. One is in the shipyard for maintenance and five are cold-stacked. All three submersibles are cold-stacked.

International Offshore operates 11 jackup rigs and one platform rig outside of the U.S. Gulf of Mexico. This segment operates two jackup rigs and one platform rig in Mexico and two jackup rigs in both Saudi Arabia and India. We have one jackup rig working offshore in Qatar and Malaysia and one rig in Gabon whose contract is being negotiated for early termination. In addition, this segment has one jackup rig currently undergoing an upgrade in Namibia and one jackup rig cold-stacked in Trinidad.

Inland operates 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. Eight of our inland barges are either operating on short-term contracts or available and nine are cold-stacked.

Domestic Liftboats operates 45 liftboats in the U.S. Gulf of Mexico.

International Liftboats operates 20 liftboats. Eighteen are operating offshore West Africa, including five liftboats owned by a third party. One liftboat is operating offshore Middle East. One liftboat is in a Middle Eastern shipyard undergoing refurbishment and it is being marketed in the Middle East region.

Delta Towing our Delta Towing business operates a fleet of 30 inland tugs, 16 offshore tugs, 34 crew boats, 46 deck barges, 17 shale barges and four spud barges along and in the U.S. Gulf of Mexico and along the Southeastern coast. Currently, 24 crew boats, 13 inland tugs and seven offshore tugs are cold-stacked.

In January 2009, we entered into an agreement with Mosvold Middle East Jackup Ltd. whereby we will market, manage and operate two 300 foot, high-specification new-build jackup drilling rigs. The rigs, which have an independent leg cantilever design, are under construction in the Middle East and have expected delivery dates of December 2009 and April 2010. We will have worldwide, exclusive marketing rights, except in U.S. sanctioned countries. All operating and capital expenses incurred to operate the rig will be paid for or reimbursed by Mosvold Middle East Jackup Ltd. Upon commencement of a drilling contract, we will receive a commencement fee and an ongoing management fee for the remainder of the contract.

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Our Fleet

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. Mat 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-two of our jackup rigs are mat-supported and nine are independent leg rigs.

Our rigs are used primarily for exploration and development drilling in shallow waters. Twenty-four 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 19, 2009, 18 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 $94,193. 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 19, 2009.

Rig Name	Type	Year Built	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 110	MC	1981	100/20	20,000	Trinidad	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	Shipyard
Hercules 152	MC	1980	150/22	20,000	U.S. GOM	Contracted
Hercules 153	MC	1980(c)	150/22	25,000	U.S. GOM	Cold Stacked
Hercules 156	ILC	1983	150/14	20,000	Gabon	Contracted
Hercules 170	ILC	1981(d)	170/16	16,000	Qatar	Contracted
Hercules 173	MC	1971	173/22	15,000	U.S. GOM	Contracted

Hercules 185	ILC	1982(d)	120/20	20,000	Namibia	Shipyard
Hercules 200	MC	1979	200/23	20,000	U.S. GOM	Ready Stacked
Hercules 201	MC	1981	200/23	20,000	U.S. GOM	Contracted
Hercules 202	MC	1981	200/23	20,000	U.S. GOM	Contracted
Hercules 203	MC	1982	200/23	20,000	U.S. GOM	Contracted
Hercules 204	MC	1981	200/23	20,000	U.S. GOM	Contracted
Hercules 205	MC	1979	200/23	20,000	Mexico	Contracted
Hercules 206	MC	1980	200/23	20,000	Mexico	Contracted
Hercules 207	MC	1981	200/23	20,000	U.S. GOM	Cold Stacked
Hercules 208(e)	MC	1980(f)	200/22	20,000	Malaysia	Contracted
Hercules 211	MC	1980	200/23	18,000(g)	U.S. GOM	Cold Stacked

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Rig Name	Type	Year Built	Maximum/ Minimum Water Depth Rating (Feet)	Rated Drilling Depth(a) (Feet)	Location	Status(b)
Hercules 250	MS	1974	250/24	20,000	U.S. GOM	Contracted
Hercules 251	MS	1978	250/24	20,000	U.S. GOM	Shipyard
Hercules 252	MS	1978	250/24	20,000	U.S. GOM	Ready Stacked
Hercules 253	MS	1982	250/24	20,000	U.S. GOM	Shipyard
Hercules 257	MS	1979	250/24	20,000	U.S. GOM	Contracted
Hercules 258	MS	1979(f)	250/24	20,000	India	Contracted
Hercules 260	ILC	1979(f)	250/12	20,000	India	Contracted
Hercules 261	ILC	1979(f)	250/12	20,000	Saudi Arabia	Contracted
Hercules 262	ILC	1982(f)	250/12	20,000	Saudi Arabia	Contracted
Hercules 350	ILC	1982	350/16	25,000	U.S. GOM	Ready Stacked

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

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

(c) Rig upgrade and/or major refurbishment was completed in 2007.

(d) *Hercules 170* completed its rig upgrade and major refurbishment in 2006 and *Hercules 185* is currently undergoing an upgrade and major refurbishment that will be completed in 2009.

(e) This rig is currently unable to operate in the U.S. Gulf of Mexico due to regulatory restrictions.

(f) Rig upgrade and/or major refurbishment was completed in 2008.

(g) 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 suitable 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

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submersible rig and Plat means a platform drilling rig. The following table contains information regarding our other drilling rig fleet as of February 19, 2009.

Rig Name	Type	Year Built	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(c)	85/14	30,000	U.S. GOM	Cold Stacked
Hercules 78	Sub	1985(c)	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 designated as Contracted are under contract while 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) Rig upgrade and/or major refurbishment was completed in 2007.

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. Most of our barge drilling rigs are suitable for deep gas drilling.

The following table contains information regarding our barge drilling rig fleet as of February 19, 2009.

Rig Name	Type	Year Built	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	Warm 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	Warm Stacked
19	Conv.	1974	1,000	14,000	U.S. GOM	Cold Stacked

27	Posted	1979 (c)	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	Contracted
41	Posted	1981	3,000	30,000	U.S. GOM	Ready Stacked
46	Posted	1979	3,000	30,000	U.S. GOM	Cold Stacked
48	Posted	1982	3,000	30,000	U.S. GOM	Warm 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	Contracted
57	Posted	1975	2,000	25,000	U.S. GOM	Cold Stacked
64	Posted	1979	3,000	30,000	U.S. GOM	Warm Stacked

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

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

(c) Rig upgrade and/or major refurbishment was completed in 2008.

Liftboats

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. 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.

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. 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. The U.S. Coast Guard restricts the operation of liftboats to water depths less than 180 feet, so boats with longer leg lengths are useful primarily on taller platforms. Eight of our liftboats in the U.S. Gulf of Mexico have leg lengths of 190 feet or greater, which allows us to service approximately 83% of the approximately 3,900 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 19, 2009, we owned 45 liftboats operating in the U.S. Gulf of Mexico, 13 liftboats operating in West Africa, one liftboat operating in the Middle East, and one liftboat undergoing refurbishment in a Middle Eastern shipyard. 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 19, 2009.

	Year	Leg	Deck	Maximum	Gross

Liftboat Name(1)	Built	Length (Feet)	Area (Square feet)	Deck Load (Pounds)	Location	Tonnage
Whale Shark	2005	260	8,170	729,000	UAE	99
Tigershark	2001	230	5,300	1,000,000	U.S. GOM	469
Kingfish	1996	229	5,000	500,000	U.S. GOM	188
Man-O-War	1996	229	5,000	500,000	U.S. GOM	188
Wahoo	1981	215	4,525	500,000	U.S. GOM	491
Blue Shark	1981	215	3,800	400,000	Nigeria	1,182
Amberjack	1981	205	3,800	500,000	Bahrain	417

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Liftboat Name(1)	Year Built	Leg Length (Feet)	Deck Area (Square feet)	Maximum Deck Load (Pounds)	Location	Gross Tonnage
Bullshark	1998	200	7,000	1,000,000	U.S. GOM	859
Creole Fish	2001	200	5,000	798,000	U.S. GOM	192
Cutlassfish	2006	200	5,000	798,000	U.S. GOM	183
Black Jack	1997	200	4,000	480,000	Nigeria	777
Swordfish	2000	190	4,000	700,000	U.S. GOM	189
Mako	2003	175	5,074	654,000	U.S. GOM	168
Leatherjack	1998	175	3,215	575,850	U.S. GOM	168
Oilfish	1996	170	3,200	590,000	Nigeria	495
Manta Ray	1981	150	2,400	200,000	U.S. GOM	194
Seabass	1983	150	2,600	200,000	U.S. GOM	186
F.J. Leleux(2)	1981	150	2,600	200,000	Nigeria	407
Black Marlin	1984	150	2,600	200,000	Nigeria	407
Hammerhead	1980	145	1,648	150,000	U.S. GOM	178
Pilotfish	1990	145	2,400	175,000	Nigeria	292
Rudderfish	1991	145	3,000	100,000	Nigeria	309
Blue Runner	1980	140	3,400	300,000	U.S. GOM	174
Starfish	1978	140	2,266	150,000	U.S. GOM	99
Rainbow Runner	1981	140	3,400	300,000	U.S. GOM	174
Pompano	1981	130	1,864	100,000	U.S. GOM	196
Sandshark	1982	130	1,940	150,000	U.S. GOM	196
Stingray	1979	130	2,266	150,000	U.S. GOM	99
Albacore	1985	130	1,764	150,000	U.S. GOM	171
Moray	1980	130	1,824	130,000	U.S. GOM	178
Skipfish	1985	130	1,116	110,000	U.S. GOM	91
Sailfish	1982	130	1,764	137,500	U.S. GOM	179
Mahi Mahi	1980	130	1,710	142,000	U.S. GOM	99
Triggerfish	2001	130	2,400	150,000	U.S. GOM	195
Scamp	1984	130	2,400	150,000	Nigeria	195
Rockfish	1981	125	1,728	150,000	U.S. GOM	192
Gar	1978	120	2,100	150,000	U.S. GOM	98
Grouper	1979	120	2,100	150,000	U.S. GOM	97
Sea Robin	1984	120	1,507	110,000	U.S. GOM	98
Tilapia	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	1978	120	2,000	100,000	Nigeria	229
Tigerfish	1980	120	2,000	100,000	Nigeria	210
Zoal Albrecht(2)	1982	120	2,000	100,000	Nigeria	213
Barracuda	1979	105	1,648	110,000	U.S. GOM	93
Carp	1978	105	1,648	110,000	U.S. GOM	98
Cobia	1978	105	1,648	110,000	U.S. GOM	94
Dolphin	1980	105	1,648	110,000	U.S. GOM	97

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Liftboat Name(1)	Year Built	Leg Length (Feet)	Deck Area (Square feet)	Maximum Deck Load (Pounds)	Location	Gross Tonnage
Herring	1979	105	1,648	110,000	U.S. GOM	97
Marlin	1979	105	1,648	110,000	U.S. GOM	97
Corina	1974	105	953	100,000	U.S. GOM	98
Pike	1980	105	1,360	130,000	U.S. GOM	92
Remora	1976	105	1,179	100,000	U.S. GOM	94
Wolffish	1977	105	1,044	100,000	U.S. GOM	99
Seabream	1980	105	1,140	100,000	U.S. GOM	92
Sea Trout	1978	105	1,500	100,000	U.S. GOM	97
Tarpon	1979	105	1,648	110,000	U.S. GOM	97
Palometa	1972	105	780	100,000	U.S. GOM	99
Jackfish	1978	105	1,648	110,000	U.S. GOM	99
Bonefish	1978	105	1,344	90,000	Nigeria	97
Croaker	1976	105	1,344	72,000	Nigeria	82
Gemfish	1978	105	2,000	100,000	Nigeria	223
Tapertail	1979	105	1,392	110,000	Nigeria	100

(1) The *Palometa* and *Wolffish* are currently cold-stacked. The *Whale Shark* is in a shipyard in the UAE undergoing regulatory and other modifications and repairs and is expected to re-enter service in the second quarter of 2009. All other liftboats are either available or operating.

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

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, and 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 rigs to other 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. Chevron Corporation accounted for 12%, 21% and 35% of our consolidated revenues for the years ended December 31, 2008, 2007 and 2006, respectively. No other customer accounted for more than 10% of our consolidated revenues in any period.

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. If our customers terminate or require us to renegotiate some of our significant contracts, such as the contracts included in our International Offshore division, and we are unable to secure new contracts on substantially similar terms, or if contracts are suspended for an extended period of time, our financial condition and results of operations could be adversely affected.

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

The following table reflects the amount of our contract backlog by year as of February 19, 2009. 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 revenues for mobilization, demobilization, contract preparation and customer reimbursables. The amount of actual revenues earned and the actual periods during which revenues are earned will be different than the amount 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.

	For the Years Ending December 31,					
	Total	2009	2010	2011	2012	Thereafter
	(In thousands)					
Domestic Offshore	$ 43,431	$ 43,431	$	$	$	$
International Offshore	681,323	281,951	271,070	128,302		
Inland	2,101	2,101				
Total	$ 726,855	$ 327,483	$ 271,070	$ 128,302	$	$

Employees

As of December 31, 2008, we had approximately 3,100 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. 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 employers liability, general liability, vessel pollution and other coverages. Our insurance coverage includes self-insured retentions and deductibles that we must pay or absorb. Additionally, under certain policies, we are responsible for 10% of the losses above the applicable retention or deductible. This additional amount is often referred to as quota share. Management believes that adequate accruals have been made on known and expected exposures for the self-insured retentions, deductibles and for our quota share. 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 and damages. Further, while we have a large number of diversified underwriters, several underwriters that currently provide coverage under our insurance policies have been impacted by the recent global financial crisis. If one or more these underwriters failed, we would be exposed to having portions of our claims uninsured.

In May 2008, we completed the renewal of all of our key insurance policies. Our primary marine package provides for hull and machinery coverage for our rigs and liftboats up to a scheduled value for each asset. The maximum coverage for these assets is $2.9 billion; however, coverage for U.S. Gulf of Mexico named windstorm damage is subject to an annual aggregate limit on liability of $200.0 million. The policies are subject to exclusions, limitations, deductibles, self-insured retention and other conditions. Deductibles for events that are not U.S. Gulf of Mexico named windstorm events are 10% of insured values per occurrence for drilling rigs, and range from $0.3 million to $1.0 million per occurrence for liftboats, depending on the insured value of the particular vessel. The deductibles for drilling rigs and liftboats in a U.S. Gulf of Mexico named windstorm event are the greater of $10.0 million or the operational deductible for each U.S. Gulf of Mexico named windstorm. We are self-insured for 10% above the deductibles for removal of wreck, sue and labor, collision, protection and indemnity general liability and hull and physical damage policies. The protection and indemnity coverage under the primary marine package has a $5.0 million limit per occurrence with excess liability coverage up to $200.0 million. The primary marine package also provides coverage for cargo and charterer s legal liability. Vessel pollution is covered under a Water Quality Insurance Syndicate policy. In addition to the marine package, we have separate policies providing coverage for onshore general liability, employer s liability, auto liability and non-owned aircraft liability, with customary deductibles and coverage as well as a separate primary marine package for our Delta Towing business. Due to heavy damages and significant claims of oil and gas companies as a result of Hurricanes Gustav and Ike, we expect insurance coverage for removal of wreck, liability and hull and machinery for our domestic drilling rigs to be limited or more expensive in the future. As a result, when we renew our insurance in the second quarter of 2009, our premiums may increase significantly or we may be required to assume more risk or carry substantially higher self-insured retention and deductibles.

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 and the U.S. Customs and Border Protection Service, 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. 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 will 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.

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 above. 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.

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.

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Segment and Geographic Information

Information with respect to revenues, operating income and total assets attributable to our segments and revenues and long-lived assets by geographic areas of operations is presented in Note 16 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.

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Item 1A. *Risk Factors*

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 in 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. Oil and natural gas prices and our customers expectations of potential changes in these prices significantly affect this level of activity. 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 and have recently declined considerably. On July 2, 2008 natural gas prices were $13.31 per MMBtu at the Henry Hub. They subsequently declined sharply, reaching a low of $4.33 per MMBtu at the Henry Hub on February 18, 2009. As of February 19, 2009, the closing price of natural gas at the Henry Hub was $4.45 per MMBtu. Oil prices in the past year, based on the spot price for West Texas intermediate crude, have ranged from a high of $145.29 as of July 3, 2008, to a low of $31.41 as of December 22, 2008, with a closing price of $39.48 as of February 19, 2009. 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;
- expectations regarding future commodity prices;
- advances in exploration, development and production technology;
- the ability of the Organization of Petroleum Exporting Countries, commonly called OPEC, to set and maintain 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, uncertainty or instability resulting from an escalation or additional outbreak of armed hostilities or other crises in the Middle East and other significant oil and natural gas producing regions or further acts of terrorism in the United States, or elsewhere; and

acts of terrorism in the United States and elsewhere.

Depending on the market prices of oil and natural gas, and even during periods of high commodity prices, companies exploring for and producing oil and natural gas may cancel or curtail their drilling programs, or reduce their levels of capital expenditures for exploration and production for a variety of reasons, including their lack of success in exploration efforts. Any reduction in the demand for drilling and liftboat services may materially erode dayrates and utilization rates for our units, which would adversely affect our financial condition and results of operations.
Continued hostilities in the Middle East and the occurrence or threat of terrorist attacks against the United States or other countries could cause a downturn in the economies of the United States and those of other countries. A lower level of economic activity could result in a decline in

energy consumption, which could cause our revenues and margins to decline and limit our future growth prospects.

The offshore service industry is highly cyclical, and certain of our contracts, primarily in the U.S. Gulf of Mexico, are short-term contracts. The volatility of the industry, coupled with our short-term contracts, could 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 intensify the competition in the industry and often result in rigs or liftboats being idle for long periods of time. We may be required to stack rigs or liftboats or enter into lower dayrate contracts in response to market conditions in the future. In the U.S. Gulf of Mexico, contracts are generally short term, and oil and natural gas companies tend to respond quickly to upward or downward changes in prices. Due to the short-term nature of most of our contracts, including for our rigs and liftboats in the U.S. Gulf of Mexico and for some of our international liftboats, changes in market conditions can quickly affect our business. In addition, customers generally have the right to terminate our contracts with little or no notice, and without penalty. As a result of the cyclicality of our industry, we expect our results of operations to be volatile. Prolonged periods of low utilization and dayrates could result in the recognition of impairment charges if future cash flow estimates, based upon information available to management at the time, indicate that our rigs carrying value may not be recoverable.

A significant portion of our business is conducted in the shallow-water 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.

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. 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.

Many other companies in the drilling industry are larger than we are and have more diverse fleets, or fleets with generally higher specifications, and greater resources than we have. In the past, rigs like ours have been stacked earlier in the cycle of decreased rig demand than our competitors higher specification rigs and have been reactivated later in the cycle, which has adversely impacted our business and could be repeated in the future. In addition, higher specification rigs may be more adaptable to different operating conditions and have greater flexibility to move to areas of demand in response to changes in market conditions. In recent years, an increasing amount of exploration and production expenditures have been concentrated in deeper water drilling programs and deeper formations requiring higher specification rigs. This trend is expected to continue and could result in a decline in demand for the rigs in our fleet. Some of our competitors also are incorporated in tax-haven countries 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. In addition, the competitive environment has intensified as recent mergers within the oil and natural gas industry have reduced the number of available customers and suppliers, resulting in increased price competition and fewer alternatives for sourcing of key supplies. Finally, competition among drilling and marine service providers is also affected by each provider s reputation for safety and quality. We may not be able to maintain our competitive position, and we believe that competition for contracts will continue to be intense in the foreseeable future. Our inability to compete successfully may reduce our profitability.

Our customers may seek to cancel or renegotiate some of our drilling and liftboat contracts during periods of depressed market conditions 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. Some of our contracts with our customers include terms allowing them to terminate 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 some of our significant contracts, such as the contracts in our International Offshore segment, and we are unable to secure new contracts on substantially similar terms, our revenues and profitability could be materially reduced.

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

As of February 19, 2009, our total contract drilling backlog for our Domestic Offshore, International Offshore and Inland segments was approximately $726.9 million. We may not be able to perform under these contracts due to events beyond our control, and our customers may seek to cancel or renegotiate our contracts for various reasons, including those described above or in connection with the financial crisis or falling commodity prices. 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 business involves numerous operating hazards, 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

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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 peculiar to 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, such as Hurricane Gustav in September 2008, Hurricane Ike in September 2008, Hurricane Rita in September 2005, Hurricane Katrina in August 2005 and Hurricane Ivan in September 2004, could have a material adverse effect on our 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. 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.

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 not totally insurable.

As a result of a number of recent catastrophic events like Hurricanes Ike, Ivan, Katrina and Rita, 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 Hurricanes Ike, Ivan, Katrina and Rita. As a result, 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 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.

If a significant accident or other event resulting in damage to our rigs or liftboats, including severe weather, terrorist acts, 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.

Our customers may be unable or unwilling to indemnify us.

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

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, as well as operate one liftboat in the Middle East. In addition, we have one liftboat undergoing regulatory and other modifications and repairs in the Middle East. We also operate drilling rigs in India, Southeast Asia, Qatar, Saudi Arabia, Mexico and West Africa. We have one jackup rig undergoing an upgrade in Namibia and one jackup rig cold-stacked in Trinidad. 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;
- piracy;
- increased operating costs;
- complications associated with repairing and replacing equipment in remote locations;
- repudiation, modification or renegotiation of contracts;
- limitations on insurance coverage, such as war risk coverage in certain areas;
- import-export quotas;
- confiscatory taxation;
- work stoppages or spikes, particularly in the Nigerian and Mexican labor environment;
- unexpected changes in regulatory requirements;
- wage and price controls;
- imposition of trade barriers;
- imposition or changes in enforcement of local content laws;
- restrictions on currency or capital repatriations;
- currency fluctuations and devaluations; and
- other forms of government regulation and economic conditions that are beyond our control.

As a result of our international expansion the exposure to these risks will increase. Our financial condition and results of operations could be susceptible to adverse events beyond our control that may occur in the particular countries or regions in which we are active.

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 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 less developed countries can be subject to legal systems which are not as mature or predictable as those in more developed countries, which can lead to greater uncertainty in legal matters and proceedings.

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Due to our international operations, we may experience currency exchange losses where revenues are received and expenses are paid in nonconvertible currencies or where we do not hedge an exposure to a foreign currency. We may also incur losses as a result of an inability to collect revenues because of a shortage of convertible currency available to the country of operation, controls over currency exchange or controls over the repatriation of income or capital.

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

We derive a significant amount of our revenue from a single major integrated energy company. Chevron Corporation represented approximately 12%, 21% and 35% of our consolidated revenues for the years ended December 31, 2008, 2007, and 2006, respectively. In addition, Chevron Corporation accounts for 73.2% of the revenues for our International Liftboats segment. Our financial condition and results of operations will be materially adversely affected if Chevron curtails its activities in the U.S. Gulf of Mexico or Nigeria, terminates its contracts with us, fails to renew its existing contracts or refuses to award new contracts to us and we are unable to enter into contracts with new customers at comparable dayrates. In addition, the loss of any of our other significant customers 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.

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, particularly relative to other markets, could also lead to jackup rigs, other mobile offshore drilling units and liftboats being moved into the U.S. Gulf of Mexico or could lead to increased construction and upgrade programs by our competitors. Some of our competitors have already announced plans to upgrade existing equipment or build additional jackup rigs with higher specifications than our rigs. According to ODS-Petrodata, as of February 20, 2009, 70 jackup rigs had been ordered by industry participants, national oil companies and financial investors for delivery through 2011. Not all of the rigs currently under construction have been contracted for future work, which may intensify price competition as scheduled delivery dates occur. In addition, as of February 2009, we believe there were also 10 liftboats under construction or on order in the United States that may be used in the U.S. Gulf of Mexico. A significant increase in the supply of jackup rigs, other mobile offshore drilling units or liftboats could adversely affect both our utilization and dayrates.

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 or deterioration to equipment and machinery in excess of engineering estimates and assumptions;

unanticipated actual or purported change orders;

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work stoppages;

latent damages or deterioration to hull, equipment and machinery in excess of engineering estimates and assumptions;

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, 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 may not earn a dayrate during the period they are out of service.

Our 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, the announced construction of new rigs includes approximately 70 higher specification jackup rigs. Further, 22 of our 31 jackup rigs are mat-supported, which are generally limited to areas with soft bottom conditions like much of the Gulf of Mexico. Most of the new rigs available in the second half of 2009 and beyond are currently without contracts, which may intensify price competition as scheduled delivery dates occur. Particularly during market downturns when there is decreased rig demand, higher specification rigs may be more likely to obtain contracts than lower specification jackup rigs such as ours. In the past, lower specification rigs have been stacked earlier in the cycle of decreased rig demand than higher specification rigs and have been reactivated later in the cycle, which may adversely impact our business. In addition, higher specification rigs may be more adaptable to different operating conditions and therefore have greater flexibility to move to areas of demand in response to changes in market conditions. Because a majority of our rigs were designed specifically for drilling in the shallow-water U.S. Gulf of Mexico, our ability to move them to other regions in response to changes in market conditions is limited. Furthermore, in recent years, an increasing amount of exploration and production expenditures have been concentrated in deepwater drilling programs and deeper formations, including deep natural gas prospects, requiring higher specification jackup rigs, semisubmersible drilling rigs or drillships. This trend is expected to continue and could result in a decline in demand for lower specification jackup rigs like ours, which could have an adverse impact on our financial condition and results of operations. Furthermore, one of our customers, Pemex Exploración y Producción (PEMEX), has indicated a shifting focus in drilling rig requirements since the beginning of 2008, with more emphasis placed on independent leg cantilever rigs rated for 205 foot water depth or greater, versus mat cantilever rigs rated for 200 foot water depth. It is possible that demand in Mexico for our 200 foot mat cantilever fleet could decline and the future contracting opportunities for such rigs in Mexico could diminish.

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TODCO s tax sharing agreement with Transocean may require continuing substantial payments.

We, as successor to TODCO, and TODCO s former parent Transocean Holdings Inc. are parties to a tax sharing agreement that was originally entered into in connection with TODCO s initial public offering in 2004. The tax sharing agreement was amended and restated in November 2006. The tax sharing agreement required us to make an acceleration payment to Transocean upon completion of the TODCO acquisition. Additionally, the tax sharing agreement continues to require that additional payments be made to Transocean based on a portion of the expected tax benefit from the exercise of certain compensatory stock options to acquire Transocean common stock attributable to current and former TODCO employees and board members. The estimated amount of payments to Transocean related to compensatory options that remain outstanding at December 31, 2008, assuming a Transocean stock price of $47.25 per share at the time of exercise of the compensatory options (the actual price of Transocean s common stock at December 31, 2008), is approximately $4.9 million. There is no certainty that we will realize future economic benefits from TODCO s tax benefits equal to the amount of the payments required under the tax sharing agreement.

The recent worldwide financial and credit crisis could lead to an extended worldwide economic recession and have a material adverse effect on our revenue and profitability.

The recent worldwide financial and credit crisis has reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide. The shortage of liquidity and credit combined with recent substantial losses in worldwide equity markets could lead to an extended worldwide economic recession. A slowdown in economic activity caused by a recession would likely reduce worldwide demand for energy and result in lower oil and natural gas prices. Forecasted crude oil prices for 2009 have dropped substantially in recent months. Demand for our services depends on oil and natural gas industry activity and expenditure levels that are directly affected by trends in oil and natural gas prices. Demand for our services is particularly sensitive to the level of exploration, development and production activity of, and the corresponding capital spending by, oil and natural gas companies, including national oil companies. Any prolonged reduction in oil and natural gas prices will depress the immediate 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 given the long-term nature of many large-scale development projects. 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.

The global financial crisis may have impacts on our business and financial condition that we currently cannot predict.

The continued credit crisis and related instability in the global financial system has had, and may continue to have, an impact on our business and our financial condition. We may face significant challenges if conditions in the financial markets do not improve. Our ability to access the capital markets may be severely restricted at a time when we would like, or need, to access such markets, which could have an impact on our flexibility to react to changing economic and business conditions. The credit crisis could have an impact on the lenders under our credit facility or on our customers, causing them to fail to meet their obligations to us.

In order to execute our growth strategy, we may require additional capital in the future, which may not be available to us.

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 or equity financings to execute our growth strategy and to fund capital expenditures. Adequate sources of capital funding may not be available when needed or may not be available on favorable terms. If we raise additional funds by issuing additional equity securities, dilution to the holdings of existing stockholders may result. If funding is insufficient at any time in the future, we may be unable to fund maintenance requirements and acquisitions, take advantage of business opportunities or respond to competitive pressures, any of which could harm our business.

Acquisitions are an important component of our business strategy. Our acquisition strategy may be unsuccessful if we are unable to identify and complete future acquisitions, fail to successfully integrate acquired assets or businesses we acquire, are unable to obtain financing for acquisitions on acceptable terms or incorrectly predict operating results.

The acquisition of assets or businesses that are complementary to our drilling and liftboat operations is an important component of our business strategy. We believe that acquisition opportunities may arise from time to time, and any such acquisition could be significant. At any given time, discussions with one or more potential sellers may be at different stages. However, any such discussions may or may not result in the consummation of an acquisition transaction, and we may not be able to identify or complete any acquisitions. Any such transactions 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. 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.

In addition, we may not be able to obtain, on terms we find acceptable, sufficient financing that may be required for any such acquisition or investment.

If we are unsuccessful in completing acquisitions of other operations or assets, our financial condition could be adversely affected and we may be unable to implement an important component of our business strategy successfully. In addition, if we are unsuccessful in integrating our acquisitions in a timely and cost-effective manner, our financial condition and results of operations could be adversely affected.

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

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

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

Governmental laws and regulations may add to our costs or limit drilling activity and liftboat operations.

Our operations are affected in varying degrees by governmental laws and regulations. The industries in which we operate are dependent on demand for services from the oil and natural gas industry and, accordingly, are also affected by changing tax and other laws relating to the energy business generally. We are also subject to the jurisdiction of the United States Coast Guard, the National Transportation Safety Board and the United States Customs and Border Protection Service, 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 those 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 these conventions, laws, regulations and standards may in the future add significantly to our operating costs or limit our activities.

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 have an adverse effect on 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 do not necessarily fluctuate in proportion to changes in operating revenues.

We do not expect our operating and maintenance costs with respect to our rigs to necessarily fluctuate in proportion to changes in operating revenues. Operating revenues 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.

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 disputes, personal injury, environmental, asbestos and other toxic tort, employment, tax and securities litigation, and other 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 the hurricanes in 2005 and, more recently, by Hurricanes Gustav and Ike. 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 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. They could also be adversely affected by changes in the valuation of our deferred tax assets and liabilities, 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 debt could adversely affect our ability to operate our business and make it difficult to meet our debt service obligations.

As of December 31, 2008, we had total outstanding debt of approximately $1,054.2 billion. This debt represented approximately 53.7% of our total book capitalization. After giving effect to the April 2008 increase of $100 million of available capacity under our revolving credit facility, as of December 31, 2008, we had up to $250 million of available capacity under that facility, of which $29.0 million was committed related to issued standby letters of credit. We may continue to borrow to fund working capital or other needs in the near term up to the remaining availability. Our debt and the limitations imposed on us by our existing or future debt agreements could have significant consequences on 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;

we may be exposed to risks inherent in interest rate fluctuations because our borrowings generally are at variable rates of interest, which would result in higher interest expense to the extent we have not hedged such risk in the event of increases in interest rates; and we could be more vulnerable in the event of a downturn in our business that would leave us less able to take advantage of significant business opportunities and to react to changes in our business and in market or industry conditions.

Our ability to make payments on and to refinance our indebtedness, including the convertible notes issued by us on June 3, 2008, 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 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 or from other sources, 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.

Our senior secured credit agreement imposes significant operating and financial restrictions, which may prevent us from capitalizing on business opportunities and taking some actions.

Our senior secured credit agreement imposes significant operating and financial restrictions on us. These limitations are subject to a number of important qualifications and exceptions. These restrictions limit our ability to:

make investments and other restricted payments, including dividends;

incur or guarantee additional indebtedness;

create or incur liens;

restrict dividend or other payments by our subsidiaries to us;

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

engage in transactions with affiliates.

Our credit agreement also requires us to maintain a minimum fixed charge coverage ratio and maximum leverage ratio. In addition, commencing with the year ending December 31, 2008, we are required to prepay our $900.0 million term loan with 50% of our excess cash flow until the outstanding principal balance of the term loan is less than $550.0 million. 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 a future downturn in our business.

If we are unable to comply with the restrictions and covenants in the agreements governing our indebtedness, there could be a default under the terms of these agreements, which could result in an acceleration of payment of funds that we have borrowed.

If we are unable to comply with the restrictions and covenants in the agreements governing our indebtedness or in current or future debt financing agreements, there could be a default under the terms of these agreements. Our ability to comply with these restrictions and covenants, including meeting financial ratios and tests, may be affected by events beyond our control. If a default occurs under these agreements, lenders could terminate their commitments to lend or accelerate the outstanding loans and declare all amounts borrowed due and payable. Borrowings under other debt instruments that contain cross-acceleration or cross-default provisions may also be accelerated and become due and payable. If any of these events occur, our assets might not be sufficient to repay in full all of our outstanding indebtedness, and we may be unable to find alternative financing. Even if we could obtain alternative financing, that financing might not be on terms that are favorable or acceptable. If we were unable to repay amounts borrowed, the holders of the debt could initiate a bankruptcy proceeding or liquidation proceeding against collateral.

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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 the 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 senior secured 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. Several of our vessels and substantially all of our other personal property, are pledged to collateralize our senior secured credit agreement.

We maintain our principal executive office in Houston, Texas, which is under lease. We lease office space in Lafayette, Louisiana; Houma, Louisiana; Al Khobar, Saudi Arabia; La Romaine, Trinidad; Luanda, Angola; and Ciudad del Carmen, Mexico. We also lease warehouses and yard facilities in Houma, Louisiana; Broussard, Louisiana; Al Khobar, Saudi Arabia and La Romaine, Trinidad. We lease warehouses, office space and residential premises in Qatar, India, Malaysia, Nigeria and Cayman Islands. In addition, we lease a waterfront dock and maintenance facility in Nigeria.

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 acquisition of TODCO, we also assumed certain other material legal proceedings from TODCO and its subsidiaries.

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

Robert E. Aaron et al. vs. Phillips 66 Company et al. Circuit Court, Second Judicial District, Jones County, Mississippi. This is the case name used to refer to several cases that 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. As of the date of this report, 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 continue to monitor a small group of these other cases. We have not determined which entity would be responsible for such claims under the Master Separation Agreement between TODCO and its former parent. We intend to defend ourselves vigorously and, based on the limited information available at this time, 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 position. However, we cannot predict with certainty the outcome or effect of any of the litigation matters specifically described above or of any such 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 management s current estimates.

Item 4. *Submission of Matters to a Vote of Security Holders*

There were no matters submitted to a vote of security holders during the fourth quarter of 2008.

PART II

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

Quarterly Common Stock Prices and Dividend Policy

Our common stock is traded on the NASDAQ Global Select Market under the symbol HERO. As of February 20, 2009, there were 85 stockholders of record. On February 20, 2009, the closing price of our common stock as reported by NASDAQ was $1.78 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**
2008		
Fourth Quarter	$ 14.94	$ 3.06
Third Quarter	39.35	13.08
Second Quarter	39.47	24.07
First Quarter	27.52	20.00

	Price	
	High	**Low**

2007		
Fourth Quarter	$ 28.43	$ 22.93
Third Quarter	34.98	24.88
Second Quarter	36.97	25.45
First Quarter	29.24	23.80

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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 senior secured credit agreement restricts 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, 2008	212	$ 7.10	N/A	N/A
November 1 - 30, 2008	6,336	7.23	N/A	N/A
December 1 - 31, 2008			N/A	N/A
Total	6,548	7.22	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 2008, 2007 or 2006, and currently do not have, a share repurchase program in place. However, on June 3, 2008, we completed an offering of $250.0 million aggregate original principal amount of our 3.375% Convertible Senior Notes due 2038 (Notes). We sold the Notes to the Initial Purchasers in reliance on the exemption from registration provided by Section 4(2) of the Securities Act of 1933, and we were advised by the Initial Purchasers that the Initial Purchasers resold the Notes only to qualified institutional buyers in reliance on Rule 144A under the Securities Act. We used $49.2 million of the net proceeds to repurchase, concurrently with the issuance of the Notes, approximately 1,450,000 shares of our common stock in privately negotiated transactions at a purchase price of $33.95 per share. For additional information regarding the 3.375% Convertible Senior Notes and the terms of conversion, see Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Debt and our Form 8-K filed June 3, 2008.

Item 6. ***Selected Financial Data***

We have derived the following condensed consolidated financial information as of December 31, 2008 and 2007 and for the years ended December 31, 2008, 2007 and 2006 from our audited consolidated financial statements included in Item 8 of this annual report. The condensed consolidated financial information as of December 31, 2006 and 2005 and for the year ended December 31, 2005 as well as for the period from inception (July 27, 2004) to December 31, 2004 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. The condensed consolidated financial information as of December 31, 2004 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, 2005.

We were formed in July 2004 and commenced operations in August 2004. From our formation to December 31, 2008, 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. We have included pro forma information related to the TODCO acquisition in Note 4 to the Consolidated Financial Statements included in Item 8 of this annual report.

In addition, in connection with our initial public offering, we converted from a Delaware limited liability company to a Delaware corporation on November 1, 2005. Upon the conversion, each outstanding membership interest of the limited liability company was converted to 350 shares of common stock of the corporation. Share-based information contained herein assumes that we had effected the conversion of each outstanding membership interest into 350 shares of common stock for all periods prior to the conversion. Prior to the conversion, our owners elected to be taxed at the member unit holder level rather than at the company level. As a result, we did not recognize any tax provision on our income prior to the conversion. Upon completion of the conversion, we recorded a tax provision of $12.1 million related to the recognition of deferred taxes equal to the tax effect of the difference between the book and tax basis of our assets and liabilities as of the effective date of the conversion.

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, 2008(a)	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005	Period from Inception to December 31, 2004
			(In thousands, except per share data)		
Statement of Operations Data:					
Revenues	$ 1,111,807	$ 726,278	$ 344,312	$ 161,334	$ 31,728
Operating income (loss)	(1,120,913)	225,642	158,057	55,859	9,907
Income (loss) from continuing operations	(1,069,343)	136,012	119,050	27,456	8,065
Earnings (loss) per share from continuing operations:					
Basic	$ (12.10)	$ 2.31	$ 3.80	$ 1.10	$ 0.55
Diluted	(12.10)	2.28	3.70	1.08	0.55
Balance Sheet Data (as of end of period):					
Cash and cash equivalents	$ 106,455	$ 212,452	$ 72,772	$ 47,575	$ 14,460
Working capital	185,285	325,068	110,897	70,083	30,283
Total assets	2,590,895	3,643,948	605,581	354,825	132,156
Long-term debt, net of current portion	1,042,766	890,013	91,850	93,250	53,000
Total stockholders equity	907,772	2,011,433	394,851	215,943	71,087
Cash dividends per share					

(a) 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, 2008	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005	Period from Inception to December 31, 2004
			(In thousands)		
Other Financial Data:					
Net cash provided by (used in):					
Operating activities	$ 269,948	$ 175,741	$ 124,241	$ 54,762	$ (8,528)
Investing activities	(515,787)	(825,007)	(149,983)	(174,952)	(94,241)
Financing activities	139,842	788,946	50,939	153,305	117,229
Capital expenditures(a)	585,084	155,390	204,456	168,038	94,443
Deferred drydocking expenditures	17,269	20,772	12,544	7,369	601

(a) 2008 includes the purchase of the *Hercules 350*, the *Hercules 262* and the *Hercules 261* as well as related equipment.

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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, 2008 and 2007 and for the years ended December 31, 2008, 2007 and 2006 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 provide shallow-water drilling and marine services to the oil and natural gas exploration and production industry in the U.S. Gulf of Mexico and internationally. We provide these services to major integrated energy companies, independent oil and natural gas operators and national oil companies.

In July 2007, we completed the acquisition of TODCO for total consideration of approximately $2,397.8 million, consisting of $925.8 million in cash and 56.6 million shares of common stock. TODCO, a provider of contract drilling and marine services in the U.S. Gulf of Mexico and international markets, owned and operated 24 jackup rigs, 27 barge rigs, three submersible rigs, nine land rigs, one platform rig and a fleet of marine support vessels. The TODCO acquisition positioned us as a leading shallow-water drilling provider as well as expanded our international presence and diversified our fleet. In the first quarter of 2008, we furthered our strategic growth initiative by purchasing two jackup drilling rigs and related equipment for $220.0 million. In addition, during the second quarter of 2008, we purchased a third jackup rig and related equipment for $100.0 million.

We operate our business as six divisions: (1) Domestic Offshore, (2) International Offshore, (3) Inland, (4) Domestic Liftboats, (5) International Liftboats, and (6) Delta Towing. Previously, we reported an Other segment that included Delta Towing and the land rigs. The land rigs were sold in December 2007 and the results of the land rig operations are included in Discontinued Operation.

In January 2009, we reclassified four of our cold-stacked jackup rigs located in the U.S. Gulf of Mexico and 10 of our cold-stacked inland barges as retired. These rigs require extensive refurbishment and currently are not expected to re-enter active service. As of February 19, 2009, our business segments included the following:

Domestic Offshore operates 20 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. Fourteen of the jackup rigs are either working on short-term contracts or available. One is in the shipyard for maintenance and five are cold-stacked. All three submersibles are cold-stacked.

International Offshore operates 11 jackup rigs and one platform rig outside of the U.S. Gulf of Mexico. This segment operates two jackup rigs and one platform rig in Mexico and two jackup rigs in both Saudi Arabia and India. We have one jackup rig working offshore in Qatar and Malaysia and one rig in Gabon whose contract is being negotiated for early termination. In addition, this segment has one jackup rig currently undergoing an upgrade in Namibia and one jackup rig cold-stacked in Trinidad.

Inland operates 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. Eight of our inland barges are either operating on short-term contracts or available to be contracted and nine are cold-stacked.

Domestic Liftboats operates 45 liftboats in the U.S. Gulf of Mexico.

International Liftboats operates 20 liftboats. Eighteen are operating offshore West Africa, including five liftboats owned by a third party. One liftboat is operating offshore Middle East. One liftboat is in a Middle Eastern shipyard undergoing refurbishment and it is being marketed in the Middle East region.

Delta Towing our Delta Towing business operates a fleet of 30 inland tugs, 16 offshore tugs, 34 crew boats, 46 deck barges, 17 shale barges and four spud barges along and in the U.S. Gulf of Mexico and along the Southeastern coast. Currently, 24 crew boats, 13 inland tugs and seven offshore tugs are cold-stacked.

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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 that support a broad range of offshore support services, including platform maintenance, platform construction, well intervention and decommissioning 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 revenues are 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. 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 revenues 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.

RESULTS OF OPERATIONS

On July 11, 2007, we completed the acquisition of TODCO for total consideration of approximately $2,397.8 million, consisting of $925.8 million in cash and 56.6 million shares of common stock. Our results include activity from this acquired business from the date of acquisition. The acquisition significantly impacts the comparability of the 2008 and 2007 periods with the 2006 period.

On average, domestic industry conditions were generally weaker in 2008 as evidenced by lower average jackup, inland barge and liftboat dayrates in 2008 as compared to 2007. International industry conditions remained strong throughout 2007 and 2008 with increasing demand for jackups and higher average dayrates for both jackups and liftboats.

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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, 2008	2007	2006
	(Dollars in thousands)		
Domestic Offshore:			
Number of rigs (as of end of period)(a)	27	27	6
Revenues	$ 382,358	$ 241,452	$ 160,761
Operating expenses	227,884	122,131	51,862
Impairment of goodwill	507,194		
Impairment of property and equipment	174,613		
Depreciation and amortization expense	66,850	35,143	8,882
General and administrative expenses	4,673	6,105	6,980
Operating income (loss)	$ (598,856)	$ 78,073	$ 93,037
International Offshore:			
Number of rigs (as of end of period)	12	10	3
Revenues	$ 327,983	$ 144,778	$ 30,460
Operating expenses	147,899	59,593	13,377
Impairment of goodwill	150,886		
Depreciation and amortization expense	37,865	15,513	2,547
General and administrative expenses	2,980	1,863	1,606
Operating income (loss)	$ (11,647)	$ 67,809	$ 12,930
Inland:			
Number of barges (as of end of period)(a)	27	27	
Revenues	$ 162,487	$ 107,100	$
Operating expenses	125,656	56,636	
Impairment of goodwill	205,474		
Impairment of property and equipment	202,055		
Depreciation and amortization expense	43,107	16,264	
General and administrative expenses	8,347	533	
Operating income (loss)	$ (422,152)	$ 33,667	$
Domestic Liftboats:			
Number of liftboats (as of end of period)	45	47	47
Revenues	$ 94,755	$ 137,745	$ 133,929
Operating expenses	54,474	59,902	49,025
Depreciation and amortization expense	21,317	24,969	18,854
General and administrative expenses	2,386	2,190	2,259
Operating income	$ 16,578	$ 50,684	$ 63,791

International Liftboats:			
Number of liftboats (as of end of period)	20	18	17
Revenues	$ 85,896	$ 63,282	$ 19,162
Operating expenses	39,122	31,879	9,874
Depreciation and amortization expense	9,912	7,619	1,923
General and administrative expenses	5,990	3,888	3,056
Operating income	$ 30,872	$ 19,896	$ 4,309

(a) In January 2009, we retired four Domestic Offshore rigs and ten Inland barges.

	Year Ended December 31, 2008	2007	2006
	(Dollars in thousands)		
Delta Towing:			
Revenues	$ 58,328	$ 31,921	$
Operating expenses	36,676	16,050	
Impairment of goodwill	86,733		
Depreciation and amortization expense	10,926	4,598	
General and administrative expenses	4,058	1,011	
Operating income (loss)	$ (80,065)	$ 10,262	$
Total Company:			
Revenues	$ 1,111,807	$ 726,278	$ 344,312
Operating expenses	631,711	346,191	124,138
Impairment of goodwill	950,287		
Impairment of property and equipment	376,668		
Depreciation and amortization expense	192,894	104,634	32,310
General and administrative expenses	81,160	49,811	29,807
Operating income (loss)	(1,120,913)	225,642	158,057
Interest expense	(59,486)	(34,859)	(9,278)
Gain on disposal of assets			30,690
Gain (loss) on early retirement of debt, net	41,313	(2,182)	
Other, net	3,315	6,483	4,038
Income (loss) before income taxes	(1,135,771)	195,084	183,507
Income tax benefit (provision)	66,428	(59,072)	(64,457)
Income (loss) from continuing operations	(1,069,343)	136,012	119,050
Income (loss) from discontinued operation, net of taxes	(1,520)	510	
Net income (loss)	$ (1,070,863)	$ 136,522	$ 119,050

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

	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

	Year Ended December 31, 2007				
	Operating Days	**Available Days**	**Utilization(1)**	**Average Revenue per Day(2)**	**Average Operating Expense per Day(3)**
Domestic Offshore	3,265	4,958	65.9%	$ 73,952	$ 24,633
International Offshore	1,549	1,625	95.3%	93,465	36,673
Inland	2,279	2,941	77.5%	46,994	19,257
Domestic Liftboats	11,265	16,749	67.3%	12,228	3,576
International Liftboats	5,077	6,149	82.6%	12,464	5,184

	Year Ended December 31, 2006				
	Operating Days	**Available Days**	**Utilization(1)**	**Average Revenue per Day(2)**	**Average Operating Expense per Day(3)**
Domestic Offshore	1,973	2,078	94.9%	$ 81,480	$ 24,957
International Offshore	305	321	95.0%	99,868	41,673
Inland	n/a	n/a	n/a	n/a	n/a
Domestic Liftboats	11,895	15,416	77.2%	11,259	3,180
International Liftboats	1,765	2,009	87.9%	10,857	4,915

(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 Domestic Offshore revenue is a total of $0.4 million related to amortization of contract specific capital expenditures reimbursed by the customer for the year ended December 31, 2007. There was no such revenue in the years ended December 31, 2008 and 2006. Included in International Offshore revenue is a total of $11.6 million, $3.2 million and $2.6 million related to amortization of deferred mobilization revenue and contract specific capital expenditures reimbursed by the customer for the years ended December 31, 2008, 2007 and 2006, respectively. Included in revenue for our International Offshore segment for the year ended December 31, 2006 is $2.0 million earned for a timely departure of *Hercules 170* from the shipyard in the second quarter of 2006. Included in International Liftboats revenue is a total of $0.3 million related to amortization of deferred mobilization revenue for the year ended December 31, 2008. There was no such revenue in the years ended December 31, 2007 and 2006.

(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. Included in International Offshore operating expense is a total of $5.6 million, $2.8 million and $1.6 million related to amortization of deferred mobilization expenses for the years ended December 31, 2008, 2007 and 2006, respectively.

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 as our customers may reduce drilling activity. Accordingly, our operating results may vary from quarter to quarter, depending on factors outside of our control.

2008 Compared to 2007

Revenues

Consolidated. Total revenues for 2008 were $1,111.8 million compared with $726.3 million for 2007, an increase of $385.5 million, or 53%. This increase resulted primarily from revenues generated from assets acquired from TODCO (Acquired Assets) in July 2007. Total revenues included $15.6 million in reimbursements from our customers for expenses paid by us in 2008 compared with $15.2 million in 2007.

Domestic Offshore. Revenues for our Domestic Offshore segment were $382.4 million for 2008 compared with $241.5 million for 2007, an increase of $140.9 million, or 58%. Revenues for 2008 include approximately $266.8 million compared to $119.4 million for 2007 from the Acquired Assets. Revenue increased $171.0 million due to additional operating days primarily from the Acquired Assets, partially offset by a $30.1 million decrease due to lower average dayrates. Average revenue per rig per day decreased to $64,730 in 2008 from $73,952 in 2007. Average utilization was 72.3% in 2008 compared with 65.9% in 2007. Revenues for our Domestic Offshore segment include $1.3 million and $2.4 million in reimbursements from our customers for expenses paid by us in 2008 and 2007, respectively.

International Offshore. Revenues for our International Offshore segment were $328.0 million for 2008 compared with $144.8 million for 2007, an increase of $183.2 million, or 127%. Revenues for 2008 include approximately $124.5 million compared to $65.1 million for 2007 from the Acquired Assets. Revenue increased $143.4 million due to additional operating days primarily from the Acquired Assets and $39.8 million due to higher average dayrates. Average revenue per rig per day was $119,137 in 2008 compared with $93,465 in 2007 as a result of the commencement of *Hercules 260* and the associated revenue from the provision of marine services, and certain rigs operating at higher dayrates in 2008. Included in our revenues for the International Offshore segment is a total of $11.6 million and $3.2 million related to amortization of deferred mobilization revenue and contract specific capital expenditures reimbursed by the customer for 2008 and 2007, respectively. In addition, revenues for our International Offshore segment included $1.0 million and $1.5 million in reimbursements from our customers for expenses paid by us in 2008 and 2007, respectively.

Inland. Revenues for our Inland segment were $162.5 million for 2008 compared with $107.1 million for the 2007, an increase of $55.4 million, or 52%. The 2007 revenue is for the period from July 11, 2007 to December 31, 2007 as we did not have an Inland segment prior to the TODCO acquisition. Average dayrates and average utilization in 2008 declined to $40,140 and 68.8% from $46,994 and 77.5% in 2007, respectively. Lower revenue per day also reflects our customers lower drilling activity. Revenues for our Inland segment include $1.5 million and $0.7 million in reimbursements from our customers for expenses paid by us in 2008 and 2007, respectively.

Domestic Liftboats. Revenues for our Domestic Liftboats segment were $94.8 million for 2008 compared with $137.7 million in 2007, a decrease of $43.0 million, or 31%. This decrease resulted primarily from lower average dayrates, which contributed $34.5 million of the decrease, and fewer operating days, which contributed $8.5 million of the decrease. Operating days decreased to 10,343 in 2008 from 11,265 in 2007 due primarily to lower customer activity in the Gulf of Mexico in 2008 as compared to the 2007. Average utilization also declined to 65.5% in 2008 from 67.3% in 2007. Average revenue per vessel per day was $9,161 in 2008 compared with $12,228 in 2007, a decrease of $3,067. Approximately $2,369 of the decrease in average revenue per vessel per day was due to lower dayrates and approximately $698 was due to mix of vessel class. Revenues for our Domestic Liftboats segment included $4.8 million in reimbursements from our customers for expenses paid by us in 2008 compared with $5.6 million in 2007.

International Liftboats. Revenues for our International Liftboats segment were $85.9 million for 2008 compared with $63.3 million in 2007, an increase of $22.6 million, or 36%. The increase resulted primarily from higher average dayrates, which contributed $23.5 million of the increase, partially offset by fewer operating days. Operating days decreased from 5,077 days in 2007 to 5,028 days in 2008. Average revenue per liftboat per day was $17,084 in 2008 compared with $12,464 in 2007, with average utilization of 77.3% in 2008 compared with 82.6% in 2007. Revenues for our International Liftboats segment included $6.3 million and $4.7 million in reimbursements from our customers for expenses paid by us in 2008 and 2007, respectively.

Delta Towing. Revenues for our Delta Towing segment were $58.3 million for 2008 compared with $31.9 million for the 2007, an increase of $26.4 million, or 83%. Prior to our acquisition of TODCO in July 2007, we did not have a Delta Towing segment.

Operating Expenses

Consolidated. Total operating expenses for 2008 were $631.7 million compared with $346.2 million in 2007, an increase of $285.5 million, or 82%. This increase is further described below.

Domestic Offshore. Operating expenses for our Domestic Offshore segment were $227.9 million in 2008 compared with $122.1 million in 2007, an increase of $105.8 million, or 87%. Operating expenses for 2008 include approximately $146.8 million associated with the Acquired Assets compared to approximately $67.9 million in 2007. Available days increased to 8,166 in 2008 from 4,958 in 2007. Average operating expenses per rig per day were $27,906 in 2008 compared with $24,633 in 2007. The increase was driven primarily by higher costs related to labor and repairs and maintenance, partially offset by lower insurance costs.

International Offshore. Operating expenses for our International Offshore segment were $147.9 million in 2008 compared with $59.6 million in 2007, an increase of $88.3 million, or 148%. Operating expenses for 2008 include approximately $19.9 million associated with the Acquired Assets compared to $30.2 million in 2007. Available days increased to 3,005 in 2008 from 1,625 in 2007. Average operating expenses per rig per day were $49,218 in 2008 compared with $36,673 in 2007. The increase resulted primarily from higher costs related to marine service equipment rentals, labor and additional amortization of deferred mobilization and contract preparation expenses. Included in operating expense is $5.6 million in amortization of deferred mobilization expense in 2008 compared with $2.8 million in 2007.

Inland. Operating expenses for our Inland segment were $125.7 million in 2008 compared with $56.6 million in 2007, an increase of $69.0 million, or 122%. Available days increased to 5,885 in 2008 from 2,941 in 2007 due to the full year of operations in 2008, partially offset by cold stacking additional barges in 2008. Average operating expenses per rig per day were $21,352 in 2008 compared with $19,257 in 2007. The increase was driven primarily by higher costs related to labor and fuel, partially offset by lower equipment rental costs. Prior to our acquisition of TODCO in July 2007, we did not have an Inland segment.

Domestic Liftboats. Operating expenses for our Domestic Liftboats segment were $54.5 million in 2008 compared with $59.9 million in 2007, a decrease of $5.4 million, or 9%. Available days decreased to 15,785 in 2008 from 16,749 in 2007. Average operating expenses per vessel per day were $3,451 in 2008 compared with $3,576 in 2007. The decrease was primarily due to lower repairs and maintenance and insurance costs.

International Liftboats. Operating expenses for our International Liftboats segment were $39.1 million for 2008 compared with $31.9 million in 2007, an increase of $7.2 million, or 23%. Average operating expenses per liftboat per day were $6,018 in 2008 compared with $5,184 in 2007. This increase was driven primarily by costs accrued for a payment to a former owner, as well as increased repairs and maintenance costs.

Delta Towing. Operating expenses for our Delta Towing segment were $36.7 million in 2008 compared with $16.1 million in 2007, an increase of $20.6 million, or 129% as we did not have a Delta Towing segment prior to our acquisition of TODCO in July 2007.

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Impairment of Goodwill

In the year ended December 31, 2008, we incurred $950.3 million related to the impairment of our goodwill. There were no comparable charges in the year ended December 31, 2007.

Impairment of Property and Equipment

In the year ended December 31, 2008, we incurred $376.7 million of impairment charges related to certain property and equipment on our Domestic Offshore and Inland segments. There were no comparable charges in the year ended December 31, 2007.

Depreciation and Amortization

Depreciation and amortization expense in 2008 was $192.9 million compared with $104.6 million in 2007, an increase of $88.3 million, or 84%. This increase resulted partially from the full year depreciation related to the Acquired Assets. Depreciation related to Acquired Assets was approximately $135.9 million for 2008 compared to approximately $52.1 million in 2007.

General and Administrative Expenses

General and administrative expenses in 2008 were $81.2 million compared with $49.8 million in 2007, an increase of $31.3 million, or 63%. The increase is primarily related to incurring the full year incremental general and administrative costs associated with the Acquired Assets in 2008, a provision for doubtful accounts receivable of $6.2 million, as well as $7.5 million in executive severance related costs.

Interest Expense

Interest expense increased $24.6 million, or 71%. The increase was primarily due to interest on our borrowings under our 2007 senior secured term loan and interest on our 3.375% Convertible Senior Notes issued in June 2008.

Gain (Loss) on Early Retirement of Debt, Net

In 2008, the gain on early retirement of debt in the amount of $41.3 million related to the December 2008, redemption of $88.2 million aggregate principal amount of the 3.375% Convertible Senior Notes for a cost of $44.8 million which resulted in a gain of $43.4 million and the related write off of $2.1 million of unamortized issuance costs. In 2007, the loss on early retirement of debt in the amount of $2.2 million related to the write off of deferred financing fees in connection with repayment of term loan principal in April and July 2007.

Other Income

Other income in 2008 was $3.3 million compared with $6.5 million in 2007, a decrease of $3.2 million or 49%. This decrease is primarily due to lower interest income due to lower cash balances in 2008.

Income Tax Benefit (Provision)

Income tax benefit was $66.4 million on pre-tax loss of $1,135.8 million during 2008, compared to a provision of $59.1 million on pre-tax income of $195.1 million for 2007. The effective tax rate decreased to a tax benefit of 5.8% in 2008 from a tax provision of 30.3% in 2007. The decrease in the effective tax rate primarily reflects the impact of the non-deductible goodwill impairment.

Discontinued Operation

We had a loss from discontinued operation, net of taxes of $1.5 million in 2008 compared to income from discontinued operation, net of taxes of $0.5 million in 2007. The 2008 loss includes the impact of the wind down costs associated with our land rigs sold in December 2007.

2007 Compared to 2006

Revenues

Consolidated. Total revenues for 2007 were $726.3 million compared with $344.3 million for 2006, an increase of $382.0 million, or 111%. This increase resulted primarily from revenues generated from TODCO acquired in July 2007. Total revenues included $15.2 million in reimbursements from our customers for expenses paid by us in 2007 compared with $7.5 million in 2006.

Domestic Offshore. Revenues for our Domestic Offshore segment were $241.5 million for 2007 compared with $160.8 million for 2006, an increase of $80.7 million, or 50%. Revenues for 2007 include approximately $119.4 million from TODCO. Excluding the revenue from TODCO, revenue decreased by $38.7 million, of which $23.7 million was due to fewer operating days and $15.0 million was due to lower average dayrates for our fleet. Average utilization was 65.9% in 2007 compared with 94.9% in 2006 primarily due to the stacking of rigs in 2007 and our customers lower drilling activity. Average revenue per rig per day was $73,952 in 2007 compared with $81,480 in 2006. Lower revenue per day also reflects our customers lower drilling activity. Revenues for our Domestic Offshore segment included $2.4 million and $1.1 million in reimbursements from our customers for expenses paid by us in 2007 and 2006, respectively.

International Offshore. Revenues for our International Offshore segment were $144.8 million for 2007 compared with $30.5 million for 2006, an increase of $114.3 million, or 375%. Revenues for 2007 include approximately $65.1 million from TODCO. Excluding the impact of the acquisition, revenue increased by $49.2 million, of which $46.2 million was due primarily to additional operating days resulting from *Hercules 258* being in service the entire period in 2007. Included in our revenues for the International Offshore segment is a total of $3.2 million and $2.6 million related to amortization of deferred mobilization revenue and contract specific capital expenditures reimbursed by the customer for the year ended December 31, 2007 and 2006, respectively. In addition, revenues for our International Offshore segment included $1.5 million and $0.2 million in reimbursements from our customers for expenses paid by us in 2007 and 2006, respectively.

Inland. Revenues for our Inland segment were $107.1 million in 2007, with 2,279 operating days and average revenue per rig per day of $46,994. Revenues for our Inland segment included $0.7 million in reimbursements from our customers for expenses paid by us in 2007. Prior to our acquisition of TODCO in July 2007, we did not have an Inland segment.

Domestic Liftboats. Revenues for our Domestic Liftboats segment were $137.7 million for 2007 compared with $133.9 million in 2006, an increase of $3.8 million, or 3%. This increase resulted primarily from higher average dayrates, which contributed $11.5 million of the increase, and partially offset by fewer operating days, which contributed $7.7 million of a decrease. Operating days decreased to 11,265 in 2007 from 11,895 in 2006 due primarily to 264 days of severe weather in 2007 as compared to 2006. Average utilization also declined to 67.3% in 2007 from 77.2% in 2006 as customers repair and maintenance activities declined. Average revenue per vessel per day was $12,228 in 2007 compared with $11,259 in 2006. Revenues for our Domestic Liftboats segment included $5.6 million and $4.8 million in reimbursements from our customers for expenses paid by us in 2007 and 2006, respectively.

International Liftboats. Revenues for our International Liftboats segment were $63.3 million for 2007 compared with $19.1 million in 2006, an increase of $44.1 million, or 230%. This increase is primarily due to an acquisition in the fourth quarter 2006 which resulted in an increase in operating days from 1,765 days in 2006 to 5,077 days in 2007. Average revenue per liftboat per day was $12,464 in 2007 compared with $10,857 in 2006, with average utilization of 82.6% in 2007 compared with 87.9% in 2006. Revenues for our International Liftboats segment included $4.7 million and $1.4 million in reimbursements from our customers for expenses paid by us in 2007 and 2006, respectively.

Delta Towing. Revenues for our Delta Towing segment were $31.9 million in 2007 and included $0.3 million in reimbursements from our customers for expenses paid by us in 2007. Prior to our acquisition of TODCO in July 2007, we did not have a Delta Towing segment.

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Operating Expenses

Consolidated. Total operating expenses for 2007 were $346.2 million compared with $124.1 million in 2006, an increase of $222.1 million, or 179%. This increase is further described below.

Domestic Offshore. Operating expenses for our Domestic Offshore segment were $122.1 million in 2007 compared with $51.8 million in 2006, an increase of $70.3 million, or 135%. Operating expenses for 2007 include approximately $67.9 million associated with the TODCO acquisition. Available days increased to 4,958 in 2007 from 2,078 in 2006. Average operating expenses per rig per day were slightly lower; $24,633 in 2007 compared with $24,957 in 2006. On a per day basis, average operating expenses per rig decreased primarily due to lower labor and insurance costs, partially offset by higher repairs and maintenance costs.

International Offshore. Operating expenses for our International Offshore segment were $59.6 million in 2007 compared with $13.4 million in 2006, an increase of $46.2 million, or 345%. Operating expenses for 2007 include approximately $30.2 million associated with the TODCO acquisition. Available days increased to 1,625 in 2007 from 321 in 2006. Average operating expenses per rig per day were $36,673 in 2007 compared with $41,673 in 2006. Included in operating expense is $2.8 million and $1.6 million in amortization of deferred mobilization expense for 2007 and 2006, respectively.

Inland. Operating expenses for our Inland segment were $56.6 million in 2007, with 2,941 available days and average operating expenses per rig per day of $19,257. Prior to our acquisition of TODCO in July 2007, we did not have an Inland segment.

Domestic Liftboats. Operating expenses for our Domestic Liftboats segment were $59.9 million in 2007 compared with $49.0 million in 2006, an increase of $10.9 million, or 22%. Available days increased to 16,749 in 2007 from 15,416 in 2006. Average operating expenses per vessel per day increased to $3,576 in 2007 compared with $3,180 in 2006, primarily from an increase in labor costs.

International Liftboats. Operating expenses for our International Liftboats segment were $31.9 million for 2007 compared with $9.9 million in 2006, an increase of $22.0 million, or 223%. The increase is primarily due to additional liftboats acquired in the fourth quarter of 2006. Average operating expenses per liftboat per day were $5,184 in 2007 compared with $4,915 in 2006. This increase was driven primarily by higher repairs and maintenance, fuel and travel costs.

Delta Towing. Operating expenses for our Delta Towing segment were $16.1 million in 2007. Prior to our acquisition of TODCO in July 2007, we did not have a Delta Towing segment.

Depreciation and Amortization

Depreciation and amortization expense in 2007 was $104.6 million compared with $32.3 million in 2006, an increase of $72.3 million, or 224%. This increase resulted primarily from additional depreciation of approximately $52.1 million related to assets acquired in the TODCO acquisition.

General and Administrative Expenses

General and administrative expenses in 2007 were $49.8 million compared with $29.8 million in 2006, an increase of $20.0 million, or 67%. The increase is primarily related to incremental general and administrative costs associated with TODCO, as well as a $10.9 million increase in corporate labor related costs, which includes $3.1 million in acquisition and severance related costs.

Interest Expense

Interest expense in 2007 was $34.9 million compared with $9.3 million in 2006, an increase of $25.6 million, or 276%. The increase was primarily due to interest on our borrowings under our new senior secured term loan.

Loss on Early Retirement of Debt

The loss on early retirement of debt in the amount of $2.2 million related to the write off of deferred financing fees in connection with repayment of term loan principal in April and July 2007.

Other Income

Other income in 2007 was $6.5 million compared with $4.0 million in 2006, an increase of $2.4 million. This increase primarily related to additional interest income earned in 2007.

Discontinued Operation

We had Income from Discontinued Operation, Net of Taxes of $0.5 million in 2007 associated with our land rigs acquired in July 2007 and sold in December 2007.

Income Tax Provision

Income tax expense was $59.1 million on pre-tax income of $195.1 million during 2007, compared to $64.5 million on pre-tax income of $183.5 million for 2006. The effective tax rate decreased to 30.3% in 2007 from 35.1% in 2006. The decrease in the effective tax rate results from a higher percentage of pretax income being derived from our international operations where a portion of such earnings are permanently reinvested. The decrease also reflects a lower overall state income tax rate.

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 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 months, there has been substantial volatility and a decline in commodity prices. In addition, there has been uncertainty in the capital markets and available financing is limited. If these conditions persist for a prolonged length of time, our business and the businesses of our customers could be adversely impacted. This in turn 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 marketable securities, goodwill, and intangible assets. Inherent in such policies are certain key assumptions and estimates.

Cash and Cash Equivalents and Marketable Securities

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. From time to time we may invest a portion of our available cash in marketable securities. Marketable securities are classified as available for sale and are stated at fair value on the Consolidated Balance Sheets. As of December 31, 2008, we had no investments in marketable securities. As of December 31, 2007, we had marketable securities with a fair value and cost basis of $39.3 million.

Realized and unrealized gains and losses related to marketable securities are calculated using the specific identification method. Unrealized gains or losses, net of taxes, are included in Accumulated Other Comprehensive Loss on the Consolidated Balance Sheets until realized. Realized gains or losses are included in Other,

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Net in the Consolidated Statements of Operations. Proceeds of $39.3 million and $112.4 million were received from sales and maturities of marketable securities for the year ended December 31, 2008 and 2007, respectively. There were no realized or unrealized gains or losses related to these securities during the years ended December 31, 2008 and 2007.

Goodwill

In accordance with Statement of Financial Accounting Standards (SFAS) No. 142, *Goodwill and Other Intangible Assets* (SFAS No. 142), we are required to test for the impairment of goodwill and other intangible assets with indefinite lives on at least an annual basis. Recoverability of goodwill is evaluated using a two-step process. The first step involves a comparison of the fair value of each of the reporting units with its carrying amount. If a reporting unit s carrying amount exceeds its fair value, the second step is performed. The second step involves a comparison of the implied fair value and carrying value of that reporting unit s goodwill. To the extent that a reporting unit s carrying amount exceeds the implied fair value of its goodwill, an impairment loss is recognized. Fair value is estimated using discounted cash flows and other market-related valuation models, including earnings multiples and comparable asset market values. In making an assessment of fair value, we rely on current and past experience concerning our industry cycles which historically have proven to be extremely volatile. In addition, we make future assumptions based on a number of factors including future operating performance, expected economic conditions and actions we expect to take. Rates used to discount future cash flows are dependent upon interest rates and the cost of capital at a point in time. There are inherent uncertainties related to these factors and our judgment in applying them to the analysis of goodwill impairment.

We performed a preliminary annual impairment assessment as of October 1, 2008. However, during the fourth quarter of 2008, our market capitalization continued to decline significantly, therefore, we completed our analysis as of December 31, 2008. As of December 31, 2008, our market capitalization was significantly below our book value. We 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, we recorded a goodwill impairment of $950.3 million, which represented all of our goodwill as of December 31, 2008.

Other Intangible Assets

In connection with the acquisition of TODCO, we allocated $17.6 million in value to certain international customer contracts. These amounts are being amortized over the life of the contracts. As of December 31, 2008, the customer contracts had a carrying value of $7.2 million, net of accumulated amortization of $10.4 million, and are included in Other Assets, Net on the Consolidated Balance Sheets. We analyzed these intangible assets for impairment as of December 31, 2008 and noted that the assets were recoverable under SFAS No. 144.

Amortization expense was $7.6 million and $2.8 million for the year ended December 31, 2008 and 2007. Future estimated amortization expense for the carrying amount of intangible assets as of December 31, 2008 is expected to be as follows (in thousands):

2009	$ 4,781
2010	1,814
2011	658
2012	
2013	

Property and Equipment

Property and equipment represents 80.6% of our total assets as of December 31, 2008. 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 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 below). 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. For property and equipment, the determination of recoverability is made based on the estimated undiscounted future net cash flows of the assets being reviewed. Any actual impairment charge would be recorded using the estimated discounted value of future cash flows. 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.

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 has 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 outlook as an indicator of impairment and assessed the rig assets of the Inland and Domestic Offshore segments for impairment. When analyzing our assets for impairment, we separate our marketable rigs, those rigs 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 rigs, those rigs that have been cold stacked for an extended period of time or those rigs that we do not reasonably expect to market in the foreseeable future. Based on an undiscounted cash flow analysis, it was determined that the non-marketable rigs for both segments were impaired and 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. There were no impairment charges for the periods ended December 31, 2007 and 2006.

Revenue Recognition

Revenues are generated from our rigs and liftboats working under dayrate contracts as the services are performed. 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 revenues and reimbursement for contract specific capital expenditures, which are recognized as services are performed over the term of the related drilling contract.

Income Taxes

We provide for income taxes in accordance with SFAS No. 109, *Accounting for Income Taxes*. This standard 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 contests our right to certain deduction and also claims the subsidiary did not remit withholding tax due on certain of these deductions. We are pursuing our alternatives to resolve this assessment. As required by local statutory requirements, we have provided a surety bond for an amount equal to $13 million as of December 31, 2008 to contest these assessments.

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. We recognized $2.1 million of deferred U.S. tax expense on foreign earnings which management expects to repatriate in the future.

Allowance for Doubtful Accounts

Accounts receivable represents approximately 11.3% of our total assets and 63.7% of our current assets as of December 31, 2008. We continuously monitor our accounts receivable from our customers to identify any collectability issues. An allowance for doubtful accounts is established when a review of customer accounts indicates that a specific amount will not be collected. We establish an allowance for doubtful accounts based on the actual amount we believe is not collectable. As of December 31, 2008 and 2007, there was $7.8 million and $0.6 million in allowance for doubtful accounts, respectively. During 2008, we increased our allowance for doubtful accounts for an inland barge customer.

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, 2008 and 2007, our net deferred charges related to regulatory inspection costs totaled $5.4 million and $6.8 million, respectively. The amortization of the regulatory inspection costs was reported as part of our depreciation and amortization expense.

Stock-Based Compensation

On January 1, 2006, we adopted the modified prospective provisions of SFAS No. 123 (revised 2004) Share-Based Payment (SFAS No. 123R). Prior to the adoptions of SFAS No. 123R, we followed the intrinsic value method as prescribed in Accounting Principles Board Opinion No. 25 Accounting for Stock Issued to Employees (APB Opinion 25) and related interpretations. SFAS No. 123R requires that compensation cost for stock options is recognized beginning with the effective date based on the requirements of (a) SFAS No. 123R for all share-based payments granted after January 1, 2006 and (b) SFAS No. 123 for all share-based payments granted to employees prior to January 1, 2006 that remain unvested on January 1, 2006. SFAS No. 123R requires that any unearned compensation related to share-based payments awarded prior to adoption be eliminated against the appropriate equity account. Under the new standard, our estimate of compensation expense will require a number of complex and subjective assumptions including our stock price volatility, employee exercise patterns (expected life of the options), future forfeitures and related tax effects.

We are estimating that the cost relating to stock options granted through December 31, 2008 will be $5.4 million over the remaining vesting period of 1.8 years and the cost relating to restricted shares granted through December 31, 2008 will be $9.9 million over the remaining vesting period of 1.7 years; however, due

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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

In general, demand for our drilling rigs is a function of our customers capital spending plans, which are largely driven by current commodity prices and their expectations of future commodity prices. Demand in the U.S. Gulf of Mexico is particularly driven by natural gas prices, with demand internationally typically driven by oil prices.

As of February 19, 2009, the spot price for Henry Hub natural gas was $4.45 per MMBtu, a significant decline from $8.91 per MMBtu one year earlier. The twelve month strip, or the average of the next twelve month s futures contract, was $4.84 per MMBtu on February 19, 2009, down from $9.34 a year earlier. Along with the negative impact the financial crisis has had on demand, recent increases in onshore production in the U.S., driven by a significant increase in onshore drilling activity, have put downward pressure on natural gas prices. Growing deepwater production and potential increased deliveries of liquefied natural gas are also factors which have weighed on prices. These factors, together with decline rates, weather and industrial demand will likely remain key drivers in the natural gas market for the foreseeable future.

Oil prices have also declined significantly over the last several months, relative to the levels of the past several years. Since June 30, 2008, the price of WTI has declined from $140.00 to $39.48 on February 19, 2009, with a current twelve month strip of $46.05 due primarily to the anticipated effects of global economic weakness, and a significant strengthening in the U.S. dollar.

Many of our customers have announced significant capital spending reductions relative to 2008 spending. While the substantial recent declines in both natural gas and oil prices are a primary factor, the weak global economic outlook, shut-in production related to damage sustained during Hurricanes Gustav and Ike, and a more difficult environment to raise outside capital, have all contributed to this curtailed level of capital spending. This is particularly likely for our U.S. Gulf of Mexico focused customers whose drilling programs are shorter term in nature and can be adjusted more quickly in response to commodity price fluctuations. Many of these Gulf of Mexico focused customers are smaller and employ more financial leverage and may face difficulty in raising outside funding for drilling programs. While international spending programs are much longer-term in nature, and the customers tend to have greater financial resources, international capital spending is also expected to decline, following nine years of growth, but to a lesser degree.

Global demand for jackup rigs has increased significantly over the last several years with international regions such as the Middle East, India and Mexico being particularly strong. Demand for jackups worldwide, excluding the U.S. Gulf of Mexico, increased from 200 in 2001 to 326 in February 2009. This international demand has drawn available rigs from the U.S. Gulf of Mexico. As a result, the supply of jackup rigs in the U.S. Gulf of Mexico has declined considerably over the last several years from a high of 157 jackups in 2001 to only 77 currently, according to published industry sources.

In addition to spurring migration of rigs out of the U.S., strong global demand for jackups over the past few years has encouraged newbuilds. According to ODS-Petrodata, as of February 20, 2009, 70 jackup rigs have been ordered by industry participants, national oil companies and financial investors for delivery through 2011. Given the recent financial crisis and the weakened outlook, a number of orders have already been cancelled and we anticipate that several of these remaining orders will be delayed or cancelled. However, we expect the majority of these rigs will be delivered and will compete directly with our fleet. As a result of generally higher dayrates, longer duration contracts and lower insurance costs, which are prevalent internationally, among other factors, we believe the vast majority of the newbuild jackup rigs will target international regions rather than the U.S. Gulf of Mexico. Our ability to expand our international drilling operations may be limited by the increased supply of newbuild jackup rigs.

While the overall current supply of jackup rigs in the U.S. Gulf of Mexico is 77, several of these rigs are either in the shipyard or cold-stacked, and the marketed supply is approximately 60. While the number of jackups located in the U.S. Gulf of Mexico has declined significantly over the last several years, current demand of 45 jackups as of February 20, 2009 is also considerably lower than three years ago when 88 jackups were operating in January 2006. A combination of factors has resulted in this decline in the number of rigs from the levels experienced over the previous several years, including declining target reservoir sizes and increasing finding, development and lifting costs.

A further reduction in the number of rigs operating in the U.S. Gulf of Mexico is possible; however, the pace of migration of jackup rigs from the region to international regions will likely slow as much of the expected growth in international demand will be met by the aforementioned newbuild deliveries. Further a modest reduction in the supply in the U.S. Gulf of Mexico may not be sufficient to offset declining demand resulting from our customers curtailed capital spending in 2009.

The global financial and credit crisis has reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide. The shortage of liquidity and credit combined with recent substantial losses in worldwide equity markets could lead to an extended global recession. A slowdown in economic activity caused by a recession would likely reduce demand for energy and result in lower oil and natural gas prices. Such a slowdown in economic activity would likely result in a corresponding decline in the demand for our jackup rigs and other services, which could have a material adverse effect on our revenue, profitability and liquidity.

While the outlook for drilling activity in 2009 has certainly been hampered by the aforementioned weaker commodity prices and the global credit crisis, a number of factors give us optimism for the longer-term. First, with steep initial decline rates in many North American natural gas basins and a likely continued substantial reduction in the rig count in the coming months, the recent strong natural gas market production growth, could quickly slow or even reverse. With respect to international markets, which are typically driven by crude oil prices, the lack of any significant oil production growth over the last 5 years, despite a more than doubling of international exploration and production capital spending over this period, leads us to believe that production would quickly respond to a decline in exploration and production spending.

Furthermore, the offshore drilling market remains highly competitive and cyclical, and it has historically been difficult to forecast future market conditions. While future commodity price expectations have typically been a key driver for demand for drilling rigs, other factors also affect our customers drilling programs, including the quality of drilling prospects, exploration success, relative production costs, and availability of insurance and political and regulatory environments. Additionally, the offshore drilling business has historically been cyclical, marked by periods of low demand, excess rig supply and low dayrates, followed by periods of high demand, short rig supply and increasing dayrates. These cycles have been volatile and are subject to rapid change.

Inland

The 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, to a lesser degree, crude oil. Barge rig drilling activity historically lags activity in the U.S. Gulf of Mexico due to a number of factors such as the lengthy permitting process that operators must go through prior to drilling a well in Louisiana, where the majority of our inland drilling takes place, and the predominance of smaller independent operators active in inland waters.

Inland barge drilling activity has slowed over the past year and dayrates have softened as a result of the number of the key operators have curtailed or ceased their activity in the inland market for various reasons including lack of funding, lack of drilling success and re-allocation of capital to other onshore basins. We expect activity levels will decline further during 2009, as our inland barge drilling customers are impacted by the recent drop in commodity prices and may lack external funding due to the financial crisis.

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 movement in commodity prices as for offshore drilling rigs, commodity prices are still a key driver of the demand for liftboats. Despite the production maintenance related nature of the majority of the work, some of the work may be deferred from time to time.

Following the active 2005 hurricane season, which caused tremendous damage to the infrastructure in the U.S. Gulf of Mexico, liftboat utilization and dayrates in the region were stronger than historical levels for approximately two years. As activity levels declined to more typical levels and supply increased as approximately 15 new liftboats were delivered for work in the U.S. Gulf of Mexico over the past two years, dayrates softened.

Activity levels increased again in late 2008 as customers addressed damage caused by the hurricanes Gustav and Ike; however, the damage was not as extensive as from the 2005 hurricane season, so the higher activity levels are expected only to continue into the first quarter of 2009. Dayrates once again increased, responding to the tightened supply and demand balance but are already declining as the preponderance of the higher priority repair work has been completed.

As of February 2009 we believe that there were another 10 liftboats under construction or on order in the U.S., with anticipated delivery dates through 2010. Once delivered, these liftboats may further impact the demand and utilization of our domestic liftboat fleet.

Our customers growth in international capital spending for the last several years, coupled with an aging infrastructure and significant increases in the cost of alternatives for servicing this infrastructure, has generally resulted in strong demand for our liftboats in West Africa. As international markets mature and the focus shifts from exploration to development, in locations such as West Africa, Middle East and Southeast Asia, we would expect to experience strong demand growth for liftboats. However, an expected reduction in exploration and production companies capital spending in international markets in 2009, may temporarily slow or reverse this trend. Over the longer term, we anticipate that there may be contract opportunities in international locations for liftboats currently working in the U.S. Gulf of Mexico and for newly constructed liftboats. We recently mobilized two of our liftboats to the Middle East from the U.S. Gulf of Mexico and are actively marketing the vessels for use on projects with short and long-term contract opportunities. While we believe that international demand for liftboats will continue to increase over the longer term, the political instability in certain regions may negatively impact our customers capital spending plans.

Labor Markets

We require highly skilled personnel to operate our rigs, barges and liftboats and to support our business. Competition for skilled rig personnel may intensify, particularly in international markets, as 70 new offshore jackup rigs are under construction and 32 are scheduled to enter the global fleet during 2009. If competition for personnel intensifies, our labor costs will likewise increase, although we do not believe at this time that our operations will be limited.

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LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

Sources and uses of cash for 2008 and 2007 are as follows:

	2008	2007
Net Cash Provided by Operating Activities	$ 269.9	$ 175.7
Net Cash Used in Investing Activities:		
Acquisition of Assets	(320.8)	
Acquisition of Business, Net of Cash Acquired		(728.4)
Additions to Property and Equipment	(264.2)	(155.4)
Deferred Drydocking Expenditures	(17.3)	(20.8)
Sale of (Investment in) Marketable Securities	39.3	(39.3)
Proceeds from Sale of Assets, Net	17.0	109.7
Insurance Proceeds Received	30.2	4.3
Other		4.9
Total	(515.8)	(825.0)
Net Cash Provided by Financing Activities:		
Short-term Debt Borrowings (Repayments), Net	2.5	(1.4)
Long-term Debt Borrowings	350.0	900.0
Long-term Debt Repayments	(121.5)	(97.8)
Redemption of 3.375% Convertible Senior Notes	(44.8)	
Common Stock Repurchases	(49.2)	
Proceeds from Exercise of Stock Options	5.1	2.1
Excess Tax Benefit from Stock-Based Arrangements	5.9	3.8
Payment of Debt Issuance Costs	(8.1)	(17.8)
Other		0.1
Total	139.9	789.0
Net Increase (Decrease) in Cash and Cash Equivalents	$ (106.0)	$ 139.7

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 be required to make prepayments on our term loan to the extent the debt is not permitted under the 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.

Our term loan agreement requires that we meet certain financial ratios and tests, which we currently meet. However, if the market for our services does not improve or continues to decline over the near-term, we may not be able to meet the financial ratios and tests, which would result in an event of default under our credit agreement and could prevent us from borrowing under our revolving credit facility, which would in turn have a material adverse effect on our available liquidity. Additionally, an event of default could result in us having to immediately repay all amounts outstanding under our term loan facility and our revolving credit facility and in the foreclosure of liens on our assets.

Cash Requirements and Contractual Obligations

Asset Acquisition

In February 2008, we entered into a definitive agreement to purchase three jackup drilling rigs and related equipment for approximately $320.0 million. The purchase of two of the jackup drilling rigs for $220.0 million was completed in the first quarter and in the second quarter of 2008 we purchased the third jackup rig for $100.0 million. We funded the purchase of the first two rigs with cash on hand and funded the acquisition of the third jackup rig with cash on hand and a portion from borrowings under our revolving credit facility. The $100.0 million borrowed under the revolving credit facility was repaid with a portion of the proceeds received from the issuance of the 3.375% Convertible Senior Notes.

Debt

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

In July 2007, we terminated all prior facilities and we entered into a new $1,050.0 million credit facility, consisting of a $900.0 million term loan and a $150.0 million revolving credit facility. On April 28, 2008, we entered into an agreement with the revolving lenders under our existing credit facility and certain new lenders to increase the maximum amount of our revolving credit facility from $150.0 million to $250.0 million. The increased availability under the facility is to be used for working capital, capital expenditures and other general corporate purposes. 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. The facility includes a diverse group of lenders with no single commitment greater than $30.0 million. No amounts were outstanding and $29.0 million in stand-by letters of credit had been issued under the revolving credit facility as of December 31, 2008. The remaining availability under this revolving credit facility was $221.0 million at December 31, 2008.

As of December 31, 2008, $886.5 million was outstanding on the term loan facility and the interest rate was 3.21%. The annualized effective interest rate was 5.88% for the year ended December 31, 2008 after giving consideration to derivative activity. The fair value of the amount outstanding on the term loan facility as of December 31, 2008 approximated $571.8 million.

The revolving credit facility and our term loan are governed by a credit agreement that includes customary events of default and two financial covenants that are tested quarterly: a fixed charge coverage ratio and a leverage ratio. Both financial covenants incorporate our last 12 months of EBITDA, as defined in the credit agreement. We were in compliance with these covenants at December 31, 2008. However, if the market for our services does not improve or continues to decline over the near-term, we may not be able to meet the financial ratios and tests, which would result in an event of default under our credit agreement and could prevent us from borrowing under our revolving credit facility, which would in turn have a material adverse effect on our available liquidity. Additionally, an event of default could result in us having to immediately repay all amounts outstanding under our term loan facility and our revolving credit facility and in the foreclosure of liens on our assets. 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, liens, investments and affiliate transactions.

In May 2008 and July 2007, we entered into derivative instruments with the purpose of hedging future interest payments on our term loan facility. We entered into a floating to fixed interest rate swap with varying notional amounts beginning with $100.0 million with a settlement date of October 1, 2008 and ending with $75.0 million with a settlement date of December 31, 2009. We receive an interest rate of three-month LIBOR and pay a fixed coupon of 2.980% over six quarters. The terms and settlement dates of the swap match those of the term loan. We entered into a floating to fixed interest rate swap with decreasing notional amounts beginning with $400.0 million with a settlement date of December 31, 2007 and ending with $50.0 million with a settlement date of April 1, 2009. We receive an interest rate of three-month LIBOR and pay a fixed coupon of 5.307% over six quarters. The terms and settlement dates of the swap match those of the term loan. We also entered into a zero cost LIBOR collar on $300.0 million of term loan principal over three years, with a ceiling of 5.75% and a floor of 4.99%. The counterparty is obligated to pay us in any quarter that actual LIBOR resets above 5.75% and we pay the counterparty in any quarter that actual LIBOR resets below 4.99%. The terms and settlement dates of the collar match those of the term loan. The change in the fair value of these hedging instruments resulted in a decrease in derivative assets of $0.3 million and an increase in derivative liabilities of $10.2 million during the year ended December 31, 2008. We had net unrealized losses on hedge transactions of $6.8 million, net of tax of $3.7 million, $8.9 million, net of tax of $4.8 million and net unrealized gains of $0.3 million, net of tax of $0.2 million for the years ended December 31, 2008, 2007 and 2006, respectively. We did not recognize a gain or loss due to hedge ineffectiveness in the Consolidated Statements of Operations for the years ended December 31, 2008, 2007 and 2006 related to these hedging instruments. In addition, our interest expense was increased by $7.7 million during the year ended December 31, 2008 and was decreased by $0.2 million during the year ended December 31, 2007 as a result of our interest rate derivative instruments.

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. The interest on the 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 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. 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. Net proceeds of $243.5 million were used to purchase approximately 1.45 million shares, or $49.2 million, of our 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.

During December 2008, we redeemed $88.2 million aggregate principal amount of the 3.375% Convertible Senior Notes for a cost of $44.8 million resulting in a net gain of $43.4 million. In addition, we expensed $2.1 million of unamortized issuance costs in connection with the redemption. The repurchase effectively reduced the number of conversion shares potentially issuable in relation to the 3.375% Convertible Senior Notes from approximately 5.0 million to approximately 3.2 million. The carrying amount and fair value of the 3.375% Convertible Senior Notes was $161.8 million and $77.2 million, respectively at December 31, 2008.

In connection with the TODCO acquisition in July 2007, we assumed senior notes and an unsecured line of credit with a bank in Venezuela. The senior notes included 6.95% Senior Notes due in April 2008, 7.375% Senior Notes due in April 2018, and 9.5% Senior Notes due in December 2008 (collectively, Senior Notes). The 6.95% Senior Notes and the 9.5% Senior Notes were repaid in April 2008 and December 2008, respectively. The fair market value of the 7.375% Senior Notes at December 31, 2008 was approximately $2.5 million based on the most recent market valuations. In July 2008, the line of credit was changed to an overdraft facility and the maximum amount available to be drawn was increased to 9.0 million Bolivares Fuertes from 6.0 million Bolivares Fuertes. The overdraft facility is designed to manage local currency liquidity in Venezuela. The maximum amount available to be drawn at December 31, 2008 is 9.0 million Bolivares Fuertes ($4.2 million at the exchange rate at December 31, 2008), and there was 5.1 million Bolivares Fuertes ($2.5 million at the exchange rate at December 31, 2008) outstanding at December 31, 2008.

In 2008, 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 $35.2 million was financed through these arrangements, and $11.1 million was outstanding at December 31, 2008. The interest rate on these notes is 4.42% and the notes mature in April 2009.

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Capital Expenditures

We expect to spend a total of approximately $90 million on capital expenditures excluding asset acquisitions during 2009. Planned capital expenditures include refurbishment and an upgrade to certain of our rigs, liftboats and other marine vessels.

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.

The timing and amounts we actually spend in connection with our plans to upgrade and refurbish other selected rigs and liftboats are subject to our discretion and will depend on our view of market conditions and our cash flows. 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. If we do complete any such acquisitions, we may make significant capital commitments for such purposes. Any such transactions could involve the payment by us of a substantial amount of cash. We would likely fund the cash portion of such transactions, if any, through cash balances on hand, the incurrence of additional debt, or sales of assets, equity interests or other securities or a combination thereof. 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, we experience poor results in our operations or we fail to meet covenants under our term loan facility.

Contractual Obligations

Our contractual obligations and commitments principally include obligations associated with our outstanding indebtedness, FIN 48 liability, surety bonds, letters of credit, future minimum operating lease obligations, purchase commitments and management compensation obligations. During 2008, there were no material changes outside the ordinary course of business in the specified contractual obligations, other than the issuance of the $250.0 million of 3.375% Convertible Senior Notes.

The following table summarizes our contractual obligations and contingent commitments by period as of December 31, 2008:

Contractual Obligations and Contingent Commitments	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years	Total
	Payments due by Period (In thousands)				
Recorded Obligations:					
Long-term debt obligations	$ 11,455	$ 18,000	$ 1,021,254	$ 3,508	$ 1,054,217
Insurance note payable	11,126				11,126
FIN 48 liability(b)	17,209				17,209
Purchase obligations(a)	16,506				16,506
Other	2,273				2,273
Unrecorded Obligations:					
Letters of credit	19,110	9,961			29,071
Surety Bonds	38,905	12,462			51,367
Management compensation obligations	3,335	6,376			9,711
Purchase obligations(a)	18,304				18,304
Operating lease obligations	6,267	5,925	2,491	4,850	19,533
Total contractual obligations	$ 144,490	$ 52,724	$ 1,023,745	$ 8,358	$ 1,229,317

(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) FIN 48 liabilities of $5.7 million have been excluded from the table above as a reasonably reliable estimate of the period of cash settlement cannot be made.

Off-Balance Sheet Arrangements

Guarantees

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

Letters of Credit and Surety Bonds

We execute 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, 2008, we had $80.4 million of letters of credit and surety bonds outstanding, consisting of $0.1 million in an unsecured outstanding letter of credit, $29.0 million letters of credit outstanding under our revolver and $51.3 million outstanding in surety bonds that guarantee our performance as it relates to our drilling contracts, insurance, tax and other obligations in various jurisdictions. If the beneficiaries called these letters of credit and surety bonds, the called amount would become an on-balance sheet liability, and our available liquidity would be reduced by the amount called.

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Accounting Pronouncements

In October, 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) No. 157-3, *Determining the Fair Value of a Financial Asset when the Market for that Asset is not Active* (FSP No. 157-3). FSP No. 157-3 clarifies the application of SFAS No. 157, *Fair Value Measurements* (SFAS No. 157) in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. FSP No. 157-3 was effective upon issuance and was adopted by us without material impact to our financial statements.

In May 2008, the FASB issued FSP No. APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement)* (FSP 14-1), which clarifies the accounting for convertible debt instruments that may be settled in cash (including partial cash settlement) upon conversion. FSP 14-1 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. FSP 14-1 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 our consolidated statement of operations. The interest rate to be used under FSP 14-1 will therefore be significantly higher than the rate on our Convertible Senior Notes due 2038 that is currently used, which is equal to the coupon rate of 3.375 percent. FSP 14-1 is effective as of January 1, 2009, requires retrospective application to the terms of instruments as they existed for all periods presented and early adoption is not permitted. Had this new standard been effective for the fiscal year ended December 31, 2008, we estimate interest expense would have increased by approximately $4.3 million, and diluted loss per share from continuing operations would have increased by approximately $0.03 per share. In addition, we expect the gain of $43.4 million recognized on the redemption of $88.2 million of the Convertible Senior Notes due 2038 would have approximated $22.8 million had this new standard been effective at that time. FSP 14-1 will have no direct effect on our cash flow.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities* (SFAS No. 161). SFAS No. 161 amends SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS No. 133), requiring enhanced disclosures about an entity s derivative and hedging activities thereby improving the transparency of financial reporting. SFAS No. 161 disclosures provide additional information on how and why derivative instruments are being used. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged.

In December 2007, the FASB issued SFAS No. 141R*, Business Combinations* (SFAS No. 141R). SFAS No. 141R replaces SFAS No. 141, *Business Combinations* (SFAS No. 141), and applies to all transactions and other events in which one entity obtains control over one or more other businesses. SFAS No. 141R requires an acquirer, upon initially obtaining control of another entity, to recognize the assets, liabilities and any non-controlling interest in the acquiree at fair value as of the acquisition date. Contingent consideration is required to be recognized and measured at fair value on the date of acquisition rather than at a later date when the amount of that consideration may be determinable beyond a reasonable doubt. SFAS No. 141R requires acquirers to expense acquisition-related costs as incurred rather than allocating such costs to the assets acquired and liabilities assumed, as was previously the case under SFAS No. 141. SFAS No. 141R may have a significant impact on the Company s accounting for any business combinations closing on or after January 1, 2009.

We adopted, without material impact to our consolidated financial statements, the provisions of SFAS No. 157 related to financial assets and liabilities and to nonfinancial assets and liabilities measured at fair value on a recurring basis on January 1, 2008. SFAS No. 157 defines fair value, establishes a framework for measuring fair value under generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 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. In February 2008, the FASB issued FSP SFAS No. 157-2, *Effective Date of FASB Statement No. 157*, which defers the effective date of SFAS No. 157 for one year for certain nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis. Effective January 1, 2009, we will adopt the provision for nonfinancial assets and liabilities that are not required or permitted to be measured at fair value on a recurring basis, which include those measured at fair value in impairment testing and those initially measured at fair value in a business combination. We do not expect the provisions of SFAS No. 157 related to these items to have a material impact on our consolidated financial statements.

We adopted, without material impact to our consolidated financial statements, the provisions of SFAS No. 159*, The Fair Value Option for Financial Assets and Financial Liabilities* (SFAS No. 159) on January 1, 2008. SFAS No. 159 permits companies to choose to measure certain financial instruments and certain other items at fair value and requires that unrealized gains and losses on items for which the fair value option has been elected be reported in earnings.

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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 ability to enter into new contracts for our rigs and liftboats and future utilization rates for the units;
- the correlation between demand for our rigs and our liftboats and our earnings and customers expectations of energy prices;
- future capital expenditures and refurbishment, repair and upgrade costs;
- expected completion times for our refurbishment and upgrade projects;
- sufficiency and availability of funds for required capital expenditures, working capital and debt service;
- our plans regarding increased international operations;
- expected useful lives of our rigs and liftboats;
- liabilities under laws 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 improvements in offshore drilling activity and dayrates, market conditions, demand for our rigs and liftboats, operating revenues, operating and maintenance expense, 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:

- oil and natural gas prices and industry expectations about future prices;
- demand for 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 and other oil and natural gas producing regions or further acts of terrorism in the United States, or elsewhere;

the impact of governmental laws and regulations;

the adequacy 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;

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

operating hazards such as severe weather and seas, fires, cratering, blowouts, war, terrorism and cancellation or unavailability of insurance 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.

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

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

Interest Rate Exposure

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

As of December 31, 2008, the long-term borrowings that were outstanding subject to fixed interest rate risk consisted of the 7.375% Senior Notes due April 2018 and the 3.375% Convertible Senior Notes due June 2038. The carrying amount and fair value of the 7.375% Senior Notes was $3.5 million and $2.5 million, respectively. The carrying amount and fair value of the 3.375% Convertible Senior Notes was $161.8 million and $77.2 million, respectively.

As of December 31, 2008 the interest rate for the $886.5 million outstanding under the term loan was 3.21%. If the interest rate averaged 1% more for 2009 than the rates as of December 31, 2008, annual interest expense would increase by approximately $8.9 million. This sensitivity analysis assumes there are no changes in our financial structure and excludes the impact of our hedging activities. The fair value of the amount outstanding on the term loan facility as of December 31, 2008 approximated $571.8 million.

We believe our other debt instruments, which are short term in nature, totaling $2.5 million as of December 31, 2008 approximate fair value.

Interest Rate Swaps and Derivatives

We manage our debt portfolio to achieve an overall desired position of fixed and floating rates and may employ hedge transactions such as interest rate swaps and zero cost LIBOR collars as tools to achieve that goal. The major risks from interest rate derivatives include changes in the interest rates affecting the fair value of such instruments, potential increases in interest expense due to market decreases in floating interest rates and the creditworthiness of the counterparties in such transactions. The counterparties to our interest rate swaps and zero cost LIBOR collar are creditworthy multinational commercial banks. We believe that the risk of counterparty nonperformance is not currently material, but counterparty risk has recently increased throughout the financial system. Our interest expense was increased by $7.7 million in 2008 as a result of our interest rate derivative transactions. (See the information set forth under the caption Debt in Part II, Item 7.

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Management s Discussion and Analysis of Financial Condition and Results of Operations *Liquidity and Capital Resources*.)

In connection with the credit facility, in July 2007 we entered into hedge transactions with the purpose of fixing the interest rate on decreasing notional amounts beginning with $400.0 million with a settlement date of December 31, 2007 and ending with $50.0 million with a settlement date of April 1, 2009. We also entered into a zero cost LIBOR collar on $300.0 million of term loan principal over three years, with a ceiling of 5.75% and a floor of 4.99%. The table below provides the scheduled reduction in notional amounts related to the interest rate swap (in thousands):

January 1, 2009 March 31, 2009	$ 50,000

In addition, as it relates to our credit facility, in May 2008 we entered into a floating to fixed interest rate swap with the purpose of fixing the interest rate on varying notional amounts beginning with $100.0 million with a settlement date of October 1, 2008 and ending with $75.0 million with a settlement date of December 31, 2009. The table below provides the schedule of notional amounts related to the interest rate swap (in thousands):

December 31, 2008 - March 31, 2009	$ 325,000
April 1, 2009 - June 30, 2009	250,000
July 1, 2009 - September 30, 2009	175,000
October 1, 2009 - December 30, 2009	75,000

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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, 2008 and 2007, and the related consolidated statements of operations, stockholders equity, cash flows and comprehensive income for each of the two years in the period ended December 31, 2008. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Hercules Offshore, Inc. and subsidiaries at December 31, 2008 and 2007, and the consolidated results of their operations and their cash flows for each of the two years in the period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, in 2006 the Company adopted the provisions of Statement of Financial Accounting Standards No. 123 (revised 2004), Share-Based Payments. In addition, as described in Note 15 to the consolidated financial statements, in 2007 the Company adopted the provisions of Financial Accounting Standards Board Interpretation No. 48, Accounting for Uncertainty in Income Taxes.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Hercules Offshore, Inc. s internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2009, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 25, 2009

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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. s internal control over financial reporting as of December 31, 2008, 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. s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Report of Management 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. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, 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, 2007 and 2008, and the related consolidated statements of operations, stockholders equity, cash flows and comprehensive income for each of the two years in the period ended December 31, 2008 of Hercules Offshore, Inc., and our report dated February 25, 2009, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas

February 25, 2009

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Hercules Offshore, Inc.

We have audited the accompanying consolidated statements of operations, comprehensive income, stockholders equity, and cash flows of Hercules Offshore, Inc. and subsidiaries for the year ended December 31, 2006. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements 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 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 audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the results of operations and cash flows of Hercules Offshore, Inc. and subsidiaries for the year ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Houston, Texas
February 23, 2007

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2008	December 31, 2007
	(In thousands, except par value)	
ASSETS		
Current Assets:		
Cash and Cash Equivalents	$ 106,455	$ 212,452
Marketable Securities		39,300
Accounts Receivable, Net	293,089	221,663
Insurance Claims Receivable	776	43,342
Supplies	2,587	2,494
Prepaids	23,033	31,417
Current Deferred Tax Asset	17,379	18,960
Other	16,706	23,565
	460,025	593,193
Property and Equipment, Net	2,088,530	2,060,224
Goodwill		940,241
Other Assets, Net	42,340	50,290
	$ 2,590,895	$ 3,643,948
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Short-term Debt and Current Portion of Long-term Debt	$ 11,455	$ 21,653
Insurance Note Payable	11,126	16,931
Accounts Payable	99,823	105,527
Accrued Liabilities	83,424	80,138
Taxes Payable	32,440	23,006
Other Current Liabilities	36,472	20,870
	274,740	268,125
Long-term Debt, Net of Current Portion	1,042,766	890,013
Other Liabilities	35,529	15,493
Deferred Income Taxes	330,088	458,884
Commitments and Contingencies		
Stockholders Equity:		
Common Stock, $0.01 par value; 200,000 Shares Authorized; 89,459 and 88,876 Shares Issued, Respectively; 87,976 and 88,857 Shares Outstanding, Respectively	895	889
Capital in Excess of Par Value	1,755,392	1,731,882
Treasury Stock, at Cost, 1,483 Shares and 19 Shares, Respectively	(50,081)	(582)

Accumulated Other Comprehensive Loss	(14,932)	(8,117)
Retained Earnings (Deficit)	(783,502)	287,361
	907,772	2,011,433
	$ 2,590,895	$ 3,643,948

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, 2008	2007	2006
	(In thousands, except per share data)		
Revenues	$ 1,111,807	$ 726,278	$ 344,312
Costs and Expenses:			
Operating Expenses	631,711	346,191	124,138
Impairment of Goodwill	950,287		
Impairment of Property and Equipment	376,668		
Depreciation and Amortization	192,894	104,634	32,310
General and Administrative	81,160	49,811	29,807
	2,232,720	500,636	186,255
Operating Income (Loss)	(1,120,913)	225,642	158,057
Other Income (Expense):			
Interest Expense	(59,486)	(34,859)	(9,278)
Gain on Disposal of Assets			30,690
Gain (Loss) on Early Retirement of Debt, Net	41,313	(2,182)	
Other, Net	3,315	6,483	4,038
Income (Loss) Before Income Taxes	(1,135,771)	195,084	183,507
Income Tax Benefit (Provision)	66,428	(59,072)	(64,457)
Income (Loss) from Continuing Operations	(1,069,343)	136,012	119,050
Income (Loss) from Discontinued Operation, Net of Taxes	(1,520)	510	
Net Income (Loss)	$ (1,070,863)	$ 136,522	$ 119,050
Basic Earnings (Loss) Per Share:			
Income (Loss) from Continuing Operations	$ (12.10)	$ 2.31	$ 3.80
Income (Loss) from Discontinued Operation	(0.02)	0.01	
Net Income (Loss)	$ (12.12)	$ 2.32	$ 3.80
Diluted Earnings (Loss) Per Share:			
Income (Loss) from Continuing Operations	$ (12.10)	$ 2.28	$ 3.70
Income (Loss) from Discontinued Operation	(0.02)	0.01	
Net Income (Loss)	$ (12.12)	$ 2.29	$ 3.70
Weighted Average Shares Outstanding:			
Basic	88,351	58,897	31,327

Diluted	88,351	59,563	32,203

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, 2008		December 31, 2007		December 31, 2006	
	Shares	Amount	Shares	Amount	Shares	Amount
			(In thousands)			
Common Stock:						
Balance at Beginning of Period	88,876	$ 889	32,008	$ 320	30,243	$ 302
Exercise of Stock Options	478	5	250	3	129	2
Issuance of Common Stock, Net			56,618	566	1,600	16
Issuance of Restricted Stock	105	1			36	
Balance at End of Period	89,459	895	88,876	889	32,008	320
Capital in Excess of Par Value:						
Balance at Beginning of Period		1,731,882		243,157		184,698
Exercise of Stock Options		5,122		2,052		1,230
Issuance of Common Stock, Net				1,471,379		54,182
Issuance of Restricted Stock		(1)				
Reclass of Restricted Stock						(1,322)
Compensation Expense Recognized		12,535		7,680		3,098
Compensation Capitalized as part of the Purchase Price Allocation				3,778		
Excess Tax Benefit From Stock-Based Arrangements		5,860		3,836		1,271
Other		(6)				
Balance at End of Period		1,755,392		1,731,882		243,157
Treasury Stock:						
Balance at Beginning of Period	(19)	(582)	(6)	(220)		
Repurchase of Common Stock	(1,464)	(49,499)	(13)	(362)	(6)	(220)
Balance at End of Period	(1,483)	(50,081)	(19)	(582)	(6)	(220)
Restricted Stock:						
Balance at Beginning of Period						(1,322)
Reclass of Restricted Stock						1,322
Balance at End of Period						
Accumulated Comprehensive Income (Loss):						
Balance at Beginning of Period		(8,117)		755		476
		(6,815)		(8,872)		279

Change in Unrealized Gain (Loss) on Hedge Transactions, Net of Tax of $3,669, $4,778 and $(150), Respectively						
Balance at End of Period, Net of Tax of $8,040, $4,371 and $(407), Respectively		(14,932)		(8,117)		755
Retained Earnings (Deficit):						
Balance at Beginning of Period		287,361		150,839		31,789
Net Income (Loss)		(1,070,863)		136,522		119,050
Balance at End of Period		(783,502)		287,361		150,839
Total Stockholders Equity	87,976	$ 907,772	88,857	$ 2,011,433	32,002	$ 394,851

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

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31, 2008	2007	2006
	(In thousands)		
Net Income (Loss)	$ (1,070,863)	$ 136,522	$ 119,050
Other Comprehensive Income (Loss):			
Reclassification of (gains) losses, net included in net income	5,034	(897)	(382)
Other comprehensive gains (losses), net	(11,849)	(7,975)	661
Comprehensive Income (Loss)	$ (1,077,678)	$ 127,650	$ 119,329

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, 2008	2007	2006
	(In thousands)		
Cash Flows from Operating Activities:			
Net Income (Loss)	$ (1,070,863)	$ 136,522	$ 119,050
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities:			
Depreciation and Amortization	192,918	109,064	32,310
Stock-Based Compensation Expense	12,535	7,680	3,098
Deferred Income Taxes	(111,952)	2,841	27,200
Provision for Doubtful Accounts Receivable	6,167		
Amortization of Deferred Financing Fees	4,036	1,805	686
Gain on Disposal of Assets	(3,029)	(4,491)	(30,779)
Excess Tax Benefit from Stock-Based Arrangements	(5,860)	(3,836)	(1,271)
(Gain) Loss on Early Retirement of Debt, Net	(41,313)	2,182	
Impairment of Goodwill	950,287		
Impairment of Property and Equipment	376,668		
(Increase) Decrease in Operating Assets -			
Accounts Receivable	(78,510)	58,827	(50,653)
Insurance Claims Receivable	(840)	(13,565)	5,919
Prepaid Expenses and Other	53,635	9,263	(12,617)
Increase (Decrease) in Operating Liabilities -			
Accounts Payable	(5,482)	(6,794)	15,842
Insurance Note Payable	(45,173)	(25,301)	3,657
Other Current Liabilities	17,125	15,239	11,499
Tax Sharing Agreement Payment	(4,000)	(116,003)	
Other Liabilities	23,599	2,308	300
Net Cash Provided by Operating Activities	269,948	175,741	124,241
Cash Flows from Investing Activities:			
Acquisition of Business, Net of Cash Acquired		(728,396)	
Acquisition of Assets	(320,839)		
Additions of Property and Equipment	(264,245)	(155,390)	(204,456)
Deferred Drydocking Expenditures	(17,269)	(20,772)	(12,544)
Investment in Marketable Securities		(151,675)	
Proceeds from Sale of Marketable Securities	39,300	112,375	
Insurance Proceeds Received	30,221	4,285	61,278
Proceeds from Sale of Assets, Net	17,045	109,745	5,989
(Increase) Decrease in Restricted Cash		4,821	(250)
Net Cash Used in Investing Activities	(515,787)	(825,007)	(149,983)
Cash Flow from Financing Activities:			
Short-term Debt Borrowings (Repayments), Net	2,455	(1,395)	

Long-term Debt Borrowings	350,000	900,000	
Long-term Debt Repayments	(121,427)	(97,750)	(1,400)
Redemption of 3.375% Convertible Senior Notes	(44,848)		
Common Stock Repurchases	(49,228)		
Proceeds from Issuance of Common Stock, Net			54,198
Proceeds from Exercise of Stock Options	5,127	2,054	1,232
Excess Tax Benefit from Stock-Based Arrangements	5,860	3,836	1,271
Payment of Debt Issuance Costs	(8,097)	(17,753)	(630)
(Distributions to) Contributions from Members			(3,732)
Other		(46)	
Net Cash Provided by Financing Activities	139,842	788,946	50,939
Net Increase (Decrease) in Cash and Cash Equivalents	(105,997)	139,680	25,197
Cash and Cash Equivalents at Beginning of Period	212,452	72,772	47,575
Cash and Cash Equivalents at End of Period	$ 106,455	$ 212,452	$ 72,772

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

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Nature of Business and Significant Accounting Policies

Organization

Hercules Offshore, LLC was formed in July 2004 as a Delaware limited liability company. On November 1, 2005 in connection with its initial public offering, Hercules Offshore, LLC and its subsidiaries was converted to a Delaware corporation named Hercules Offshore, Inc. (the Conversion). Upon the Conversion, each outstanding membership unit of the limited liability company was converted into common stock of the corporation.

The Company provides shallow-water drilling and marine services to the oil and natural gas exploration and production industry in the U.S. Gulf of Mexico and international locations through its Domestic Offshore, International Offshore, Inland, Domestic Liftboats, International Liftboats and Delta Towing segments (See Note 16). At December 31, 2008, the Company owned a fleet of 35 jackup rigs, 27 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. However, in January 2009, the Company reclassified four of its cold-stacked jackup rigs located in the U.S. Gulf of Mexico and 10 of its cold-stacked inland barges as retired. These rigs would require extensive refurbishment and are not expected to re-enter active service. The Company operates in ten countries on four continents.

On July 11, 2007, the Company completed the acquisition of TODCO (See Note 4), a provider of contract oil and gas drilling services in the U.S. Gulf of Mexico and international locations. TODCO owned and operated 24 jackup rigs, 27 barge rigs, three submersible rigs, nine land rigs, one platform rig and a fleet of marine support vessels. During the fourth quarter of 2007, the Company sold the nine land rigs and related assets (See Note 5). 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.

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.

Reclassifications

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

Cash and Cash Equivalents and Marketable Securities

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. From time to time the Company may invest a portion of its available cash in marketable securities. Marketable securities are classified as available for sale and are stated at fair value on the Consolidated Balance Sheets. At December 31, 2008, the Company had no investments in marketable securities. At December 31, 2007, the Company had marketable securities with a fair value and cost basis of $39.3 million.

Realized and unrealized gains and losses related to marketable securities are calculated using the specific identification method. Unrealized gains or losses, net of taxes, are included in Accumulated Other Comprehensive Loss on the Consolidated Balance Sheets until realized. Realized gains or losses are included in Other, Net in the Consolidated Statements of Operations. Proceeds of $39.3 million and $112.4 million were received

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

from sales and maturities of marketable securities for the years ended December 31, 2008 and 2007, respectively. There were no realized or unrealized gains or losses related to these securities in the years ended December 31, 2008, 2007 and 2006.

Revenue Recognition

Revenues generated from our contracts are recognized as services are performed. 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 one month are recognized as services are performed over the term of the related drilling contract. Amounts related to mobilization fees are summarized below (in thousands):

	Years Ended December 31,		
	2008	**2007**	**2006**
Mobilization revenue deferred	$ 33,727	$ 6,517	$ 5,680
Mobilization expense deferred	7,490	3,340	3,287
Mobilization revenue recognized	11,860	3,060	2,590
Mobilization expense recognized	5,550	2,839	1,600

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.

The Company records reimbursements from customers for out-of-pocket expenses as revenues and the related cost as direct operating expenses. Total revenues from such reimbursements were $15.6 million, $15.4 million and $7.5 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Stock-Based Compensation

On January 1, 2006, the Company adopted the modified prospective provisions of Statement of Financial Accounting Standards (SFAS) No. 123 (revised 2004), *Share-Based Payment* (SFAS No. 123R). Prior to the adoptions of SFAS No. 123R, the Company followed the intrinsic value method as prescribed in Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* (APB Opinion 25) and related interpretations. SFAS No. 123R requires that compensation cost for stock options is recognized beginning with the effective date based on the requirements of (a) SFAS No. 123R for all share-based payments granted after January 1, 2006 and (b) SFAS No. 123 for all share-based payments granted to employees prior to January 1, 2006 that remain unvested on January 1, 2006. SFAS No. 123R requires that any unearned compensation related to share-based payments awarded prior to adoption be eliminated against the appropriate equity account. Under the new standard, the Company s estimate of compensation expense will require a number of complex and subjective assumptions including its stock price volatility, employee exercise patterns (expected life of the options), future forfeitures and related tax effects.

The Company estimates the cost relating to stock options granted through December 31, 2008 will be $5.4 million over the remaining vesting period of 1.8 years and the cost relating to restricted shares granted through December 31, 2008 will be $9.9 million over the remaining vesting period of 1.7 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

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 $7.8 million and $0.6 million at December 31, 2008 and 2007, respectively. During 2008, the Company increased its allowance for doubtful accounts for an inland barge customer.

Insurance Claims Receivable

Insurance claims receivable include amounts the Company incurred related to insurance claims the Company filed under its insurance policies. At December 31, 2008 and 2007, $0.8 million and $43.3 million were outstanding for insurance claims receivable, respectively. During the year ended December 31, 2008, the Company received $30.2 million in proceeds related primarily to the settlement of claims for damage incurred during Hurricanes Rita and Katrina as well as damage to *Hercules 205* in a collision. In addition, the Company adjusted its insurance claims receivables by $13.2 million in its final purchase price allocation and recorded additional claims of $0.9 million.

Prepaid Expenses

Prepaid expenses consist of prepaid insurance, prepaid income tax and other prepayments. At December 31, 2008 and December 31, 2007, prepaid insurance totaled $14.3 million and $21.6 million, respectively. At December 31, 2008 and 2007, prepaid taxes totaled $6.4 million and $6.2 million, respectively.

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 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.

Amortization 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 in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* (SFAS No. 144). 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 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

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

related asset or group of assets being evaluated. Actual impairment charges are recorded using an estimate of discounted future cash flows.

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 has 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 in accordance with SFAS No. 144 and assessed the rig assets of the Inland and Domestic Offshore segments for impairment. When analyzing its assets for impairment, the Company separates its marketable rigs, those rigs 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 rigs, those rigs that have been cold stacked for an extended period of time or those rigs that the Company currently does not reasonably expect to market in the foreseeable future. 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. There were no impairment charges for the periods ended December 31, 2007 and 2006.

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 in accordance with SFAS No. 142, *Goodwill and Other Intangible Assets* (SFAS No. 142). This test is generally performed by the Company on October 1 or more frequently if the Company believes impairment indicators are present. The Company determined its reporting units to be the same as its operating segments under SFAS No. 131, *Disclosures about Segments of an Enterprise and Related Information* .

Recoverability of goodwill is evaluated using a two-step process. The first step involves a comparison of the fair value of each of the reporting units with its carrying amount. If a reporting unit s carrying amount exceeds its fair value, the second step is performed. The second step involves a comparison of the implied fair value and carrying value of that reporting unit s goodwill. To the extent that a reporting unit s carrying amount exceeds the implied fair value of its goodwill, an impairment loss is recognized. Fair value is estimated using discounted cash flows and other market-related valuation models, including earnings multiples and comparable asset market values. In making an assessment of fair value, the Company relies on current and past experience concerning its industry cycles which historically have proven to be extremely volatile. In addition, the Company makes future assumptions based on a number of factors including future operating performance, expected economic conditions and actions the Company expects to take. Rates used to discount future cash flows are dependent upon interest rates and the cost of capital at a point in time. There are inherent uncertainties related to these factors and management s judgment in applying them to the analysis of goodwill impairment.

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 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.

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The changes in the carrying amount of goodwill for the years ended December 31, 2008 and 2007 are as follows (in thousands):

	Domestic Offshore	International Offshore	Inland	Delta Towing	Total
As of January 1, 2007	$	$	$	$	$
Goodwill acquired during the period	513,602	133,046	206,264	87,329	940,241
As of December 31, 2007	$ 513,602	$ 133,046	$ 206,264	$ 87,329	$ 940,241
Purchase Price and Other Adjustments	(6,408)	17,840	(790)	(596)	10,046
Impairment	(507,194)	(150,886)	(205,474)	(86,733)	(950,287)
As of December 31, 2008	$	$	$	$	$

Other Intangible Assets

In connection with the acquisition of TODCO (See Note 4), the Company allocated $17.6 million in value to certain international customer contracts. These amounts are being amortized over the life of the contracts. As of December 31, 2008 and 2007, the customer contracts had a carrying value of $7.2 million and $14.8 million, net of accumulated amortization of $10.4 million and $2.8 million, respectively, and are included in Other Assets, Net on the Consolidated Balance Sheets. The Company analyzed these intangible assets for impairment as of December 31, 2008 and noted that the assets were recoverable under SFAS No. 144.

Amortization expense was $7.6 million and $2.8 million for the years ended December 31, 2008 and 2007, respectively. Future estimated amortization expense for the carrying amount of intangible assets as of December 31, 2008 is expected to be as follows (in thousands):

2009	$ 4,781
2010	1,814
2011	658
2012	
2013	

Other Assets

Other assets consist of drydocking costs for marine vessels, other intangible assets, deferred costs, financing fees, investments, deposits and other. 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, 2008 and 2007 were

$6.5 million and $8.2 million, respectively. Amortization expense for drydocking costs was $19.0 million, $18.4 million and $10.7 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Financing fees are deferred and amortized over the life of the applicable debt instrument. Unamortized deferred financing fees at December 31, 2008 and 2007 were $18.2 million and $16.2 million, respectively. The amortization expense related to the deferred financing fees is included in interest expense on the Consolidated Statements of Operations. Amortization expense for financing fees was $4.0 million, $1.8 million and $0.7 million for the years ended December 31, 2008, 2007 and 2006, respectively. The Company recognized a pretax charge of $2.1 million related to the write off of unamortized issuance costs in connection with the redemption of a portion of its 3.375% Convertible Senior Notes in December 2008 (See Note 10). The Company recognized a pretax charge of $2.2 million in 2007 related to the write off of deferred financing fees in connection with the early debt repayment (See Note 10).

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. 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. The Company recognized $2.1 million of deferred U.S. tax expense on foreign earnings which management expects to repatriate in the future. 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 length of time an offshore drilling unit will be used in a given location, the Company would adjust deferred taxes accordingly (See Note 15).

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 revenues and expenses during the reporting period. On an ongoing basis, the Company evaluates its estimates, including those related to bad debts, investments, intangible assets, goodwill, property, plant 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, 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, 7.375% Senior Notes and term loan facility is estimated based on the current rates offered for debt with similar risks and remaining maturities. The Company believes its other debt instruments, which are short-term in nature, approximate fair value.

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Accounting Pronouncements

In October 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) No. 157-3, *Determining the Fair Value of a Financial Asset when the Market for that Asset is not Active* (FSP No. 157-3). FSP No. 157-3 clarifies the application of SFAS No. 157, *Fair Value Measurements* (SFAS No. 157) in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. FSP No. 157-3 was effective upon issuance and was adopted by the Company without material impact to its financial statements.

In May 2008, the FASB issued FSP No. APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement)* (FSP 14-1), which clarifies the accounting for convertible debt instruments that may be settled in cash (including partial cash settlement) upon conversion. FSP 14-1 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. FSP 14-1 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 interest rate to be used under FSP 14-1 will therefore be significantly higher than the rate on the Company s Convertible Senior Notes due 2038 that is currently used, which is equal to the coupon rate of 3.375 percent. FSP 14-1 is effective for the Company as of January 1, 2009, requires retrospective application to the terms of instruments as they existed for all periods presented and early adoption is not permitted. Had this new standard been effective for the fiscal year ended December 31, 2008, the Company estimates interest expense would have increased by approximately $4.3 million, and diluted loss per share from continuing operations would have increased by approximately $0.03 per share. In addition, the Company expects the gain of $43.4 million recognized on the redemption of $88.2 million of the Convertible Senior Notes due 2038 would have approximated $22.8 million had this new standard been effective at that time. FSP 14-1 will have no direct effect on the Company s cash flow.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities* (SFAS No. 161). SFAS No. 161 amends SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS No. 133) requiring enhanced disclosures about an entity s derivative and hedging activities thereby improving the transparency of financial reporting. SFAS No. 161 s disclosures provide additional information on how and why derivative instruments are being used. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged.

In December 2007, the FASB issued SFAS No. 141R, *Business Combinations* (SFAS No. 141R). SFAS No. 141R replaces SFAS No. 141, *Business Combinations* (SFAS No. 141), and applies to all transactions and other events in which one entity obtains control over one or more other businesses. SFAS No. 141R requires an acquirer, upon initially obtaining control of another entity, to recognize the assets, liabilities and any non-controlling interest in the acquiree at fair value as of the acquisition date. Contingent consideration is required to be recognized and measured at fair value on the date of acquisition rather than at a later date when the amount of that consideration may be determinable beyond a reasonable doubt. SFAS No. 141R requires acquirers to expense acquisition-related costs as incurred rather than allocating such costs to the assets acquired and liabilities assumed, as was previously the case under SFAS No. 141. SFAS No. 141R may have a significant impact on the Company s accounting for any business combinations closing on or after January 1, 2009.

The Company adopted, without material impact to its consolidated financial statements, the provisions of SFAS No. 157 related to financial assets and liabilities and to nonfinancial assets and liabilities measured at fair value on a recurring basis on January 1, 2008. SFAS No. 157 defines fair value, establishes a framework

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

for measuring fair value under generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 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. In February 2008, the FASB issued FSP SFAS No. 157-2, *Effective Date of FASB Statement No. 157*, which defers the effective date of SFAS No. 157 for one year for certain nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis. Effective January 1, 2009, the Company will adopt the provision for nonfinancial assets and liabilities that are not required or permitted to be measured at fair value on a recurring basis, which include those measured at fair value in impairment testing and those initially measured at fair value in a business combination. The Company does not expect the provisions of SFAS No. 157 related to these items to have a material impact on its consolidated financial statements.

The Company adopted, without material impact to its consolidated financial statements, the provisions of SFAS No. 159*, The Fair Value Option for Financial Assets and Financial Liabilities* (SFAS No. 159) on January 1, 2008. SFAS No. 159 permits companies to choose to measure certain financial instruments and certain other items at fair value and requires that unrealized gains and losses on items for which the fair value option has been elected be reported in earnings.

2. Property and Equipment, Net

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

	December 31, 2008	December 31, 2007
Drilling rigs and marine equipment	$ 2,248,713	$ 1,914,018
Drilling machinery and equipment	47,062	235,680
Leasehold improvements	10,615	9,722
Automobiles and trucks	1,812	2,470
Computer equipment	15,294	10,505
Furniture and fixtures	1,484	962
Total property and equipment, at cost	2,324,980	2,173,357
Less accumulated depreciation	(236,450)	(113,133)
Total property and equipment, net	$ 2,088,530	$ 2,060,224

3. Earnings Per Share

The reconciliation of the numerator and denominator used for the computation of basic and diluted earnings per share is as follows (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Denominator:			
Weighted average basic shares	88,351	58,897	31,327
Add effect of stock equivalents		666	876
Weighted average diluted shares	88,351	59,563	32,203

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

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 3,009,099 and 350,080 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, 2008 and 2007, respectively. There were no anti-dilutive stock equivalents for the year ended December 31, 2006.

4. Asset Acquisitions and Business Combination

On July 11, 2007, the Company acquired TODCO for total consideration of approximately $2,397.8 million, consisting of $925.8 million in cash and 56.6 million shares of common stock. The fair value of the shares issued was determined for accounting purposes using an average price of $25.99, which represented the average closing price of the Company s stock for a period before and after the date of the merger agreement with TODCO. In addition, the Company incurred additional consideration in the amount of $41.6 million related primarily to transaction related costs, cash payments to non-continuing employees and the conversion of certain employee equity awards. The results of TODCO are included in the Company s results from the date of acquisition. The acquisition expanded the Company s international presence and diversified the Company s fleet.

The total consideration was allocated to TODCO s net tangible and identifiable intangible assets based on their estimated fair values. The excess of the purchase price over the net assets was recorded as goodwill (See Note 1).

The final allocation of the consideration is as follows:

	July 11, 2007 (In thousands)
Cash and Cash Equivalents	$ 235,163
Accounts Receivable	190,452
Insurance Claims Receivable	20,875
Current Deferred Tax Asset	19,319
Prepaid Expenses and Other	14,121
Property and Equipment, Net	1,685,837
Goodwill	950,287
Other Assets, Net	26,508
Total Assets	3,142,562
Short-Term Debt	(3,618)
Accounts Payable	(82,977)
Income Taxes Payable	(9,289)
Other Current Liabilities	(64,153)
Long-Term Debt	(14,062)
Deferred Tax Liabilities	(523,520)
Other Liabilities	(5,621)

Total Purchase Price	$	2,439,322

The following presents the consolidated financial information for the Company on a pro forma basis assuming the acquisition of TODCO had occurred as of the beginning of the periods presented. The historical financial information has been adjusted to give effect to pro forma items that are directly attributable to the acquisition and expected to have a continuing impact on consolidated results. These items include adjustments

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

to record the incremental depreciation expense related to the increase in fair value of the acquired assets, to record the additional interest expense related to the incremental borrowings and to reclassify certain items to conform to the Company s financial reporting presentation.

The unaudited pro forma financial information set forth below has been compiled from historical financial statements and other information, but is not necessarily indicative of the results that actually would have been achieved had the transaction occurred on the dates indicated or that may be achieved in the future:

	Year Ended December 31,	
	2007	2006
	(In millions, except per share amounts)	
Revenues	$ 1,182.4	$ 1,189.7
Net Income	193.8	223.1
Basic earnings per share	2.19	2.53
Diluted earnings per share	2.16	2.50

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.

5. Dispositions

During the second quarter of 2008, the Company sold *Hercules 256* for gross proceeds of $8.5 million, which approximated the carrying value of this asset.

During the fourth quarter of 2007, the Company sold the nine land rigs and related assets purchased in the TODCO acquisition for gross proceeds of $107.0 million, which approximated the carrying value of these assets. In addition, during 2007, the Company sold several marine support vessels purchased in the TODCO acquisition for gross proceeds of $3.2 million, which approximated the carrying value of the vessels.

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 as a discontinued operation for all periods presented.

Interest charges have been allocated to the discontinued operation in accordance with Emerging Issues Task Force (EITF) Issue No. 87-24, *Allocation of Interest to Discontinued Operations*. The interest was allocated based on a pro rata calculation of the net assets of the discontinued operation to the Company s consolidated net assets. Interest allocated to the discontinued operation was $1.1 million for the year ended December 31, 2007.

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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, 2008	Year Ended December 31, 2007
Revenues	$ 1,818	$ 40,515
Income (Loss) Before Income Taxes	$ (2,341)	$ 4,429
Income Tax (Provision) Benefit	821	(3,919)
Income (Loss) from Discontinued Operation, Net of Taxes	$ (1,520)	$ 510

7. Stock-based Compensation

On January 1, 2006, the Company adopted the modified prospective provisions of SFAS No. 123 (revised 2004) *Share-Based Payment* (SFAS No. 123R). Prior to the adoption of SFAS No. 123R, the Company followed the intrinsic value method as prescribed in Accounting Principles Board Opinion No. 25 *Accounting for Stock Issued to Employees* (APB Opinion 25) and related interpretations. SFAS No. 123R requires that compensation cost for stock options is recognized beginning with the effective date based on the requirements of (a) SFAS No. 123R for all share-based payments granted after January 1, 2006 and (b) SFAS No. 123 for all share-based payments granted to employees prior to January 1, 2006 that remain unvested on January 1, 2006. SFAS No. 123R requires that any unearned compensation related to share-based payments awarded prior to adoption be eliminated against the appropriate equity account. Additionally, SFAS No. 123R requires 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 prospectively as cash flows from financing activities. The Company classified $5.9 million, $3.8 million, and $1.3 million in excess tax benefits as a financing cash inflow for the years ended December 31, 2008, 2007 and 2006, respectively, in accordance with SFAS No. 123R.

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. On April 26, 2006, the Company s stockholders approved an increase in the shares available for grant or award under the 2004 Plan by 1.0 million shares. Additionally, in July 2007, the Company s stockholders approved an increase in the shares available for grant or award under the 2004 Plan by an additional 6.8 million shares to a total of 10.3 million. At December 31, 2008, approximately 5.9 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 after the initial public offering are subject to a three year vesting period with some effective one-third on each anniversary of the grant date and others effective on the third anniversary of the grant date. 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 was calculated based on the closing price of the Company s stock on the day of grant. The total fair value of restricted stock grants is amortized to expense on a straight-line basis over the vesting period.

The unrecognized compensation cost related to the Company s unvested stock options and restricted share grants as of December 31, 2008 was $5.4 million and $9.9 million, respectively, and is expected to be recognized over a weighted-average period of 1.8 years and 1.7 years, respectively.

Cash received from stock option exercises was $5.1 million, $2.1 million and $1.2 million during the years ended December 31, 2008, 2007 and 2006, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company recognized $12.5 million, $7.7 million and $3.1 million in employee stock-based compensation expense during the years ended December 31, 2008, 2007 and 2006, respectively. The related income tax benefit recognized for the years ended December 31, 2008, 2007 and 2006 was $4.4 million, $2.7 million and $1.1 million respectively. In conjunction with the acquisition of TODCO (See Note 4), the Company assumed 0.3 million stock options held by former TODCO employees and issued 20,608 restricted stock awards in exchange for deferred performance units held by former TODCO employees. All of these awards are fully vested. In 2007, the Company capitalized $3.8 million related to these awards as part of the purchase price allocation. The Company did not capitalize any stock-based compensation during 2008 and 2006.

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:

	2008	2007	2006
Dividend yield			
Expected price volatility	40.8%	35.0%	
Risk-free interest rate	2.85%	4.58%	
Expected life of options (in years)	6.0	5.9	
Weighted-average fair value of options granted	$ 6.35	$ 11.18	

The Company used the historical volatility of comparable companies to estimate its volatility. In addition, the Company used the simplified method to estimate the expected life of the options granted. The total fair value of options granted is amortized to expense on a straight-line basis over the vesting period.

The following table reflects the impact of adopting SFAS No. 123R (dollars in thousands, except per share data):

	Year Ended December 31, 2006
Compensation expense related to stock options, net of tax of $736	$ 1,367
Basic earnings per share impact	(0.04)
Diluted earnings per share impact	(0.04)
Cash flow from operating activities impact	(3,374)
Cash flow from financing activities impact	1,271

The following table summarizes stock option activity under the 2004 Plan as of December 31, 2008 and changes during the year then ended:

	Weighted-Average	Average Remaining	Aggregate

Options	Shares	Exercise Price	Contractual Term	Intrinsic Value (In thousands)
Outstanding at January 1, 2008	2,314,802	$ 17.39	7.98	$ 17,558
Granted	947,800	15.28		
Exercised	(478,169)	10.72		
Forfeited	(38,223)	24.10		
Outstanding at December 31, 2008	2,746,210	17.73	7.96	643
Vested or Expected to Vest at December 31, 2008	2,701,707	17.70	7.94	643
Exercisable at December 31, 2008	1,687,810	18.42	7.11	643

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The weighted-average grant date fair value of options granted during the years ended December 31, 2008 and 2007 was $6.35, and $11.18, respectively. There were no options granted in 2006. The intrinsic value of options exercised during 2008, 2007 and 2006 was $11.7 million, $5.2 million and $3.4 million, respectively.

The following table summarizes information about restricted stock outstanding as of December 31, 2008 and changes during the year then ended:

	Restricted Stock	Weighted-Average Grant Date Fair Value
Non-Vested at January 1, 2008	282,364	$ 26.42
Granted	417,655	26.12
Vested	(105,539)	28.15
Forfeited	(102,176)	26.65
Non-Vested at December 31, 2008	492,304	25.93

The weighted-average grant date fair value of restricted stock granted during the years ended 2008, 2007 and 2006 was $26.12, $28.75 and $34.94, respectively. The total fair value of restricted stock vested during the years ended 2008, 2007 and 2006 was $2.6 million, $1.4 million and $0.8 million, respectively.

8. Accrued Liabilities

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

	December 31, 2008	December 31, 2007
Accrued Liabilities:		
Taxes other than Income	$ 17,610	$ 21,686
Accrued Payroll and Employee Benefits	36,160	27,941
Accrued Self-Insurance Claims	29,541	29,973
Other	113	538
	$ 83,424	$ 80,138

9. Benefit Plans

The Company currently has two 401(k) plans in which substantially all U.S. employees are eligible to participate. Under the legacy Hercules plan, the Company matched participant contributions equal to 100% of the first 3% and 50% of the next 2% of a participant s eligible compensation. Under the plans acquired in the TODCO acquisition (See Note 4), the Company matched participant contributions equal to 100% of the first 6% of each participant s base salary for the legacy TODCO plan and for Delta Towing s plan the Company matched participant contributions up to 50% of the first 6% of each participant s eligible compensation. Effective January 1, 2008, the legacy Hercules plan and legacy TODCO plan discussed above were merged into one plan and in 2008 the Company made matching participant contributions equal to 100% of the first 6% of each participant s salary. In addition, effective January 1, 2008 the Delta Towing plan was changed and the Company made matching participant contributions equal to 100% of the first 6% of each participant s base salary. The Company made total matching contributions of $8.6 million, $5.0 million and $1.9 million for the years ended December 31, 2008, 2007 and 2006, respectively.

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10. Debt

Debt is comprised of the following (in thousands):

	December 31, 2008	December 31, 2007
Term Loan Facility, due July 2013	$ 886,500	$ 895,500
3.375% Convertible Senior Notes due June 2038	161,754	
9.5% Senior Notes, due December 2008		10,432
7.375% Senior Notes, due April 2018	3,512	3,513
6.95% Senior Notes, due April 2008		2,221
Foreign Overdraft Facility	2,455	
Total Debt	1,054,221	911,666
Less Short-term Debt and Current Portion of Long-term Debt	11,455	21,653
Total Long-term Debt, Net of Current Portion	$ 1,042,766	$ 890,013

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

2009	$ 11,455
2010	9,000
2011	9,000
2012	9,000
2013	1,012,254
Thereafter	3,512
	$ 1,054,221

Senior secured credit agreement

In 2007, the Company repaid and terminated its senior secured credit agreement with a syndicate of financial institutions that, as amended, provided for a $140.0 million term loan and a $75.0 million revolving credit facility and recognized a pretax charge of $2.2 million related to the write off of deferred financing fees in connection with the early repayment. Additionally, the Company cancelled all derivative instruments related to the term loan, which included two interest rate swaps on a total of $70.0 million of the term loan principal and two interest rate caps on a total of $20.0 million of the term loan principal (See Note 11).

In connection with the July 2007 acquisition of TODCO (See Note 4), the Company entered into a new $1,050.0 million credit facility, consisting of a $900.0 million term loan facility and a $150.0 million revolving credit facility. 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 credit facility, the Company entered into derivative instruments with the purpose of hedging future interest payments (See Note 11).

On April 28, 2008, the Company and certain of its subsidiaries entered into an agreement with the revolving lenders under its existing credit facility and certain new lenders to increase the maximum amount of the Company s revolving credit facility from $150.0 million to $250.0 million. The increased availability under the facility is to be used for working capital, capital expenditures and other general corporate purposes. 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. The facility includes a diverse

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

group of lenders with no single commitment greater than $30.0 million. Amounts outstanding under the revolving credit facility bear interest at the eurodollar rate or the base prime rate plus a margin. The applicable margin under the revolving credit facility varies depending on its leverage ratio, with the applicable margin for revolving loans bearing interest at the eurodollar rate ranging between 1.25% and 1.75% per annum and the applicable margin for revolving loans bearing interest at the base prime rate ranging between 0.25% and 0.75% per annum. The Company pays a commitment fee on the unused portion of the revolving credit facility, which ranges between 0.25% and 0.375% depending on its leverage ratio. The Company pays a letter of credit fee of between 1.25% and 1.75% per annum with respect to the undrawn amount of each letter of credit issued under the revolving credit facility. No amounts were outstanding and $29.0 million in standby letters of credit had been issued under the revolving credit facility as of December 31, 2008. The remaining availability under this revolving credit facility was $221.0 million at December 31, 2008.

The principal amount of the term loan amortizes in equal quarterly installments of $2.25 million, with the balance due on July 11, 2013. In addition, the Company is required to prepay the term loan with:

- the net proceeds from sales of certain assets to the extent that the Company does not reinvest the proceeds in its business within one year;
- the net proceeds from casualties or condemnations of assets to the extent that the Company does not reinvest the proceeds in its business within one year;
- the net proceeds of debt that the Company incurs to the extent that such debt is not permitted by the credit agreement;
- 50% of the net proceeds that the Company receives from any issuance of preferred stock; and
- commencing with the fiscal year ending December 31, 2008, 50% of the Company s excess cash flow until the outstanding principal balance of the term loan is less than $550.0 million.

Other than the quarterly payments referred to above and these mandatory prepayments, the term loan facility requires interest-only payments on a quarterly basis until maturity. The Company is permitted to prepay amounts outstanding under the term loan facility at any time without penalty. Amounts outstanding under the term loan facility bear interest at the eurodollar rate or the base prime rate plus a margin. The applicable margin under the term loan facility varies depending on the Company s leverage ratio, with the applicable margin for term loans bearing interest at the eurodollar rate ranging between 1.50% and 1.75% per annum and the applicable margin for term loans bearing interest at the base prime rate ranging between 0.50% and 0.75% per annum. As of December 31, 2008, $886.5 million was outstanding on the term loan facility and the interest rate was 3.21%. The annualized effective rate of interest was 5.88% for the year ended December 31, 2008 after giving consideration to derivative activities. The fair value of the amount outstanding on the term loan facility as of December 31, 2008 approximated $571.8 million.

The Company s obligations under the credit agreement are secured by liens on several 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 several of their vessels and substantially all of their other personal property.

The Company s liquidity is comprised of cash on hand, cash from operations and availability under the revolving credit facility. The Company also maintains a shelf registration statement covering the future issuance from time to time of various types of securities, including debt and equity securities. If the Company issues any debt securities off the shelf or otherwise incur debt, it would be required to make prepayments on the term loan to the extent the debt is not permitted under the term loan. The Company currently believes it will have adequate liquidity to fund its operations for the foreseeable future. However, to the extent the Company does not generate sufficient cash from operations, it may need to raise additional funds through public or private debt or equity offerings.

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The Company s term loan agreement requires that it meet certain financial ratios and tests, which are currently met. However, if the market for the Company s services does not improve or continues to decline over the near-term, it may not be able to meet the financial ratios and tests, which would result in an event of default under the credit agreement and could prevent the Company from borrowing under the revolving credit facility, which would in turn have a material adverse effect on the Company s available liquidity. Additionally, an event of default could result in the Company having to immediately repay all amounts outstanding under the term loan facility and the revolving credit facility and in the foreclosure of liens on assets. 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, liens, investments and affiliate transactions.

Senior notes and other debt

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 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 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. 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.

During December 2008, the Company redeemed $88.2 million aggregate principal amount of the 3.375% Convertible Senior Notes for a cost of $44.8 million resulting in a net gain of $43.4 million. In addition, we expensed $2.1 million of unamortized issuance costs in connection with the redemption. The repurchase effectively reduced the number of conversion shares potentially issuable in relation to the 3.375% Convertible Senior Notes from approximately 5.0 million to approximately 3.2 million. The carrying amount and fair value of the 3.375% Convertible Senior Notes was $161.8 million and $77.2 million, respectively, at December 31, 2008.

The Company determined 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.

In connection with the TODCO acquisition in July 2007, the Company assumed senior notes and an unsecured line of credit with a bank in Venezuela. The senior notes included 6.95% Senior Notes due in April 2008, 7.375% Senior Notes due in April 2018, and 9.5% Senior Notes due in December 2008 (collectively, Senior Notes). The 6.95% Senior Notes and the 9.5% Senior Notes were repaid in April 2008 and December 2008, respectively. The fair market value of the 7.375% Senior Notes at December 31, 2008 was approximately $2.5 million based on the most recent market valuations. In July 2008, the line of credit was changed to an overdraft facility and the maximum amount available to be drawn was increased to 9.0 million Bolivares Fuertes from 6.0 million Bolivares Fuertes. The overdraft facility is designed to manage local currency liquidity in Venezuela. The maximum amount available to be drawn at December 31, 2008 was

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9.0 million Bolivares Fuertes ($4.2 million at the exchange rate at December 31, 2008), and there were 5.1 million Bolivares Fuertes ($2.5 million at the exchange rate at December 31, 2008) outstanding at December 31, 2008. The carrying value of $2.5 million at December 31, 2008 also approximates the fair value of this overdraft facility due to its short-term nature.

11. Derivative Instruments and Hedging

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. The Company cancelled an interest rate swap on $35.0 million of term loan principal in conjunction with a debt repayment in April 2007 and received proceeds and recognized a gain of $0.3 million. In July 2007, the Company cancelled an interest rate swap on $35.0 million of term loan principal and two interest rate caps on a total of $20.0 million of term loan principal and received proceeds and recognized a gain of $0.4 million.

In May 2008 and July 2007, the Company entered into derivative instruments with the purpose of hedging future interest payments on its term loan facility. In May 2008, the Company entered into a floating to fixed interest rate swap with varying notional amounts beginning with $100.0 million with a settlement date of October 1, 2008 and ending with $75.0 million with a settlement date of December 31, 2009. The Company receives an interest rate of three-month LIBOR and pays a fixed coupon of 2.980% over six quarters. The terms and settlement dates of the swap match those of the term loan. In July 2007, the Company entered into a floating to fixed interest rate swap with decreasing notional amounts beginning with $400.0 million with a settlement date of December 31, 2007 and ending with $50.0 million with a settlement date of April 1, 2009. The Company will receive a payment equal to the product of three-month LIBOR and the notional amount and will pay a fixed coupon of 5.307% on the notional amount over six quarters. The terms and settlement dates of the swap match those of the term loan. In July 2007, the Company also entered into a zero cost LIBOR collar on $300.0 million of term loan principal over three years, with a ceiling of 5.75% and a floor of 4.99%. The counterparty is obligated to pay the Company in any quarter that actual LIBOR resets above 5.75% and the Company pays the counterparty in any quarter that actual LIBOR resets below 4.99%. The terms and settlement dates of the collar match those of the term loan.

The following table provides the schedule of notional amounts related to the May 2008 interest rate swap (in thousands):

December 31, 2008-March 31, 2009	$ 325,000
April 1, 2009-June 30, 2009	250,000
July 1, 2009-September 30, 2009	175,000
October 1, 2009-December 30, 2009	75,000

The following table provides the scheduled reduction in notional amounts related to the July 2007 interest rate swap (in thousands):

January 1, 2009-March 31, 2009	$ 50,000

These hedge transactions are being accounted for as cash flow hedges under SFAS No. 133, as amended by SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities (an amendment of FASB Statement No. 133)*, and SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*. The fair value of these hedging instruments is included in Other, Other Assets, Net, Other Current Liabilities and Other Liabilities and the cumulative unrealized loss, net of tax, is included in Accumulated Other Comprehensive Loss on the Consolidated Balance Sheets. The Company did not recognize a gain or loss due to hedge ineffectiveness in the Consolidated Statements of Operations for the years ended December 31, 2008, 2007 and 2006 related to these hedging instruments. The Company expects

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to realize $15.6 million of unrealized loss in the Consolidated Statements of Operations for the year ended December 31, 2009.

A summary of amounts relating to derivative instruments is provided below (in thousands):

	December 31, 2008	December 31, 2007
Fair value included in Other	$ 21	$
Fair value included in Other Assets, Net		322
Fair value included in Other Current Liabilities	15,669	4,025
Fair value included in Other Liabilities	7,324	8,784
Cumulative unrealized loss, net of tax of $8,040 and $4,371, respectively included in Accumulated Other Comprehensive Loss	(14,932)	(8,117)

	Recognized Gain (Loss) in Consolidated Statements of Operations for the Year Ended December 31,		
	2008	2007	2006
Realized gains included in Other, Net	$	$ 658	$ 588
Realized gains (losses) included in Interest Expense	$ (7,745)	$ 239	$

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. SFAS No. 157 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.

The valuation techniques that may be used to measure fair value are as follows:

(A) *Market approach* Uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities

(B) *Income approach* Uses valuation techniques to convert future amounts to a single present amount based on current market expectations about those future amounts, including present value techniques, option-pricing models and excess earnings method

(C) *Cost approach* Based on the amount that currently would be required to replace the service capacity of an asset (replacement cost)

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The following table represents our derivative assets and liabilities measured at fair value on a recurring basis as of December 31, 2008 (in thousands):

	Total Fair Value Measurement December 31, 2008	Quoted Prices in Active Markets for Identical Asset or Liability (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Valuation Technique
Derivative Assets	$ 21	$	$ 21	$	A
Derivative Liabilities	22,993		22,993		A

12. Supplemental Cash Flow Information

The following summarizes investing activities relating to acquisitions integrated into the Company s operations for the periods shown (in thousands):

	Year Ended December 31, 2007
Fair Value of Assets, net of cash acquired	$ 1,974,086
Goodwill	940,241
Common Stock Issuance	(1,475,763)
Total Liabilities	(710,168)
Cash Consideration, net of cash acquired	$ 728,396

	Year Ended December 31,		
	2008	2007	2006
	(In thousands)		
Cash paid during the period for:			
Interest, net of capitalized interest	$ 55,865	$ 36,426	$ 8,246
Income taxes	42,854	45,893	27,363

During 2008 and 2007, the Company capitalized interest of $8.8 million and $1.4 million, respectively. The Company did not capitalize interest in 2006.

During the years ended December 31, 2008, 2007 and 2006, the Company had non-cash activities related to its interest rate derivatives of $(6.8) million, $(8.9) million and $0.3 million, respectively.

13. 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.

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14. Sales to Major Customers

The customer base for the Company is primarily concentrated in the oil and natural gas exploration and production industry. Sales to customers exceeding 10 percent or more of the Company s total revenue are as follows:

	Year Ended December 31,		
	2008	2007	2006
Chevron Corporation	12%	21%	35%

In addition, Chevron Corporation accounted for 73.2% and 84.9% of the revenue for the Company s International Liftboats segment in the years ended December 31, 2008 and 2007, respectively.

15. Income Taxes

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

	Year Ended December 31,		
	2008	2007	2006
United States	$ (1,248,346)	$ 111,064	$ 168,885
Foreign	112,575	84,020	14,622
Total	$ (1,135,771)	$ 195,084	$ 183,507

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

	Year Ended December 31,		
	2008	2007	2006
Current-United States	$ 11,733	$ 23,262	$ 33,054
Current-foreign	31,103	11,217	3,070
Current-state	1,867	3,284	1,133
Current income tax provision	44,703	37,763	37,257
Deferred-United States	(96,344)	23,315	26,597
Deferred-foreign	(5,683)	(159)	(59)
Deferred-state	(9,104)	(1,847)	662

Deferred income tax (benefit) provision	(111,131)	21,309	27,200
Total income tax (benefit) provision	$ (66,428)	$ 59,072	$ 64,457

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

	December 31, 2008	December 31, 2007
Deferred tax assets:		
Net operating loss carryforward (Federal, State & Foreign)	$ 53,868	$ 95,939
Credit carryforwards	31,180	28,271
Accrued expenses	15,698	17,200
Unearned income	6,370	4,509
Intangibles	3,569	99
Stock Based Compensation	4,523	2,931
Other	9,123	4,700
Deferred tax assets	124,331	153,649
Deferred tax liabilities:		
Fixed assets	(428,427)	(582,233)
Deferred expenses	(2,612)	(7,820)
Other	(6,001)	(3,520)
Deferred tax liabilities	(437,040)	(593,573)
Net deferred tax liabilities	$ (312,709)	$ (439,924)

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

	Year Ended December 31, 2008	2007	2006
Statutory rate	35.0%	35.0%	35.0%
Effect of:			
Impairment of Goodwill	(29.3)		
State income taxes	0.7	0.1	1.1
Taxes on foreign earnings at greater (lesser) than the U.S. statutory rate	(0.4)	(4.4)	(1.0)
Other	(0.2)	(0.4)	
Effective rate	5.8%	30.3%	35.1%

The amount of consolidated U.S. net operating losses (NOLs) available as of December 31, 2008 is approximately $153 million. These NOLs will expire in the years 2017 through 2024. 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. In addition, the Company has $31.2 million of non-expiring alternative minimum tax credits.

We recognized $2.1 million of deferred U.S. tax expense on foreign earnings which management expects to repatriate in the future. 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, 2008, the aggregate amount of undistributed earnings of the foreign subsidiaries was $108.8 million. Upon distribution of these earnings in the form of dividends or otherwise, the Company

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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.

The Company, as successor to TODCO, and TODCO s former parent Transocean Ltd. are parties to a tax sharing agreement that was originally entered into in connection with TODCO s initial public offering in 2004. The tax sharing agreement was amended and restated in November 2006 in a negotiated settlement of disputes between Transocean and TODCO over the terms of the original tax sharing agreement. The tax sharing agreement continues to require that additional payments be made to Transocean based on a portion of the expected tax benefit from the exercise of certain compensatory stock options to acquire Transocean common stock attributable to current and former TODCO employees and board members. The estimated amount of payments to Transocean related to compensatory options that remain outstanding at December 31, 2008, assuming a Transocean stock price of $47.25 per share at the time of exercise of the compensatory options (the actual price of Transocean s common stock at December 31, 2008), is approximately $4.9 million. The Company accounts for the exercise of Transocean stock options held by current and former TODCO employees and board members in the period in which such option is exercised. As tax deductions are generated from the exercise of the stock options and in accordance with SFAS No. 109, *Accounting for the Income Taxes* (SFAS No. 109) and SFAS No. 123R, *Share Based Payment* (SFAS No. 123R), the Company takes a current tax deduction for the value of the stock option tax deduction, pays Transocean for 55% of the value of the deduction and increases additional paid-in capital by 45% of the deduction. Because of the Company s current NOL position, the tax benefit of the stock option deduction is reclassified as a reduction in net deferred tax liability. There is no certainty that the Company will realize future economic benefits from TODCO s tax benefits equal to the amount of the payments required under the tax sharing agreement.

Effective January 1, 2007, the Company adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). Its adoption did not have a material impact on the Company s Consolidated Balance Sheet, Consolidated Statement of Operations or Consolidated Statement of Cash Flows. 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. During 2008, the Company recorded interest and penalties of $3.1 million through the Consolidated Statement of Operations. In addition, we 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 2007 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 2002 through 2007.

The following table presents the reconciliation of the total amounts of unrecognized tax benefits from January 1, 2008 to December 31, 2008 (in thousands):

Balance as of January 1, 2008	$

Increases related to current year tax positions	5,467
Increases related to tax positions taken in earlier periods	8,009
Balance as of December 31, 2008	$ 13,476

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From time to time, our tax returns are subject to review and examination by various tax authorities within the jurisdictions in which we operate. We are currently contesting tax assessments in Mexico, Nigeria, 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, for approximately $20.7 million (based on the current exchange rates at the time of the assessment and inclusive of penalties) relating to calendar years 1998 through 2001. In March 2003, TODCO paid approximately $2.6 million of the assessment, plus approximately $0.3 million in interest, and we are contesting the remainder of the assessment with the Venezuelan Tax Court. After TODCO made the partial assessment payment, it received a revised assessment in September 2003 of approximately $16.7 million (based on the current exchange rates at the time of the assessment and inclusive of penalties). Thereafter, TODCO filed an administrative tax appeal with SENIAT and the tax authority rendered a decision that reduced the tax assessment to $8.1 million (based on the current exchange rates at the time of the decision). TODCO then initiated a judicial tax court appeal with the Venezuelan Tax Court to set aside the $8.1 million administrative tax assessment. In August 2008, the Venezuelan Tax Court ruled in favor of TODCO; however, SENIAT has the right to appeal this case to the Venezuelan Supreme Court. We do not expect the ultimate resolution of this assessment to have a material impact on our consolidated results of operations, financial condition or cash flows. 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 contests the Company s right to certain deductions and also claims it did not remit withholding tax due on certain of these deductions. The Company is pursuing its alternatives to resolve this assessment. As required by local statutory requirements, we have provided a surety bond for an amount equal to $13 million as of December 31, 2008, to contest these assessments. In 2008, the Mexican tax authorities commenced an audit for the 2005 tax year. Depending on the ultimate outcome of the 2004 assessment and the 2005 audit, the Company anticipates that the Mexican tax authorities could make similar assessments for other open tax years.

As of December 31, 2008, the Company has $10.6 million unrecognized tax benefits that, if recognized, would impact the effective income tax rate. It is reasonably possible that, within the next 12 months, total unrecognized tax benefits may decrease as a result of a potential resolution of the aforementioned ongoing tax audits. The Company estimates that these events could reasonably result in a possible decrease in unrecognized tax benefits of up to $8.0 million.

16. 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. Previously, the Company reported an Other segment that included Delta Towing and the land rigs. The land rigs were sold in December 2007 (See Note 5 and 6) and the results of the land rig operations in 2007 and the wind down costs in 2008 are included in Discontinued Operation on the Consolidated Statements of Operations. 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. The following describes the Company s reporting segments as of December 31, 2008:

Domestic Offshore includes 24 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.

International Offshore includes 11 jackup rigs and one platform rig outside of the U.S. Gulf of Mexico. The Company has one jackup rig working offshore in Saudi Arabia and Malaysia, one rig ready

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

stacked in Gabon and one rig undergoing repairs in Qatar. The Company has two jackup rigs working offshore in India and two jackup rigs and one platform rig operating in Mexico. In addition, the Company had one jackup rig undergoing customer acceptance in Saudi Arabia, one jackup rig currently undergoing an upgrade in Namibia and one jackup rig cold-stacked in Trinidad.

Inland includes a fleet of 12 conventional and 15 posted barge rigs that operate inland in marshes, rivers, lakes and shallow bay or coastal waterways along the U.S. Gulf Coast.

Domestic Liftboats includes 45 liftboats in the U.S. Gulf of Mexico.

International Liftboats includes 20 liftboats. Eighteen are operating offshore West Africa, including five liftboats owned by a third party. One liftboat is operating offshore Middle East. One liftboat is in a Middle Eastern shipyard undergoing refurbishment and it is being marketed in the Middle East region.

Delta Towing the Company s Delta Towing business operates a fleet of 31 inland tugs, 16 offshore tugs, 34 crew boats, 46 deck barges, 17 shale barges and four spud barges along and in the U.S. Gulf of Mexico and along the Southeastern coast. As of December 31, 2008, 14 crew boats, three inland tugs and six offshore tugs are cold-stacked.

In January 2009, the Company reclassified four of its cold-stacked rigs located in the U.S. Gulf of Mexico and 10 of its cold-stacked inland barges as retired. These rigs would require extensive refurbishment and currently are not expected to re-enter active service.

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 that 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, 2008			Year Ended December 31, 2007		
	Revenue	Income (Loss) from Operations	Depreciation and Amortization	Revenue	Income from Operations	Depreciation and Amortization
Domestic Offshore(a)	$ 382,358	$ (598,856)	$ 66,850	$ 241,452	$ 78,073	$ 35,143
International Offshore(b)	327,983	(11,647)	37,865	144,778	67,809	15,513
Inland(c)	162,487	(422,152)	43,107	107,100	33,667	16,264
Domestic Liftboats	94,755	16,578	21,317	137,745	50,684	24,969
International Liftboats	85,896	30,872	9,912	63,282	19,896	7,619
Delta Towing(d)	58,328	(80,065)	10,926	31,921	10,262	4,598
	$ 1,111,807	$ (1,065,270)	$ 189,977	$ 726,278	$ 260,391	$ 104,106
Corporate		(55,643)	2,917		(34,749)	528

Total Company	$ 1,111,807	$ (1,120,913)	$ 192,894	$ 726,278	$ 225,642	$ 104,634

(a) 2008 Income (Loss) from Operations for the Company s Domestic Offshore Segment 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 for the Company s International Offshore Segment includes an impairment of goodwill charge of $150.9 million.

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(c) 2008 Income (Loss) from Operations for the Company s Inland Segment 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 for the Company s Delta Towing Segment includes an impairment of goodwill charge of $86.7 million.

	Year Ended December 31, 2006		
	Revenue	Income from Operations	Depreciation and Amortization
Domestic Offshore	$ 160,761	$ 93,037	$ 8,882
International Offshore	30,460	12,930	2,547
Inland			
Domestic Liftboats	133,929	63,791	18,854
International Liftboats	19,162	4,309	1,923
Delta Towing			
	$ 344,312	$ 174,067	$ 32,206
Corporate		(16,010)	104
Total Company	$ 344,312	$ 158,057	$ 32,310

	Total Assets	
	December 31, 2008	December 31, 2007
Domestic Offshore(a)	$ 930,988	$ 1,504,548
International Offshore(b)	955,911	681,742
Inland(c)	217,477	646,120
Domestic Liftboats	148,307	186,568
International Liftboats	168,356	149,813
Delta Towing(d)	92,371	193,963
Corporate	77,485	281,194
Total Company	$ 2,590,895	$ 3,643,948

(a)

2008 Assets for the Company s Domestic Offshore Segment reflect the $507.2 million and $174.6 million impairment of goodwill and impairment of property and equipment, respectively.

(b) 2008 Assets for the Company s International Offshore Segment reflect the impairment of goodwill of $150.9 million.

(c) 2008 Assets for the Company s Inland Segment reflect $205.5 million and $202.1 million impairment of goodwill and impairment of property and equipment, respectively.

(d) 2008 Assets for the Company s Delta Towing Segment reflect the impairment of goodwill of $86.7 million.

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Year Ended December 31,		
	2008(a)	**2007**	**2006**
Capital Expenditures and Deferred Drydocking Expenditures:			
Domestic Offshore	$ 139,893	$ 22,720	$ 76,635
International Offshore	390,732	78,455	20,100
Inland	39,739	17,145	
Domestic Liftboats	12,362	16,950	66,279
International Liftboats	8,302	20,183	53,955
Delta Towing	4,125	4,024	
Corporate	7,200	16,685	31
Total Company	$ 602,353	$ 176,162	$ 217,000

(a) Includes the purchase of the *Hercules 350*, the *Hercules 262* and the *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 revenues generated by such assets during the periods. The following tables present revenues and long-lived assets by country based on the location of the service provided (in thousands):

	Year Ended December 31,		
	2008	**2007**	**2006**
Operating Revenues:			
United States	$ 697,930	$ 514,911	$ 294,690
Saudi Arabia	371		
India	93,544	52,501	12,392
Mexico	90,815	28,364	
Nigeria	83,141	60,384	18,440
Other(a)	146,006	70,118	18,790
Total	$ 1,111,807	$ 726,278	$ 344,312

	As of December 31,	
	2008	**2007**

Long-Lived Assets:		
United States	$ 1,226,379	$ 2,375,874
Saudi Arabia	301,147	
India	157,686	128,773
Mexico	101,429	161,568
Nigeria	79,886	82,455
Other(a)	264,343	302,085
Total	$ 2,130,870	$ 3,050,755

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

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

17. Commitments and Contingencies

Operating Leases

The Company has operating lease commitments that expire at various dates through 2017. As of December 31, 2008, future minimum lease payments related to operating leases were as follows (in thousands):

Years Ended December 31,	
2009	$ 6,267
2010	3,934
2011	1,991
2012	1,303
2013	1,188
Thereafter	4,850
Total	$ 19,533

Rental expense for all operating leases was $13.3 million, $2.8 million and $1.6 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Legal Proceedings

The Company is involved in various claims and lawsuits in the normal course of business. As of December 31, 2008, management did not believe any accruals were necessary in accordance with SFAS No. 5, *Accounting for Contingencies*.

In connection with the 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, 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. As of the date of this report, approximately

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 continues to monitor a small group of these other cases. The Company has not determined which entity would be responsible for such claims under the Master Separation Agreement between TODCO and its former parent. The Company intends to defend vigorously and, based on the limited information available at this time, 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 position.

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, 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.

The Company maintains insurance coverage that includes coverage for physical damage, third party liability, workers compensation and employers liability, general liability, vessel pollution and other coverages.

In May 2008, the Company completed the renewal of all of its key insurance policies. The Company s primary marine package provides for hull and machinery coverage for the Company s rigs and liftboats up to a scheduled value for each asset. The maximum coverage for these assets is $2.9 billion; however, coverage for U.S. Gulf of Mexico named windstorm damage is subject to an annual aggregate limit on liability of $200.0 million. The policies are subject to exclusions, limitations, deductibles, self-insured retention and other conditions. Deductibles for events that are not U.S. Gulf of Mexico named windstorm events are 10% of insured values per occurrence for drilling rigs, and range from $0.3 million to $1.0 million per occurrence for liftboats, depending on the insured value of the particular vessel. The deductibles for drilling rigs and liftboats in a U.S. Gulf of Mexico named windstorm event are the greater of

$10.0 million or the operational deductible

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

for each U.S. Gulf of Mexico named windstorm. The Company is self-insured for 10% above the deductibles for removal of wreck, sue and labor, collision, protection and indemnity general liability and hull and physical damage policies. The protection and indemnity coverage under the primary marine package has a $5.0 million limit per occurrence with excess liability coverage up to $200.0 million. The primary marine package also provides coverage for cargo and charterer s legal liability. Vessel pollution is covered under a Water Quality Insurance Syndicate policy. In addition to the marine package, the Company has separate policies providing coverage for onshore general liability, employer s liability, auto liability and non-owned aircraft liability, with customary deductibles and coverage as well as a separate primary marine package for its Delta Towing business.

In 2008, 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 $35.2 million was financed through these arrangements of which $11.1 million was outstanding at December 31, 2008. The interest rate on these notes is 4.42% and the notes mature in April 2009. There was $16.9 million outstanding in insurance note payable at December 31, 2007 at an interest rate of 5.75%.

Surety Bonds and Unsecured Letters of Credit

In connection with the TODCO acquisition in July 2007 (See Note 4), the Company assumed certain surety bonds. There was $51.4 million outstanding related to surety bonds at December 31, 2008. The surety bonds guarantee our performance as it relates to the Company s drilling contracts, insurance, tax and other obligations in 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.

The Company had $0.1 million in unsecured letters of credit outstanding at December 31, 2008.

Insurance Claims

The Company acquired several jackup rigs in the TODCO acquisition (See Note 4) that were damaged by Hurricanes Rita and Katrina and one jackup rig that was damaged in a collision. During the year ended December 31, 2008, the Company received $30.2 million in proceeds related primarily to the settlement of claims for damage incurred during Hurricanes Rita and Katrina as well as damage to *Hercules 205* in a collision. At December 31, 2008, $0.8 million was outstanding for insurance claims receivable.

In August 2005, two of the Company s jackup rigs, *Hercules 120* and *Rig 25*, sustained damage during Hurricane Katrina. *Rig 25* was insured for $50.0 million, and the Company reached a settlement with its insurance underwriters and received net insurance proceeds of $48.8 million related to this claim in 2006, which represents the insured value less the negotiated salvage value of $1.3 million. The Company retained title to the rig and removed usable materials and equipment to be used on its other rigs. The Company recognized a gain of $29.6 million in March 2006 related to its insurance claim on *Rig 25*, which represented the gross proceeds of $50.0 million expected to be received, less the rig book value of $20.1 million and less $0.3 million of items related to the salvage operation of the rig not reimbursed by the Company s insurance carriers. *Hercules 120* sustained substantial damage to its mat and was moved to a shipyard in Mississippi to repair the damage. The rig returned to service in April 2006. As of December 31, 2006 all insurance claims relating to these jackup rigs have been paid.

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

18. Unaudited Interim Financial Data

Unaudited interim financial information for the years ended December 31, 2008 and 2007 is as follows (in thousands, except per share amounts):

	Quarter Ended			
	March 31	June 30	September 30	December 31(a)
2008				
Operating Revenues	$ 212,494	$ 270,106	$ 315,738	$ 313,469
Operating Income (Loss)	21,364	40,852	67,057	(1,250,186)
Income (Loss) from Continuing Operations	4,875	16,652	33,126	(1,123,996)
Loss from Discontinued Operation, Net of Taxes	(389)	(209)	(168)	(754)
Net Income (Loss)	$ 4,486	$ 16,443	$ 32,958	$ (1,124,750)
Basic Earnings (Loss) Per Share:				
Income (Loss) from Continuing Operations	$ 0.05	$ 0.19	$ 0.38	$ (12.78)
Loss from Discontinued Operation			(0.01)	(0.01)
Net Income (Loss)	$ 0.05	$ 0.19	$ 0.37	$ (12.79)
Diluted Earnings (Loss) Per Share:				
Income (Loss) from Continuing Operations	$ 0.05	$ 0.19	$ 0.37	$ (12.78)
Loss from Discontinued Operation		(0.01)		(0.01)
Net Income (Loss)	$ 0.05	$ 0.18	$ 0.37	$ (12.79)

(a) Includes $950.3 million and $376.7 million in impairment of goodwill and impairment of property and equipment charges, respectively.

	Quarter Ended			
	March 31	June 30	September 30	December 31
2007				
Operating Revenues	$ 110,464	$ 99,044	$ 272,573	$ 244,197
Operating Income	48,044	33,104	87,604	56,890
Income from Continuing Operations	33,391	23,466	46,352	32,803

Income (Loss) from Discontinued Operation, Net of Taxes						2,019		(1,509)
Net Income	$	33,391	$	23,466	$	48,371	$	31,294
Basic Earnings Per Share:								
Income from Continuing Operations	$	1.04	$	0.73	$	0.56	$	0.37
Income (Loss) from Discontinued Operation						0.03		(0.02)
Net Income	$	1.04	$	0.73	$	0.59	$	0.35
Diluted Earnings Per Share:								
Income from Continuing Operations	$	1.03	$	0.72	$	0.56	$	0.37
Income (Loss) from Discontinued Operation						0.02		(0.02)
Net Income	$	1.03	$	0.72	$	0.58	$	0.35

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

19. Related Parties

The Company s management believes all of the following transactions were carried out on an arm s-length basis.

The Company provided $3.3 million and $0.7 million in drilling services during the years ended December 31, 2008 and 2007, respectively, to Carrizo Oil and Gas, Inc. There were no services provided during the year ended December 31, 2006. Two members of the Company s Board of Directors are members of the Board of Directors of Carrizo Oil and Gas, Inc.

The Company provided $10.3 million and $3.9 million in drilling services during the years ended December 31, 2008 and 2007, respectively, to Peregrine Oil & Gas of which a member of the Company s Board of Directors is a member of the Board of Directors of Peregrine Oil & Gas. There were no services provided during the year ended December 31, 2006.

The Company incurred expense of $1.3 million, $0.4 million and $2.4 million related to transactions with T-3 Energy Services during the years ended December 31, 2008, 2007 and 2006, respectively. The Company s Senior Vice President and Chief Financial Officer and a member of the Company s Board of Directors are members of the Board of Directors for T-3 Energy Services.

The Company provided $22.3 million and $5.7 million in drilling services during the years ended December 31, 2008 and 2007, respectively, to Hall-Houston Exploration III, L.P. in which the Company holds a three percent investment. There were no services provided during the year ended December 31, 2006.

The Company incurred expense of $0.7 million, $0.8 million and $0.1 million for insurance premiums with HCC Insurance Holdings during the years ended December 31, 2008, 2007 and 2006, respectively. A member of the Company s Board of Directors became a member of the Board of Directors of HCC Insurance Holdings in November 2008.

The Company incurred expense of $2.4 million and $0.2 million related to transactions with Louisiana Electric Rig Service, Inc. during the years ended December 31, 2008 and 2007, respectively, and $1.8 million, $1.1 million and $0.1 million related to transactions with Southwest Oilfield Products, Inc. during the years ended December 31, 2008, 2007 and 2006, respectively. There were no payments to Louisiana Electric Rig Service, Inc. during the year ended December 31, 2006. Two members of the Company s Board of Directors are Managing Directors of Lime Rock Partners who purchased Louisiana Electric Rig Service, Inc. and Southwest Oilfield Products, Inc. in December 2008 and June 2008, respectively.

The Company paid the expenses of the selling stockholders in connection with public offerings of the Company s common stock in April and November 2006, including a single firm of attorneys for the selling stockholders, other than the underwriting discounts, commissions and taxes with respect to shares of common stock sold by the selling stockholders and the fees and expenses of any other attorneys, accountants and other advisors separately retained by them. A member of the Company s Board of Directors and a former Vice President of the Company were selling stockholders in the April 2006 offering. LR Hercules Holdings, LP and Greenhill & Co., Inc. and its affiliates were selling stockholders in the April and November 2006 offerings. The total fees paid by the Company with respect to the offerings, including expenses paid on behalf of the selling stockholders, were approximately $1.2 million.

20. Subsequent Event

In January 2009, the Company entered into an agreement with Mosvold Middle East Jackup Ltd. whereby it will market, manage and operate two 300 foot, high-specification new-build jackup drilling rigs. The rigs, which have an independent leg cantilever design, are under construction in the Middle East and have expected delivery dates of December 2009 and April 2010. The Company will have worldwide, exclusive marketing rights, except in U.S. sanctioned countries. All operating and capital expenses incurred to operate the rig will be paid for or reimbursed by Mosvold Middle East Jackup Ltd. Upon commencement of a drilling contract, the Company will receive a commencement fee and an ongoing management fee for the remainder of the contract.

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

None.

Item 9A. ***Controls and Procedures***

Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including John T. Rynd, our Chief Executive Officer and President, and Lisa W. Rodriguez, our Senior Vice President and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934 as of the end of the period covered by this annual report. Based upon that evaluation, Mr. Rynd and Ms. Rodriguez, acting in their capacities as our principal executive officer and our principal financial officer, concluded that, as of December 31, 2008, our disclosure controls and procedures were effective, in all material respects, with respect to the recording, processing, summarizing and reporting, within the time periods specified in the SEC s rules and forms, of information required to be disclosed by us in the reports that we file or submit under the Exchange Act.

During the year ended December 31, 2008, we converted a majority of our domestic and all of our international locations operational and financial functions to the Oracle enterprise resource planning (ERP) software system. The new ERP system affects every aspect of our operations, including procurement, finance and accounting, engineering, human resources and benefits and asset maintenance.

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, 2008. 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, 2008, our internal control over financial reporting is effective based on those criteria.

Our independent registered public accounting firm has audited management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2008, 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, 2008.

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, 2008.

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, 2008.

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, 2008.

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, 2008.

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 Schedules*

All 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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(3) *Exhibits:*

Exhibit Number	Description
2.1	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).
2.2	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 of Hercules (incorporated by reference to Exhibit 3.1 to Hercules Current Report on Form 8-K dated July 11, 2007 (File No. 0-51582) (the 2007 Form 8-K)).
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 2007 Form 8-K). 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, dates 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).
10.1	Separation Agreement dated as of June 20, 2008, between Hercules and Randall D. Stilley (incorporated by reference to Exhibit 10.1 to Hercules Current Report on Form 8-K dated June 23, 2008 (File No.-0-51582)).
10.2	Separation Agreement dated as of December 15, 2008, between Hercules and Randal R. Reed (incorporated by reference to Exhibit 10.1 to Hercules Current Report on Form 8-K dated December 19, 2008, 2008 (File No.-0-51582)) (the 2008 Form 8-K).
10.3	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.
10.4	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)).
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10.12	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)).
10.13	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).
10.14	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)).
*10.15	Form of Stock Option Agreement.
*10.16	Form of Restricted Stock Agreement for Employees and Consultants.
10.17	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)).
*10.18	Hercules Offshore, Inc. Amended and Restated Deferred Compensation Plan.
10.19	Schedule of executive officer and director compensation arrangements.
10.20	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)).
10.21	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)).
10.22	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)).
10.23	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)).
10.24	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)).
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*21.1	Subsidiaries of Hercules.
*23.1	Consent of Ernst & Young LLP.
*23.2	Consent of Grant Thornton 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.

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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 February 25, 2009.

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 February 25, 2009.

Signatures	Title
/s/ JOHN T. RYND **John T. Rynd**	Chief Executive Officer, President and Director (Principal Executive Officer)
/s/ LISA W. RODRIGUEZ **Lisa W. Rodriguez**	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ TROY L. CARSON **Troy L. Carson**	Vice President and Corporate Controller (Principal Accounting Officer)
/s/ JOHN T. REYNOLDS **John T. Reynolds**	Chairman of the Board
/s/ THOMAS N. AMONETT **Thomas N. Amonett**	Director
/s/ SUZANNE V. BAER **Suzanne V. Baer**	Director
/s/ THOMAS R. BATES, JR. **Thomas R. Bates, Jr.**	Director
/s/ THOMAS M HAMILTON	Director

Thomas M Hamilton	
/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	

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