HERCULES OFFSHORE, INC.
Form 10-K
February 27, 2008

Table of Contents

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, 2007

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 þ No o

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, 2007, based on the closing price on the Nasdaq Global Select Market on such date, was approximately $936.6 million. (As of such date, the registrant s directors and executive officers and LR Hercules Holdings, LP and its affiliates were considered affiliates of the registrant for this purpose.)

As of February 20, 2008, there were 88,860,523 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, 2008 are incorporated by reference into Part III of this report.

TABLE OF CONTENTS

Table of Contents

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 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 furthered our strategic growth initiative by completing 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, 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 December 2007, we sold the nine land rigs for proceeds of $107.0 million.

We historically reported our business activities in four business segments, Domestic Contract Drilling Services, International Contract Drilling Services, Domestic Marine Services and International Marine Services. In connection with the acquisition of TODCO, we conducted a review of our segments. Our historical operating divisions have been combined with the businesses of TODCO and now operate as six divisions: (1) Domestic Offshore, (2) International Offshore, (3) Inland, (4) Domestic Liftboats, (5) International Liftboats and (6) Other. Domestic Offshore includes our legacy Domestic Contract Drilling Services business and TODCO s domestic offshore rigs operating in the U.S. Gulf of Mexico, while International Offshore includes our legacy International Contract Drilling Services and TODCO s offshore rigs operating internationally. Inland includes the former TODCO U.S. inland barge business. Domestic Liftboats includes our legacy Domestic Marine Services business, while International Liftboats includes our legacy International Marine Services business. Our Other segment includes Delta Towing and, prior to the December 2007 divestiture, the activities of our land rigs. The following describes our operations for each reporting segment:

Domestic Offshore operates 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 250 feet.

International Offshore operates nine jackup rigs and one platform rig outside of the U.S. Gulf of Mexico. We have one jackup rig working offshore in each of the following international locations: Qatar, India, Angola, Cameroon and Trinidad. This segment operates two jackup rigs and one platform rig in Mexico. In addition, this segment has one jackup rig currently undergoing reactivation in Southeast Asia and one jackup rig currently undergoing contract preparation work and customer acceptance in India.

Inland operates 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 operates 47 liftboats in the U.S. Gulf of Mexico.

International Liftboats operates 18 liftboats offshore West Africa, including five liftboats owned by a third party and one undergoing refurbishment.

Other our Delta Towing business operates a fleet of 33 inland tugs, 17 offshore tugs, 34 crew boats, 45 deck barges, 17 shale barges and four spud barges along and in the U.S. Gulf of Mexico. Our land rig operations, which were sold in December 2007, included one land rig in Trinidad, two land rigs in the United States and six land rigs in Venezuela.

Table of Contents

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-six of our jackup rigs are mat-supported and seven are independent leg rigs.

Our rigs are used primarily for exploration and development drilling in shallow waters. Twenty-two of our rigs have a cantilever design that permits the drilling platform to be extended out from the hull to perform drilling or workover operations over some types of preexisting platforms or structures. Eleven 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 20, 2008, 17 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 $78,816. 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 20, 2008.

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	Stacked Ready
Hercules 101	MC	1980	100/20	20,000	U.S. GOM	Stacked Ready
Hercules 110	MC	1981	100/20	20,000	Trinidad	Contracted
Hercules 120	MC	1958	120/22	18,000	U.S. GOM	Contracted
Hercules 150	ILC	1979	150/10	20,000	U.S. GOM	Stacked Ready
Hercules 152	MC	1980	150/22	20,000	U.S. GOM	Contracted
Hercules 153	MC	1980	150/22	25,000	U.S. GOM	Warm Stacked
Hercules 155	ILC	1980	150/15	20,000	U.S. GOM	Cold Stacked
Hercules 156	ILC	1983	150/14	20,000	Cameroon	Contracted
Hercules 170	ILC	1981	170/16	16,000	Qatar	Contracted
Hercules 173	MC	1971	173/22	15,000	U.S. GOM	Contracted
Hercules 185	ILC	1982	120/20	20,000	Angola	Contracted

Hercules 191	MS	1978	160/20	20,000	U.S. GOM	Cold Stacked
Hercules 200	MC	1979	200/23	20,000	U.S. GOM	Contracted
Hercules 201	MC	1981	200/23	20,000	U.S. GOM	Contracted
Hercules 202	MC	1981	200/23	20,000	U.S. GOM	Stacked Ready
Hercules 203	MC	1982	200/23	20,000	U.S. GOM	Shipyard
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	Contracted
Hercules 208(c)	MC	1980	200/22	20,000	Malaysia	Shipyard/Contracted
Hercules 211	MC	1980	200/23	18,000(d)	U.S. GOM	Contracted

Table of Contents

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	Warm Stacked
Hercules 251	MS	1978	250/24	20,000	U.S. GOM	Stacked Ready
Hercules 252	MS	1978	250/24	20,000	U.S. GOM	Contracted
Hercules 253	MS	1982	250/24	20,000	U.S. GOM	Contracted
Hercules 254	MS	1977	250/24	20,000	U.S. GOM	Cold Stacked
Hercules 255	MS	1977	250/24	20,000	U.S. GOM	Cold Stacked
Hercules 256	MS	1977	250/24	20,000	U.S. GOM	Cold Stacked
Hercules 257	MS	1979	250/24	20,000	U.S. GOM	Stacked Ready
Hercules 258	MS	1979	250/24	20,000	India	Contracted
Hercules 260	ILC	1979	250/12	20,000	India	Shipyard/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 Stacked Ready are not under contract but generally are ready for service. Rigs described as Warm Stacked may have a reduced number of crew, but only require a full crew to be ready for service. Rigs described as Cold Stacked are not actively marketed, normally require the hiring of an entire crew and require a maintenance review and refurbishment before they can function as a drilling rig. Rigs described as Shipyard are undergoing maintenance, repairs, or upgrades and may or may not be actively marketed depending on the length of stay in the shipyard.

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

(d) 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 submersible rig and Plat means a platform drilling rig. The following table contains information regarding our other drilling rig fleet as of February 20, 2008.

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	Warm Stacked
Hercules 77	Sub	1982	85/14	30,000	U.S. GOM	Warm Stacked
Hercules 78	Sub	1985	85/14	30,000	U.S. GOM	Warm Stacked
Platform 3	Plat	1993	N/A	25,000	Mexico	Contracted

Table of Contents

(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 Warm Stacked may have a reduced number of crew, but only require a full crew to be ready for service.

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 27 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 20, 2008.

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	Stacked Ready
7	Posted	1978	2,000	25,000	U.S. GOM	Cold Stacked
9	Posted	1981	2,000	25,000	U.S. GOM	Contracted
10	Posted	1981	2,000	25,000	U.S. GOM	Cold Stacked
11	Conv.	1982	3,000	30,000	U.S. GOM	Contracted
15	Conv.	1981	2,000	25,000	U.S. GOM	Contracted
17	Posted	1981	3,000	30,000	U.S. GOM	Contracted
19	Conv.	1974	1,000	14,000	U.S. GOM	Stacked Ready
20(c)	Conv.	1968	1,000	14,000	U.S. GOM	Cold Stacked
21	Conv.	1979	1,600	15,000	U.S. GOM	Cold Stacked
23	Conv.	1995	1,000	14,000	U.S. GOM	Cold Stacked
27	Posted	1979	3,000	30,000	U.S. GOM	Contracted
28	Conv.	1980	3,000	30,000	U.S. GOM	Warm Stacked
29	Conv.	1981	3,000	30,000	U.S. GOM	Contracted
30	Conv.	1981	3,000	30,000	U.S. GOM	Cold Stacked
31	Conv.	1982	3,000	30,000	U.S. GOM	Cold Stacked
32	Conv.	1982	3,000	30,000	U.S. GOM	Cold Stacked
41	Posted	1981	3,000	30,000	U.S. GOM	Contracted
46	Posted	1979	3,000	30,000	U.S. GOM	Contracted
47	Posted	1982	3,000	30,000	U.S. GOM	Cold Stacked
48	Posted	1982	3,000	30,000	U.S. GOM	Shipyard
49	Posted	1980	3,000	30,000	U.S. GOM	Shipyard
52	Posted	1981	2,000	25,000	U.S. GOM	Contracted
55	Posted	1981	3,000	30,000	U.S. GOM	Stacked Ready

57	Posted	1975	2,000	25,000	U.S. GOM	Contracted
61	Posted	1978	3,000	30,000	U.S. GOM	Cold Stacked
64	Posted	1979	3,000	30,000	U.S. GOM	Contracted

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

Table of Contents

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

(c) In 2003, this barge was severely damaged by fire. This rig is no longer operating and will require substantial refurbishment to return to service.

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. Ten 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 4,000 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 20, 2008, we owned 47 liftboats operating in the U.S. Gulf of Mexico and 13 liftboats operating in West Africa. 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 20, 2008.

Liftboat Name(1)	Year Built	Leg Length (Feet)	Deck Area (Square feet)	Maximum Deck Load (Pounds)	Location	Gross Tonnage
Whale Shark	2005	260	8,170	729,000	U.S. GOM	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

Liftboat Name(1)	Year Built	Leg Length (Feet)	Deck Area (Square feet)	Maximum Deck Load (Pounds)	Location	Gross Tonnage
Blue Shark	1981	215	3,800	400,000	Nigeria	1,182
Amberjack	1981	205	3,800	500,000	U.S. GOM	417
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

8

Table of Contents

Liftboat Name(1)	Year Built	Leg Length (Feet)	Deck Area (Square feet)	Maximum Deck Load (Pounds)	Location	Gross Tonnage
Cobia	1978	105	1,648	110,000	U.S. GOM	94
Dolphin	1980	105	1,648	110,000	U.S. GOM	97
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 *Black Jack*, which we acquired in June 2007 and is undergoing refurbishment, is expected to be available by April 2008. The *Pike* is currently cold-stacked. 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. Many of our competitors in the shallow-water business have greater financial and other resources than we have and may be better able to make technological improvements to existing equipment or replace equipment that becomes obsolete.

Customers

Our customers primarily include major integrated energy companies, independent oil and natural gas operators and national oil companies. Chevron Corporation accounted for 21% and 35% of our consolidated revenues for the years ended December 31, 2007 and 2006. Chevron and Bois d Arc Energy accounted for 31% and 12%, respectively, of our consolidated revenues for the year ended December 31, 2005. 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. In general, dayrate drilling contracts provide for payment on a dayrate basis, with higher rates while the unit is operating and lower rates for periods of mobilization or when operations are interrupted or restricted by equipment breakdowns, adverse weather conditions or other factors.

Table of Contents

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 generally have the right to terminate our contracts with little or no prior notice, and without penalty. 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.

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 in the U.S. Gulf of Mexico generally are for shorter terms than are drilling contracts. However, most of our liftboat contracts in West Africa have initial contract terms of two years plus a renewal option, with a few others for shorter terms similar to the U.S. Gulf of Mexico 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 20, 2008. Backlog is indicative of the full contractual dayrate. The amount of actual revenue earned and the actual periods during which revenues are earned will be different than the amounts and periods shown in the tables below due to various factors including shipyard and maintenance projects, other downtime and other factors that result in lower applicable dayrates than the full contractual operating dayrate, as well as the ability of our customers to terminate contracts under certain circumstances. Our contract backlog is calculated by multiplying the contracted operating dayrate by the number of days remaining in the firm contract period, excluding revenues for mobilization, demobilization and contract preparation.

		For the years ending December 31,				
	Total	**2008**	**2009**	**2010**	**2011**	**Thereafter**
			(in thousands)			
Domestic Offshore	$ 46,172	$ 46,172	$	$	$	$
International Offshore	570,395	213,759	181,071	134,975	40,590	
Inland	19,660	19,660				
Total	$ 636,227	$ 279,591	$ 181,071	$ 134,975	$ 40,590	$

Employees

As of December 31, 2007, we had approximately 3,300 employees. We require skilled personnel to operate and provide technical services and support for our rigs, barges and liftboats. As a result, we conduct extensive personnel recruiting, training and safety programs. As of December 31, 2007, certain of our employees in West Africa and Venezuela were 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.

Table of Contents

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.

In July 2007, 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 $2.6 billion; however, coverage for U.S. Gulf of Mexico named windstorm damage is subject to an annual aggregate limit on liability of $150.0 million. The policies are subject to deductibles, self-insured retentions 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 applicable 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. 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. We intend to renew certain of our insurance policies in the first half of 2008 and we do not expect significant increases to insurance premiums and fees for coverage of our operations, assets and personnel base.

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. 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. This decision may result in imposition of permit or other requirements on the discharges of ballast water and other vessel wastewaters. 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. Because we do not yet know what ballast water requirements will be imposed, we cannot estimate the potential financial impact at this time. However, we believe that any financial impacts resulting from the vacation 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 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. Two of our liftboats rely on an exemption from coastwise laws in order to operate in the U.S. Gulf of Mexico. If these liftboats were to lose this exemption, we would be unable to use them in the U.S. Gulf of Mexico and would be forced to seek opportunities for them 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 over 400 gross tons, 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 website at *www.herculesoffshore.com*. On our website we make available, free of charge, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file or furnish them to the SEC. These filings also are available at the SEC s Internet website at *www.sec.gov*. Information contained on our website is not part of this annual report.

Segment and Geographic Information

Information with respect to 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 15 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 Financial Analysis of Financial Condition and Results of Operations in Item 7 of this annual report.

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. On December 13, 2005 natural gas prices were $15.39 per MMBtu at the Henry Hub. They subsequently declined sharply, reaching a low of $3.63 per MMBtu at the Henry Hub on September 29, 2006. As of February 15, 2008, the closing price of natural gas at the Henry Hub was $8.73 per MMBtu. Oil prices since January 1, 2007, based on the spot price for West Texas intermediate crude, have ranged from $50.48 as of January 18, 2007 to $99.62 as of January 2, 2008, with a closing price of $95.50 as of February 15, 2008. 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, producing and delivering oil and natural gas;
- political, economic and weather conditions in the United States and elsewhere;

imports of liquefied natural gas;

- expectations regarding future 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;
- the development and exploitation of alternative fuels;
- the policies of various governments regarding exploration and development of their oil and natural gas reserves; and
- 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.

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.

A significant portion of our business is conducted in the shallow-water U.S. Gulf of Mexico, where market conditions are highly cyclical and subject to rapid change. The mature nature of this region could result in less drilling activity in the area, thereby reducing demand for our services.

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 idle 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, 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.

In addition, 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.

Table of Contents

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. 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.

The terms of some of our dayrate drilling contracts may limit our ability to benefit from increasing dayrates in an improving market.

Although historically our offshore drilling contracts in the U.S. Gulf of Mexico generally have been on a short-term basis, from time to time, and particularly in international locations, we may enter into longer term contracts. The duration of offshore drilling contracts is generally determined by market demand and the strategies of the offshore drilling contractors and their customers. In periods of rising demand for offshore rigs, a drilling contractor generally would prefer to enter into well-to-well or other shorter term contracts that would allow the contractor to profit from increasing dayrates, while customers with reasonably definite drilling programs would typically prefer longer term contracts in order to maintain dayrates at a consistent level. Conversely, in periods of decreasing demand for offshore rigs, a drilling contractor generally would prefer longer term contracts to preserve dayrates and utilization, while customers generally would prefer well-to-well contracts or other shorter term contracts that would allow the customer to benefit from the decreasing dayrates. Our inability to fully benefit from increasing dayrates in an improving market, due to the long-term nature of some of our contracts, may adversely affect our profitability.

Our drilling and liftboat contracts may be terminated due to events beyond our control.

Our customers may terminate some of our drilling and liftboat contracts if the unit is destroyed or lost or if operations are suspended for a specified period of time as a result of a breakdown of our equipment, or due to events beyond the control of either party. In some cases, our drilling contracts and liftboat contracts may be terminable upon specified advance notice from the customer and after some termination payment (which would not fully compensate us for the loss of the contract). The likelihood that a customer may seek to terminate a contract is increased during periods of market weakness. Early termination of a contract may result in a rig or liftboat being idle for an extended period of time, which could adversely affect 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 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 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 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 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

Table of Contents

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 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, including India. As of February 20, 2008, we owned or operated 18 liftboats operating offshore West Africa, including Nigeria, nine jackup rigs operating offshore or located in the following locations: Mexico, Qatar, India, Angola, Malaysia and Trinidad, and one platform rig in Mexico. 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, particularly in the Nigerian 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, including our acquisition of jack-ups and a platform rig in the acquisition of TODCO, 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 country or region 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 units 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.

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 21%, 35% and 31% of our consolidated revenues for the years ended December 31, 2007, 2006 and 2005. In addition, Chevron Corporation accounts for 85% 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 8, 2008, 85 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 20, 2008, we believe there were also ten 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. We are currently upgrading and refurbishing *Hercules 208* and *Black Jack* and are making or planning to make contract specific modifications to *Hercules 260* and *Hercules 258*.

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;
- unanticipated actual or purported change orders;
- 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;
- financial or other difficulties at shipyards;
- adverse weather conditions; and
- inability to obtain required permits or approvals.

We may experience delays and costs overruns in the refurbishment of *Hercules 208* due to certain of the factors listed above. Delays could put at risk our planned arrangements to commence operations on schedule. We are exposed to penalties for failure to complete the rig and commence operations in a timely manner.

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. 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 85 higher specification jackup rigs. 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

Table of Contents

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.

The impact of purchase accounting associated with our acquisition of TODCO could adversely affect our results of operations and financial condition.

Purchase accounting required us to allocate the price paid in the acquisition of TODCO to the assets acquired on the basis of their fair values at the time of the closing of the acquisition. Those adjustments resulted in significant increases in the carrying values of acquired property, plant and equipment costs. The increased value of property, plant and equipment has increased our depreciation expense, which has reduced reported earnings but has had no effect on cash flows.

As a result of the acquisition, we have recorded significant goodwill on our balance sheet. We will assess the realizability of the goodwill we have on our books annually as well as whenever events or changes in circumstances indicate that the goodwill may be impaired. These events or circumstances generally include operating losses or a significant decline in earnings associated with the acquired business, which may affect one or more of our reported segments. Our ability to realize the value of the goodwill will depend on the future cash flows of our businesses. These cash flows in turn depend in part on how well we have integrated these businesses. If we are not able to realize the value of the goodwill, we may be required to incur material charges relating to the impairment of those assets. In addition, the goodwill will be tested annually to assess this amount for impairment under generally accepted accounting principles. If we conclude that the goodwill associated with the TODCO acquisition is impaired or, additionally, that the carrying value of assets acquired are impaired, the amount of the impairment would reduce the amount of earnings we would otherwise report but would have no effect on our cash flows.

Our business is expected to continue to be cyclical. The goodwill associated with the acquisition and the increased carrying values of TODCO s assets on our balance sheet could, therefore, increase the potential for impairment of the goodwill and the carrying values of the assets acquired.

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

We, as successor to TODCO, and TODCO s former parent Transocean 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 in a negotiated settlement of disputes between Transocean and TODCO over the terms of the original tax sharing agreement. The tax sharing agreement required us to make an acceleration payment to Transocean upon completion of the TODCO acquisition as a result of the deemed utilization of TODCO s pre-IPO tax benefits. Subsequent to the completion of the TODCO acquisition, we paid $116 million to Transocean in satisfaction of those obligations. The basis of determination for the change in control payment is subject to a differing interpretation by Transocean.

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 TODCO employees and board members. The estimated amount of payments to Transocean related to compensatory options that remain outstanding at December 31, 2007, assuming a Transocean stock price of $143.15 per share at the time of exercise of the compensatory options (the actual price of Transocean s common stock at December 31, 2007), is approximately $25.4 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.

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

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 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 employ a sufficient number of skilled workers or an increase in labor costs could hurt our operations.

We require skilled personnel to operate and provide technical services and support for our rigs and liftboats. In periods of increasing activity and when the number of operating units in our areas of operation increases, either because of new construction, re-activation of idle units or the mobilization of units into the region, shortages of qualified personnel could arise, creating upward pressure on wages and difficulty in staffing our units. The shortages of qualified personnel or the inability to obtain and retain qualified personnel also could negatively affect the quality and timeliness of our work. In addition, our ability to expand our operations depends in part upon our ability to increase the size of our skilled labor force. Moreover, our labor costs increased significantly in 2006 and 2007, and we expect this trend to continue, but at a slower pace in 2008.

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,

Table of Contents

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. 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 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, 2007, we have total outstanding debt of approximately $912 million. This debt represents approximately 31% of our total capitalization. We have up to $150 million of available capacity under our revolving credit facility of which $28.1 million has been committed related to issued standby letters of credit. We may continue to borrow to fund working capital or other needs, including to fund the purchase price of three rigs from Transocean Inc., in the near term up to the remaining $121.9 million. 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 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 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.

These limitations are subject to a number of important qualifications and exceptions. 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 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.

Because we have a limited operating history, you may not be able to evaluate our current business and future earnings prospects accurately.

We were formed in July 2004 to provide drilling and liftboat services to the oil and natural gas exploration and production industry. As a result, we have limited operating history upon which you can base an evaluation of our current business and our future earnings prospects.

We limit foreign ownership of our company, which 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.-flag 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-U.S. 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.

Restrictions on the percentage ownership of our outstanding capital stock by non-U.S. citizens may subject the shares held by such non-U.S. citizens to restrictions, limitations and redemption.

Our certificate of incorporation 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 U.S. 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 U.S. 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; La Romaine, Trinidad; Luanda, Angola; and Ciudad del Carmen, Mexico. We also lease warehouses and yard facilities in Houma, Louisiana; Broussard, Louisiana and La Romaine, Trinidad. We lease warehouses, office space and residential premises in Qatar, India, 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 March 2007, two TODCO stockholder lawsuits were filed in the District Court of Harris County, Texas, both alleging that the TODCO board of directors (which includes three of our current directors) breached their fiduciary duties in approving the merger with a subsidiary of our company. The first lawsuit, *Frank Donio v. Jan Rask, et al* , then pending in the 269th Judicial District Court of Harris County, Texas, Cause No. 2007-16357, is a purported stockholder class action suit against the TODCO directors and contains claims for breach of fiduciary duty. The second lawsuit, *Robert Foster v. Jan Rask, et al.*, then pending in the 333rd Judicial District Court of Harris County, Texas, Cause No. 2007-16397, is a stockholder derivative action purportedly filed on behalf of TODCO against the TODCO directors (which includes three of our current directors) and us, and contains claims for breach of fiduciary duties of loyalty, due care, candor, good faith and/or fair dealing; corporate waste; unlawful self dealing; and claims that the defendants conspired, aided and abetted and/or assisted one another in a common plan to breach these fiduciary duties. Both lawsuits allege, among other things, that the TODCO directors engaged in self-dealing in approving the merger with us by advancing their own personal interests or those of TODCO s senior management at the expense of the TODCO stockholders, utilized a defective sales process not designed to maximize TODCO stockholder value, and failed to consider any value maximizing alternatives, thus causing TODCO stockholders to receive an unfair price for their shares of TODCO common stock. The second lawsuit also alleges that we conspired, aided and abetted or assisted in these violations. In addition, the second suit alleges that TODCO s directors breached their fiduciary duties by allegedly improperly awarding stock options to certain officers at a time when they allegedly knew the merger was imminent and the stock options would vest immediately upon consummation of the merger. The second suit also names the officers who received these stock option awards as defendants and alleges three causes of action against them: (1) a breach of fiduciary duty claim for having received allegedly improperly awarded stock options, (2) an unjust enrichment claim seeking a constructive trust, and (3) rescission of the stock option awards.

Both lawsuits seek, among other things, rescission of the merger, imposition of a constructive trust in favor of plaintiffs upon any benefits improperly received by the defendants, attorneys fees and expenses associated with the lawsuits and any other equitable relief the courts deem just and proper. On August 29, 2007, the two lawsuits were consolidated and transferred to the 270th Judicial District Court of Harris County,

Texas. We, the TODCO directors, and the officers named as defendants believe the asserted claims are without merit, and each intends to defend them vigorously.

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 of 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.

In December 2002, TODCO received an assessment for corporate income taxes from SENIAT, the national Venezuelan tax authority, of 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 2000. 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

Table of Contents

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. 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. We have not yet received any proposed adjustments from SENIAT arising from this audit. We believe we are owed indemnity from TODCO s former parent under the tax sharing agreement for any losses we incur as a result of these legal proceedings.

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.

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 2007.

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, 2008, there were 79 stockholders of record. On February 20, 2008, the closing price of our common stock as reported by NASDAQ was $26.75 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**
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

	Price	
	High	**Low**
2006		
Fourth Quarter	$ 36.97	$ 28.14
Third Quarter	36.23	28.72
Second Quarter	43.89	29.14
First Quarter	36.70	27.68

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:

Total

Period	Total Number of Shares Purchased(1)	Average Price Paid per Share	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, 2007			N/A	N/A
November 1 30, 2007	6,172	$ 26.95	N/A	N/A
December 1 31, 2007			N/A	N/A
Total	6,172	26.95	N/A	N/A

(1) Represents the surrender of shares of 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 2007 or 2006, and currently do not have, a share repurchase program in place.

Table of Contents

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

We have derived the following condensed consolidated financial information as of December 31, 2007 and 2006 and for the years ended December 31, 2007, 2006 and 2005 from our audited consolidated financial statements included in Item 8 of this annual report. The condensed consolidated financial information as of December 31, 2005 and 2004 and 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.

We were formed in July 2004 and commenced operations in August 2004. From our formation to December 31, 2007, 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 date 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 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, 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	$ 766,793	$ 344,312	$ 161,334	$ 31,728
Operating income	231,459	158,057	55,859	9,907
Net income	136,522	119,050	27,456	8,065
Earnings per share:				
Basic	$ 2.32	$ 3.80	$ 1.10	$ 0.55
Diluted	2.29	3.70	1.08	0.55
Balance Sheet Data (as of end of period):				
Cash and cash equivalents	$ 212,452	$ 72,772	$ 47,575	$ 14,460

Working capital	327,684	110,897	70,083	30,283
Total assets	3,642,539	605,581	354,825	132,156
Long-term debt, net of current portion	890,013	91,850	93,250	53,000
Total stockholders equity	2,011,433	394,851	215,943	71,087
Cash dividends per share				

	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)			
Other Financial Data:				
Net cash provided by (used in):				
Operating activities	$ 178,319	$ 124,241	$ 54,762	$ (8,528)
Investing activities	(825,007)	(149,983)	(174,952)	(94,241)
Financing activities	786,368	50,939	153,305	117,229
Capital expenditures	155,390	204,456	168,038	94,443
Deferred drydocking expenditures	20,772	12,544	7,369	601

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, 2007 and 2006 and for the years ended December 31, 2007, 2006 and 2005 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 furthered our strategic growth initiative by completing 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 December 2007, we sold our land rigs for proceeds of $107.0 million.

We historically reported our business activities in four business segments, Domestic Contract Drilling Services, International Contract Drilling Services, Domestic Marine Services and International Marine Services. In connection with the acquisition of TODCO, we conducted a review of our segments. Our historical operating divisions have been combined with the acquired businesses and now operate as six divisions: (1) Domestic Offshore, (2) International Offshore, (3) Inland, (4) Domestic Liftboats, (5) International Liftboats and (6) Other. Domestic Offshore includes our legacy Domestic Contract Drilling Services businesses and TODCO s domestic offshore rigs operating in the U.S. Gulf of Mexico, while International Offshore includes our legacy International Contract Drilling Services and TODCO s offshore rigs operating internationally. Inland includes the acquired U.S. inland barge business. Domestic Liftboats includes our legacy Domestic Marine Services business, while International Liftboats includes our legacy

International Marine Services business. Our Other segment includes Delta Towing and the activities of our land rigs. We sold the land rigs in December 2007. The following describes our operations for each reporting segment:

Domestic Offshore operates 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 250 feet.

International Offshore operates nine jackup rigs and one platform rig outside of the U.S. Gulf of Mexico. We have one jackup rig working offshore in each of the following international locations: Qatar, India, Angola, Cameroon and Trinidad. This segment operates two jackup rigs and one platform rig in

Mexico. In addition, this segment has one jackup rig currently undergoing reactivation in Southeast Asia and one jackup rig currently undergoing contract preparation work and customer acceptance in India.

Inland operates 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 operates 47 liftboats in the U.S. Gulf of Mexico.

International Liftboats operates 18 liftboats offshore West Africa, including five liftboats owned by a third party and one undergoing refurbishment.

Other our Delta Towing business operates a fleet of 33 inland tugs, 17 offshore tugs, 34 crew boats, 45 deck barges, 17 shale barges and four spud barges along and in the U.S. Gulf of Mexico. In December 2007, we sold our land rig operations which included one land rig in Trinidad, two land rigs in the United States and six land rigs in Venezuela.

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 and the number and type of units in our fleet. 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 through attrition and redeployment, but a small crew is retained. Warm-stacked rigs generally can be reactivated in one to two 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.

Table of Contents

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 2007 results include activity from this acquired business from the date of acquisition. The acquisition significantly impacts the comparability of the 2007 period with the other periods presented.

Domestic industry conditions were generally weaker for jackup rigs during 2007 compared to 2006, as evidenced by our lower dayrates and utilization. Despite a continued reduction in supply, jackup dayrates in the U.S. Gulf of Mexico generally peaked in early summer of 2006 and have since declined due to a decline in drilling activity. Demand for jackup rigs reached a low of 47 rigs in October 2007. International industry conditions remained strong throughout 2006 and 2007. Liftboat dayrates increased throughout 2007 in the United States and West Africa.

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

	Year Ended December 31,		
	2007	**2006**	**2005**
	(Dollars in thousands)		
Domestic Offshore:			
Number of rigs (as of end of period)	27	6	9
Revenues	$ 241,452	$ 160,761	$ 103,422
Operating Expenses	122,131	51,862	48,330
Depreciation and amortization expense	35,143	8,882	5,547
General and administrative expenses	6,105	6,980	5,486
Operating income	$ 78,073	$ 93,037	$ 44,059
International Offshore:			
Number of rigs (as of end of period)	10	3	
Revenues	$ 144,778	$ 30,460	$
Operating expenses	59,593	13,377	
Depreciation and amortization expense	15,513	2,547	
General and administrative expenses	1,863	1,606	
Operating income	$ 67,809	$ 12,930	$
Inland:			
Number of rigs (as of end of period)	27		
Revenues	$ 107,100	$	$
Operating expenses	56,636		
Depreciation and amortization expense	16,264		
General and administrative expenses	533		
Operating income	$ 33,667	$	$

Domestic Liftboats:			
Number of liftboats (as of end of period)	47	47	42
Revenues	$ 137,745	$ 133,929	$ 55,740
Operating expenses	59,902	49,025	28,413
Depreciation and amortization expense	24,969	18,854	8,031
General and administrative expenses	2,190	2,259	1,888
Operating income	$ 50,684	$ 63,791	$ 17,408
International Liftboats:			
Number of liftboats (as of end of period)	18	17	4
Revenues	$ 63,282	$ 19,162	$ 2,172
Operating expenses	31,879	9,874	1,071
Depreciation and amortization expense	7,619	1,923	176
General and administrative expenses	3,888	3,056	336
Operating income	$ 19,896	$ 4,309	$ 589

Table of Contents

	Year Ended December 31, 2007	2006	2005
	(Dollars in thousands)		
Other:			
Revenues	$ 72,436	$	$
Operating expenses	46,318		
Depreciation and amortization expense	9,028		
General and administrative expenses	1,011		
Operating income	$ 16,079	$	$
Total Company:			
Revenues	$ 766,793	$ 344,312	$ 161,334
Operating expenses	376,459	124,138	77,814
Depreciation and amortization expense	109,064	32,310	13,790
General and administrative expenses	49,811	29,807	13,871
Operating income	231,459	158,057	55,859
Interest expense	(36,055)	(9,278)	(9,880)
Gain on disposal of assets		30,690	
Loss on early retirement of debt	(2,182)		(4,078)
Other income	6,291	4,038	924
Income before income taxes	199,513	183,507	42,825
Income tax provision	(62,991)	(64,457)	(15,369)
Net income	$ 136,522	$ 119,050	$ 27,456

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

	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

	Year Ended December 31, 2005				
	Operating Days	Available Days	Utilization(1)	Average Revenue per Day(2)	Average Operating Expense per Day(3)
Domestic Offshore	2,192	2,309	94.9%	$ 47,177	$ 20,932
International Offshore	n/a	n/a	n/a	n/a	n/a
Inland	n/a	n/a	n/a	n/a	n/a
Domestic Liftboats	8,571	10,971	78.1%	6,503	2,590
International Liftboats	212	212	100.0%	10,243	5,052

(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 twelve months ended December 31, 2007. There was no such revenue in the twelve months ended December 31, 2006 and 2005. Included in International Offshore revenue 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 twelve months ended December 31, 2007 and 2006, respectively. There was no revenue recognized in 2005 related to the amortization of deferred mobilization revenue and contract specific capital expenditures. Included in revenue for our International Offshore segment for the twelve months 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.

(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 $2.8 million and $1.6 million related to amortization of deferred mobilization expenses for the twelve months ended December 31, 2007 and 2006, respectively. There was no expense recognized in 2005 related to the amortization of deferred mobilization expenses.

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.

Table of Contents

2007 Compared to 2006

Revenues

Consolidated. Total revenues for 2007 were $766.8 million compared with $344.3 million for 2006, an increase of $422.5 million, or 123%. This increase resulted primarily from revenues generated from TODCO acquired in July 2007. Total revenues included $15.4 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.

Other. Revenues for our Other segment were $72.4 million in 2007 and included $0.5 million in reimbursements from our customers for expenses paid by us in 2006. Prior to our acquisition of TODCO in July 2007, we did not have an Other segment.

Table of Contents

Operating Expenses

Consolidated. Total operating expenses for 2007 were $376.5 million compared with $124.1 million in 2006, an increase of $252.3 million, or 203%. 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.

Other. Operating expenses for our Other segment were $46.3 million in 2007. Prior to our acquisition of TODCO in July 2007, we did not have an Other segment.

Depreciation and Amortization

Depreciation and amortization expense in 2007 was $109.1 million compared with $32.3 million in 2006, an increase of $76.8 million, or 238%. This increase resulted primarily from additional depreciation of approximately $57.0 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 $36.1 million compared with $9.3 million in 2006, an increase of $26.8 million, or 289%. 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 $6.3 million compared with $4.0 million in 2006, an increase of $2.3 million. This increase primarily related to additional interest income earned in 2007.

Income Tax Provision

Income tax expense was $63.0 million on pre-tax income of $199.5 million during 2007, compared to $64.5 million on pre-tax income of $183.5 million for 2006. The effective tax rate decreased to 31.6% 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.

2006 Compared to 2005

Revenues

Consolidated. Total revenues for 2006 were $344.3 million compared with $161.3 million for 2005, an increase of $183.0 million, or 113%. This increase resulted primarily from higher average dayrates in our Domestic Offshore and Domestic Liftboats segments, additional operating days in our Domestic and International Liftboats segments, due primarily to the acquisition of liftboats since June 2005, and the commencement of operations in our International Offshore segment in 2006. Total revenues included $7.5 million in reimbursements from our customers for expenses paid by us in 2006 compared with $4.6 million in 2005.

Domestic Offshore. Revenues for our Domestic Offshore segment were $160.8 million for 2006 compared with $103.4 million for 2005, an increase of $57.4 million, or 56%. This increase resulted primarily from higher average dayrates for our fleet, which accounted for $75.2 million partially offset by $17.8 million related to reduced utilization on four of our rigs, two of which sustained damage during Hurricane Katrina in August 2005. Operating days decreased to 1,973 in 2006 from 2,192 in 2005. *Rig 25* did not operate in 2006 and was scrapped due to damage sustained in Hurricane Katrina, and operated 235 days in 2005. Three of our rigs were in the shipyard for repairs, upgrades and refurbishments during 2006, including *Hercules 120,* which sustained damage during Hurricane Katrina. Average revenue per rig per day was $81,480 in 2006 compared with $47,177 in 2005, with average utilization of 94.9% in both 2006 and 2005. Revenues for our Domestic Offshore segment included $1.1 million in reimbursements from our customers for expenses paid by us in 2006 compared with $2.3 million in 2005.

International Offshore. As of December 31, 2006, our International Offshore segment comprised one jackup rig working offshore Qatar, one jackup rig working offshore India and a third jackup rig undergoing upgrade and refurbishment. Revenues for our International Offshore segment were $30.5 million for 2006. Average revenue per rig per day was $99,868, operating days were 305 and average utilization was 95.0% in 2006. Included in revenue for 2006 is $2.6 million related to amortization of deferred mobilization revenue and contract specific capital expenditures reimbursed by the customer. Revenues in our International Offshore segment include reimbursements from our customers of $0.2 million for expenses paid by us. We did not have an International Offshore segment in 2005.

Domestic Liftboats. Revenues for our Domestic Liftboats segment were $133.9 million for 2006 compared with $55.7 million in 2005, an increase of $78.2 million, or 140%. This increase resulted primarily from additional operating days, which contributed $37.4 million, and higher average dayrates, which contributed $40.8 million. Operating days in 2006 were 11,895 compared with 8,571 operating days in 2005, with the increase due primarily to acquisitions. Average revenue per liftboat per day was $11,259 in 2006 compared with $6,503 in 2005, with average utilization of 77.2% in 2006 compared with 78.1% in 2005. The increase in average dayrates was attributable primarily to increased demand in the aftermath of Hurricane

Katrina and Hurricane Rita. Revenues for our Domestic Liftboats segment included $4.8 million in reimbursements from our customers for expenses paid by us in 2006 compared with $2.3 million in 2005.

International Liftboats. Revenues for our International Liftboats segment were $19.1 million for 2006 compared with $2.2 million in 2005, an increase of $16.9 million, or 768%. This increase is due to acquisition activity which resulted in an increase in operating days from 212 days in 2005 to 1,765 days in 2006. Average revenue per liftboat per day was $10,857 in 2006 compared with $10,243 in 2005, with average utilization of 87.9% in 2006 compared with 100.0% in 2005. Revenues for our International Liftboats segment included $1.4 million in reimbursements from our customers for expenses paid by us in 2006. There was no reimbursable income in our International Liftboats segment in 2005.

Operating Expenses

Consolidated. Total operating expenses for 2006 were $124.1 million compared with $77.8 million in 2005, an increase of $46.3 million, or 60%. This increase resulted primarily from the increase in rig and liftboat operating expenses described below.

Domestic Offshore. Operating expenses for our Domestic Offshore segment were $51.8 million in 2006 and $48.3 million in 2005, an increase of $3.5 million or 7%. A $1.0 million deductible was recorded in 2005 for damage sustained by one of our rigs during Hurricane Katrina. Available days decreased to 2,078 in 2006 from 2,309 in 2005. Average operating expenses per rig per day were $24,957 in 2006 compared with $20,932 in 2005. The increase in operating expense per rig per day is due in part to the inclusion of operating expenses for *Hercules 120* during 2006 while the rig was undergoing repairs for damage sustained during Hurricane Katrina partially offset by a $1.0 million insurance deductible in 2005. *Hercules 120* was in the shipyard for 112 days in 2006. On a per day basis, average operating expenses per rig increased $4,025. The increase resulted primarily from an increase in labor expenses, which increased $2,412 per day, an increase in insurance costs, which increased $1,854 per day, and an increase in rig maintenance costs, which increased $763 per day.

International Offshore. Operating expenses for our International Offshore segment were $13.4 million for 2006, and averaged $41,673 per rig per day. Included in operating expense is $1.6 million related to amortization of deferred mobilization expense. We did not have an International Offshore segment in 2005.

Domestic Liftboats. Operating expenses for our Domestic Liftboats segment were $49.0 million for 2006 compared with $28.4 million in 2005, an increase of $20.6 million, or 73%. The increase is primarily due to liftboat acquisitions and additional operating days. Average operating expenses per liftboat per day were $3,180 in 2006 compared with $2,590 in 2005. This increase resulted primarily from an increase in labor expenses, which increased $366 per day, an increase in insurance costs, which increased $97 per day, and an increase in liftboat maintenance costs, which increased $92 per day.

International Liftboats. Operating expenses for our International Liftboats segment were $9.9 million for 2006 compared with $1.1 million in 2005, an increase of $8.8 million, or 800%. The increase is due to additional liftboats acquired. Average operating expenses per liftboat per day were $4,915 in 2006 compared with $5,052 in 2005.

Depreciation and Amortization

Depreciation and amortization expense in 2006 was $32.3 million compared with $13.8 million in 2005, an increase of $18.5 million, or 134%. This increase resulted primarily from an additional $3.3 million in depreciation expense for our Domestic Offshore segment, $4.1 million for our Domestic Liftboats segment and $1.8 million for our International Liftboats segment. This increase in depreciation expense for these segments is related primarily to acquisition activity during 2005 and 2006. Depreciation expense for our International Offshore segment was $2.5 million. Additionally, amortization of regulatory inspections and related drydockings increased $6.8 million.

General and Administrative Expenses

General and administrative expenses in 2006 were $29.8 million compared with $13.9 million in 2005, an increase of $15.9 million, or 114%. General and administrative expenses for our corporate office increased from $6.2 million in 2005 to $15.9 million in 2006, an increase of $9.7 million. This increase is due to increased headcount, additional professional fees related to increased regulatory requirements as a public company and additional stock-based compensation expense of $3.0 million. General and administrative expenses related to our segments increased $6.2 million primarily associated with our international expansion.

Gain on Disposal of Assets

The gain on disposal of assets in 2006 of $30.7 million consisted of $29.6 million related to the insurance settlement on the loss of *Rig 25* in Hurricane Katrina and $1.1 million related to the gain on the sale of *Rig 41*. There was no gain on disposal of assets in 2005.

Income Tax Provision

Income tax expense was $64.5 million on pre-tax income of $183.5 million during 2006, compared to $15.4 million on pre-tax income of $42.8 million for 2005. On November 1, 2005, in connection with our initial public offering, we converted from a limited liability company to a corporation. Prior to the conversion, we elected to be taxed as a partnership. As such, the members of our company were taxed on their proportionate share of net income prior to the conversion and no provision or liability for income taxes was included in our consolidated financial statements. When we became a taxable entity in the conversion, a provision of approximately $12.1 million was made reflecting the tax effect of the difference between the book and tax basis of our assets and liabilities as of November 1, 2005, the effective date of the conversion. The tax rate was 35.1% in 2006 and 35.9% in 2005.

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. 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 cash and cash equivalents and marketable securities, goodwill, other intangible assets, property and equipment, revenue recognition, income tax, allowance for doubtful accounts, deferred charges and stock-based compensation. Inherent in such policies are certain key assumptions and estimates.

Cash and Cash Equivalents and Marketable Securities

Beginning in March 2007, we began investing 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. At December 31, 2007, we had marketable securities with a fair value and cost basis of $39.3 million. Proceeds of $112.4 million were received from sales and maturities of marketable securities for the year ended December 31,

2007. There were no realized or unrealized gains or losses related to these 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. Realized and unrealized gains and losses related

Table of Contents

to marketable securities are calculated using the specific identification method. Unrealized gains or losses, net of taxes, are included in Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheets until realized. Realized gains or losses are included in Other, Net in the Consolidated Statements of Operations.

Goodwill

As of December 31, 2007, we had $940.2 million of 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. Our goodwill impairment test involves a comparison of the fair value of each of our reporting units, as defined under SFAS No. 142, with its carrying amount. Fair value is estimated using discounted cash flows and other market-related valuation models, including earnings multiples and comparable asset market values. If the fair value is determined to be less than the carrying value, the asset is considered impaired. The amount of the impairment, if any, is determined based on an allocation of the reporting unit fair values. We will test goodwill for impairment as of October 1 and will test it annually on that date unless changes occur between annual test dates that would more likely than not reduce the fair value of a reporting unit below its carrying amount. Our 2007 impairment test indicated that goodwill was not impaired.

Other Intangible Assets

In connection with the acquisition of TODCO, we allocated $17.6 million in value to certain international customer contracts within the International Offshore segment. The estimated fair value of these acquired contracts is based on preliminary valuations and is subject to change when final valuations are obtained. These contracts are being amortized over the life of the contracts. As of December 31, 2007, the customer contracts had a carrying value of $14.8 million, net of accumulated amortization of $2.8 million, and are included in Other Assets, Net on the Consolidated Balance Sheet.

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

2008	$ 8,088
2009	4,658
2010	1,466
2011	607
2012	

Property and Equipment

Property and equipment represents 56.6% of our total assets as of December 31, 2007. 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

Table of Contents

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 jackup rigs.

Revenue Recognition

Revenues are generated from our rigs and liftboats working under dayrate contracts as the services are provided. 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 amortized over 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 currently operate in nine 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.

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 $0.9 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 6.1% of our total assets and 37.5% of our current assets as of December 31, 2007. 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, 2007, there was $0.6 million in allowance for doubtful accounts.

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, 2007, our net deferred charges related to regulatory inspection costs totaled $6.8 million. 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, 2007 will be $5.8 million over the remaining vesting period of 1.4 years and the cost relating to restricted shares granted through December 31, 2007 will be $6.0 million over the remaining vesting period of 1.8 years; however, due to the uncertainty of the level of share-based payments to be granted in the future, these amounts are estimates and subject to change.

Outlook

Offshore

In general, demand for our drilling rigs is a function of our customers capital spending plans, which are largely driven by their cash flow generated from commodity production 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. Both natural gas and oil prices are higher than historical levels and are generally supportive of increased capital spending for exploration and production activities.

As of February 15, 2008, the spot price for Henry Hub natural gas was $8.73 per MMBtu and the twelve month strip, or the average of the next twelve month s futures contract was $9.06 per MMBtu. Declining reservoir sizes and increasing initial decline rates in North America have been supportive of natural gas prices, while increased onshore drilling activity, growing deepwater production and increasing liquefied natural gas deliveries have played a role in driving natural gas storage higher. These factors, together with weather and industrial demand, will likely remain key drivers in the natural gas market for the foreseeable future.

Oil prices have remained at high levels relative to historical prices for the past several years with the spot price for West Texas intermediate crude ranging from $50.48 to $99.62 per bbl since the beginning of 2006. As of February 15, 2008, the price of WTI was $95.50 with a twelve month strip of $94.23. Stronger oil prices have largely been driven by extremely strong demand growth in China and India, continued economic growth in OECD countries, and the ongoing weakness in the U.S. dollar.

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 319 in February 2008. 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 80 currently, according to published industry sources. With several of these rigs either in the shipyard or cold stacked, the marketed supply of jackups in the U.S. Gulf of Mexico is currently approximately 65.

Demand for jackup rigs in the U.S. Gulf of Mexico has also declined considerably over the last two years to 51 as of February 2008 from 88 in January 2006. A combination of factors has resulted in this decline from the levels experienced over the previous several years, including high levels of natural gas storage during late 2006 and 2007, combined with declining target reservoir sizes, increasing finding, development and lifting costs and the significant amount of property transfers. Subsequent to the 2005 hurricanes, the seasonal decline in activity during hurricane season has been more pronounced as our customers have curtailed activity in response to their risk profiles. We believe that the further reduction in supply in the U.S. Gulf of Mexico due to rigs mobilizing to international locations could mitigate the impact of recent reduced drilling demand.

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 8, 2008, 85 jackup rigs have been ordered by industry participants, national oil companies and financial investors for delivery through 2011. We anticipate that these rigs will compete directly with our fleet in international regions. As a result of higher dayrates, longer duration contracts and lower insurance costs, which are prevalent internationally, among other factors, we believe the vast majority of the new build jackup rigs will target international regions and not the U.S. Gulf of Mexico. Our ability to expand our international drilling fleet may be limited, however, by the increased supply of newbuild jackup rigs.

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 historically 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, 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 market for inland barge drilling in the U.S. generally follows the same drivers as drilling in the U.S. Gulf of Mexico with demand following operators expectations of prices for natural gas and, to a lesser degree, crude oil. However, given 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, activity for inland barges sometimes lags activity in the U.S. Gulf of Mexico.

Inland barge drilling activity has slowed over the past year and dayrates have also softened. However, based on recent discoveries and discussion with our customers, we remain optimistic about deeper targets in the inland barge area and believe this may generate growth opportunities as the trend toward deeper drilling in shallow water expands.

Liftboats

Although activity levels for liftboats in the U.S. Gulf of Mexico are not as closely correlated to movement in commodity prices as for offshore drilling rigs, a weakening in commodity prices could result in lower utilization of our liftboat fleet. Lower commodity prices tend to result in lower cash flows for our customers and, despite the production maintenance related nature of the majority of the work, some of the work may be deferred.

As of February 20, 2008, we believe that there were ten liftboats under construction or on order in the U.S. that may be used in the U.S. Gulf of Mexico, with anticipated delivery dates during 2008. Once delivered, these liftboats may impact the demand and utilization of our domestic liftboat fleet.

Our customers growth in international capital spending, 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. We anticipate that demand for liftboats will likely increase in West Africa and other international locations as these markets mature and the focus shifts from exploration to development and new platforms and other infrastructure is installed. We anticipate that there will be longer term contract opportunities in international locations for liftboats currently working in the U.S. Gulf of Mexico and for newly constructed liftboats. While we believe that international demand for liftboats will continue to

Table of Contents

increase, the political instability in certain regions may negatively impact our customers capital spending plans. We are actively marketing a number of our liftboats currently operating in the U.S. Gulf of Mexico for projects in international locations, which have long-term contract opportunities.

Labor Markets

We require highly skilled personnel to operate our rigs, barges and liftboats and to support our business. Competition for skilled rig personnel could intensify as 164 new offshore rigs are under construction and 57 are scheduled to enter the global fleet during 2008. 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. We respond to competition though retention programs, including increases in base compensation and bonuses tied to retention and utilization goals.

We have also experienced a tightening in the labor market for liftboat and marine personnel. We have instituted retention programs, along with additional programs that may become necessary to retain skilled personnel, to continue for the foreseeable future.

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

Sources and uses of cash for 2007 and 2006 is as follows:

	2007	2006
Net Cash Provided by Operating Activities	$ 178.3	$ 124.2
Net Cash Provided by (Used in) Investing Activities		
Acquisition of Business, Net of Cash Acquired	(728.4)	
Investment in Marketable Securities, Net	(39.3)	
Additions to Property and Equipment	(155.4)	(204.5)
Deferred Drydocking Expenditures	(20.8)	(12.5)
Proceeds from Sale of Assets, Net	109.7	6.0
Insurance Proceeds Received	4.3	61.3
Other	4.9	(0.2)
Total	(825.0)	(149.9)
Net Cash Provided by (Used in) Financing Activities		
Long-term and Short-term Debt Borrowings, Net of Repayments	800.9	(1.4)
Proceed from Issuance of Common Stock		54.2
Payment of Debt Issuance Costs	(17.8)	(0.6)
Other	3.3	(1.3)
Total	786.4	50.9
Net Increase in Cash and Cash Equivalents	$ 139.7	$ 25.2

Sources of Liquidity and Financing Arrangements

Our sources of liquidity include current cash and cash equivalent balances, marketable securities, cash generated from operations and committed availability under our revolving credit facility. We also maintain a shelf registration statement covering the future issuance of various types of securities, including debt and equity; however, our senior secured credit facility restricts issuance of additional debt.

Additional capital in either the form of debt or equity may be required in 2008 if we generate less than expected cash due to a deterioration of market conditions or other factors beyond our control, or if other acquisitions necessitate additional liquidity. Our future cash flows may be insufficient to meet all of our debt

Table of Contents

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 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 further 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 can provide no assurance as to the timing of any asset sales or the proceeds that could be realized by us from any such asset sale.

Cash Requirements and Contractual Obligations

Pending 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. Closing of the transaction is subject to regulatory approvals and other customary conditions. We plan to fund the acquisition with cash on hand and borrowings under our revolving credit facility.

TODCO Acquisition

In connection with the acquisition of TODCO in July 2007, we issued approximately 56.6 million of our shares of common stock and borrowed $900.0 million under a new senior secured term loan. Additionally, upon closing of the acquisition, we terminated our former credit facility and entered into a new $150.0 million revolving credit facility. In connection with the acquisition of TODCO, we assumed senior notes, an unsecured line of credit with a bank in Venezuela and surety bonds. The proceeds of the borrowings under the senior secured term loan were used, together with cash on hand, to finance the cash portion of our 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 acquisition.

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. 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. Amounts outstanding under the revolving credit facility bear interest at either the eurodollar rate or the base prime rate plus a margin. The applicable margin under the revolving credit facility varies depending on our 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. We pay a commitment fee on the unused portion of the revolving credit facility, which ranges between 0.25% and 0.375% depending on our leverage ratio. We pay 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 $28.1 million in stand-by letters of credit had been issued under the revolving credit facility as of December 31, 2007. The remaining availability under this revolving credit facility was $121.9 million at December 31, 2007.

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, we are required to prepay the term loan with:

the net proceeds from sales of certain assets to the extent that we do not reinvest the proceeds in our business within one year;

the net proceeds from casualties or condemnations of assets to the extent that we do not reinvest the proceeds in our business within one year;

the net proceeds of debt that we incur to the extent that such debt is not permitted by the credit agreement;

50% of the net proceeds that we receive from any issuance of preferred stock; and

commencing with the fiscal year ending December 31, 2008, 50% of our 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. We are 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 either the eurodollar rate or the base prime rate plus a margin. The applicable margin under the term loan facility varies depending on our 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, 2007, $895.5 million was outstanding on the term loan facility and the interest rate was 6.58%. The annualized effective interest rate was 7.06% at December 31, 2007 after giving consideration to derivative activity.

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

The credit agreement contains financial covenants that are tested quarterly relating to leverage and fixed charge coverage. 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. The credit agreement contains customary events of default. We were in compliance with these financial covenants at December 31, 2007.

In July 2007, we entered into derivative instruments with the purpose of hedging future interest payments on our new term loan facility. 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 effective interest rate is determined after giving consideration to amortization of original issue discount premium and fair value adjustments. The following table provides the scheduled reduction in notional amounts related to the interest rate swap (in thousands):

December 31, 2007-March 31, 2008	$ 350,000
April 1, 2008-June 30, 2008	300,000
July 1, 2008-September 30, 2008	200,000
October 1, 2008-December 31, 2008	100,000
January 1, 2009-March 31, 2009	50,000

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 include 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. The fair market value of these notes at December 31, 2007 was approximately $2.2 million, $3.7 million and $10.6 million, respectively. The line of credit is designed to manage local currency liquidity in Venezuela. The maximum amount available to be drawn is 6.0 billion Bolivars ($2.8 million at the exchange rate at December 31, 2007). There were no outstanding borrowings under the foreign line of credit at December 31, 2007. The weighted average interest rate on borrowings outstanding on the line of credit during the year ended December 31, 2007 was 17.7%.

In July 2007, 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 $36.2 million was financed through these arrangements, and $16.9 million was outstanding at December 31, 2007. The interest rate on these notes is 5.75% and each note matures in June 2008.

Capital Expenditures

We expect to spend a total of $176 million on capital expenditures excluding acquisitions. We expect to spend approximately $110 million in 2008 on the refurbishment and upgrade of our rigs and liftboats, excluding amounts allocated to *Hercules 185*, *Hercules 208*, *Hercules 258, Hercules 260,* the *Black Jack* and our planned equipment standardization for top-drives and cranes. 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 expect to spend $66 million relating to the continuing contract preparation work for *Hercules 258* and *Hercules 260,* the completion of the refurbishment of the *Hercules 208* and the *Black Jack*, the repairs and leg extension on *Hercules 185* and the planned standardization of certain core equipment. We expect to spend approximately $15 million in 2008 to repair and complete the leg extension on *Hercules 185,* approximately $10 million to complete the refurbishment of the *Hercules 208* and approximately $12 million and $9 million to complete the contract preparation work for *Hercules 258* and *Hercules 260*, respectively, as well as $3 million to complete the refurbishment of the *Black Jack*. In addition, we expect to spend approximately $17 million to standardize our fleet s top-drive and crane equipment in order to maximize the number of available drilling days by reducing our fleet s unplanned downtime.

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, surety bonds, letters of credit, future minimum operating lease obligations, purchase commitments and management compensation obligations. During 2007, there were no material changes outside the ordinary course of business in the specified contractual obligations, except in connection with our acquisition of TODCO on July 11, 2007.

The following table summarizes our contractual obligations and contingent commitments by period as of December 31, 2007:

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	$ 21,427	$ 18,000	$ 18,000	$ 854,008	$ 911,435
Insurance note payable	16,931				16,931
Other	408				408
Unrecorded Obligations:					
Letters of credit	1,494	17,000	9,961		28,455
Surety Bonds	46,401	19,456			65,857
Management compensation obligations	3,578	1,989			5,567
Purchase obligations (a)	46,212				46,212
Operating lease obligations	2,230	2,108	2,118	5,971	12,427
Total contractual obligations	$ 138,681	$ 58,553	$ 30,079	$ 859,979	$ 1,087,292

(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.

Off-Balance Sheet Arrangements

Guarantees

Our obligations under the credit agreement are secured by liens on several of our vessels and substantially all of our other personal property. Substantially all of our domestic 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, 2007, we had $94.4 million of letters of credit and surety bonds outstanding, consisting of $0.4 million in unsecured outstanding letters of credit, $28.1 million letters of credit outstanding under our revolver and $65.9 million outstanding in surety bonds that guarantee our performance as it relates to TODCO s 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.

Accounting Pronouncements

In December 2007, the Financial Accounting Standards Board (FASB) issued SFAS No. 141(R)*, Business Combinations* (SFAS No. 141R). SFAS No. 141R replaces SFAS No. 141, *Business Combinations*, 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

Table of Contents

rather than at a later date when the amount of that consideration may be determinable beyond a reasonable doubt. This fair value approach replaces the cost-allocation process required under SFAS No. 141 whereby the cost of an acquisition was allocated to the individual assets acquired and liabilities assumed based on their estimated fair value. 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. Under SFAS No. 141R, the requirements of SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities* would have to be met in order to accrue for a restructuring plan in purchase accounting. Pre-acquisition contingencies are to be recognized at fair value, unless it is a non-contractual contingency that is not likely to materialize, in which case, nothing should be recognized in purchase accounting and, instead, that contingency would be subject to the probable and estimable recognition criteria of SFAS No. 5, *Accounting for Contingencies.* SFAS No. 141R may have a significant impact on our accounting for business combinations closing on or after January 1, 2009.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities* (SFAS No. 159). SFAS No. 159 permits companies to choose to measure certain financial instruments and certain other items at fair value. The standard requires that unrealized gains and losses on items for which the fair value option has been elected be reported in earnings. SFAS No. 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007. We are evaluating the impact, if any, that SFAS No. 159 will have on our financial position, results of operations and cash flows.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* (SFAS No. 157). 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 will be made pursuant to other accounting pronouncements that require or permit fair value measurements. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. The provisions of SFAS No. 157 are to be applied prospectively upon adoption, except for limited specified exceptions. We are evaluating the requirements of SFAS No. 157 and do not expect the adoption to have a material impact on our financial position, results of operations and cash flows.

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 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 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, continuation of current 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 jackup 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 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 and Venezuelan 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.

Table of Contents

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, 2007, the long-term borrowings that were outstanding subject to fixed interest rate risk consist of the 7.375% Senior Notes due April 2018. The carrying amount and fair value of the 7.375% Senior Notes was $3.5 million and $3.7 million, respectively.

As of December 31, 2007 the interest rate for the $895.5 million outstanding under the term loan was 6.58%. If the interest rate averaged 1% more for 2008 than the rates as of December 31, 2007, annual interest expense would increase by approximately $9.0 million. This sensitivity analysis assumes there are no changes in our financial structure.

We believe our other debt instruments, which are short-term in nature, totaling $12.7 million as of December 31, 2007 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 swap and zero cost LIBOR collar are creditworthy multinational commercial banks. We believe that the risk of counterparty nonperformance is immaterial. Our interest expense was reduced by $0.2 million in 2007 as a result of our interest rate derivative transactions and we realized a net gain of $0.7 million related to the termination of certain derivative instruments. (See the information set forth under the caption Debt in Part 1, Item 7. 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):

December 31, 2007-March 31, 2008	$ 350,000
April 1, 2008-June 30, 2008	300,000
July 1, 2008-September 30, 2008	200,000
October 1, 2008-December 31, 2008	100,000
January 1, 2009-March 31, 2009	50,000

Table of Contents

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 sheet of Hercules Offshore, Inc. and subsidiaries as of December 31, 2007, and the related consolidated statements of operations, stockholders equity, cash flows and comprehensive income for the year then ended. 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 financial statements referred to above present fairly, in all material respects, the consolidated financial position of Hercules Offshore, Inc. and subsidiaries at December 31, 2007, and the consolidated results of their operations and their cash flows for the year then ended, 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 14 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, 2007, 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, 2008, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 25, 2008

Table of Contents

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, 2007, 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, 2007, 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 sheet of Hercules Offshore, Inc. and subsidiaries as of December 31, 2007, and the related consolidated statements of operations, stockholders equity, cash flows and comprehensive income for the year then ended, and our report dated February 25, 2008, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 25, 2008

55

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Hercules Offshore, Inc.

We have audited the accompanying consolidated balance sheet of Hercules Offshore, Inc. and subsidiaries as of December 31, 2006, and the related consolidated statements of operations, cash flows, stockholders equity and comprehensive income for the years ended December 31, 2006 and 2005. 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Hercules Offshore, Inc. and subsidiaries as of December 31, 2006 and the results of their operations and their cash flows for the years ended December 31, 2006 and 2005, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2006, the Company adopted the provisions of Statement of Financial Accounting Standards No. 123 (revised 2004), Share-Based Payments.

/s/ GRANT THORNTON LLP

Houston, Texas
February 23, 2007

Table of Contents

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2007	December 31, 2006
	(In thousands, except par value)	
ASSETS		
Current Assets:		
Cash and Cash Equivalents	$ 212,452	$ 72,772
Restricted Cash		250
Marketable Securities	39,300	
Accounts Receivable, Net	221,663	89,136
Insurance Claims Receivable	43,342	
Supplies	2,494	
Prepaids	31,417	14,438
Current Deferred Tax Asset	17,551	
Other	23,565	3,627
	591,784	180,223
Property and Equipment, Net	2,060,224	415,864
Goodwill	940,241	
Other Assets, Net	50,290	9,494
	$ 3,642,539	$ 605,581
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Short-term Debt and Current Portion of Long-term Debt	$ 21,653	$ 1,400
Insurance Note Payable	16,931	6,058
Accounts Payable	105,527	29,123
Accrued Liabilities	80,138	16,262
Taxes Payable	23,006	8,745
Other Current Liabilities	16,845	7,738
	264,100	69,326
Long-term Debt, Net of Current Portion	890,013	91,850
Other Liabilities	19,518	6,700
Deferred Income Taxes	457,475	42,854
Commitments and Contingencies		
Stockholders Equity:		
Common Stock, $0.01 par value; 200,000 Shares Authorized; 88,876 and 32,008 Shares Issued, Respectively; 88,857 and 32,002 Shares Outstanding, Respectively	889	320
Capital in Excess of Par Value	1,731,882	243,157

Treasury stock, at Cost, 19 Shares and 6 shares, Respectively	(582)	(220)
Accumulated Other Comprehensive Income (Loss)	(8,117)	755
Retained Earnings	287,361	150,839
	2,011,433	394,851
	$ 3,642,539	$ 605,581

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

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2007	2006	2005
	(In thousands, except per share data)		
Revenues	$ 766,793	$ 344,312	$ 161,334
Costs and Expenses:			
Operating Expenses	376,459	124,138	77,814
Depreciation and Amortization	109,064	32,310	13,790
General and Administrative	49,811	29,807	13,871
	535,334	186,255	105,475
Operating Income	231,459	158,057	55,859
Other Income (Expense):			
Interest Expense	(36,055)	(9,278)	(9,880)
Gain on Disposal of Assets		30,690	
Loss on Early Retirement of Debt	(2,182)		(4,078)
Other, Net	6,291	4,038	924
Income Before Income Taxes	199,513	183,507	42,825
Income Tax Provision	(62,991)	(64,457)	(15,369)
Net Income	$ 136,522	$ 119,050	$ 27,456
Earnings Per Share:			
Basic	$ 2.32	$ 3.80	$ 1.10
Diluted	$ 2.29	$ 3.70	$ 1.08
Weighted Average Shares Outstanding:			
Basic	58,897	31,327	24,919
Diluted	59,563	32,203	25,432

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

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

	December 31, 2007		December 31, 2006		December 31, 2005	
	Shares	Amount	Shares	Amount	Shares	Amount
			(In thousands)			
Member Interests:						
Balance at Beginning of Period		$		$	64	$ 63,022
Contributions from Members					4	4,329
Effect of Conversion					(68)	(67,351)
Balance at End of Period						
Common Stock:						
Balance at Beginning of Period	32,008	320	30,243	302		
Effect of Conversion					23,923	239
Exercise of Stock Options	250	3	129	2		
Issuance of Common Stock			1,600	16	6,250	62
Issuance of Common Stock, Net	56,618	566				
Issuance of Restricted Stock			36		70	1
Balance at End of Period	88,876	889	32,008	320	30,243	302
Capital in Excess of Par Value:						
Balance at Beginning of Period		243,157		184,698		
Effect of Conversion						67,112
Exercise of Stock Options		2,052		1,230		
Issuance of Common Stock, Net		1,471,379		54,182		116,187
Issuance of Restricted Stock						1,399
Reclass of Restricted Stock				(1,322)		
Compensation Expense Recognized		7,680		3,098		
Compensation Capitalized as part of the Purchase Price Allocation		3,778				
Tax Sharing Agreement with Transocean		2,578				
Excess of Tax Benefit From Stock-Based Arrangements		1,258		1,271		
Balance at End of Period		1,731,882		243,157		184,698
Treasury Stock:						
Balance at Beginning of Period	(6)	(220)				
Repurchase of Common Stock	(13)	(362)	(6)	(220)		
Balance at End of Period	(19)	(582)	(6)	(220)		

Restricted Stock:						
Balance at Beginning of Period				(1,322)		
Issuance of Restricted Stock						(1,400)
Compensation Expense Recognized						78
Reclass of Restricted Stock				1,322		
Balance at End of Period						(1,322)
Accumulated Comprehensive Income (Loss):						
Balance at Beginning of Period		755		476		
Change in Unrealized Gain (Loss) on Hedge Transactions, Net of Tax of $4,778, $(150) and $(257), Respectively		(8,872)		279		476
Balance at End of Period, net of tax of $4,371, $(407) and $(257), Respectively		(8,117)		755		476
Retained Earnings:						
Balance at Beginning of Period		150,839		31,789		8,065
Net Income		136,522		119,050		27,456
Distribution to Former Members						(3,732)
Balance at End of Period		287,361		150,839		31,789
Total Stockholders Equity	88,857	$ 2,011,433	32,002	$ 394,851	30,243	$ 215,943

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

59

Table of Contents

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2007	2006	2005
	(In thousands)		
Net Income	$ 136,522	$ 119,050	$ 27,456
Other Comprehensive Income (Loss):			
Reclassification of (gains) losses, net included in net income	(897)	(382)	73
Other comprehensive gains (losses), net	(7,975)	661	403
Comprehensive Income	$ 127,650	$ 119,329	$ 27,932

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

Table of Contents

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2007	2006	2005
		(In thousands)	
Cash Flows from Operating Activities:			
Net Income	$ 136,522	$ 119,050	$ 27,456
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:			
Depreciation and Amortization	109,064	32,310	13,790
Stock-Based Compensation Expense	7,680	3,098	78
Deferred Income Taxes	2,841	27,200	15,247
Amortization of Deferred Financing Fees	1,805	686	890
Recovery of Bad Debts			(519)
Loss on Early Retirement of Debt	2,182		4,078
Gain on Disposal of Assets	(4,491)	(30,779)	
Excess Tax Benefit from Stock-Based Arrangements	(1,258)	(1,271)	
(Increase) Decrease in Operating Assets			
Accounts Receivable	58,827	(50,653)	(12,545)
Insurance Claims Receivable	(13,565)	5,919	(5,919)
Prepaid Expenses and Other	9,263	(12,617)	(7,721)
Increase (Decrease) in Operating Liabilities			
Accounts Payable	(6,794)	15,842	11,443
Insurance Note Payable	(25,301)	3,657	1,718
Other Current Liabilities	15,239	11,499	6,766
Tax Sharing Agreement Payment	(116,003)		
Other Liabilities	2,308	300	
Net Cash Provided by Operating Activities	178,319	124,241	54,762
Cash Flows from Investing Activities:			
Acquisition of Business, Net of Cash Acquired	(728,396)		
Investment in Marketable Securities	(151,675)		
Proceeds from Sale of Marketable Securities	112,375		
Additions of Property and Equipment	(155,390)	(204,456)	(168,038)
Deferred Drydocking Expenditures	(20,772)	(12,544)	(7,369)
Insurance Proceeds Received	4,285	61,278	
Proceeds from Sale of Assets, Net	109,745	5,989	455
(Increase) Decrease in Restricted Cash	4,821	(250)	
Net Cash Used in Investing Activities	(825,007)	(149,983)	(174,952)
Cash Flows from Financing Activities:			
Short-term Debt Borrowings (Repayments), Net	(1,395)		
Long-term Debt Borrowings	900,000		185,000
Long-term Debt Repayments	(97,750)	(1,400)	(146,350)
Proceeds from Issuance of Common Stock, Net		54,198	116,249

Proceeds from Exercise of Stock Options	2,054	1,232	
Excess Tax Benefit from Stock-Based Arrangements	1,258	1,271	
Payment of Debt Issuance Costs	(17,753)	(630)	(5,923)
(Distributions to) Contributions from Members		(3,732)	4,329
Other	(46)		
Net Cash Provided by Financing Activities	786,368	50,939	153,305
Net Increase in Cash and Cash Equivalents	139,680	25,197	33,115
Cash and Cash Equivalents at Beginning of Period	72,772	47,575	14,460
Cash and Cash Equivalents at End of Period	$ 212,452	$ 72,772	$ 47,575

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

Table of Contents

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 350 shares of common stock of the corporation. Unless the context indicates otherwise, references to the Company are to Hercules Offshore, LLC and its subsidiaries for periods prior to the Conversion and to Hercules Offshore, Inc. and its subsidiaries for periods after the Conversion.

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 Other segments (See Note 15). 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). At December 31, 2007, the Company owned a fleet of 33 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 third parties. The Company operates in nine countries on four continents.

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

Beginning in March 2007, the Company began investing 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, 2007, the Company had marketable securities with a fair value and cost basis of $39.3 million. Proceeds of $112.4 million were received from sales and maturities of marketable securities for the year ended December 31, 2007. There were no realized or unrealized gains or losses related to these 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. 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 Income (Loss) on the Consolidated Balance Sheets until realized. Realized gains or losses are included in Other, Net in the Consolidated Statements of Operations.

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Restricted Cash

In connection with the acquisition of TODCO (See Note 4), the Company acquired restricted cash to support surety bonds (See Note 16) issued in relation to contracts TODCO had with Pemex Exploration and Production. As of December 31, 2007, the Company had no restricted cash balances outstanding.

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 over the term of the related drilling contract. Amounts related to mobilization fees are summarized below (in thousands):

	Year Ended December 31,		
	2007	2006	2005
Mobilization revenue deferred	$ 6,517	$ 5,680	$
Mobilization expense deferred	3,340	3,287	
Mobilization revenue recognized	3,060	2,590	
Mobilization expense recognized	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 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 $15.4 million, $7.5 million and $4.6 million for the years ended December 31, 2007, 2006 and 2005, 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, 2007 will be $5.8 million over the remaining vesting period of 1.4 years and the cost relating to restricted shares granted through December 31, 2007 will be $6.0 million over the remaining vesting period of 1.8 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.

Table of Contents

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are stated at the historical carrying amount net of write-offs and allowance for doubtful accounts. Management of the Company monitors the accounts receivable from its customers for any collectability issues. An allowance for doubtful accounts is established based on reviews of individual customer accounts, recent loss experience, current economic conditions, and other pertinent factors. Accounts deemed uncollectable are charged to the allowance. The Company had an allowance of $0.6 million at December 31, 2007 and no allowance for doubtful accounts recorded at December 31, 2006.

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, 2007, $43.3 million was outstanding for insurance claims receivable primarily related to collision damage to *Hercules 205* and hurricane damage to several rigs caused by Hurricanes Rita and Katrina. There were no claims receivable at December 31, 2006.

Prepaid Expenses

Prepaid expenses consist of prepaid insurance, prepaid income tax and other prepayments. At December 31, 2007 and December 31, 2006, prepaid insurance totaled $21.6 million and $13.9 million, respectively. At December 31, 2007, prepaid taxes totaled $6.2 million. There were no prepaid taxes at December 31, 2006.

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

Goodwill

As of December 31, 2007, the Company had $940.2 million of goodwill. In accordance with SFAS No. 142, *Goodwill and Other Intangible Assets* (SFAS No. 142), the Company is required to test for the impairment of goodwill and other intangible assets with indefinite lives on at least an annual basis. The Company s goodwill impairment test involves a comparison of the fair value of each of the Company s reporting units, as defined under SFAS No. 142, with its carrying amount. Fair value is estimated using discounted cash flows and other market-related valuation models, including earnings multiples and comparable asset market values. If the fair value is determined to be less than the carrying value, the asset is considered impaired. The amount of the impairment, if any, is determined based on an allocation of the reporting unit fair

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

values. The Company will test goodwill for impairment as of October 1 and will test it annually on that date unless changes occur between annual test dates that would more likely than not reduce the fair value of a reporting unit below its carrying amount. The Company s 2007 impairment test indicated that goodwill was not impaired.

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

	Domestic Offshore	International Offshore	Inland	Other	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

As of December 31, 2007, there was no goodwill associated with the Domestic Liftboats and International Liftboats segments.

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 within the International Offshore segment. The estimated fair value of these acquired contracts is based on preliminary valuations and is subject to change when final valuations are obtained. These contracts are being amortized over the life of the contracts. As of December 31, 2007, the customer contracts had a carrying value of $14.8 million, net of accumulated amortization of $2.8 million, and are included in Other Assets, Net on the Consolidated Balance Sheet.

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

2008	$ 8,088
2009	4,658
2010	1,466
2011	607
2012	

Impairment of Long-Lived Assets

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. 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 related asset or group of assets being evaluated. Actual impairment charges are recorded using an estimate of discounted future cash flows. There were no impairment charges for the periods ended December 31, 2007, 2006, and 2005.

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Other Assets, Net

Other assets consist of drydocking costs for marine vessels, other intangible assets, deferred mobilization costs, financing fees, unrealized gains (losses) on hedge transactions, investments 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, 2007 and 2006 were $8.2 million and $5.8 million, respectively. Amortization expense for drydocking costs was $18.4 million, $10.7 million and $3.9 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Financing fees are deferred and amortized over the life of the applicable debt instrument. Unamortized deferred financing fees at December 31, 2007 and 2006 were $16.2 million and $2.5 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 $1.8 million, $0.7 million and $0.9 million for the years ended December 31, 2007, 2006 and 2005, respectively. The Company recognized a pretax charge of $2.2 million related to the write off of deferred financing fees in connection with the early debt repayment (See Note 9).

The Company entered into several transactions to hedge its variable rate debt with the purpose and effect of fixing the interest rate on a portion of the outstanding principal of the term loan (See Note 10).

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, except to the extent that the valuation allowance relates to deferred tax assets accounted for in purchase accounting, in which case, the future reduction of any such valuation allowance would reduce goodwill.

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 $0.9 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 14).

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. 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 carrying amount of long-term debt, excluding the acquired Senior Notes (See Note 9) is equal to the fair market value because the debt bears interest at market rates. The fair value of the Company s acquired Senior Notes is estimated based on the current rates offered to the Company for debt of the same remaining maturities. The Company believes its other debt instruments, which are short-term in nature, totaling $12.7 million as of December 31, 2007, approximate fair value.

Accounting Pronouncements

In December 2007, the Financial Accounting Standards Board (FASB) issued SFAS No. 141(R), *Business Combinations* (SFAS No. 141R). SFAS No. 141R replaces SFAS No. 141, *Business Combinations*, 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. This fair value approach replaces the cost-allocation process required under SFAS No. 141 whereby the cost of an acquisition was allocated to the individual assets acquired and liabilities assumed based on their estimated fair value. 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. Under SFAS No. 141R, the requirements of SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities* would have to be met in order to accrue for a restructuring plan in purchase accounting. Pre-acquisition contingencies are to be recognized at fair value, unless it is a non-contractual contingency that is not likely to materialize, in which case, nothing should be recognized in purchase accounting and, instead, that contingency would be subject to the probable and estimable recognition criteria of SFAS No. 5, *Accounting for Contingencies.* SFAS No. 141R may have a significant impact on the Company s accounting for business combinations closing on or after January 1, 2009.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities* (SFAS No. 159). SFAS No. 159 permits companies to choose to measure certain financial instruments and certain other items at fair value. The standard requires that unrealized gains and losses on items for which the fair value option has been elected be reported in earnings. SFAS No. 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007. The Company is evaluating the impact, if any, that SFAS No. 159 will have on its financial position, results of operations and cash flows.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* (SFAS No. 157). 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

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

any new fair value measurements, rather, its application will be made pursuant to other accounting pronouncements that require or permit fair value measurements. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. The provisions of SFAS No. 157 are to be applied prospectively upon adoption, except for limited specified exceptions. The Company is evaluating the requirements of SFAS No. 157 and does not expect the adoption to have a material impact on its financial position, results of operations and cash flows.

2. Property and Equipment, net

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

	December 31,	
	2007	2006
Drilling rigs and marine equipment	$ 1,914,018	$ 420,961
Drilling machinery and equipment	235,680	23,329
Leasehold improvements	9,722	267
Automobiles and trucks	2,470	915
Computer equipment	10,505	1,040
Furniture and fixtures	962	779
Total property and equipment, at cost	2,173,357	447,291
Less accumulated depreciation	(113,133)	(31,427)
Total property and equipment, net	$ 2,060,224	$ 415,864

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, except earnings per share):

	Year Ended December 31,		
	2007	2006	2005
Numerator:			
Net income	$ 136,522	$ 119,050	$ 27,456
Denominator:			
Weighted average basic shares	58,897	31,327	24,919
Add effect of stock equivalents	666	876	513
Weighted average diluted shares	59,563	32,203	25,432

Basic earnings per share	$ 2.32	$ 3.80	$ 1.10
Diluted earnings per share	2.29	3.70	1.08

The Company calculates basic earnings per share by dividing net income by the weighted average number of shares outstanding. On November 1, 2005, in connection with its initial public offering, the Company converted from a limited liability company to a corporation. Upon the Conversion, each outstanding membership unit of the limited liability company was converted into 350 shares of common stock of the corporation. Diluted earnings per share is computed by dividing net income by the weighted average number of shares outstanding during the period as adjusted for the dilutive effect of the Company s stock option and restricted stock awards. Stock equivalents of 350,080 were anti-dilutive and are excluded from the calculation of the dilutive effect of stock equivalents for the diluted earnings per share calculation for the year ended

Table of Contents

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

December 31, 2007. There were no anti-dilutive stock equivalents for the years ended December 31, 2006 and 2005, respectively.

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 preliminary allocation of the purchase price was based on preliminary valuations and estimates, and assumptions are subject to change upon the receipt and management s review of the final valuations. The final valuation of net assets is expected to be completed no later than one year from the acquisition date.

The preliminary allocation of the consideration is as follows:

	July 11, 2007 (In thousands) (Unaudited)
Cash and Cash Equivalents	$ 235,163
Accounts Receivable	191,369
Insurance Claims Receivable	34,060
Current Deferred Tax Asset	14,320
Prepaid Expenses and Other	16,811
Property and Equipment, Net	1,685,477
Goodwill	940,241
Other Assets, Net	32,049
Total Assets	3,149,490
Short-Term Debt	(3,618)
Accounts Payable	(83,199)
Income Taxes Payable	(5,448)
Other Current Liabilities	(69,773)
Long-Term Debt	(14,062)
Deferred Tax Liabilities	(530,086)
Other Liabilities	(3,982)

Total Preliminary 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 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	$ 1,268.1	$ 1,256.4
Net Income	198.5	230.7
Basic earnings per share	2.24	2.62
Diluted earnings per share	2.21	2.58

In June 2007, the Company purchased a liftboat vessel for $7.4 million. The vessel is undergoing refurbishment and upgrades and is being marketed in West Africa.

In November 2006, the Company purchased from Halliburton West Africa Limited and Halliburton Energy Services Nigeria Limited (collectively Halliburton) eight liftboats owned by Halliburton and was assigned the contractual rights to operate five liftboats which are currently owned by a third party, and the lease of a shore-based facility and certain contracts and other assets related to the liftboats. The purchase price for the acquisition was $51.6 million, plus up to $10.0 million payable under a three-year earnout agreement. In order to secure the Company s obligations under the earnout agreement, the Company granted Halliburton a lien in the amount of $3.0 million on one of the liftboats acquired. The Company operates the five liftboats owned by the third party under a management agreement that applies while the liftboats are under contract with Chevron Nigeria Limited. The total purchase price was allocated to the liftboats based on their estimated fair values.

In June 2006, the Company acquired five liftboats from Laborde Marine Lifts, Inc. (Laborde). In addition, the Company assumed the construction of an additional liftboat pursuant to a construction agreement assigned to the Company by Laborde at the closing. Pursuant to the terms of the purchase agreement, the original purchase price of $52.0 million was reduced by $2.7 million which represented the total amount remaining due under the construction contract for the sixth liftboat as of closing. Construction of the additional liftboat was completed in July 2006 and the remaining amount due was paid to the shipyard.

In February 2006, the Company purchased *Hercules 260* for $20.1 million. The Company has completed a reactivation and upgrade project to enhance the rig s drilling capabilities and to increase the marketability of the rig in international regions. *Hercules 260* is currently undergoing contract preparation work and customer acceptance in India.

In November 2005, the Company purchased seven liftboats and related assets for $44.0 million. Three of the acquired liftboats are located in the U.S. Gulf of Mexico and are included in the Domestic Liftboats segment. The remaining four liftboats are currently operating in Nigeria and are included in the International Liftboats segment.

In September 2005, the Company purchased *Hercules 258* for $12.6 million.

In August 2005, the Company purchased the liftboat *Whale Shark* for $12.5 million.

In June 2005, the Company purchased 17 liftboats for $19.7 million. One of these liftboats was sold in August 2005. In June 2005, the Company purchased a jackup rig, *Hercules 170*, for $20.0 million.

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During January 2005, the Company completed the purchase of two jackup drilling rigs, *Rig 25* and *Hercules 257*, for $21.5 million and $20.0 million, respectively.

5. Dispositions

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.

In September 2006, the Company sold its New Iberia facility for $2.8 million, net of commissions. The Company recognized a gain of approximately $0.1 million on the sale.

In July 2006, the Company sold *Rig 41* for $3.2 million, net of commissions, and the Company recognized a gain of approximately $1.1 million on the sale.

6. 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 $1.3 million in excess tax benefits as a financing cash inflow for both years ended December 31, 2007 and 2006 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, 2007, approximately 7.1 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. Options granted prior to the Company s initial public offering on November 1, 2005 became fully vested at that date. Options issued at the time of the Company s initial public offering under the 2004 Plan have a 10-year term and vest in four equal installments, one-fourth on the effective date of grant and one-fourth thereafter on the anniversary of the grant date for the next three years. 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 is calculated based on the average of the high and low trading 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.

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The unrecognized compensation cost related to the Company s unvested stock options and restricted share grants as of December 31, 2007 was $5.8 million and $6.0 million, respectively, and is expected to be recognized over a weighted-average period of 1.4 years and 1.8 years, respectively.

Cash received from stock option exercises was $2.1 million and $1.2 million during the years ended December 31, 2007 and 2006, respectively. There were no options exercised during the year ended December 31, 2005.

The Company recognized $7.7 million, $3.1 million and $0.1 million in employee stock-based compensation expense during the years ended December 31, 2007, 2006 and 2005, respectively. The related income tax benefit recognized for the years ended December 31, 2007, 2006 and 2005 was $2.7 million, $1.1 million and $27 thousand 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. 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 2006 and 2005.

The fair value of the options granted under the 2004 Plan at the time of and after the Company s initial public offering was estimated on the date of grant using the Trinomial Lattice option pricing model with the following assumptions used:

	2007	2006	2005
Dividend yield			
Expected price volatility	35.0%		35.0%
Risk-free interest rate	4.58%		4.40%
Expected life of options (in years)	5.88		8.08
Weighted-average fair value of options granted	$ 11.18		$ 9.45

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 pro forma net income and earnings per share had we elected to adopt the fair value approach of SFAS No.123R prior to January 1, 2006 (in thousands, except per share data):

	Year Ended December 31, 2005
Net Income:	
As reported	$ 27,456

Compensation expense included in reported net income, net of income tax benefit		51
Pro forma compensation expense, net of income tax benefit		(1,752)
Pro forma	$	25,755
Basic earnings per share:		
As reported	$	1.10
Pro forma		1.03
Diluted earnings per share:		
As reported	$	1.08
Pro forma		1.01

Table of Contents

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2007 and changes during the year then ended:

Options	Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value (In thousands)
Outstanding at January 1, 2007	1,659,922	$ 11.27	8.35	29,264
Granted	591,914	26.34		
Options assumed in the TODCO acquisition	331,038	25.37		
Exercised	(250,172)	8.21		
Forfeited	(17,900)	21.31		
Outstanding at December 31, 2007	2,314,802	17.39	7.98	17,558
Vested or Expected to Vest at December 31, 2007	2,314,802	17.39	7.98	17,558
Exercisable at December 31, 2007	1,596,452	14.03	7.54	16,931

The weighted-average grant date fair value of options granted during the years ended December 31, 2007 and 2005 was $11.18, and $9.45, respectively. There were no options granted in 2006 and there were no options exercised in 2005. The intrinsic value of options exercised during 2007 and 2006 was $5.2 million and $3.4 million, respectively.

The following table summarizes information about restricted stock outstanding as of December 31, 2007 and changes during the year then ended:

Weighted-

	Restricted Stock	Average Grant Date Fair Value
Non-Vested at January 1, 2007	82,432	$ 26.48
Granted	264,487	28.75
Restricted stock issued in the TODCO acquisition	20,608	25.32
Vested	(63,253)	27.88
Forfeited	(21,910)	29.77
Non-Vested at December 31, 2007	282,364	26.42

The weighted-average grant date fair value of restricted stock granted during the years ended 2007, 2006 and 2005 was $28.75, $34.94 and $20.00, respectively. The total fair value of restricted stock vested during

Table of Contents

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the years ended 2007 and 2006 was $1.4 million and $0.8 million, respectively. There were no restricted stock vestings during the year ended December 31, 2005.

7. Accrued Liabilities

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

	December 31, 2007	December 31, 2006
Accrued Liabilities:		
Taxes other than Income	$ 21,686	$ 3,005
Accrued Payroll and Employee Benefits	27,941	12,828
Accrued Self-Insurance Claims	29,973	150
Other	538	279
	$ 80,138	$ 16,262

8. Benefit Plans

The Company has three 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. The Company made total matching contributions of $5.0 million, $1.9 million and $0.9 million for the years ended December 31, 2007, 2006 and 2005, respectively. Effective January 1, 2008, the legacy Hercules plan and legacy TODCO plan discussed above were merged into one plan and the Company will match 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 will match participant contributions equal to 100% of the first 6% of each participant s base salary.

9. Debt

Debt is comprised of the following (in thousands):

	December 31, 2007	December 31, 2006
Term Loan Facility, due July 2013	$ 895,500	$
9.5% Senior Notes, due December 2008	10,432	

7.375% Senior Notes, due April 2018		3,513		
6.95% Senior Notes, due April 2008		2,221		
Foreign Line of Credit				
Senior Secured Term Loan, due June 2010				93,250
Total Debt		911,666		93,250
Less Short-term Debt and Current Portion of Long-term Debt		21,653		1,400
Total Long-term Debt, Net of Current Portion	$	890,013	$	91,850

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

2008	$ 21,653
2009	9,000
2010	9,000
2011	9,000
2012	9,000
Thereafter	854,013
	$ 911,666

Senior secured credit agreement

The Company had a 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. In addition to scheduled repayments made by the Company in 2007 of $0.7 million, in April 2007 the Company repaid $37.0 million of the outstanding amount under the term loan and cancelled an interest rate swap on $35.0 million of the term loan principal (See Note 10). The Company recognized a pretax charge of $0.9 million related to the write off of deferred financing fees in connection with this debt repayment. In July 2007, the Company repaid the remaining $55.6 million outstanding under the term loan, together with accrued interest of $1.2 million. The Company recognized a pretax charge of $1.3 million related to the write off of deferred financing fees in connection with the July debt repayment. Additionally, the Company cancelled all derivative instruments related to the term loan, which included an interest rate swap on $35.0 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 10).

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 the 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 10).

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 $28.1 million in standby letters of credit had been issued under the revolving credit facility as of December 31, 2007. The remaining availability under this revolving credit facility was $121.9 million at December 31, 2007.

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;

Table of Contents

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2007, $895.5 million was outstanding on the term loan facility and the interest rate was 6.58%. The annualized effective rate of interest was 7.06% at December 31, 2007 after giving consideration to derivative activity.

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 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 credit agreement contains financial covenants that are tested quarterly relating to leverage and fixed charge coverage. 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. The credit agreement contains customary events of default. The Company was in compliance with these covenants at December 31, 2007.

Senior notes and other debt

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 include 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 fair market value of the Senior Notes at December 31, 2007 was approximately $2.2 million, $3.7 million and $10.6 million, respectively, based on the most recent market valuations. The line of credit is designed to manage local currency liquidity in Venezuela. The maximum amount available to be drawn is 6.0 billion Bolivars ($2.8 million at the exchange rate at December 31, 2007). There were no outstanding borrowings on the foreign line of credit at December 31, 2007. The weighted average interest rate on borrowings outstanding on the line of credit during the year ended December 31, 2007 was 17.7%.

10. 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 caps to cap the interest rate 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

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

$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 July 2007, the Company entered into derivative instruments with the purpose of hedging future interest payments on its new term loan facility. 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. 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 payment dates of the collar match those of the term loan. The following table provides the scheduled reduction in notional amounts related to the interest rate swap (in thousands):

December 31, 2007-March 31, 2008	$ 350,000
April 1, 2008-June 30, 2008	300,000
July 1, 2008-September 30, 2008	200,000
October 1, 2008-December 31, 2008	100,000
January 1, 2009-March 31, 2009	50,000

These hedge transactions are being accounted for as cash flow hedges under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* , 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 Assets and Other Liabilities and the cumulative unrealized gain/loss, net of tax, is included in Accumulated Other Comprehensive Income (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, 2007, 2006 and 2005 related to these hedging instruments. The Company expects to realize $4.0 million of unrealized loss in the Consolidated Statements of Operations for the year ended December 31, 2008.

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

	December 31,	
	2007	**2006**
Fair value included in Other Assets, Net	$ 322	$ 1,162
Fair value included in Other Liabilities	12,809	
Cumulative unrealized gain (loss), net of tax of $4,371 and $(407), respectively included in Accumulated Other Comprehensive Income	(8,117)	755

	Recognized Gain (Loss) in Consolidated Statements of Operations for the Year Ended		
	2007	2006	2005
Realized gains included in Other, net	$ 658	$ 588	$
Realized gains (losses) included in Interest Expense	239		(113)

77

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. 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

Non-cash Activities

	Year Ended December 31,		
	2007	2006	2005
	(In thousands)		
Cash paid during the period for:			
Interest, net of capitalized interest	$ 36,426	$ 8,246	$ 7,688
Income taxes	45,893	27,363	
Non-cash activities:			
Change in fair value of derivative instruments	8,872	(279)	(476)
Distribution to original members			3,732

During 2007, the Company capitalized interest of $1.4 million. The Company did not capitalize interest in 2006 and 2005.

12. Concentration of Credit Risk

The Company maintains its cash in bank deposit accounts at high credit quality financial institutions as permitted by its credit agreement. The balances, at times, may 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.

13. 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,		
	2007	**2006**	**2005**
Chevron Corporation	21%	35%	31%
Bois d Arc Energy, Inc.			12%

In addition, Chevron Corporation accounted for 84.9% of the revenue for the Company s International Liftboats segment in the year ended December 31, 2007.

Table of Contents

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

14. Income Taxes

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

	Year Ended December 31, 2007	2006	2005
United States	$ 110,060	$ 168,885	$ 42,236
Foreign	89,453	14,622	589
Total	$ 199,513	$ 183,507	$ 42,825

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

	Year Ended December 31, 2007	2006	2005
Current-United States	$ 23,262	$ 33,054	$
Current-foreign	33,604	3,070	100
Current-state	3,284	1,133	22
Current income tax provision	60,150	37,257	122
Deferred-United States	17,029	26,597	14,423
Deferred-foreign	(12,341)	(59)	
Deferred-state	(1,847)	662	824
Deferred income tax provision	2,841	27,200	15,247
Total income tax provision	$ 62,991	$ 64,457	$ 15,369

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

	December 31, 2007	2006
Deferred tax assets:		
Net operating loss carryforward (Federal & State)	$ 95,939	$

Credit carryforwards (Net of valuation allowance)	28,271	
Accrued expenses	17,200	
Unearned income	4,509	
Other	7,730	1,318
Deferred tax assets	153,649	1,318
Deferred tax liabilities:		
Fixed assets	(582,233)	(37,962)
Deferred expenses	(7,820)	(2,523)
Other	(3,520)	(3,687)
Deferred tax liabilities	(593,573)	(44,172)
Net deferred tax liabilities	$ (439,924)	$ (42,854)

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Year Ended December 31,		
	2007	**2006**	**2005**
Statutory rate	35.0%	35.0%	35.0%
Effect of:			
State income taxes	0.1	1.1	
Foreign income taxes	2.1		
Foreign earnings indefinitely reinvested	(5.1)	(1.0)	
Income of LLC prior to conversion			(27.5)
Change in tax status and other	(0.5)		28.4
Effective rate	31.6%	35.1%	35.9%

The amount of consolidated U.S. NOLs available as of December 31, 2007 is approximately $274 million. These NOLs will expire in the years 2021 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.

The Company recorded a valuation allowance of $4.0 million related to certain capital loss carryforwards and foreign net operating losses which management believes is more likely than not that some or all of the benefits may not be realized. To the extent the Company reverses a portion of the valuation allowance in the future, such adjustment would be recorded as a reduction to goodwill.

We recognized $0.9 million of deferred US 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, 2007, the aggregate undistributed earnings of the foreign subsidiaries was $62 million. Upon distribution of these earnings in the form of dividends or otherwise, the Company may be subject to U.S. income taxes and foreign withholding taxes. It is not practical, however, to estimate the amount of taxes that may be payable on the remittance of these earnings.

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 other deductions. The Company intends to vigorously contest the assessment. While the Company cannot predict or provide assurance as to the ultimate outcome, it does not believe the outcome of this assessment will have a material effect on its financial statements. Depending on the ultimate outcome of the 2004 assessment, the Company anticipates that the Mexican tax authorities could make similar assessments for other open tax years.

Tax Sharing Agreement The Company, as successor to TODCO, and TODCO s former parent Transocean 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 in a negotiated settlement of disputes between Transocean and TODCO over the terms of the original tax sharing agreement. The tax sharing agreement required the Company to make an acceleration payment to Transocean upon completion of the TODCO acquisition as a result of the deemed utilization of TODCO s pre-IPO tax benefits. Subsequent to the completion of the TODCO acquisition, the Company paid $116.0 million to Transocean in satisfaction of those obligations. The basis of determination for the change in control payment is subject to a differing interpretation by Transocean. While the Company strongly believes it has

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

complied with the requirements of the tax sharing agreement in computing the amount of the acceleration payment, at this time, the Company can not estimate whether additional payments will be due related to the acceleration payment. This payment has been presented as a reduction of operating cash flow in the Consolidated Statement of Cash Flows for the twelve months ended December 31, 2007.

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, 2007, assuming a Transocean stock price of $143.15 per share at the time of exercise of the compensatory options (the actual price of Transocean s common stock at December 31, 2007), is approximately $25.4 million. 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, Statement of Operations or 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, 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 2004 through 2006 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 2001-2006.

The Company currently does not anticipate that any tax contingencies resolved in the next 12 months will have a material impact on our Consolidated Balance Sheet, Statements of Operations or Consolidated Statement of Cash Flows. It is reasonably possible that the amount of the Company s unrecognized tax benefit could change however we do not expect any potential change to have a significant effect on our results of operations or our financial position. The Company does not currently have any unrecognized tax benefits that, if recognized, would favorably affect the effective income tax rate in any future periods. There were no accrued interest and penalties associated with uncertain tax positions as of December 31, 2007.

15. Segments

Previously, the Company reported its business activities in four business segments, Domestic Contract Drilling Services, International Contract Drilling Services, Domestic Marine Services and International Marine Services. In connection with the acquisition of TODCO (See Note 4), the Company conducted a review of its presentation of segment information. The historical four business segments of the Company have been combined with the businesses of TODCO and now operate as six business segments: (1) Domestic Offshore, (2) International Offshore, (3) Inland, (4) Domestic Liftboats, (5) International Liftboats and (6) Other. Domestic Offshore includes the Company s legacy Domestic Contract Drilling Services businesses combined with TODCO s jackup and submersible rigs operating in the

U.S. Gulf of Mexico, while International Offshore includes the Company s legacy International Contract Drilling Services business combined with TODCO s offshore rigs operating internationally. Inland includes the acquired TODCO U.S. inland barge business. Domestic Liftboats includes the Company s legacy Domestic Marine Services business, while International Liftboats includes the Company s legacy International Marine Services business. In addition, the Company acquired TODCO s Delta Towing business and land rigs. During the fourth quarter of 2007, the Company sold the nine land rigs and related assets (See Note 5). These businesses did not meet the quantitative thresholds

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

for determining reportable segments and were combined for reporting purposes in Other. The Company eliminates inter-segment revenue and expenses, if any. The following describes the Company s reporting segments as of December 31, 2007:

Domestic Offshore operates 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 250 feet.

International Offshore operates nine jackup rigs and one platform rig outside of the U.S. Gulf of Mexico. The Company has one jackup rig working offshore in each of the following international locations: Qatar, Angola, Brazil and Trinidad. The Company has two jackup rigs in India. This segment operates two jackup rigs and one platform rig in Mexico. In addition, this segment has one jackup rig currently undergoing reactivation in Southeast Asia.

Inland operates 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 operates 47 liftboats in the U.S. Gulf of Mexico.

International Liftboats operates 18 liftboats offshore West Africa, including five liftboats owned by a third party and one undergoing refurbishment.

Other The Company s Delta Towing business operates a fleet of 35 inland tugs, 17 offshore tugs, 34 crew boats, 44 deck barges, 17 shale barges and four spud barges along and in the U.S. Gulf of Mexico. In December 2007, the Company sold its land rig operations which included one land rig in Trinidad, two land rigs in the United States and six land rigs in Venezuela.

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, 2007			Year Ended December 31, 2006		
	Revenue	Income from Operations	Depreciation and Amortization	Revenue	Income from Operations	Depreciation and Amortization
Domestic Offshore	$ 241,452	$ 78,073	$ 35,143	$ 160,761	$ 93,037	$ 8,882
International Offshore	144,778	67,809	15,513	30,460	12,930	2,547
Inland	107,100	33,667	16,264			
Domestic Liftboats	137,745	50,684	24,969	133,929	63,791	18,854
International Liftboats	63,282	19,896	7,619	19,162	4,309	1,923
Other	72,436	16,079	9,028			

	766,793	266,208	108,536	344,312	174,067	32,206
Corporate		(34,749)	528		(16,010)	104
Total Company	$ 766,793	$ 231,459	$ 109,064	$ 344,312	$ 158,057	$ 32,310

Table of Contents

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Year Ended December 31, 2005		
	Revenue	Income from Operations	Depreciation and Amortization
Domestic Offshore	$ 103,422	$ 44,059	$ 5,547
International Offshore			
Inland			
Domestic Liftboats	55,740	17,408	8,031
International Liftboats	2,172	589	176
Other			
	161,334	62,056	13,754
Corporate		(6,197)	36
Total Company	$ 161,334	$ 55,859	$ 13,790

	Total Assets	
	December 31, 2007	December 31, 2006
Domestic Offshore	$ 1,504,548	$ 144,467
International Offshore	681,742	126,191
Inland	646,120	
Domestic Liftboats	186,568	192,314
International Liftboats	149,813	89,954
Other	229,979	
Corporate	243,769	52,655
Total Company	$ 3,642,539	$ 605,581

	Year Ended December 31,		
	2007	2006	2005
Capital Expenditures and Deferred Drydocking Expenditures:			
Domestic Offshore	$ 22,720	$ 76,635	$ 90,347
International Offshore	78,455	20,100	
Inland	17,145		
Domestic Liftboats	16,950	66,279	67,460

International Liftboats	20,183	53,955	17,600
Other	6,239		
Corporate	14,470	31	
Total Company	$ 176,162	$ 217,000	$ 175,407

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

Table of Contents

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

following tables present revenues and long-lived assets by country based on the location of the service provided (in thousands):

	Year Ended December 31, 2007	2006	2005
Operating Revenues:			
United States	$ 516,408	$ 294,690	$ 159,162
Mexico	28,364		
Venezuela	36,694		
Nigeria	60,384	18,440	2,172
India	52,501	12,392	
Qatar	27,146	18,068	
Other(a)	45,296	722	
Total	$ 766,793	$ 344,312	$ 161,334

	As of December 31, 2007	2006
Long-Lived Assets:		
United States	$ 2,375,874	$ 266,850
Mexico	161,568	
Nigeria	82,455	76,377
India	128,773	37,539
Qatar	32,619	35,071
Other(a)	269,466	27
Total	$ 3,050,755	$ 415,864

(a) Other represents countries in which we operate that individually had operating revenues or long-lived assets representing less than 3% of total operating revenues earned or total long-lived assets.

16. Commitments and Contingencies

Operating Leases

The Company has operating lease commitments that expire at various dates through 2018. As of December 31, 2007, future minimum lease payments related to operating leases were as follows (in thousands):

Years Ended December 31,	
2008	$ 2,230
2009	1,099
2010	1,009
2011	1,041
2012	1,077
Thereafter	5,971
Total	$ 12,427

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Rental expense for all operating leases was $2.8 million, $1.6 million and $0.6 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Legal Proceedings

The Company is involved in various claims and lawsuits in the normal course of business. As of December 31, 2007, management did not believe any accruals were necessary in accordance with SFAS No. 5, *Accounting for Contingencies*.

In March 2007, two TODCO stockholder lawsuits were filed in the District Court of Harris County, Texas, both alleging that the TODCO board of directors (which includes three of the Company s current directors) breached their fiduciary duties in approving the merger with a subsidiary of the Company. The first lawsuit, *Frank Donio v. Jan Rask, et al.*, then pending in the 269th Judicial District Court of Harris County, Texas, Cause No. 2007-16357, is a purported stockholder class action suit against the TODCO directors and contains claims for breach of fiduciary duty. The second lawsuit, *Robert Foster v. Jan Rask, et al.* , then pending in the 333rd Judicial District Court of Harris County, Texas, Cause No. 2007-16397, is a stockholder derivative action purportedly filed on behalf of TODCO against the TODCO directors (which includes three of the Company s current directors) and the Company, and contains claims for breach of fiduciary duties of loyalty, due care, candor, good faith and/or fair dealing; corporate waste; unlawful self dealing; and claims that the defendants conspired, aided and abetted and/or assisted one another in a common plan to breach these fiduciary duties. Both lawsuits allege, among other things, that the TODCO directors engaged in self-dealing in approving the merger with the Company by advancing their own personal interests or those of TODCO s senior management at the expense of the TODCO stockholders, utilized a defective sales process not designed to maximize TODCO stockholder value, and failed to consider any value maximizing alternatives, thus causing TODCO stockholders to receive an unfair price for their shares of TODCO common stock. The second lawsuit also alleges that the Company conspired, aided and abetted or assisted in these violations. In addition, the second suit alleges that TODCO s directors breached their fiduciary duties by allegedly improperly awarding stock options to certain officers at a time when they allegedly knew the merger was imminent and the stock options would vest immediately upon consummation of the merger. The second suit also names the officers who received these stock option awards as defendants and alleges three causes of action against them: (1) a breach of fiduciary duty claim for having received allegedly improperly awarded stock options, (2) an unjust enrichment claim seeking a constructive trust, and (3) rescission of the stock option awards.

Both lawsuits seek, among other things, rescission of the merger, imposition of a constructive trust in favor of plaintiffs upon any benefits improperly received by the defendants, attorneys fees and expenses associated with the lawsuits and any other equitable relief the courts deem just and proper. On August 29, 2007, the two lawsuits were consolidated and transferred to the 270th Judicial District Court of Harris County, Texas. The Company, the TODCO directors, and the officers named as defendants believe the asserted claims are without merit, and each intends to defend them vigorously.

In connection with the acquisition of TODCO, the Company 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 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 our consolidated results of operations, financial position or cash flows. The Company continues to monitor this matter.

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 of 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. 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.

In December 2002, TODCO received an assessment for corporate income taxes from SENIAT, the national Venezuelan tax authority, of 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 2000. 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. 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. The Company has not yet received any proposed adjustments from SENIAT arising from this audit. The Company believes it is owed indemnity from TODCO s former parent under the tax sharing agreement for any losses it incurs as a result of these legal proceedings.

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

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 such 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.

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 July 2007, 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 $2.6 billion; however, coverage for U.S. Gulf of Mexico named windstorm damage is subject to an annual aggregate limit on liability of $150.0 million. The policies are subject to 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. 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. In July 2007, 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 $36.2 million was financed through these arrangements and $16.9 million was outstanding at December 31, 2007. The interest rate on these notes is 5.75% and each note matures in June 2008. There was $6.1 outstanding in insurance note payable at December 31, 2006 at an interest rate of 5.75%. The Company intends to renew certain of its insurance policies in the first half of 2008 and it does not expect significant increases to insurance premiums and fees for coverage of the Company s operations, assets and personnel base.

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 $65.9 million outstanding related to surety bonds at December 31, 2007. The surety bonds guarantee our performance as it relates to TODCO 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 and Venezuela.

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The company had $0.4 million in unsecured letters of credit outstanding at December 31, 2007.

2005 Hurricanes

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.

The Company acquired several jackup rigs that were damaged by Hurricane Rita and Katrina and one jackup rig that was damaged in a collision (See Note 1). At December 31, 2007, $43.3 million was outstanding for insurance claims receivable primarily related to these events.

17. Unaudited Interim Financial Data

Unaudited interim financial information for the years ended December 31, 2007 and 2006 is as follows (in thousands, except per share amounts):

	Quarter Ended			
	March 31	**June 30**	**September 30**	**December 31**
2007				
Operating revenues	$ 110,464	$ 99,044	$ 294,365	$ 262,920
Operating income	48,044	33,104	92,864	57,447
Net income	33,391	23,466	48,371	31,294
Net income per share:				
Basic	$ 1.04	$ 0.73	$ 0.59	$ 0.35
Diluted	1.03	0.72	0.58	0.35

	Quarter Ended			
	March 31	**June 30**	**September 30**	**December 31**
2006				
Operating revenues	$ 56,133	$ 76,297	$ 97,212	$ 114,670
Operating income	21,677	35,885	47,709	52,786

Net income		30,912		22,933		29,679		35,526
Net income per share:								
Basic	$	1.02	$	0.73	$	0.93	$	1.11
Diluted		1.00		0.71		0.91		1.09

18. Related Parties

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

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

stock sold by the selling stockholders and the fees and expenses of any other attorneys, accountants and other advisors separately retained by them. Steven A. Webster, a member of the Board of Directors, and Thomas E. Hord, 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.

In January 2005, the Company purchased *Hercules 257* from Porterhouse Offshore, LP (Porterhouse). Two of the Company s officers and a manager of the Company at the time of acquisition were partners in Porterhouse, which owned and sold *Hercules 257* to the Company. The Company believes that this transaction was on terms that were reasonable and in the best interest of the Company. In the transaction, these individuals received membership interests in the Company valued at $0.2 million, $0.2 million, and $0.4 million, respectively.

19. Subsequent Event

In February 2008, the Company entered into a definitive agreement to purchase three jackup drilling rigs and related equipment for approximately $320.0 million. Closing of the transaction is subject to regulatory approvals and other customary conditions. The Company plans to fund the acquisition with cash on hand and borrowings under its revolving credit facility.

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 Randall D. Stilley, our President and Chief Executive Officer, 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 quarterly report. Based upon that evaluation, Mr. Stilley and Ms. Rodriguez, acting in their capacities as our principal executive officer and our principal financial officer, concluded that, as of December 31, 2007, 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.

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, 2007. 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, 2007, 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, 2007, 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, 2007.

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, 2007.

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, 2007.

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, 2007.

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, 2007.

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.

91

(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.
10.1	Executive Employment Agreement, dated November 3, 2006, between Hercules and Randall D. Stilley (incorporated by reference to Exhibit 10.1 to Hercules Current Report on Form 8-K dated November 3, 2006 (File No. 0-51582) (the 2006 Form 8-K)).
10.2	Employment Agreement, dated as of March 13, 2007, by and between Hercules and Lisa W. Rodriguez (incorporated by reference to Exhibit 10.1 to Hercules Current Report on Form 8-K dated March 8, 2007 (File No. 0-51582)).
10.3	Executive Employment Agreement, dated November 3, 2006, between Hercules and John T. Rynd (incorporated by reference to Exhibit 10.2 to the 2006 Form 8-K).
10.4	Executive Employment Agreement, dated November 3, 2006, between Hercules and James W. Noe (incorporated by reference to Exhibit 10.5 to the 2006 Form 8-K).
10.5	Executive Employment Agreement, dated November 3, 2006, between Hercules and Steven A. Manz (incorporated by reference to Exhibit 10.3 to the 2006 Form 8-K).
10.6	Executive Employment Agreement, dated November 3, 2006, between Hercules and Randal R. Reed (incorporated by reference to Exhibit 10.4 to the 2006 Form 8-K).

*	10.7	Executive Employment Agreement, dated January 15, 2007, between Hercules and Terrell L. Carr.

Exhibit Number	Description
10.8	Expatriate Employment Agreement, dated November 1, 2006, between Hercules and Don P. Rodney incorporated by reference to Exhibit 10.2 to Hercules Current Report on Form 8-K dated October 31, 2006 (File No. 0-51582)).
10.9	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)).
10.10	Employment Agreement, dated effective as of January 1, 2005, by and between Hercules Drilling Company, LLC and Thomas E. Hord (incorporated by reference to Exhibit 10.4 to the S-1 Registration Statement).
10.11	Amendment to Employment Agreement, dated October 31, 2006, between Hercules Drilling Company, LLC and Thomas E. Hord (incorporated by reference to Exhibit 10.1 to Hercules Current Report on Form 8-K dated October 31, 2006 (File No. 0-51582)).
10.12	Amendment to Stock Option Award Agreement, dated October 31, 2006, between Hercules and Thomas E. Hord (incorporated by reference to Exhibit 10.3 to Hercules Current Report on Form 8-K dated October 31, 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	Form of Stock Option Agreement (incorporated by reference to Exhibit 10.12 to Hercules Annual Report on Form 10-K for the year ended December 31, 2006 (File No. 0-51582)).
10.15	Form of Restricted Stock Agreement for Employees and Consultants (incorporated by reference to Exhibit 10.13 to Hercules Annual Report on Form 10-K for the year ended December 31, 2006 (File No. 0-51582)).
10.16	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)).
10.17	Hercules Offshore, Inc. Deferred Compensation Plan (incorporated by reference to Exhibit 10.1 to Hercules Current Report on Form 8-K dated January 10, 2007 (File No. 0-51582)).
* 10.18	Schedule of executive officer and director compensation arrangements.
10.19	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)).
10.20	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)).
10.21	Asset Purchase Agreement, dated as of August 23, 2006, by and among Hercules International Holdings, Ltd., Halliburton West Africa Ltd. and Halliburton Energy Services Nigeria Limited (incorporated by reference to Exhibit 10.1 to Hercules Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 0-51582)).
10.22	First Amendment to Asset Purchase Agreement, dated as of November 1, 2006, by and among Hercules International Holdings, Ltd., Hercules Oilfield Services Ltd., Halliburton West Africa Ltd. and Halliburton Energy Services Nigeria Limited (incorporated by reference to Exhibit 10.2 to Hercules Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 0-51582)).
10.23	Earnout Agreement, dated November 7, 2006, by and among Hercules Oilfield Services, Ltd., Halliburton West Africa Ltd. and Halliburton Energy Services Nigeria Limited (incorporated by reference to Exhibit 10.3 to Hercules Current Report on Form 8-K dated November 7, 2006 (File

	No. 0-51582)).
*21	Subsidiaries of Hercules.

Exhibit Number	Description
*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	Certification of the Chief Executive Officer and the Chief Financial Officer of Hercules pursuant to Section 901 of the Sarbanes-Oxley Act of 2002.
99.1	Policy Regarding Director Recommendations by Stockholders (incorporated by reference to Exhibit 99.1 to Hercules Quarterly Report on Form 10-Q for the quarter ended June 30, 2007 (File No. 0-51582)).

* Filed herewith.

Compensatory plan, contract or arrangement.

Table of Contents

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, 2008.

HERCULES OFFSHORE, INC.

By: /s/ RANDALL D. STILLEY

Randall D. Stilley

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, 2008.

Signatures	Title
/s/ RANDALL D. STILLEY **Randall D. Stilley**	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 and 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 **Thomas M Hamilton**	Director
/s/ THOMAS J. MADONNA	Director

Thomas J. Madonna	
/s/ F. GARDNER PARKER	Director
F. Gardner Parker	
/s/ THIERRY PILENKO	Director
Thierry Pilenko	
/s/ STEVEN A. WEBSTER	Director
Steven A. Webster	

Table of Contents

EXHIBIT INDEX

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.
10.1	Executive Employment Agreement, dated November 3, 2006, between Hercules and Randall D. Stilley (incorporated by reference to Exhibit 10.1 to Hercules Current Report on Form 8-K dated November 3, 2006 (File No. 0-51582) (the 2006 Form 8-K)).
10.2	Employment Agreement, dated as of March 13, 2007, by and between Hercules and Lisa W. Rodriguez (incorporated by reference to Exhibit 10.1 to Hercules Current Report on Form 8-K dated March 8, 2007 (File No. 0-51582)).
10.3	Executive Employment Agreement, dated November 3, 2006, between Hercules and John T. Rynd (incorporated by reference to Exhibit 10.2 to the 2006 Form 8-K).
10.4	Executive Employment Agreement, dated November 3, 2006, between Hercules and James W. Noe (incorporated by reference to Exhibit 10.5 to the 2006 Form 8-K).
10.5	Executive Employment Agreement, dated November 3, 2006, between Hercules and Steven A. Manz (incorporated by reference to Exhibit 10.3 to the 2006 Form 8-K).
10.6	Executive Employment Agreement, dated November 3, 2006, between Hercules and Randal R. Reed (incorporated by reference to Exhibit 10.4 to the 2006 Form 8-K).

*	10.7	Executive Employment Agreement, dated January 15, 2007, between Hercules and Terrell L. Carr.
	10.8	Expatriate Employment Agreement, dated November 1, 2006, between Hercules and Don P. Rodney incorporated by reference to Exhibit 10.2 to Hercules Current Report on Form 8-K dated October 31, 2006 (File No. 0-51582)).

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10.9	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)).
10.10	Employment Agreement, dated effective as of January 1, 2005, by and between Hercules Drilling Company, LLC and Thomas E. Hord (incorporated by reference to Exhibit 10.4 to the S-1 Registration Statement).
10.11	Amendment to Employment Agreement, dated October 31, 2006, between Hercules Drilling Company, LLC and Thomas E. Hord (incorporated by reference to Exhibit 10.1 to Hercules Current Report on Form 8-K dated October 31, 2006 (File No. 0-51582)).
10.12	Amendment to Stock Option Award Agreement, dated October 31, 2006, between Hercules and Thomas E. Hord (incorporated by reference to Exhibit 10.3 to Hercules Current Report on Form 8-K dated October 31, 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).
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