HERCULES OFFSHORE, INC.
Form 10-K
February 28, 2007
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)

OF THE SECURITIES EXCHANGE ACT of 1934

For the fiscal year ended December 31, 2006

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.*)
11 Greenway Plaza, Suite 2950 Houston, Texas	**77046**
(*Address of principal executive offices*)	(*Zip Code*)

Registrant s telephone number, including area code:

(713) 979-9300

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

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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 ¨

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

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

Indicate by check mark 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. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ Accelerated filer ¨ Non-accelerated filer ¨

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

The aggregate market value of the registrant s common stock held by non-affiliates as of June 30, 2006, based on the closing price on the Nasdaq Global Select Market on such date, was approximately $720.0 million. (As of such date, the registrant s directors and executive officers, LR Hercules Holdings, LP and its affiliates and Greenhill & Co., Inc. and its affiliates were considered affiliates of the registrant for this purpose.)

As of February 23, 2007, there were 32,242,668 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 in April 2007 are incorporated by reference into Part III of this report.

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PART I

Item 1. ***Business***

In this Annual Report on Form 10-K, we refer to Hercules Offshore, Inc. and its subsidiaries as we, the Company or Hercules Offshore, unless the context clearly indicates otherwise. Hercules Offshore, Inc. is a Delaware corporation formed in July 2004, with its principal executive offices located at 11 Greenway Plaza, Suite 2950, Houston, Texas 77046. Hercules telephone number at such address is (713) 979-9300.

Overview

We provide shallow-water drilling and liftboat services to the oil and natural gas exploration and production industry in the U.S. Gulf of Mexico and internationally. We currently operate a fleet of nine jackup rigs that are capable of drilling in maximum water depths ranging from 85 to 250 feet and a fleet of 64 liftboats with leg lengths ranging from 105 to 260 feet. We provide these services to major integrated energy companies and independent oil and natural gas operators.

Our services are reported in four segments, Domestic Contract Drilling Services, International Contract Drilling Services, Domestic Marine Services and International Marine Services. Our Domestic Contract Drilling Services and Domestic Marine Services are conducted in the U.S. Gulf of Mexico, our International Contract Drilling Services are conducted offshore Qatar and India, and our International Marine Services are conducted in West Africa.

Our Fleet

Jackup Rigs

As of February 5, 2007, eight of our jackup rigs were operating under contracts ranging in duration from well-to-well to two years, at an average contract dayrate of approximately $93,757. The following table contains information regarding our jackup rig fleet as of February 5, 2007:

Rig Name	Type	Year Built	Maximum/Minimum Water Depth Rating (feet)	Rated Drilling Depth (feet) (1)	Location	Status
11	Mat-supported, cantilever	1980	200/21	20,000(2)	U.S. Gulf of Mexico	Contracted
15	Independent leg, slot	1982	85/9	20,000	U.S. Gulf of Mexico	Contracted
16	Independent leg, cantilever	1981	170/16	16,000	Middle East	Contracted
20	Mat-supported, cantilever	1980	100/20	25,000	U.S. Gulf of Mexico	Contracted
21	Mat-supported, cantilever	1980	120/22	20,000	U.S. Gulf of Mexico	Contracted
22	Mat-supported, cantilever	1971	173/22	15,000	U.S. Gulf of Mexico	Contracted
26	Independent leg, cantilever	1979	250/12	20,000	U.S. Gulf of Mexico	Shipyard
30	Mat-supported, slot	1979	250/25	20,000	U.S. Gulf of Mexico	Contracted
31	Mat-supported, slot	1979	250/25	20,000	Asia	Contracted

(1) 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.

(2) Rated workover depth. *Rig 11* 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.

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

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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.

Our rigs are used primarily for exploration and development drilling in shallow waters. Six of our jackup rigs are mat-supported. Six 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. Three 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. However, one of our slot-type rigs has a competitive advantage in very shallow water as it is one of the few jackup rigs in the world that can drill in water depths as shallow as nine feet.

Liftboats

As of February 5, 2007, we owned 47 liftboats operating in the U.S. Gulf of Mexico and 12 liftboats operating in West Africa. In addition, we operated five liftboats in West Africa. The following table contains information regarding our liftboats as of February 5, 2007:

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. Gulf of Mexico	99
Tigershark	2001	230	5,300	1,000,000	U.S. Gulf of Mexico	469
Kingfish	1996	229	5,000	500,000	U.S. Gulf of Mexico	188
Man-O-War	1996	229	5,000	500,000	U.S. Gulf of Mexico	188
Wahoo	1981	215	4,525	500,000	U.S. Gulf of Mexico	491
Blue Shark	1982	215	3,800	400,000	Cameroon	484
Amberjack	1981	205	3,800	500,000	U.S. Gulf of Mexico	417
Bullshark	1998	200	7,000	1,000,000	U.S. Gulf of Mexico	859
Creole Fish	2001	200	5,000	798,000	U.S. Gulf of Mexico	192
Cutlassfish	2006	200	5,000	798,000	U.S. Gulf of Mexico	183
Swordfish	2000	190	4,000	700,000	U.S. Gulf of Mexico	189
Mako	2003	175	5,074	654,000	U.S. Gulf of Mexico	168
Leatherjack	1998	175	3,215	575,850	U.S. Gulf of Mexico	168
Oilfish	1996	170	3,200	590,000	Nigeria	194
Manta Ray	1981	150	2,400	200,000	U.S. Gulf of Mexico	194
Seabass	1983	150	2,600	200,000	U.S. Gulf of Mexico	186
F.J. Leleux	1982	150	2,600	200,000	Nigeria	407
Black Marlin	1983	150	2,600	200,000	Nigeria	407
Hammerhead	1980	145	1,648	150,000	U.S. Gulf of Mexico	178
Pilotfish	1990	145	2,400	175,000	Nigeria	190
Rudderfish	1991	145	3,000	200,000	Nigeria	183
Blue Runner	1980	140	3,400	300,000	U.S. Gulf of Mexico	174
Starfish	1978	140	2,266	150,000	U.S. Gulf of Mexico	99
Rainbow Runner	1981	140	3,400	300,000	U.S. Gulf of Mexico	174
Pompano	1981	130	1,864	100,000	U.S. Gulf of Mexico	196
Sandshark	1982	130	1,940	150,000	U.S. Gulf of Mexico	196
Stingray	1979	130	2,266	150,000	U.S. Gulf of Mexico	99

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Liftboat Name(1)	Year Built	Leg Length (feet)	Deck Area (square feet)	Maximum Deck Load (pounds)	Location	Gross Tonnage
Albacore	1985	130	1,764	150,000	U.S. Gulf of Mexico	171
Moray	1980	130	1,824	130,000	U.S. Gulf of Mexico	178
Skipfish	1985	130	1,116	110,000	U.S. Gulf of Mexico	91
Sailfish	1982	130	1,764	137,500	U.S. Gulf of Mexico	179
Mahi Mahi	1980	130	1,710	142,000	U.S. Gulf of Mexico	99
Triggerfish	2001	130	2,400	150,000	U.S. Gulf of Mexico	195
Scamp	1984	130	2,400	150,000	Nigeria	195
Rockfish	1981	125	1,728	150,000	U.S. Gulf of Mexico	192
Gar	1978	120	2,100	150,000	U.S. Gulf of Mexico	98
Grouper	1979	120	2,100	150,000	U.S. Gulf of Mexico	97
Sea Robin	1984	120	1,507	110,000	U.S. Gulf of Mexico	98
Tilapia	1976	120	1,280	110,000	U.S. Gulf of Mexico	97
Charlie Cobb	1980	120	2,000	100,000	Nigeria	210
Durwood Speed	1980	120	2,000	100,000	Nigeria	210
James Choat	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	1982	120	2,000	100,000	Nigeria	213
Barracuda	1979	105	1,648	110,000	U.S. Gulf of Mexico	93
Carp	1978	105	1,648	110,000	U.S. Gulf of Mexico	98
Cobia	1978	105	1,648	110,000	U.S. Gulf of Mexico	94
Dolphin	1980	105	1,648	110,000	U.S. Gulf of Mexico	97
Herring	1979	105	1,648	110,000	U.S. Gulf of Mexico	97
Marlin	1979	105	1,648	110,000	U.S. Gulf of Mexico	97
Corina	1974	105	953	100,000	U.S. Gulf of Mexico	98
Pike	1980	105	1,360	130,000	U.S. Gulf of Mexico	92
Remora	1976	105	1,179	100,000	U.S. Gulf of Mexico	94
Wolffish	1977	105	1,044	100,000	U.S. Gulf of Mexico	99
Seabream	1980	105	1,140	100,000	U.S. Gulf of Mexico	92
Sea Trout	1978	105	1,500	100,000	U.S. Gulf of Mexico	97
Tarpon	1979	105	1,648	110,000	U.S. Gulf of Mexico	97
Palometa	1972	105	780	100,000	U.S. Gulf of Mexico	99
Jackfish	1978	105	1,648	110,000	U.S Gulf of Mexico	99
Bonefish	1977	105	1,344	90,000	Nigeria	97
Croaker	1977	105	1,344	72,000	Nigeria	82
Gemfish	1978	105	2,000	100,000	Ghana	223
Tapertail	1980	105	1,392	100,000	Nigeria	100

(1) The *Pike* is currently stacked. We have commenced the reactivation of this liftboat and expect it to be available by the first quarter of 2007. All other liftboats are either available or operating.

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.

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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 3,800 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.

Competition

The shallow-water business is highly competitive. Drilling and liftboat contracts are traditionally short term in nature and are 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 and independent oil and natural gas operators. Chevron Corporation accounted for 35% of our consolidated revenues for the year ended December 31, 2006. Chevron and Bois d Arc Energy accounted for 31% and 12%, respectively, of our consolidated revenues for the year ended December 31, 2005 and 31% and 15%, respectively, of our consolidated revenues for the period from inception (July 27, 2004) to December 31, 2004, which we refer to as the period from inception to December 31, 2004 . 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. We obtain most of our contracts through competitive bidding against other contractors. 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.

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. 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 one year. Our contracts in international locations have been longer-term, with contract terms of up to two years.

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. Some of our liftboat contracts in West Africa have initial contract terms of one year, whereas others are 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.

In certain countries, we also may be required to post bonds or letters of credit in order to temporarily import equipment, including our drilling rigs and liftboats, into the country. These temporary importation bonds would secure the amount of the import duty that is payable if the equipment fails to leave the country within the time frame permitted by the local jurisdiction for the temporary importation of equipment. When the equipment is exported out of the local jurisdiction, the bond or letter of credit generally would be returned to us. Currently, we have arranged for a bank in Nigeria to issue a letter of credit valued at approximately $430,000, at December 31, 2006, with respect to our liftboats in that country, and we have executed a counter-indemnity agreement with the Nigerian bank for any liability incurred by the bank under that letter of credit.

Employees

As of December 31, 2006, we had approximately 920 employees. We require skilled personnel to operate and provide technical services and support for our rigs and liftboats. As a result, we conduct extensive personnel recruiting, training and safety programs. As of December 31, 2006, certain of our employees in West Africa 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.

Insurance

We maintain insurance coverage that includes coverage for physical damage, third-party liability, maritime employers liability, general liability, vessel pollution and other coverages. 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 $580.0 million; however, coverage for U.S. Gulf of Mexico named windstorm damage is subject to an annual aggregate limit on liability of $75.0 million. The policies are subject to deductibles and other conditions. Deductibles for events that are not U.S. Gulf of Mexico named windstorm events are $1.5 million per occurrence for drilling rigs, and range from $250,000 to $1.0 million per occurrence for liftboats, depending on the insured value of the particular vessel. The deductibles for drilling rigs in a U.S. Gulf of Mexico named windstorm event are $1.5 million per rig for each occurrence plus an additional $5.0 million for each U.S. Gulf of Mexico named windstorm. The protection and indemnity coverage under the primary marine package has a $5.0 million limit per occurrence with excess liability coverage up to $100.0 million. The primary marine package also provides coverage for cargo and charterer s legal liability. Vessel pollution is covered under a Water Quality Insurance Syndicate policy. In addition to the marine package, we have separate policies providing coverage for general domestic liability, employer s liability, domestic auto liability and non-owned aircraft liability, with customary deductibles and coverage. Insurance premiums and fees for coverage of our operations, assets and personnel base (as the same existed at June 30, 2006) are expected to be approximately $23.9 million for the twelve-month policy period ending July 1, 2007, an increase of approximately 151% over the previous policy period on an annualized basis. We are self-insured for the deductible portion of our insurance coverage.

We believe that our insurance coverage is customary for the industry and adequate for our business. However, there are risks that such insurance will not adequately protect us against or will not be available to cover all the liability from all of the consequences and hazards we may encounter in our operations.

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. We are also subject to the jurisdiction of the U.S. Coast Guard, the National Transportation Safety Board, the U.S. Customs and Border Protection Service, 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, 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 specified substances 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. Violations of monitoring, reporting and permitting requirements can result in the imposition of civil and criminal penalties. A September 2006 United States district court ruling is expected to result in certain of our vessels being required to obtain Clean Water Act permits for the discharge of ballast water. Under current Clean Water Act regulations, our vessels are exempt from such permitting requirements; however, in *Northwest Environmental Advocates v. EPA*, the federal district court in California ruled that it will vacate the exemption on September 30, 2008. Prior to this date, EPA will need to take action to regulate ballast water discharges. As a result, owners and operators of vessels will be required to comply with the regulations ultimately promulgated by EPA or face penalties. In addition to this federal development, some states have begun regulating ballast water discharges. We expect to incur certain costs to obtain Clean Water Act permits for certain of our vessels when the federal permitting exemption goes away or if states that have jurisdiction over our operations regulate ballast water discharges. 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 Coast Guard and Maritime Transportation Act of 2004 (the CGMTA) amended OPA to require the owner or operator of any non-tank vessel of 400 gross tons or more that carries oil of any kind as a fuel for main propulsion to prepare and submit a response plan that covers each applicable vessel by August 8, 2005. For vessels that have International Tonnage Certificates, gross tonnage is based on the certificate, which may vary from the standard U.S. gross tonnage for the vessel reflected in our liftboat table above. The vessel response plan must include detailed information on actions to be taken by vessel personnel to prevent or mitigate any discharge or substantial threat of discharge. We submitted the required plans to the Coast Guard prior to the August 2005 deadline.

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. In October 2003, the U.S. Coast Guard finalized regulations required to implement 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.

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.

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, which became effective internationally on May 19, 2005, 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 would, however, become 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.

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Available Information

We file annual, quarterly and special reports, proxy statements and other information with the Securities and Exchange Commission. These filings, and any amendments to these filings, are available free of charge through our internet website at *www.herculesoffshore.com* as soon as reasonably practicable after we electronically file that material with, or furnish it 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 12 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. 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, 2007, the closing price of natural gas at the Henry Hub was $8.92 per MMBtu. Oil prices increased through 2005 and the first several months of 2006, with the spot price for West Texas intermediate crude increasing from $61.04 per bbl as of January 1, 2006, to a recent peak of $77.03 on July 14, 2006 before declining to $57.99 as of February 15, 2007. 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;
- economic and weather conditions in the United States and elsewhere;
- 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;

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.

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Depending on the market prices of oil and natural gas, companies exploring for oil and natural gas may cancel or curtail their drilling programs, thereby reducing demand for drilling services. 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.

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. Dayrates also depend on the supply of rigs and vessels. Generally, excess capacity puts downward pressure on dayrates. Excess capacity can occur when newly constructed rigs and vessels enter service, when rigs and vessels are mobilized between geographic areas and when non-marketed rigs and vessels are re-activated. Many other companies in the drilling industry are larger than we are and have more diverse fleets, or fleets with generally higher specifications, and greater resources than we have. In addition, the competitive environment has intensified as recent mergers among oil and natural gas companies have reduced the number of available customers. 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

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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). 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 equipment involved and injury or death to rig or liftboat personnel. 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.

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, when we renewed our coverages in July 2006, 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

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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.

We are subject to additional political, economic, and other uncertainties as our international operations have expanded.

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. We currently own or operate 17 liftboats operating offshore West Africa, including Nigeria, Ghana and Cameroon, one drilling rig operating offshore Qatar and another operating offshore India, and we are marketing *Rig 26* to work in international markets following completion of the refurbishment and upgrade project on that rig. 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 or nationalization of assets;
- damage to our equipment or violence directed at our employees;
- increased operating costs;
- complications associated with repairing and replacing equipment in remote locations;
- 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;
- restrictions on currency 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 the liftboats owned and operated by Halliburton in West Africa (described under Management s Discussion and Analysis of Financial Condition and Results of Operations Recent Developments in Item 7 of this annual report), 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 35% and 31% of our consolidated revenues for the years ended December 31, 2006 and 2005, respectively, and 31% of our consolidated revenues for the period from inception to December 31, 2004. Three independent energy companies represented, in the aggregate, an additional 20% of our consolidated revenues for the year ended December 31, 2006. 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.

Re-activation 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, and the 2005 hurricanes have resulted in the reactivation of a number of shallow-water rigs that have been cold-stacked for the past several years. 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 9, 2007, 66 jackup rigs had been ordered by industry participants, national oil companies and financial investors for delivery through 2009. As of February 9, 2007, we believe there were also 12 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.

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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 recently completed upgrades to *Rig 16* and *Rig 31*, and we are currently upgrading and refurbishing *Rig 26*. We expect to spend a total of approximately $19.9 million in 2007 to refurbish and upgrade our rigs and liftboats.

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

We have experienced delays and costs overruns in the refurbishment of *Rig 26* due to certain of the factors listed above. Further delays could put at risk our planned arrangements to transport the rig to an international location on schedule, and could also jeopardize our ability to commence operations on schedule. We may decide to move the rig and complete the refurbishments in the area where we anticipate operating the rig, whether or not we have then obtained a commitment from an operator to reimburse us for the expense incurred in moving the rig to that area.

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.

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. 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 addition, higher specification rigs may be more adaptable to different operating conditions and therefore have greater flexibility to move to areas of demand in response to changes in market conditions. Because a majority of our rigs were designed specifically for drilling in the shallow-water U.S. Gulf of Mexico, our ability to move them to other regions in response to changes in market conditions is limited. Furthermore, in recent years, an increasing amount of exploration and production expenditures have been concentrated in deepwater drilling programs and deeper formations, including deep natural gas prospects, requiring higher specification jackup rigs, semisubmersible drilling rigs or drillships. This trend is expected to continue and could result in a decline in demand for lower specification jackup rigs like ours, which could have an adverse impact on our financial condition and results of operations.

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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. 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 2005 and in 2006 and we expect this trend to continue but at a slower pace in 2007.

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

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

Our operations are affected in varying degrees by governmental laws and regulations. The industries in which we operate are dependent on demand for services from the oil and natural gas industry and, accordingly, are also affected by changing tax and other laws relating to the energy business generally. We are also subject to the jurisdiction of the United States Coast Guard, the National Transportation Safety Board and the United States Customs and Border Protection Service, as well as private industry organizations such as the American Bureau of Shipping. We may be required to make significant capital expenditures to comply with laws and the applicable regulations and standards of those authorities and organizations. Moreover, the cost of compliance could be higher than anticipated. Similarly, our international operations are subject to 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.

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, 2006, we have total outstanding debt of approximately $93.3 million. This debt represents approximately 19.1% of our total capitalization. We have up to $75 million of available capacity under our revolving credit facility, under which we may continue to borrow to fund working capital or other needs in the near term. 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 additional indebtedness;

- create liens;

- restrict dividend or other payments by our subsidiaries to us;

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

- engage in transactions with affiliates; and

- make capital expenditures.

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. These covenants may adversely affect our ability to finance our future operations and capital needs and to pursue available business opportunities. A breach of any of these covenants could result in a default in respect of the related debt. If a default were to occur, the relevant lenders could elect to declare the debt, together with accrued interest and other fees, immediately due and payable and proceed against any collateral securing that debt.

Because we have a limited operating history and we have not provided three full years of audited financial statements, 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.

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In addition, this annual report includes audited financial statements only as of and for the years ended December 31, 2006 and 2005 and for the period from inception to December 31, 2004. We have acquired our fleet of jackup rigs and liftboats in a number of separate asset acquisitions since our formation in July 2004. We have not completed or provided in this annual report any stand-alone pre-acquisition financial statements for the assets we acquired in these transactions. As a result, and given our recent date of formation, we have not provided three full years of audited financial statements that normally would be provided in an annual report on Form 10-K.

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

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

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

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

None.

Item 2. ***Properties***

Our property consists primarily of mobile offshore drilling rigs and liftboats and ancillary equipment, substantially all of which we own. Most of our rigs and liftboats are pledged to collateralize our senior secured credit agreement. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Liquidity and Financing Arrangements Debt in Item 7 of this annual report.

We maintain our principal executive offices in Houston, Texas, which is under lease. We also lease office space in Lafayette, Louisiana and two warehouses in Broussard, Louisiana. We lease warehouses, office space and residential premises in Qatar, India, Nigeria and Cayman Islands.

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

Item 3. ***Legal Proceedings***

We and our subsidiaries are routinely involved in litigation, claims and disputes arising in the ordinary course of our business. We do not believe that ultimate liability, if any, resulting from any such pending litigation will have a material adverse effect on our financial condition or results of operations.

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 2006.

Executive Officers

We have presented below information about our executive officers as of February 15, 2007. Officers are appointed annually by the Board of Directors and serve until their successors are chosen or until their resignation or removal.

Name	Age	Position
Randall D. Stilley	53	Chief Executive Officer and President
Steven A. Manz	41	Chief Financial Officer
John T. Rynd	49	Senior Vice President of Hercules Offshore and President, Hercules Drilling Company, LLC
Randal R. Reed	50	President, Hercules Liftboat Company, LLC
James W. Noe	34	Vice President, General Counsel, Chief Compliance Officer and Secretary
Don P. Rodney	59	President, Hercules International Holdings Ltd.
James C. Bryan	59	Vice President, Human Resources

Randall D. Stilley has served as Chief Executive Officer and President since October 2004. Prior to joining Hercules, Mr. Stilley was Chief Executive Officer of Seitel, Inc., an oilfield services company, from January 2004 to October 2004. From 2000 until he joined Seitel, Mr. Stilley was an independent business consultant and managed private investments. From 1997 until 2000, Mr. Stilley was President of the Oilfield Services Division at Weatherford International, Inc., an oilfield services company. Prior to joining Weatherford in 1997, Mr. Stilley served in a variety of positions at Halliburton Company, an oilfield services company. Mr. Stilley is a member of the Energy Steering Committee at the Houston Technology Center. He is a registered professional engineer in the state of Texas and a member of the Society of Petroleum Engineers.

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Steven A. Manz has served as Chief Financial Officer since January 2005. Prior to joining Hercules, Mr. Manz worked at Noble Corporation, a contract drilling company, from May 1995 to January 2005 in a number of roles, including Managing Director of the Noble Technology Services Division from May 2003 to January 2005, Vice President of Strategic Planning from August 2000 to May 2003, Director of Accounting and Investor Relations from March 1997 to August 2000 and Internal Audit Manager from May 1995 to March 1997. Prior to joining Noble, Mr. Manz served as senior auditor of Cooper Industries, an electrical products manufacturer, from May 1993 to May 1995 and as a member of the Audit Group of Price Waterhouse LLP from August 1989 to May 1993.

John T. Rynd became Senior Vice President of Hercules Offshore and President of Hercules Drilling Company, LLC in October 2005. Prior to joining Hercules, Mr. Rynd worked at Noble Drilling Services Inc., a wholly owned subsidiary of Noble Corporation, a contract drilling company, as Vice President Investor Relations from October 2000 to September 2005 and as Vice President Marketing and Contracts from September 1994 to September 2000. From June 1990 to September 1994, Mr. Rynd worked for Chiles Offshore Corporation, a contract drilling company, including as Vice President Marketing.

Randal R. Reed has served as President of our subsidiary, Hercules Liftboat Company, LLC, since October 2004. From 1995 to October 2004, Mr. Reed was manager of the fleet of liftboats, diveboats and crewboats of Global Industries, Ltd., an oilfield services company.

James W. Noe has served as Vice President, General Counsel, Chief Compliance Officer and Secretary since October 2005. From July 2002 to October 2005, Mr. Noe was Corporate Counsel for BJ Services Company, a worldwide oilfield services company. He was also in private practice from October 1997 to July 2002. On several occasions during 2000 and 2001 while still in private practice, Mr. Noe served as counsel for Single Buoy Moorings, a company that designs, owns and operates floating production systems.

Don P. Rodney has served as President of Hercules International Holdings Ltd. since December 2005. From July 2004 to December 2005, Mr. Rodney served as Vice President, Finance of Hercules Drilling Company, LLC. From October 2003 to June 2004, Mr. Rodney was Chief Financial Officer of Unrelated HOC. Mr. Rodney was retired from July 2003 to October 2003. From November 2002 to July 2003, he was Treasurer of TODCO, a contract drilling company. Mr. Rodney was Controller, Inland Water Division of Transocean from February 2001 until October 2002. From November 1992 until January 2001, Mr. Rodney served as Vice President, Finance for R&B Falcon Drilling USA, Inc., a marine contract drilling company, and its predecessors. From 1976 to November 1992, Mr. Rodney worked for Atlantic Pacific Marine Corp., a marine contract drilling company, in a number of positions, including as Controller from 1983 until November 1992.

James C. Bryan has served as Vice President, Human Resources since January 2007. Prior to joining Hercules, Mr. Bryan performed charity work from April 2006 to December 2006 and served as Director Human Resources, Project GRAD Houston, a non-profit organization focused on increasing high school graduation rate, from October 2004 to March 2006. From 1998 through October 2004 Mr. Bryan attended seminary and served in several pastorial roles. Mr. Bryan was Vice President Administration and Human Resources for Enron Oil and Gas Co. and Houston Natural Gas from December 1984 to December 1997.

Additionally, we have retained Lisa W. Rodriguez to perform the duties of our chief financial officer on an interim basis, as Mr. Manz suffered a stroke in December 2006 and is currently recuperating at home. Ms. Rodriguez was Senior Vice President and Chief Financial Officer of Weatherford International Ltd. from June 2002 to October 2006. Ms. Rodriguez joined Weatherford in 1996 and served in several positions, including Vice President Accounting and Finance from February 2001 to June 2002, Vice President Accounting from June 2000 to February 2001 and Controller from 1999 to February 2001.

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PART II

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

Quarterly Common Stock Prices and Dividend Policy

Our common stock is traded on the NASDAQ Global Select Market under the symbol HERO. As of February 21, 2007, there were 39 stockholders of record. On February 23, 2007, the closing price of our common stock as reported by NASDAQ was $27.00 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**
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
2005		
Fourth Quarter (1)	$ 29.26	$ 20.60

(1) Reflects trading activity from October 27, 2005 through December 31, 2005.

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

Issuer Purchases of Equity Securities

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

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of a Publicly Announced Plan (2)	Maximum Number of Shares That May Yet Be Purchased Under the Plan (2)
October 1 31, 2006			N/A	N/A
November 1 30, 2006	6,242	$ 35.36	N/A	N/A
December 1 31, 2006			N/A	N/A
Total	6,242	$ 35.36	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 2006 or 2005, and currently do not have, a share repurchase program in place.

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

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

We were formed in July 2004 and commenced operations in August 2004. From our formation to December 31, 2006, we completed several significant asset acquisitions that impact the comparability of our historical financial results. Our financial results reflect the impact of the assets only after the date of their acquisition. This annual report does not include any financial information relating to the assets for periods prior to their acquisition date. We have concluded that we are not required to include such pre-acquisition financial statements in this annual report, and we believe that separate audited financial statements for the assets we acquired as of any date or for any period prior to our acquisition of those assets would not be meaningful to investors.

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 unitholder 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.

	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:			
Operating revenues	$ 344,312	$ 161,334	$ 31,728
Operating income	158,057	55,859	9,907
Net income	119,050	27,456	8,065
Earnings per share:			
Basic	$ 3.80	$ 1.10	$ 0.55
Diluted	3.70	1.08	0.55
Balance Sheet Data (as of end of period):			
Cash and cash equivalents	$ 72,772	$ 47,575	$ 14,460
Working capital	110,897	70,083	30,283
Total assets	605,581	354,825	132,156
Long-term debt, net of current portion	91,850	93,250	53,000
Total stockholders equity	394,851	215,943	71,087
Cash dividends per share			
Other Financial Data:			
Net cash provided by (used in):			
Operating activities	$ 124,247	$ 52,763	$ (6,495)
Investing activities	(149,989)	(172,953)	(96,274)
Financing activities	50,939	153,305	117,229
Capital expenditures	204,456	168,038	94,443
Deferred drydocking expenditures	12,544	7,369	601

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the accompanying consolidated financial statements as of and for the years ended December 31, 2006 and 2005 and for the period from inception (July 27, 2004) to December 31, 2004 (period from inception to December 31, 2004) 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 liftboat 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 and independent oil and natural gas operators. We report our business activities in four business segments, Domestic Contract Drilling Services, International Contract Drilling Services, Domestic Marine Services and International Marine Services. Prior to the fourth quarter of 2005, during which we first acquired liftboats operating internationally, we did not report an International Marine Services segment. Prior to the second quarter of 2006, during which we commenced work with *Rig 16* under our first international drilling contract, we did not report an International Contract Drilling Services segment.

Contract Drilling Services. We own a fleet of nine jackup rigs that can drill in maximum water depths ranging from 85 to 250 feet. Our Domestic Contract Drilling Services segment includes six jackup rigs operating in the U.S. Gulf of Mexico, and our International Contract Drilling Services segment includes one jackup rig working offshore Qatar, one jackup rig working offshore India and one jackup rig currently undergoing refurbishment and upgrade. Under most of our contract drilling service agreements, 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.

Marine Services. We own a fleet of 59 liftboats in our Domestic and International Marine Services segments, and we operate an additional five liftboats in our International Marine Services segment. Our Domestic Marine Services segment includes 47 liftboats operating in the U.S. Gulf of Mexico, and our International Marine Services segment includes 17 liftboats operating offshore West Africa, including five liftboats owned by a third party. Our liftboats are used to provide a wide range of offshore support services, including platform maintenance, platform construction, well intervention and decommissioning services, and can be moved from location to location within a short period of time. 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 other liftboat contracts in West Africa are short-term.

Our operating costs are primarily a function of fleet configuration and utilization levels. The most significant direct operating costs for our Contract Drilling Services segments are wages paid to crews, maintenance and repairs to the rigs, and marine 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 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. Rigs that have been cold-stacked typically require a lengthy reactivation project that can involve significant expenditures, particularly if the rig has been cold-stacked for a long period of time.

The most significant costs for our Marine Services segments are the wages paid to crews and the amortization of regulatory drydocking costs. Unlike our Contract Drilling Services 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 time of drydock vary depending on the condition of the vessel. All costs associated with regulatory inspections, including related drydocking costs, are deferred and amortized over a period of 12 to 24 months.

Recent Developments

Tigershark

In November 2006, one of our 230-foot class liftboats, *Tigershark*, was damaged during a storm off the coast of Louisiana. The crew was safely evacuated and the vessel was recovered and taken to a shipyard for inspection and repairs. The legs and pads of the vessel, which were previously reported missing, have been located adjacent to the platform where the vessel was working when it experienced damage. We expect to salvage the legs and pads in the first quarter of 2007. The vessel is currently in a shipyard in Louisiana undergoing repairs, which are expected to be completed in the third quarter of 2007. We carry customary liability and property insurance on the vessel, and we have notified the appropriate insurers of the incident and damage. We have accrued $1.2 million to cover the $1.0 million deductible and certain salvage costs that may not be covered by insurance. We believe that any other significant liability or damage is covered by our insurance policies.

West African Liftboat Purchase

In November 2006, we purchased from Halliburton West Africa Limited and Halliburton Energy Services Nigeria Limited (collectively Halliburton) eight liftboats owned and operated by Halliburton and were 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 our obligations under the earnout agreement, we granted Halliburton a lien in the amount of $3.0 million on one of the liftboats acquired. We operate 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, including accrued contingent consideration, was allocated to the liftboats based on their estimated fair values.

The liftboats are currently operating in the coastal waters of Nigeria, Cameroon and Ghana and have leg lengths ranging from 105 to 215 feet.

Liftboat Acquisition from Laborde

In June 2006, we acquired five liftboats from Laborde Marine Lifts, Inc. (Laborde). In addition, we assumed the construction of an additional liftboat pursuant to a construction agreement assigned to us 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 at closing under the construction contract for the sixth liftboat. Construction of the liftboat was completed in July 2006 and the additional amount due to the shipyard was paid. The liftboats have leg lengths ranging from 105 to 200 feet and are located in the U.S. Gulf of Mexico.

Public Offering of Common Stock

We completed a public offering of 9,200,000 shares of our common stock at $36.00 per share in April 2006. We issued 1,600,000 shares of common stock, while the remaining 7,600,000 shares were sold by certain selling stockholders. We received approximately $54.2 million of proceeds from the offering, net of underwriter discounts and commissions and estimated expenses. We used the net proceeds we received for general corporate purposes. In November 2006, certain selling stockholders sold 7,625,000 shares of common stock in a public offering at $33.00 per share. We did not receive any proceeds from the sale of common stock by the selling stockholders.

Insurance Renewal

In June 2006, we completed the renewal of all of our key insurance policies, except for the directors and officers liability policy, which was renewed on November 1, 2006. For additional information about our insurance program, see Business-Insurance in Item 1 of this annual report.

Overall, our insurance premiums and fees for coverage for our operations, assets and personnel base increased from approximately $9.5 million on an annualized basis in 2005 to $23.9 million under the renewed coverages, excluding acquisitions. Higher premium costs reflect the damage sustained by the oil and natural gas industry from Hurricanes Ivan, Katrina and Rita. In addition, our premiums were also affected by the large increase in the insured values of *Rig 16*, *Rig 26* and *Rig 31*, which we acquired since our last insurance renewal and have substantially upgraded, as well as the liftboats acquired in 2006.

We have obtained financing from the insurance underwriters for 75% of the premium over nine months at an interest rate of 5.75% per annum. We will incur total interest cost of approximately $435,000 under this arrangement. We reduced our total premium by $476,000, and thus offsetting the interest cost, by paying the premium for the rig package immediately.

Rig Sale Agreement

In June 2006, we entered into a definitive agreement to sell *Rig 41* for $3.2 million, net of commissions. The buyer paid a $0.3 million non-refundable deposit, and the sale closed in July 2006. We recognized a gain of approximately $1.1 million in the third quarter of 2006 on the sale.

Facility Sale Agreement

In September 2006, we sold our New Iberia facility for $2.8 million, net of commissions. We recognized a gain of approximately $0.1 million in the third quarter of 2006 on the sale.

Amendment to Credit Agreement

In June 2006, we amended our credit agreement. Among other things, the amendment increased the commitments under the revolving credit facility from $25.0 million to $75.0 million, reduced the interest rate under the revolving credit facility by 1.0% per annum, and extended the maturity date of the revolving credit facility from June 29, 2008 to June 29, 2010. It also removed the limitations on investments by us in our subsidiaries that are not guarantors to the credit agreement. The previous limit of $25.0 million on such investments was replaced by a collateral maintenance test that requires us to maintain a ratio of (1) the orderly liquidation value of all of the vessels mortgaged pursuant to the credit agreement to (2) the sum of the revolving commitments and outstanding term loans under the credit agreement, of not less than 1.25 to 1.00. In addition, the dollar limits on other investments (including acquisitions) by us were eliminated, provided we are in compliance with our covenants under the credit agreement after giving effect to the investment and, with respect to an investment greater than $25.0 million, our leverage ratio is not greater than 3.50 to 1.00 prior to and after giving effect to such investment. The existing annual limit of $25.0 million on capital expenditures and the interest coverage ratio were replaced by a fixed charge coverage ratio, which requires us to maintain a ratio of (1) EBITDA less maintenance capital expenditures and cash taxes paid to (2) fixed charges, of not less than 1.25 to 1.00. Furthermore, a $2.0 million limitation on insurance deductibles was removed and replaced with a requirement that we maintain insurance that is customary for the industry. Finally, a $2.5 million annual limit on asset sales was increased to an aggregate basket of $95.0 million for the term of the credit agreement, provided the net proceeds from such asset sales are used to repay amounts outstanding under the term loan. We paid $0.4 million in fees related to the amendment. In February 2007 we further amended our credit agreement to increase the limitation on operating lease commitments to $10.0 million from $1.0 million.

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Results of Operations

The following table sets forth our operating days, average utilization rates, average revenue and expenses per day, revenues and operating expenses by operating segment and other selected information for the periods indicated. Market conditions were generally stronger for both jackup rigs and liftboats during 2006 compared to 2005, as evidenced by our higher dayrates. Our jackup rigs were contracted at dayrates ranging from approximately $53,000 to $140,000 in 2006, as compared to dayrates ranging from approximately $31,000 to $70,000 in 2005. Our liftboats were contracted at dayrates ranging from approximately $5,070 to $32,000 in 2006, as compared to dayrates ranging from approximately $2,200 to $20,500 in 2005. 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 slightly due to a decline in drilling activity. Liftboat dayrates increased throughout 2006, both in the United States and West Africa. These dayrates do not include reimbursement from customers under the related contracts.

	For the Year Ended December 31, 2006	For the Year Ended December 31, 2005	Period from Inception to December 31, 2004
	(Dollars in thousands, except per day amounts)		
Domestic Contract Drilling Services Segment:			
Number of rigs (as of end of period)	6	9	5
Operating days	1,973	2,192	748
Available days	2,078	2,309	751
Utilization (1)	94.9%	94.9%	99.6%
Average revenue per rig per day (2)	$ 81,480	$ 47,177	$ 32,098
Average operating expense per rig per day (3)	$ 24,957	$ 20,932	$ 17,046
Revenues	$ 160,761	$ 103,422	$ 24,006
Operating expenses, excluding depreciation and amortization	$ 51,862	$ 48,330	$ 12,799
Depreciation and amortization expense	$ 8,882	$ 5,547	$ 1,070
General and administrative expenses, excluding depreciation and amortization	$ 6,980	$ 5,486	$ 1,972
Operating income	$ 93,037	$ 44,059	$ 8,165
International Contract Drilling Services Segment:			
Number of rigs (as of end of period)	3		
Operating days	305		
Available days	321		
Utilization (1)	95.0%		
Average revenue per rig per day (2)	$ 99,868	$	$
Average operating expense per rig per day (3)	$ 41,673	$	$
Revenues	$ 30,460	$	$
Operating expenses, excluding depreciation and amortization	$ 13,377	$	$
Depreciation and amortization expense	$ 2,547	$	$
General and administrative expenses, excluding depreciation and amortization	$ 1,606	$	$
Operating income	$ 12,930	$	$
Domestic Marine Services Segment:			
Number of liftboats (as of end of period)	47	42	22
Operating days	11,895	8,571	1,350
Available days	15,416	10,971	1,958
Utilization (1)	77.2%	78.1%	68.9%
Average revenue per liftboat per day (2)	$ 11,259	$ 6,503	$ 5,720
Average operating expense per liftboat per day (3)	$ 3,180	$ 2,590	$ 2,144

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	For the Year Ended December 31, 2006	For the Year Ended December 31, 2005	Period from Inception to December 31, 2004
	(Dollars in thousands, except per day amounts)		
Revenues	$ 133,929	$ 55,740	$ 7,722
Operating expenses, excluding depreciation and amortization	$ 49,025	$ 28,413	$ 4,198
Depreciation and amortization expense	$ 18,854	$ 8,031	$ 946
General and administrative expenses, excluding depreciation and amortization	$ 2,259	$ 1,888	$ 581
Operating income	$ 63,791	$ 17,408	$ 1,997
International Marine Services Segment:			
Number of liftboats (as of end of period)	17	4	
Operating days	1,765	212	
Available days	2,009	212	
Utilization (1)	87.9%	100.0%	
Average revenue per liftboat per day (2)	$ 10,857	$ 10,243	$
Average operating expense per liftboat per day (3)	$ 4,915	$ 5,052	$
Revenues	$ 19,162	$ 2,172	$
Operating expenses, excluding depreciation and amortization	$ 9,874	$ 1,071	$
Depreciation and amortization expense	$ 1,923	$ 176	$
General and administrative expenses, excluding depreciation and amortization	$ 3,056	$ 336	$
Operating income	$ 4,309	$ 589	$
Total Company:			
Revenues	$ 344,312	$ 161,334	$ 31,728
Operating expenses, excluding depreciation and amortization	$ 124,138	$ 77,814	$ 16,997
Depreciation and amortization expense	$ 32,310	$ 13,790	$ 2,016
General and administrative expenses, excluding depreciation and amortization	$ 29,807	$ 13,871	$ 2,808
Operating income	$ 158,057	$ 55,859	$ 9,907
Interest expense	$ 9,278	$ 9,880	$ 2,070
Loss on early retirement of debt	$	$ 4,078	$
Gain on disposal of asset	$ 30,690	$	$
Other income	$ 4,038	$ 924	$ 228
Income before income taxes	$ 183,507	$ 42,825	$ 8,065
Income tax provision	$ 64,457	$ 15,369	$
Net income	$ 119,050	$ 27,456	$ 8,065

(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, which included *Rig 16, Rig 21, Rig 26* and *Rig 31*, or cold-stacked units, which included three of our liftboats, 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 revenue is a total of $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, 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 operating expense is a total of $1.6 million related to amortization of deferred mobilization expenses for the year ended December 31, 2006.

Our domestic 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, such as Hurricane Rita in September 2005, Hurricane Katrina in August 2005 and Hurricane Ivan in September 2004, may also affect 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. Accordingly, our operating results may vary from quarter to quarter, depending on factors outside of our control.

We have not provided below a comparison of our International Contract Drilling Services segment because that segment was established subsequent to December 31, 2005.

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 Contract Drilling and Domestic Marine Services segments, additional operating days in our Domestic and International Marine Services segments, due primarily to the acquisition of liftboats since June 2005, and the commencement of operations in our International Contract Drilling Services 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 Contract Drilling Services Segment. Revenues for our Domestic Contract Drilling Services 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 has been 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 *Rig 21* 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 Contract Drilling Services segment included $1.1 million in reimbursements from our customers for expenses paid by us in 2006 compared with $2.3 million in 2005.

Domestic Marine Services Segment. Revenues for our Domestic Marine Services 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 Marine Services 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 Marine Services Segment. Revenues for our International Marine Services 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 Marine Services 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 Marine Services segment in 2005.

Operating Expenses

Consolidated. Total operating expenses, excluding depreciation and amortization, 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 Contract Drilling Services Segment. Operating expenses, excluding depreciation and amortization, for our Domestic Contract Drilling Services 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 *Rig 21* 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. *Rig 21* 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.

Domestic Marine Services Segment. Operating expenses, excluding depreciation and amortization, for our Domestic Marine Services 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 Marine Services Segment. Operating expenses, excluding depreciation and amortization, for our International Marine Services 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 an additional $3.3 million in depreciation expense for our Domestic Contract Drilling Services segment, $4.1 million for our Domestic Marine Services segment and $1.8 million for our International Marine Services segment. This increase in depreciation expense for these segments is related primarily to acquisition activity during 2005 and 2006. Depreciation expense for our International Contract Drilling Services 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, excluding depreciation and amortization, in 2006 were $29.8 million compared with $13.9 million in 2005, an increase of $15.9 million, or 114%. This increase is due primarily to higher general and administrative expenses for our corporate offices in addition to increases in general and administrative expenses in our operating segments. 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 increased $1.5 million, $0.4 million and $2.7 million in our Domestic Contract Drilling Services, Domestic Marine Services and International Marine Services segments, respectively. General and administrative expense for our International Contract Drilling Services segment in 2006 was $1.6 million, which represents expenses associated with our operations in Qatar and India that commenced operation in 2006.

Interest Expense

Interest expense in 2006 was $9.3 million compared with $9.9 million in 2005, a decrease of $0.6 million, or 6%. This decrease resulted from a decrease in the average interest rate on our overall borrowings and lower average debt balances. The average interest rate decreased to 7.67% in 2006 from 8.35% in 2005.

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.

Other Income

Other income in 2006 was $4.0 million compared with $0.9 million in 2005, an increase of $3.1 million. This increase is due to higher cash balances resulting in increased interest income and realized gains related to our interest rate hedging activity.

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.

International Contract Drilling Services Segment

Our International Contract Drilling Services segment comprises one jackup rig working offshore Qatar, one jackup rig working offshore India and a third jackup rig currently undergoing upgrade and refurbishment. Revenues for our International Contract Drilling Services 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 Contract Drilling Services segment include reimbursements from our customers of $0.2 million for expenses paid by us. Operating expenses, excluding depreciation and amortization, for our International Contract Drilling Services 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.

Year Ended December 31, 2005 Compared with the Period from Inception to December 31, 2004

We have presented below a comparison of certain daily operating and financial information and utilization for the year ended December 31, 2005 and the period from inception to December 31, 2004, (the 2004 Period), because we believe it provides the most meaningful comparative analysis of our results of operations for those periods and provides meaningful trend information over those periods. We have not provided a comparison of the full period revenues and operating expenses. We do not believe such a comparison would be meaningful since our results of operations for the 2004 Period include only the results from five rigs and 22 liftboats for all or a portion of a five-month period as compared with the results from nine rigs and 46 liftboats for all or a portion of a full year period in 2005.

Average Revenue per Day

Domestic Contract Drilling Services Segment. Average revenue per rig per day for our Domestic Contract Drilling Services segment increased to $47,177 for 2005 compared with $32,098 for the 2004 Period, an increase of 47%. The increase resulted from higher dayrates on our rigs and the January 2005 acquisition of *Rig 30*, which earned dayrates during 2005 higher than the average for the rest of our fleet.

Domestic Marine Services Segment. Average revenue per liftboat per day for our Domestic Marine Services segment increased to $6,503 for 2005 compared with $5,720 for the 2004 Period, an increase of 14%. This increase resulted from higher dayrates for our liftboats, partially offset by the impact of Hurricanes Katrina and Rita, where we experienced 374 days of weather, cumulative for our liftboat fleet, resulting in half dayrates.

Average Operating Expense per Day

Domestic Contract Drilling Services Segment. Average operating expense per rig per day for our Domestic Contract Drilling Services segment increased to $20,932 for 2005 compared with $17,046 for the 2004 Period, an increase of 23%. The increase resulted primarily from an increase in labor expenses, which increased $1,686 per day, an increase in insurance costs, which increased $819 per day, and an increase in rig maintenance costs, which increased $558 per day. The insurance cost was impacted by the $1.0 million loss for the accrual of the deductible for insurance proceeds to repair *Rig 21*. The increase in operating expense per rig per day is due in part to the inclusion of operating expenses for *Rig 21* while the rig was undergoing repairs for damage sustained during Hurricane Katrina. During that time, the rig was not considered available and therefore no available days for the rig were included in the calculation of average operating expense per rig per day.

Domestic Marine Services Segment. Average operating expense per liftboat per day for our Domestic Marine Services segment increased to $2,590 for 2005 compared with $2,144 for the 2004 Period, an increase of 21%. This increase resulted primarily from an increase in labor expenses, which increased $279 per day, an increase in insurance costs, which increased $45 per day, and an increase in liftboat maintenance costs, which increased $100 per day.

Utilization and Operating Days

Domestic Contract Drilling Services Segment. Utilization for our Domestic Contract Drilling Services segment was 94.9% for 2005 compared with 99.6% for the 2004 Period. Operating days for 2005 totaled 2,192 compared with 748 for the 2004 Period. The 2005 period reflects our ownership of nine jackup rigs, following the acquisitions of *Rig 25* and *Rig 30* in January 2005, *Rig 16* in June 2005 and *Rig 31* in September 2005. *Rig 16* and *Rig 31* were undergoing refurbishment during 2005. The 2004 Period reflects our ownership of only five jackup rigs.

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Domestic Marine Services Segment. Utilization for our Domestic Marine Services segment was 78.1% for 2005 compared with 68.9% for the 2004 Period. Operating days for 2005 totaled 8,571 compared with 1,350 for the 2004 Period. The 2005 period reflects our ownership of 42 liftboats in the segment following the acquisition of 17 liftboats in June 2005, the *Whale Shark* in August 2005 and three liftboats in November 2005 and the sale of one liftboat in August 2005. The 2004 Period reflects our ownership of 22 liftboats for approximately three months in 2004.

Other Information

General and Administrative Expenses

General and administrative expenses, excluding depreciation and amortization, were $13.9 million for 2005, compared with $2.8 million for the 2004 Period. Our Domestic Contract Drilling Services and Domestic Marine Services segments incurred additional general and administrative expenses of $3.5 million and $1.3 million, respectively. General and administrative expenses for our International Marine Services segment were $0.3 million in 2005. General and administrative expenses for our corporate office were $6.2 million in 2005 compared with $0.3 million in the 2004 Period. Included in our corporate general and administrative expenses for 2005 are $2.2 million of expenses related to our initial public offering.

Interest Expense

Interest expense was $9.9 million for 2005, compared with $2.1 million for the 2004 Period. The 2005 expense reflects higher average debt balances.

Other Income

Other income was $0.9 million for 2005, compared with $0.2 million for the 2004 Period. Results for 2005 included $0.6 million of interest income associated with short-term investments of cash.

Period from Inception to December 31, 2004

Revenues

Consolidated. Total revenues were $31.7 million for the 2004 Period. Revenues for the period include activity for the five jackup rigs acquired in August 2004 and for the 22 liftboats acquired in October 2004. Total revenues included $0.9 million in reimbursements from our customers for expenses paid by us.

Domestic Contract Drilling Services Segment. Revenues for our Domestic Contract Drilling Services segment were $24.0 million for the 2004 Period. Segment revenues included activity for the five jackup rigs beginning in August 2004. Average revenue per rig per day was $32,098, operating days were 748 and average utilization was 99.6%. Revenues for our Domestic Contract Drilling Services segment included $0.6 million in reimbursements from our customers for expenses paid by us.

Domestic Marine Services Segment. Revenues for our Domestic Marine Services segment were $7.7 million for the 2004 Period. Segment revenues included activity for the 22 liftboats beginning on October 2, 2004. Average revenue per liftboat per day was $5,720, operating days were 1,350 and average utilization was 68.9%. Revenues for our Domestic Marine Services segment included $0.3 million in reimbursements from our customers for expenses paid by us.

Operating Expenses

Consolidated. Total operating expenses, excluding depreciation and amortization, were $17.0 million for the 2004 Period. Total operating expenses included expenses for five jackup rigs beginning in August 2004 and for 22 liftboats beginning in October 2004.

Domestic Contract Drilling Services Segment. Operating expenses, excluding depreciation and amortization, for our Domestic Contract Drilling Services segment were $12.8 million for the 2004 Period. Average operating expenses per rig were $17,046 per day. Average labor costs per rig, which include wages and benefits paid to crews, were $9,631 per day. Rig maintenance expenses per rig, excluding capitalized costs, were $2,508 per day. Other rig expenses, which included catering, rentals, communications, insurance and mobilization costs, averaged $4,907 per rig per day.

Domestic Marine Services Segment. Operating expenses, excluding depreciation and amortization, for our Domestic Marine Services segment were $4.2 million for the 2004 Period. Segment expenses included three months of activity from the inception of the segment on October 2, 2004 with the acquisition of 22 liftboats. Our most significant operating expenses were labor ($2.2 million), vessel maintenance, excluding capital expenditures and drydocking costs ($0.5 million), and insurance ($0.4 million). Operating expenses on our liftboats averaged $2,144 per liftboat per day in the period, ranging from $1,158 per day for the smaller vessels to $3,014 per day for the larger vessels.

General and Administrative Expenses

General and administrative expenses, excluding depreciation and amortization, were $2.8 million for the 2004 Period.

Interest Expense

Interest expense was $2.1 million for the 2004 Period, which represented interest due on a $28.0 million term loan used to fund the acquisition of five jackup rigs in August 2004 and an additional $28.0 million term loan used to fund the acquisition of 22 liftboats in October 2004.

Rig and Liftboat Information

We did not own any jackup rigs at the beginning of the 2004 Period. We acquired five jackup rigs and assumed the management of another jackup rig from an unrelated party in August 2004. During the 2004 Period, those jackup rigs were contracted at dayrates ranging from approximately $23,000 to $37,000.

We did not own any liftboats at the beginning of the 2004 Period. We acquired 22 liftboats in October 2004. During the 2004 Period, those liftboats were contracted at dayrates ranging from approximately $3,300 to $13,700.

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 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.

Property and Equipment

Property and equipment represents 68.7% of our total assets as of December 31, 2006. 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 non-current assets on the Consolidated Balance Sheet and amortized on the straight-line method over a period of 12 to 24 months (see -Deferred Charges below). Depreciation is computed using the straight-line method, after allowing for salvage value where applicable, over the useful life of the asset, which is typically 15 years for our rigs and liftboats. We review our property and equipment for potential impairment when events or changes in circumstances indicate that the carrying value of any asset may not be recoverable. For property and equipment, the determination of recoverability is made based on the estimated undiscounted future net cash flows of the assets being reviewed. Any actual impairment charge would be recorded using the estimated discounted value of future cash flows. Our estimates, assumptions and judgments used in the application of our property and equipment accounting policies reflect both historical experience and expectations regarding future industry conditions and operations. Using different estimates, assumptions and judgments, especially those involving the useful lives of our rigs and liftboats and expectations regarding future industry conditions and operations, would result in different carrying values of assets and results of operations. For example, a prolonged downturn in the drilling industry in which utilization and dayrates were significantly reduced could result in an impairment of the carrying value of our 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 Statement of Financial Accounting Standards (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 six 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 our international rigs are owned or operated, directly or indirectly, by our wholly owned Cayman Islands subsidiaries. Earnings from these subsidiaries are reinvested internationally and remittance to the United States is indefinitely postponed. Consequently, no U.S. tax expense or benefits were recognized on these earnings or losses in 2006.

Allowance for Doubtful Accounts

Accounts receivable represents approximately 14.7% of our total assets and 49.5% of our current assets as of December 31, 2006. 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, 2006, there was no 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 to 24 months. As of December 31, 2006, our net deferred charges related to regulatory inspection costs totaled $5.8 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, 2006 will be $3.8 million over the remaining vesting period of 22 months; 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

Contract Drilling Services

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. Spot natural gas prices are extremely volatile and ranged from a high of $9.87 per mmbtu to a low of $3.63 per mmbtu during 2006. As of February 15, 2007, the spot price for Henry Hub natural gas was $8.92 per mmbtu and the twelve month strip, or the average of the next twelve month s futures contract was $8.09 per mmbtu. Oil prices increased through 2005 and the first several months of

2006, with the spot price for West Texas intermediate crude increasing from $61.04 per bbl as of January 1, 2006, to a recent peak of $77.03 per bbl on July 14, 2006 before declining to $57.99 per bbl as of February 15, 2007. Both natural gas and oil prices are higher than historical levels and are generally supportive of increased capital spending for exploration and production activities.

Global demand for jackup rigs has increased significantly over the last several years. International markets such as the Middle East, India and Mexico have been particularly strong and have drawn available rigs from other regions such as 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 90 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 Gulf of Mexico is currently approximately 75. We anticipate that there will be additional need for jackups in several international locations, which could further reduce the supply of rigs in the U.S. Gulf of Mexico.

The reduced supply of available rigs in the region, together with historically high commodity prices, generally resulted in strong dayrates for our domestic drilling units in 2006. However, a combination of factors since mid-2006, including record high natural gas storage during late 2006 and extreme volatility in gas prices, have caused demand to decline in the U.S. Gulf of Mexico and as a result, market dayrates have declined from their recent highs. 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 potential reduced drilling demand.

According to ODS-Petrodata, as of February 1, 2007, 66 jackup rigs have been ordered by industry participants, national oil companies and financial investors for delivery through 2009. We do not anticipate that these rigs will compete directly with our fleet, but may indirectly impact us through competition in other markets. Our ability to expand our international drilling fleet may be limited, however, by the increased supply of newbuild rigs. In addition, nine idle jackups in the U.S. Gulf of Mexico owned by our competitors have been cold stacked for all of 2006, and in some cases, several years earlier. We believe that these idle jackup rigs will require extensive capital expenditures to refurbish and bring back into service, but our competitors may opt to reactivate these rigs.

As a result of the extensive damage caused by Hurricanes Rita and Katrina, insurance underwriters sustained significant losses on claims and in 2006 significantly increased the cost of premiums for assets operating in the U.S. Gulf of Mexico and significantly reduced the amount of coverage offered for named windstorm damage. Most companies with insurance policies covering assets in the U.S. Gulf of Mexico have an aggregate limit for what they can recover for assets damaged during named windstorms, which typically is much lower than the total insured value of those assets, as is the case with our insurance coverages. As long as these limits exist, we do not anticipate that newly constructed jackups will be moved to the Gulf of Mexico during hurricane season, which runs from June to November.

The offshore drilling market remains highly competitive and cyclical, and it has been historically 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.

Marine Services

Because of the significant damage to production platforms, pipelines and other equipment in the U.S. Gulf of Mexico caused by Hurricanes Katrina and Rita, demand for our domestic liftboats for inspection and repair work has been very strong over the last two years, with steadily increasing dayrates for most of this period. While some of our liftboats are continuing to perform hurricane repair work, it appears that the mix of well intervention and construction and maintenance work is returning to more normal levels during 2007. As a result, we believe our utilization will follow more typical seasonal patterns during 2007 with lower utilization during the winter months.

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 continued 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 15, 2007, we believe that there were 12 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 2007 and 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, 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. 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. Generally, we believe demand for liftboats in international locations will be driven by the maintenance of this aging offshore infrastructure in certain areas and by the installation of new infrastructure in other areas, which will be influenced by oil and natural gas prices and our customers capital spending plans. We have actively marketed 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 and liftboats and to support our business. Competition for skilled personnel continues to intensify as new rigs and liftboats enter the market. We have also experienced a tightening in the labor market for rig personnel due to the increasing number of new offshore and onshore rigs in the U.S. markets. In response to these conditions, we have instituted retention programs, including increases in base compensation and bonuses tied to retention and utilization goals. We expect these programs, along with additional programs that may become necessary to retain skilled personnel, to continue for the foreseeable future. If this trend continues, our labor costs will likewise continue to increase, although we do not believe at this time that our operations will be limited.

Many of the shipyards in the U.S. have experienced similar labor issues, including those that we use for the refurbishment and maintenance of our drillings rigs or that support the maintenance of our liftboat fleet. We have, in some instances, experienced delays in shipyard projects on our drilling rigs or lower utilization for our liftboats as some shipyards have experienced a limit on their production due to labor shortages.

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Liquidity and Capital Resources

Historical Cash Flows

Sources and uses of cash for the years ended December 31, 2006 and 2005 are as follows:

	Year Ended December 31, 2006	Year Ended December 31, 2005
	(in millions)	
Net cash provided by operating activities		
Net income	$ 119.1	$ 27.5
Depreciation and amortization	32.3	13.8
Increase in accounts payable and other current liabilities	27.6	18.2
Increase in insurance note payable	3.7	1.7
Deferred income tax provision	27.2	15.2
Stock-based compensation	3.1	0.1
Excess tax benefit from stock-based payment arrangements	(1.3)	
Loss on early retirement of debt		4.1
Gain on disposal of assets	(30.7)	
Gain on sale of assets	(0.1)	
Increase in accounts receivable, insurance claims receivable and other current assets	(56.7)	(27.8)
Total	$ 124.2	$ 52.8
Net cash used in investing activities		
Acquisition of *Rig 25* and *Rig 30*	$	$ (41.5)
Acquisition of 17 liftboats		(19.8)
Acquisition of *Rig 16*		(20.0)
Acquisition of the *Whale Shark*		(12.5)
Acquisition of *Rig 31*		(12.6)
Acquisition of seven liftboats		(44.0)
Acquisition of *Rig 26*	(20.1)	
Acquisition of six liftboats	(52.0)	
Acquisition of eight liftboats	(52.9)	
Refurbishment and upgrade of *Rig 16*	(10.3)	(5.7)
Refurbishment and upgrade of *Rig 31*	(22.9)	(2.9)
Refurbishment and upgrade of *Rig 26*	(27.3)	
Other rig refurbishments	(16.5)	(4.3)
Refurbishments of liftboats	(2.8)	
Deferred drydocking expenditures for liftboats	(12.5)	(7.4)
Insurance proceeds	61.3	
Proceeds from sale of assets	6.0	
Increase in restricted cash	(0.3)	
Other	0.3	(2.3)
Total	$ (150.0)	$ (173.0)
Net cash provided by financing activities		
Proceeds from borrowings	$	$ 185.0
Repayment of debt	(1.4)	(146.4)
Proceeds from issuance of common stock	54.2	116.3
Excess tax benefit from stock-based payment arrangements	1.3	
Proceeds from exercise of stock options	1.2	
(Distributions to) contributions from members	(3.7)	4.3

Payment of debt issuance costs	(0.6)	(5.9)
Total	$ 51.0	$ 153.3

Cash from operations, proceeds from our public offering of common stock in April 2006, insurance proceeds received for the loss of *Rig 25,* proceeds from the sale of *Rig 41* and our New Iberia facility and cash on hand represented our primary source of liquidity for 2006. For the same period, our primary uses of cash were acquisitions of $125.0 million, capital expenditures on our remaining fleet of $79.8 million and deferred drydocking expenditures of $12.5 million. Proceeds from our initial public offering, borrowings from our creditors and our cash flow from operations represented our primary sources of liquidity for 2005. For the same period, our primary uses of cash were the acquisitions of rigs and liftboats for our fleet.

Sources of Liquidity and Financing Arrangements

We believe that our current cash on hand and our cash flow from operations through December 31, 2007, together with availability under our revolving credit facility, will be adequate during such period to repay our debts as they become due, to make normal recurring capital additions and improvements, to meet working capital requirements, to complete the refurbishment and upgrade of *Rig 26* and otherwise to operate our business. Additional capital in either the form of debt or equity may be required in 2007 if we generate less than expected cash due to a deterioration of market conditions or other factors beyond our control, or if an acquisition necessitates additional liquidity. 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 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.

Debt

Our current debt structure is used to fund our business operations, and our revolving credit facility is a source of liquidity. As of December 31, 2006, we had outstanding long-term debt of $93.3 million, including current maturities of $1.4 million.

In June 2005, we entered into a senior secured credit agreement with a syndicate of financial institutions. This agreement, as amended, provides for a $140.0 million term loan and a $75.0 million revolving credit facility. We may seek commitments to increase the amount available under the credit agreement by an additional $25.0 million if our leverage ratio, after giving effect to the incurrence of the additional $25.0 million of borrowings, is no greater than 2.5 to 1.

The revolving credit facility provides for swing line loans of up to $5.0 million and for the issuance of up to $5.0 million of letters of credit. The revolving loans bear interest at a rate equal to, at our option, either (1) the highest of (a) Comerica Bank s base rate, (b) the three-month certificate of deposit rate plus 0.5% and (c) the Federal funds effective rate plus 0.5%, in each case plus 1.25%, or (2) LIBOR plus 2.25%. We may prepay the revolving loans at any time without premium or penalty. The revolving loans mature in June 2010. We are required to pay a commitment fee of 0.375% on the average daily amount of the unused commitment amount of the revolving credit facility and a letter of credit fee of 2.25%, plus a fronting fee of 0.125%, with respect to the undrawn amount of each issued letter of credit. As of December 31, 2006, no amounts were outstanding and no letters of credit had been issued under the revolving credit facility.

The term loan bears interest at a rate equal to, at our option, either (1) the highest of (a) Comerica Bank s base rate, (b) the three-month certificate of deposit rate plus 0.5% and (c) the Federal funds effective rate plus 0.5%, in each case plus 2.25%, or (2) LIBOR plus 3.25%. As of December 31, 2006, $93.3 million of the principal amount of the term loan was outstanding, and the interest rate was 8.63%. In accordance with the credit agreement, in July 2005, we entered into hedge transactions with the purpose and effect of fixing the interest rate on $70.0 million of the outstanding principal amount of the term loan at 7.54% for three years. In addition, we entered into hedge transactions with the purpose and effect of capping the interest rate on an additional $20.0 million of such principal amount at 8.25% for three years. Principal payments of $350,000 are due quarterly, and the outstanding principal balance of the term loan is payable in full in June 2010. We may prepay the term loan at any time without premium or penalty.

We are required to prepay the term loan with:

- the proceeds from sales of certain assets;
- the proceeds from casualties or condemnations of assets to the extent that the net cash proceeds from any such casualty or condemnation exceed $1.0 million and are not reinvested within one year;
- the net proceeds of certain debt for borrowed money;
- 25% of the net proceeds of any public or private offering of our equity securities, provided that holders of the term loan may reject the mandatory prepayment; and
- 50% of excess cash flow if either our leverage ratio is above 3.0 to 1.0 or the outstanding principal balance of the term loan is greater than $110.0 million.

Our obligations under the credit agreement are secured by our liftboats, all of our domestic rigs and substantially all of our other personal property, including all the equity of our domestic subsidiaries and 65% of the equity of certain of our foreign subsidiaries. All of our domestic material subsidiaries guarantee our obligations under the agreement and have granted similar liens on substantially all of their assets. Our foreign subsidiaries are not guarantors, and the assets owned by our foreign subsidiaries are not held as collateral for the loans.

The credit agreement contains financial covenants relating to leverage, fixed charge coverage and collateral coverage. Other covenants contained in the agreement restrict, among other things, repurchases of equity interests, mergers, asset dispositions, guaranties, debt, liens, acquisitions, dividends, distributions, investments, affiliate transactions, prepayments of other debt and capital expenditures. The credit agreement permits us to make advances to and investments in our foreign subsidiaries provided we meet applicable financial covenants. We are currently in compliance in all material respects with our covenants under the credit agreement. The credit agreement contains customary events of default.

As of December 31, 2006, we had a letter of credit supported by a restricted cash deposit of $250,000 issued outside of the revolving credit facility.

Capital Expenditures

We expect to spend approximately $19.9 million in 2007 on the refurbishment and upgrade of our rigs and liftboats. Refurbishment entails replacing or rebuilding the operating equipment, and is often costly. Costs associated with refurbishment activities which substantially extend the useful life of the asset are capitalized.

We differentiate a refurbishment from an upgrade, in which we materially increase 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. As part of our acquisitions of *Rig 16*, *Rig 31* and *Rig 26*, we had to undertake both a major refurbishment project and upgrade of each rig to make them competitive with rigs that are already in operation.

We expect to spend approximately $19.6 million in 2007 to complete the upgrade of *Rig 26*. In addition, 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 table below sets forth information with respect to certain of our capital expenditure projects for 2005 and 2006, estimated amounts for 2007 and total estimated amounts for the project.

	2005 Expenditures	2006 Expenditures	Estimated 2007 Expenditures (in millions)	Total Expenditures or Estimated Expenditures	Completion or Expected Completion
Rig 16 refurbishment and upgrade	$ 5.7	$ 10.3	$	$ 16.0	Second Quarter 2006
Rig 31 refurbishment and upgrade	2.9	22.9		25.8	Third Quarter 2006
Rig 26 refurbishment and upgrade		27.3	19.6	46.9	Second Quarter 2007
Other refurbishments and upgrades	0.3	7.8	0.3	8.4	Various
Commissioning of *Whale Shark*	0.5			0.5	First Quarter 2006
Drydockings of liftboats	7.4	12.5	19.6	Ongoing	Ongoing

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. 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 senior secured credit facility.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2006:

	Payments due by year				
Contractual Obligations	**2007**	**2008 to 2009**	**2010 to 2011 (in thousands)**	**Thereafter**	**Total**
Long-term debt obligations	$ 1,400	$ 2,800	$ 89,050	$	$ 93,250
Management compensation obligations	2,430	2,433	92		4,955
Purchase commitments	3,773				3,773
Operating lease obligations	729	641	319		1,689
Total contractual obligations	$ 8,332	$ 5,874	$ 89,461	$	$ 103,667

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements.

Accounting Pronouncements

In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109* (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with SFAS No. 109, *Accounting for Income Taxes.* FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

FIN 48 also requires expanded disclosure with respect to the uncertainty in income tax assets and liabilities. FIN 48 is effective for fiscal years beginning after December 15, 2006, and we will adopt it in the first quarter of 2007. The effect of adoption of FIN 48 is required to be recognized as a change in accounting principle through a cumulative-effect adjustment to retained earnings as of the beginning of the year of adoption. We continue to evaluate the effects of FIN 48 on our Consolidated Balance Sheet and Statement of Operations.

In September 2006, the Securities and Exchange Commission staff issued Staff Accounting Bulletin No. 108, Considering the Effects of Prior Year Misstatements in Current Year Financial Statements (SAB 108). SAB 108 was issued to provide consistency with respect to the manner in which companies quantify financial statement misstatements. SAB 108 establishes an approach that requires companies to quantify misstatements in financial statements based on effects of the misstatement on both the Consolidated Balance Sheet and Statement of Operations and the related financial statement disclosures. Additionally, companies are required to evaluate the cumulative effect of errors existing in prior years that previously had been considered immaterial. Adoption of SAB 108 is encouraged for interim periods of the first fiscal year beginning after November 15, 2006 and we have applied SAB 108 in connection with the preparation of our annual financial statements for the year ended December 31, 2006. Adoption of SAB 108 had no impact on our Consolidated Balance Sheet, Statement of Operations or Statement of Cash Flow.

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 in 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 Consolidated Balance Sheet or Statement of Operations.

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FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical fact, included in this annual report that address 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;
- amounts expected to be paid by insurance proceeds for the salvage and repair of the *Tigershark*;
- 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;

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- the availability of skilled personnel;
- labor relations and work stoppages, particularly in the Nigerian labor environment;
- 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 exposed to interest rate risk with respect to our variable rate debt. All of the debt under our term loan is at variable rates. As of December 31, 2006, the interest rate for the $93.3 million outstanding under the term loan was 8.63%. In accordance with the credit agreement, in July 2005, we entered into hedge transactions with the purpose and effect of fixing the interest rate on $70.0 million of the outstanding principal amount of the term loan at 7.54% for three years. In addition, we entered into hedge transactions with the purpose and effect of capping the interest rate on an additional $20.0 million of such principal amount at 8.25% for three years. We entered into these instruments other than for trading purposes. A hypothetical 100 basis point increase in the average interest rate on our variable rate debt outstanding as of December 31, 2006 would increase our annual interest expense by approximately $0.9 million.

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors

Hercules Offshore, Inc.

We have audited the accompanying consolidated balance sheets of Hercules Offshore, Inc. and subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of operations, cash flows, stockholders equity and comprehensive income for the years ended December 31, 2006 and 2005 and for the period from July 27, 2004 (inception) to December 31, 2004. 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 2005, and the results of their operations and their cash flows for the years ended December 31, 2006 and 2005 and the period from July 27, 2004 (inception) to December 31, 2004, 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.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Hercules Offshore, Inc. and subsidiaries internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated February 23, 2007, expressed an unqualified opinion on management s assessment of the effectiveness of internal control over financial reporting and an unqualified opinion on the effectiveness of internal control over financial reporting.

/s/ GRANT THORNTON LLP
Houston, Texas

February 23, 2007

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors

Hercules Offshore, Inc.

We have audited management s assessment, included in the accompanying Management s Report on Internal Control over Financial Reporting, appearing under Item 9A, that Hercules Offshore, Inc. and subsidiaries maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Hercules Offshore, Inc. s and subsidiaries management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of 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, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

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

In our opinion, management s assessment that Hercules Offshore, Inc. and subsidiaries maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also in our opinion, Hercules Offshore, Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Hercules Offshore, Inc. and subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of operations, cash flows, stockholders equity and comprehensive income for the years ended December 31, 2006 and 2005 and for the period from July 27, 2004 (inception) to December 31, 2004 and our report dated February 23, 2007 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP
Houston, Texas
February 23, 2007

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(In thousands, except par value)

	December 31, 2006	December 31, 2005
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 72,772	$ 47,575
Restricted cash	250	
Accounts receivable	89,136	38,484
Assets held for sale		2,040
Insurance claims receivable		5,919
Prepaid expenses and other	18,065	6,193
Total current assets	180,223	100,211
PROPERTY AND EQUIPMENT, net	415,864	247,443
OTHER ASSETS, net	9,494	7,171
Total assets	$ 605,581	$ 354,825
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES		
Current portion of long-term debt	$ 1,400	$ 1,400
Insurance note payable	6,058	2,401
Accounts payable	29,123	13,281
Accrued liabilities	16,262	11,165
Taxes payable	8,745	122
Interest payable	2,105	1,759
Other current liabilities	5,633	
Total current liabilities	69,326	30,128
LONG-TERM DEBT, net of current portion	91,850	93,250
OTHER LIABILITIES	6,700	
DEFERRED INCOME TAXES	42,854	15,504
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS EQUITY		
Common stock, par value $0.01 per share; 200,000 shares authorized; 32,008 and 30,243 shares issued; 32,002 and 30,243 outstanding	320	302
Additional paid-in capital	243,157	184,698
Treasury stock, at cost, 6 shares	(220)	
Restricted stock (unearned compensation)		(1,322)
Accumulated other comprehensive income	755	476
Retained earnings	150,839	31,789
Total stockholders equity	394,851	215,943
Total liabilities and stockholders equity	$ 605,581	$ 354,825

The accompanying notes are an integral part of these statements.

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except share data)

	Year Ended December 31, 2006	Year Ended December 31, 2005	Period from inception (July 27, 2004) to December 31, 2004
REVENUES			
Contract drilling services	$ 191,221	$ 103,422	$ 24,006
Marine services	153,091	57,912	7,722
	344,312	161,334	31,728
COSTS AND EXPENSES			
Operating expenses for contract drilling services, excluding depreciation and amortization	65,239	48,330	12,799
Operating expenses for marine services, excluding depreciation and amortization	58,899	29,484	4,198
Depreciation and amortization	32,310	13,790	2,016
General and administrative, excluding depreciation and amortization	29,807	13,871	2,808
	186,255	105,475	21,821
OPERATING INCOME	158,057	55,859	9,907
OTHER INCOME (EXPENSE)			
Interest expense	(9,278)	(9,880)	(2,070)
Gain on disposal of assets	30,690		
Loss on early retirement of debt		(4,078)	
Other, net	4,038	924	228
INCOME BEFORE INCOME TAXES	183,507	42,825	8,065
INCOME TAX PROVISION			
Current income tax	(37,257)	(122)	
Deferred income tax	(27,200)	(15,247)	
NET INCOME	$ 119,050	$ 27,456	$ 8,065
EARNINGS PER SHARE (SEE NOTE 3)			
Basic	$ 3.80	$ 1.10	$ 0.55
Diluted	$ 3.70	$ 1.08	$ 0.55
WEIGHTED AVERAGE SHARES OUTSTANDING			
Basic	31,327,420	24,919,273	14,689,724
Diluted	32,203,446	25,431,822	14,689,724

The accompanying notes are an integral part of these statements.

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Year Ended December 31, 2006	Year Ended December 31, 2005	Period from inception (July 27, 2004) to December 31, 2004
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 119,050	$ 27,456	$ 8,065
Adjustments to reconcile net income to net cash provided by (used in) operating activities			
Depreciation and amortization	32,310	13,790	2,016
Stock-based compensation expense	3,098	78	
Deferred income taxes	27,200	15,247	
Amortization of deferred financing fees	686	890	215
(Recovery of) provision for bad debts		(519)	519
Loss on early retirement of debt		4,078	
Gain on disposal of assets	(30,690)		
Gain on sale of assets	(89)		
Excess tax benefit from stock-based arrangements	(1,271)		
(Increase) decrease in operating assets			
(Increase) in accounts receivable	(50,653)	(12,545)	(20,020)
(Increase) decrease in insurance claims receivable	5,919	(5,919)	
(Increase) in prepaid expenses and other	(12,611)	(9,720)	(2,359)
Increase in operating liabilities			
Increase in accounts payable	15,842	11,443	1,838
Increase in insurance note payable	3,657	1,718	
Increase in other current liabilities	11,499	6,766	2,548
Increase in other liabilities	300		683
Net cash provided by (used in) operating activities	124,247	52,763	(6,495)
CASH FLOWS FROM INVESTING ACTIVITIES			
Purchase of property and equipment	(204,456)	(168,038)	(94,443)
Deferred drydocking expenditures	(12,544)	(7,369)	(601)
Insurance proceeds	61,278		
Proceeds from disposal of assets, net of commissions	5,989	455	803
Increase in restricted cash	(250)		
Decrease (increase) in deposits	(6)	1,999	(2,033)
Net cash used in investing activities	(149,989)	(172,953)	(96,274)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from borrowings		185,000	56,000
Payment of debt	(1,400)	(146,350)	
Proceeds from issuance of common stock, net	54,198	116,249	
Proceeds from exercise of stock options	1,232		
Excess tax benefit from stock-based arrangements	1,271		
Payment of debt issuance costs	(630)	(5,923)	(1,793)
(Distributions to) contributions from members	(3,732)	4,329	63,022

Net cash provided by financing activities		50,939		153,305		117,229
NET INCREASE IN CASH AND CASH EQUIVALENTS		25,197		33,115		14,460
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD		47,575		14,460		
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$	72,772	$	47,575	$	14,460

The accompanying notes are an integral part of these statements.

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

(In thousands)

	December 31, 2006		December 31, 2005		December 31, 2004	
	Shares	Amount	Shares	Amount	Units	Amount
MEMBER INTERESTS						
Balance at beginning of period		$	64	$ 63,022		$
Contributions from members			4	4,329	64	63,022
Effect of conversion			(68)	(67,351)		
Balance at end of period					64	63,022
COMMON STOCK						
Balance at beginning of period	30,243	302				
Effect of conversion			23,923	239		
Exercise of stock options	129	2				
Issuance of common stock	1,600	16	6,250	62		
Issuance of restricted stock	36		70	1		
Balance at end of period	32,008	320	30,243	302		
ADDITIONAL PAID-IN CAPITAL						
Balance at beginning of period		184,698				
Effect of conversion				67,112		
Exercise of stock options		1,230				
Issuance of common stock, net		54,182		116,187		
Issuance of restricted stock				1,399		
Reclass of restricted stock		(1,322)				
Compensation expense recognized		3,098				
Excess of tax benefit from stock-based arrangements		1,271				
Balance at end of period		243,157		184,698		
TREASURY STOCK						
Balance at beginning of period						
Repurchase of common stock	(6)	(220)				
Balance at end of period	(6)	(220)				
RESTRICTED STOCK						
Balance at beginning 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						
Balance at beginning of period		476				
Change in unrealized gain on hedge transaction, net of tax		279		476		

Balance at end of period		755		476		
RETAINED EARNINGS						
Balance at beginning of period		31,789		8,065		
Net income		119,050		27,456		8,065
Distribution to former members				(3,732)		
Balance at end of period		150,839		31,789		8,065
TOTAL STOCKHOLDERS EQUITY	32,002	$ 394,851	30,243	$ 215,943	64	$ 71,087

The accompanying notes are an integral part of these statements.

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(In thousands)

	Year Ended December 31, 2006	Year Ended December 31, 2005	Period from inception (July 27, 2004) to December 31, 2004
NET INCOME	$ 119,050	$ 27,456	$ 8,065
OTHER COMPREHENSIVE INCOME			
Unrealized gains on hedge transactions (net of tax expense of $150 and $257)	279	476	
COMPREHENSIVE INCOME	$ 119,329	$ 27,932	$ 8,065

The accompanying notes are an integral part of these statements.

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 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 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 for periods prior to the Conversion and to Hercules Offshore, Inc. for periods after the Conversion.

The Company provides shallow-water drilling and liftboat services to the oil and gas exploration and production industry in the U.S. Gulf of Mexico and international markets through its Domestic Contract Drilling Services, International Contract Drilling Services, Domestic Marine Services and International Marine Services segments. The Company owns nine jackup drilling rigs and 59 liftboat vessels and operates an additional five liftboat vessels owned by third parties.

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.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand, demand deposits with banks and all highly liquid investments with original maturities of three months or less. Cash in bank accounts outside of the United States was $425,643 as of December 31, 2006.

Revenue Recognition

Revenues generated from our Contract Drilling Services and Marine Services contracts are recognized as services are performed. For certain Contract Drilling Services 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. The Company deferred $5,680,000 of revenue and $3,286,963 of expenses related to the mobilization of rigs under long term contracts for the year ended December 31, 2006. The Company recognized $2,590,000 of revenue and $1,600,272 of expense related to mobilization in the year ended December 31, 2006. At December 31, 2006, the Company had $3,090,000 of deferred mobilization revenue and $1,686,692 of deferred mobilization expense recorded on its Consolidated Balance Sheets. The Company did not defer mobilization revenue or expense during 2005 or the period from inception (July 27, 2004) to December 31, 2004 (period from inception to December 31, 2004).

For certain Contract Drilling Services 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 drilling contract. The Company capitalizes such capital improvements and depreciates them over the useful life of the asset. The Company deferred $251,277 of revenue and recognized $50,255 of revenue related to such fees in the year ended December 31, 2006, and at December 31, 2006 had $201,022 recorded on its Consolidated Balance Sheets. The Company did not defer revenue related to fees received from customers for capital improvements to rigs during 2005 or the period from inception to December 31, 2004.

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 $7,478,781 and $4,627,525 for the years ended December 31, 2006 and 2005, respectively, and $892,700 for the period from inception to December 31, 2004, respectively.

Supplemental Cash Flow Information

	Year Ended December 31, 2006	Year Ended December 31, 2005 (in thousands)	Period from inception to December 31, 2004
Cash paid during the period for:			
Interest	$ 8,246	$ 7,688	$ 1,484
Income taxes	$ 27,363	$	$
Non-cash financing activity:			
Distribution to original members	$	$ 3,732	$

Other non-cash activity includes a $7,300,000 accrual for contingent consideration related to the November 2006 liftboat acquisition.

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 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 (tax deduction that is in excess of the compensation costs related tax benefit) be reported prospectively as cash flows from financing activities. The Company classified $1,271,269 in excess tax benefits as a financing cash inflow for the year ended December 31, 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 1,000,000 shares. At December 31, 2006, 1,504,734 shares were available for grant or award under the 2004 Plan. The Nominating, Governance and 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. The Company issues originally issued shares upon exercise of stock options.

The Company is estimating that the cost relating to stock options granted through December 31, 2006 will be $3,758,074 over the remaining vesting period of 22 months; 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. The total fair value of stock options vested during the year ended December 31, 2006 was $3,300,705.

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The following table summarizes stock option activity under the 2004 Plan:

	Year Ended December 31, 2006		Year Ended December 31, 2005	
	Number of Shares Underlying Options	Weighted Average Exercise Price	Number of Shares Underlying Options	Weighted Average Exercise Price
Outstanding at beginning of period	1,839,500	$ 11.38		$
Granted			1,839,500	11.38
Exercised	(129,453)	9.52		
Forfeited	(50,125)	20.00		
Outstanding at end of period	1,659,922	11.27	1,839,500	11.38
Exercisable at end of period	1,260,922	8.51	1,168,625	6.44

The intrinsic value of options exercised during the year ended December 31, 2006 was $3,362,125.

The following table summarizes information about stock options outstanding at December 31, 2006:

	Options Outstanding			Options Exercisable	
	Number Outstanding	Weighted Average Remaining Life (Years)	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
Exercise Prices					
$2.86	772,500	7.83	$ 2.86	772,500	$ 2.86
5.71	87,500	8.33	5.71	87,500	5.71
20.00	799,922	8.83	20.00	400,922	20.00
	1,659,922	8.35	11.27	1,260,922	8.51

The aggregate intrinsic value at December 31, 2006 of options outstanding and options exercisable was $29,264,425 and $25,710,200, respectively.

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 (dollars in thousands):

	Year Ended December 31, 2005	Period from inception to December 31, 2004
Net income-as reported	$ 27,456	$ 8,065
Compensation expense, net of tax, as reported	51	
Compensation expense, net of tax, pro forma	(1,752)	
Net income-pro forma	$ 25,755	$ 8,065
Earnings per share:		

Basic-as reported	$	1.10	$	0.55
Basic-pro forma	$	1.03	$	0.55
Diluted-as reported	$	1.08	$	0.55
Diluted-pro forma	$	1.01	$	0.55

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

	Twelve Months 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 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:

Dividend yield	
Expected price volatility	35.00%
Risk-free interest rate	4.40%
Expected life of options in years	8.08
Weighted-average fair value of options granted	$ 9.45

The following table summarizes information about restricted stock outstanding as of December 31, 2006 (dollars in thousands):

Grant Date	Grant Type	Number of Shares	Value per Share on Grant Date	Vesting Period (Years)	Gross Compensation Cost Year Ended December 31, 2006	Gross Compensation Cost Year Ended December 31, 2005	Net of Tax - Compensation Cost Year Ended December 31, 2006	Net of Tax - Compensation Cost Year Ended December 31, 2005
October 2005	Employee	70,000	$ 20.00	3	$ 467	$ 78	$ 303	$ 51
February 2006	Employee	9,900	30.38	3	92		60	
April 2006	Non-employee director	12,000	40.00	1	360		234	
May 2006	Employee	5,000	34.03	3	38		25	
August 2006	Non-employee director	866	32.70	0.67	18		12	
September 2006	Employee	5,000	33.36	3	18		12	
December 2006	Employee	3,000	34.53	3	3		2	
					$ 996	$ 78	$ 648	$ 51

At December 31, 2006 there was $1,576,355 of total unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted-average period of 1.9 years. The total fair value of restricted shares vested during the year ended December 31, 2006 was $811,090.

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. During the period from inception to December 31, 2004, the Company recorded a provision for bad debts of $519,165. During the second quarter of 2005, the Company recorded an additional provision for bad debts of $318,967. The

Company received payment for the full amount of the receivable of $838,132 during September 2005, and the allowance was reversed. There was no allowance at December 31, 2006 or 2005.

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Insurance Claims Receivable

Insurance claims receivable include amounts the Company incurred related to insurance claims the Company filed under its insurance policies. The claims related to the repair of damage sustained by *Rig 21*, the salvage costs for *Rig 25* and costs related to the clean-up efforts at the Company s New Iberia facilities. At December 31, 2005, $5,919,308 was outstanding for insurance claims receivable related to Hurricanes Katrina and Rita. There were no claims receivable at December 31, 2006.

Prepaid Expenses and Other Current Assets

Prepaid expenses and other current assets consist of prepaid insurance, current deferred mobilization costs and other. At December 31, 2006 and December 31, 2005, prepaid insurance totaled $13,876,951 and $6,101,284, respectively. At December 31, 2006 deferred mobilization costs totaled $1,686,692, of which $1,644,886 is included in current prepaid expenses. There were no deferred mobilization costs at December 31, 2005.

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 non-current assets on the Consolidated Balance Sheets and amortized on the straight-line method over a period of 12 to 24 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 life of the lease.

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

	Years
Drilling rigs and marine equipment	15
Drilling machinery and equipment	3
Furniture and fixtures	5
Computer equipment	3
Automobiles and trucks	3
Building	20

Assets Held for Sale

Assets are classified as held for sale when the Company has a plan for disposal and those assets meet the held for sale criteria of SFAS No. 144, Accounting for Impairment or Disposal of Long-Lived Assets .

In September 2006, the Company sold its New Iberia facility for $2,850,000, net of commissions. The Company recognized a gain of approximately $88,300 in the third quarter of 2006 on the sale.

During the first quarter of 2005, the Company s Domestic Contract Drilling Services segment committed to a plan to sell *Rig 41,* a platform rig, in connection with the Company s efforts to dispose of certain non-strategic assets. The Company entered into a definitive agreement to sell *Rig 41* in October 2005 and received a deposit of $181,250. The buyer terminated the agreement in December 2005 and the Company recorded the deposit to other income on the Consolidated Statement of Operations. In July 2006, the Company sold *Rig 41* for $3,150,000, net of commissions, and the Company recognized a gain of approximately $1,110,000 in the third quarter of 2006 on the sale.

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Impairment of Long-Lived Assets

The carrying value of long-lived assets, principally property and equipment, is reviewed for potential impairment when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. 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, 2006, 2005 and 2004.

Other Assets

Other assets consist of drydocking costs for liftboats, financing fees, unrealized gain on hedge transactions and other. The drydock costs are capitalized at cost and amortized on the straight-line method over a period of 12 to 24 months. Drydocking costs, net of accumulated amortization, at December 31, 2006 and 2005 were $5,780,289 and $3,906,106, respectively. Accumulated amortization of drydocking costs at December 31, 2006 and 2005 was $5,247,651 and $2,967,062, respectively. Amortization expense for drydocking costs was $10,670,040, $3,915,142 and $149,228 for the years ended December 31, 2006 and 2005 and the period from inception to December 31, 2004, respectively.

Financing fees are deferred and amortized over the life of the applicable debt instrument. Unamortized deferred financing fees at December 31, 2006 were $2,476,059, net of accumulated amortization of $1,084,610. Unamortized deferred financing fees at December 31, 2005 were $2,531,966, net of accumulated amortization of $398,806. 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 $685,803, $890,848 and $215,285 for the years ended December 31, 2006 and December 31, 2005 and the period from inception to December 31, 2004, respectively.

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 7).

Income Taxes

The Company s 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 the Company operates. Certain of the Company s international rigs are owned or operated, directly or indirectly, by the Company s wholly owned Cayman Islands subsidiaries. Earnings from these subsidiaries are reinvested internationally and remittance to the United States is indefinitely postponed. Consequently, no U.S. tax expense or benefits were recognized on these earnings or losses in 2006. 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 11).

The Company was a limited liability company until its conversion to a Delaware corporation on November 1, 2005. Prior to the Conversion, the Company elected to be taxed as a partnership. As such, the members of the Company were taxed on their proportionate share of net income prior to the Conversion and no provision or liability for income taxes is included in the Company s accompanying financial statements for periods prior to the Conversion. When the Company became a taxable entity in the Conversion, a provision of $12,145,040 was made reflecting the tax effect of the difference between the book and tax basis of assets and liabilities as of November 1, 2005, the effective date of the Conversion. Following the Conversion, income taxes have been provided based upon the tax laws and rates in effect in the countries and states in which operations are conducted and income is earned.

In February 2006, in accordance with the terms of the limited liability company operating agreement governing the Company prior to the Conversion (the Operating Agreement), the Company made a distribution of $3,731,660 to the former members of the Company for taxes in respect of the ten-month period ended upon the Conversion. The former members did not receive any other distributions prior to the Conversion, and other than this required distribution relating to taxes, the earnings generated by the Company were retained by the Company as part of its stockholders equity balance upon the Conversion. The Company has no further obligation under the Operating Agreement to make any such distributions.

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 is equal to the fair market value because the debt bears interest at market rates.

Accounting Pronouncements

In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109* (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with SFAS No. 109, *Accounting for Income Taxes.* FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

FIN 48 also requires expanded disclosure with respect to the uncertainty in income tax assets and liabilities. FIN 48 is effective for fiscal years beginning after December 15, 2006, and the Company will adopt it in the first quarter of 2007. The effect of adoption of FIN 48 is required to be recognized as a change in accounting principle through a cumulative-effect adjustment to retained earnings as of the beginning of the year of adoption. The Company continues to evaluate the effects of FIN 48 on its Consolidated Balance Sheet and Statement of Operations.

In September 2006, the Securities and Exchange Commission staff issued Staff Accounting Bulletin No. 108, Considering the Effects of Prior Year Misstatements in Current Year Financial Statements (SAB 108). SAB 108 was issued to provide consistency with respect to the manner in which companies quantify financial statement misstatements. SAB 108 establishes an approach that requires companies to quantify misstatements in financial statements based on effects of the misstatement on both the Consolidated Balance Sheet and Statement of Operations and the related financial statement disclosures. Additionally, companies are required to evaluate the cumulative effect of errors existing in prior years that previously had been considered immaterial. The Company has adopted SAB 108 and its adoption did not have an impact on the Company s Consolidated Balance Sheet, Statement of Operations or Statement of Cash Flow.

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 in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair

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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 expect the adoption to have a material impact on its Consolidated Balance Sheet or Statement of Operations.

NOTE 2 PROPERTY AND EQUIPMENT

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

	December 31, 2006	December 31, 2005
Drilling rigs and marine equipment	$ 420,961	$ 252,892
Drilling machinery and equipment	23,329	1,546
Building	267	2,400
Land		600
Automobiles and trucks	915	601
Computer equipment	1,040	128
Furniture and fixtures	779	991
Total property and equipment	447,291	259,158
Less accumulated depreciation	(31,427)	(11,715)
Total property and equipment, net	$ 415,864	$ 247,443

NOTE 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 (net income in thousands):

	Year Ended December 31, 2006	Year Ended December 31, 2005	Period from Inception to December 31, 2004
Numerator:			
Net income	$ 119,050	$ 27,456	$ 8,065
Denominator:			
Weighted average basic shares	31,327,420	24,919,273	14,689,724
Add effect of stock options and restricted stock	876,026	512,549	
Weighted average diluted shares	32,203,446	25,431,822	14,689,724
Basic earnings per share	$ 3.80	$ 1.10	$ 0.55
Diluted earnings per share	$ 3.70	$ 1.08	$ 0.55

The Company calculates 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. Share-based information contained herein assumes that the Company had effected the conversion of each outstanding member unit into 350 shares of common stock for all periods prior to the Conversion. Diluted earnings per share include the dilutive effects of any outstanding stock options and restricted stock calculated under the treasury stock method. Options with an exercise price equal to or in excess of the average market price of the Company s shares are excluded from the calculation of the dilutive effect of stock options for diluted earnings per share calculations.

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NOTE 4 ASSET ACQUISITIONS

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 $51,592,479, plus up to $10,000,000 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 $3,000,000 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, including accrued contingent consideration, 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 $52,000,000 was reduced by $2,655,830, 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 *Rig 26* for $20,100,000. *Rig 26* had been cold stacked for the prior six years. The Company has commenced a reactivation and upgrade project to enhance the rig s drilling capabilities and to increase the marketability of the rig in international regions.

In November 2005, the Company purchased seven liftboats and related assets for $44,000,000. Three of the acquired liftboats are located in the U.S. Gulf of Mexico and are included in the Domestic Marine Services segment. The remaining four liftboats are currently operating in Nigeria and are included in the International Marine Services segment.

In September 2005, the Company purchased *Rig 31* for $12,600,000.

In August 2005, the Company purchased the liftboat *Whale Shark* for $12,500,000.

In June 2005, the Company purchased 17 liftboats for $19,725,000. One of these liftboats was being held for sale and was sold in August 2005 (see NOTE 1). In June 2005, the Company purchased a jackup rig, *Rig 16*, for $20,000,000.

During January 2005, the Company completed the purchase of two jackup drilling rigs, *Rig 25* and *Rig 30*, for $21,500,000 and $20,000,000, respectively.

NOTE 5 BENEFIT PLANS

The Company has a 401(k) plan in which substantially all U.S. employees are eligible to participate. The Company matches participant contributions equal to 100% of the first 3% and 50% of the next 2% of a participant s salary. The Company made matching contributions of $1,859,791, $917,733 and $167,858 for the years ended December 31, 2006 and 2005 and the period from inception to December 31, 2004, respectively.

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NOTE 6 LONG-TERM DEBT

Long-term debt is comprised of the following (in thousands):

	December 31, 2006	December 31, 2005
Senior secured term loan due June 2010	$ 93,250	$ 94,650
Total debt	93,250	94,650
Less debt due within one year	1,400	1,400
Total long-term debt	$ 91,850	$ 93,250

Aggregate principal repayments of long-term debt for the next five years and thereafter are as follows (in thousands):

	2007	2008	2009	2010	2011	Thereafter
Senior secured term loan due June 2010	$ 1,400	$ 1,400	$ 1,400	$ 89,050	$	$

Senior secured credit agreement

In June 2005, the Company entered into a senior secured credit agreement with a syndicate of financial institutions. This agreement, as amended, provides for a $140,000,000 term loan and a $75,000,000 revolving credit facility. The Company may seek commitments to increase the amount available under the credit agreement by an additional $25,000,000 if its leverage ratio, after giving effect to the incurrence of the additional $25,000,000 of borrowings, is no greater than 2.5 to 1. Amounts repaid under the term loan cannot be reborrowed except pursuant to such an increase in availability.

The revolving credit facility provides for swing line loans of up to $5,000,000 and for the issuance of up to $5,000,000 of letters of credit. The revolving loans bear interest at a rate equal to, at the Company s option, either (1) the highest of (a) Comerica Bank s base rate, (b) the three-month certificate of deposit rate plus 0.5% and (c) the Federal funds effective rate plus 0.5%, in each case plus 1.25%, or (2) LIBOR plus 2.25%. The Company may prepay the revolving loans at any time without premium or penalty. The revolving loans mature in June 2010. The Company is required to pay a commitment fee of 0.375% on the average daily amount of the unused commitment amount of the revolving credit facility and a letter of credit fee of 2.25%, plus a fronting fee of 0.125%, with respect to the undrawn amount of each issued letter of credit. As of December 31, 2006, no amounts were outstanding and no letters of credit had been issued under the revolving credit facility.

The term loan bears interest at a rate equal to, at the Company s option, either (1) the highest of (a) Comerica Bank s base rate, (b) the three-month certificate of deposit rate plus 0.5% and (c) the Federal funds effective rate plus 0.5%, in each case plus 2.25%, or (2) LIBOR plus 3.25%. Principal payments of $350,000 are due quarterly, and the outstanding principal balance of the term loan is payable in full in June 2010. The Company may prepay the term loan at any time without premium or penalty. The Company is required to make prepayments on the term loan in certain cases. As of December 31, 2006, $93,250,000 of the principal amount of the term loan was outstanding, and the interest rate was 8.63%. In accordance with the credit agreement, in July 2005, the Company entered into hedge transactions with the purpose and effect of fixing the interest rate on $70,000,000 of the outstanding principal amount of the term loan at 7.54% for three years. In addition, the Company entered into hedge transactions with the purpose and effect of capping the interest rate on an additional $20,000,000 of such principal amount at 8.25% for three years. (See NOTE 7.) In November 2005, the Company repaid $45,000,000 of the outstanding amount under the term loan, together with the accrued and unpaid interest of $273,750, with proceeds from the Company s initial public offering. The Company recognized a pretax charge of $1,291,921 related to the write off of deferred financing fees in connection with the repayment in the fourth quarter of 2005.

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The credit agreement contains financial covenants relating to leverage, fixed charge coverage and collateral coverage. Other covenants contained in the agreement restrict, among other things, repurchases of equity interests, mergers, asset dispositions, guaranties, debt, liens, acquisitions, dividends, distributions, investments, affiliate transactions, prepayments of other debt and capital expenditures. The credit agreement permits the Company to make advances to and investments in its foreign subsidiaries provided it meets applicable financial covenants. The credit agreement contains customary events of default.

The Company s obligations under the credit agreement are secured by its liftboats, all of its domestic rigs and substantially all of its other personal property, including all the equity of its domestic subsidiaries and 65% of the equity of certain foreign subsidiaries. All of the Company s material domestic subsidiaries guarantee the Company s obligations under the agreement and have granted similar liens on substantially all of their assets. The Company s foreign subsidiaries are not guarantors and the assets owned by the foreign subsidiaries are not held as collateral for the loans.

In January 2006, the Company amended the credit agreement to provide for, among other things, the release of the guaranty, security agreement and vessel mortgages recently entered into by two of its Cayman subsidiaries in connection with the transfer to such subsidiaries of *Rig 16* and *Rig 31*. In addition, the Company is permitted to advance up to $20,000,000 to these two Cayman subsidiaries and to invest an additional $25,000,000 million in its foreign subsidiaries.

In June 2006, the Company further amended the credit agreement. Among other things, the amendment increased the commitments under the revolving credit facility from $25,000,000 to $75,000,000, reduced the interest rate under the revolving credit facility by 1.0% per annum, and extended the maturity date of the revolving credit facility from June 29, 2008 to June 29, 2010. It also removed the limitations on investments by the Company in its subsidiaries that are not guarantors to the credit agreement. The previous limit of $25,000,000 on such investments in its subsidiaries was replaced by a collateral maintenance test that requires the Company to maintain a ratio of (1) the orderly liquidation value of all of the vessels mortgaged pursuant to the credit agreement to (2) the sum of the revolving commitments and outstanding term loans under the credit agreement, of not less than 1.25 to 1.00. In addition, the dollar limits on other investments (including acquisitions) by the Company were eliminated, provided the Company is in compliance with its covenants under the credit agreement after giving effect to the investment and, with respect to an investment greater than $25,000,000, the Company s leverage ratio is not greater than 3.50 to 1.00 prior to and after giving effect to such investment. The existing annual limit of $25,000,000 on capital expenditures and the interest coverage ratio were replaced by a fixed charge coverage ratio, which requires the Company to maintain a ratio of (1) EBITDA less maintenance capital expenditures and cash taxes paid to (2) fixed charges, of not less than 1.25 to 1.00. Furthermore, a $2,000,000 limitation on insurance deductibles was removed and replaced with a requirement that the Company maintain insurance that is customary for the industry. Finally, a $2,500,000 annual limit on asset sales was increased to an aggregate basket of $95,000,000 for the term of the credit agreement, provided the net proceeds from such asset sales are used to repay amounts outstanding under the term loan.

The Company paid $629,896 in fees in the year ended December 31, 2006 related to the amendments discussed above.

As of December 31, 2006, the Company had a letter of credit supported by a restricted cash deposit of $250,000 issued outside of the revolving credit facility.

NOTE 7 DERIVATIVE INSTRUMENTS AND HEDGING

In July 2005, 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. The Company entered into two floating-to-fixed interest rate swaps on a total of $70,000,000 of the term loan principal under which the Company receives an interest rate of three-month LIBOR and pays a fixed coupon over three years,

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with the terms of the swaps matching those of the term loan. The Company also entered into two purchased interest rate caps hedging interest payments made on a total of $20,000,000 of the term loan principal at a strike price of 5.0% over three years. The counterparty is obligated to pay the Company in any quarter that actual LIBOR resets above the strike price, with the terms of the caps matching those of the term loan. All hedge transactions have payment dates of October 1, January 1, April 1 and July 1.

These hedging arrangements effectively fix the interest rate on $70,000,000 of the principal amount at 7.54% for three years and cap the interest rate on $20,000,000 of the principal amount at 8.25% for three years. 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 was $1,162,317 and $732,903 at December 31, 2006 and December 31, 2005, respectively, and is included in other assets on the Consolidated Balance Sheets. The cumulative net unrealized gain on these hedging instruments was $755,505, net of tax of $406,812, and $476,387, net of tax of $256,516, and is included in accumulated other comprehensive income in the Consolidated Balance Sheets at December 31, 2006 and December 31, 2005, respectively. The Company expects to realize $738,712 of unrealized gain in the Consolidated Statements of Operations for the year ended December 31, 2007. 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, 2006 and 2005 related to these hedging instruments. The Company recognized a gain of $587,624 in other, net in the Consolidated Statements of Operations for the year ended December 31, 2006 related to the interest rate swaps. The Company recognized a loss of $112,966 in interest expense in the Consolidated Statements of Operations for the year ended December 31, 2005 related to the interest rate swaps.

NOTE 8 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 required payment is unlikely to occur. In addition, Chevron Corporation accounts for 93% of the revenue for the Company s International Marine Services segment.

NOTE 9 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, 2006	Year Ended December 31, 2005	Period from Inception to December 31, 2004
Chevron Corporation	35%	31%	31%
Bois d Arc Energy, Inc.		12%	15%

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NOTE 10 COMPREHENSIVE INCOME

The components of accumulated other comprehensive income at December 31, 2006, December 31, 2005 and December 31, 2004, net of tax, are as follows (in thousands):

Balance at December 31, 2004	$
Reclassification of losses included in net income	73
Other comprehensive gain	403
Balance at December 31, 2005	476
Reclassification of gains included in net income	(382)
Other comprehensive gain	661
Balance at December 31, 2006	$ 755

NOTE 11 INCOME TAXES

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

	Year Ended December 31, 2006	Year Ended December 31, 2005	Period from Inception to December 31, 2004
United States	$ 168,885	$ 42,236	$ 8,065
Foreign	14,622	589	
Total	$ 183,507	$ 42,825	$ 8,065

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

	Year Ended December 31, 2006	Year Ended December 31, 2005	Period from Inception to December 31, 2004
Current-United States	$ 33,054	$	$
Current-foreign	3,070	100	
Current-state	1,133	22	
Subtotal-current	$ 37,257	$ 122	$
Deferred-United States	$ 26,597	$ 14,423	$
Deferred-foreign	(59)		
Deferred-state	662	824	
Subtotal-deferred	$ 27,200	$ 15,247	$

Total income tax provision	$	64,457	$	15,369	$

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

	Year Ended December 31, 2006		Year Ended December 31, 2005	
Deferred tax assets:				
Incentive compensation	$	950	$	
Workers compensation and other		309		
Deferred foreign revenue		59		
Net operating loss carryforward				
United States				773
State				44
Deferred tax assets	$	1,318	$	817
Deferred tax liabilities:				
Excess of net book over remaining tax basis				
Fixed assets	$	37,962	$	12,679
Prepaid insurance		3,687		2,257
Deferred drydocking and other		2,523		1,385
Deferred tax liabilities	$	44,172	$	16,321
Net deferred tax liabilities	$	42,854	$	15,504

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

	Year Ended December 31, 2006	Year Ended December 31, 2005	Period from Inception to December 31, 2004
Statutory rate	35.0%	35.0%	
Effect of :			
State income taxes	1.1		
Foreign earnings indefinitely reinvested	(1.0)		
Income of LLC prior to conversion		(27.5)	
Change in tax status and other		28.4	
Total	35.1%	35.9%	

During 2005, the Company generated a net operating loss of $3,110,251 for United States income tax purposes. This loss can be carried forward 20 years. During 2006, the Company utilized this loss to offset taxable income generated during the year.

NOTE 12 SEGMENTS

The Company s operations are aggregated into four reportable segments: (i) Domestic Contract Drilling Services, (ii) International Contract Drilling Services, (iii) Domestic Marine Services and (iv) International Marine Services. The Contract Drilling Services segments consist of jackup rigs used in support of offshore drilling activities. The Domestic Contract Drilling Services segment consists of jackup rigs operated in the U.S. Gulf of Mexico, while the International Contract Drilling Services segment consists of jackup rigs operated outside of the U.S. Gulf of Mexico (which currently consists of one jackup rig operating offshore Qatar, one jackup rig operating offshore India and one jackup rig currently undergoing refurbishment and upgrade). The Marine Services segments consist of liftboats used in offshore support services. The

Domestic Marine Services segment consists of liftboats operated in the U.S. Gulf of Mexico, while the International Marine Services segment consists of liftboats operated outside of the U.S. Gulf of Mexico (which currently consists of the Company s liftboats operating in West Africa). The Company eliminates intersegment revenue and expenses, if any.

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Operating results, total assets and capital expenditures by segment were as follows (in thousands):

Year Ended December 31, 2006

	Domestic Contract Drilling Services	International Contract Drilling Services	Domestic Marine Services	International Marine Services	Corporate and Other	Total
Revenues	$ 160,761	$ 30,460	$ 133,929	$ 19,162	$	$ 344,312
Operating expenses, excluding depreciation and amortization	51,862	13,377	49,025	9,874		124,138
Depreciation and amortization	8,882	2,547	18,854	1,923	104	32,310
General and administrative, excluding depreciation and amortization	6,980	1,606	2,259	3,056	15,906	29,807
Operating income (loss)	93,037	12,930	63,791	4,309	(16,010)	158,057
Interest expense	(5,961)	(43)	(3,263)	(11)		(9,278)
Gain on disposal of asset	30,690					30,690
Other, net	538	165	466		2,869	4,038
Income (loss) before income taxes	118,304	13,052	60,994	4,298	(13,141)	183,507
Income tax (expense) benefit	(41,536)	(1,641)	(21,290)	(1,569)	1,579	(64,457)
Net income (loss)	$ 76,768	$ 11,411	$ 39,704	$ 2,729	$ (11,562)	$ 119,050
Total assets (at end of period)	$ 144,467	$ 126,191	$ 192,314	$ 89,954	$ 52,655	$ 605,581
Capital expenditures and deferred drydocking expenditures	$ 76,635	$ 20,100	$ 66,279	$ 53,955	$ 31	$ 217,000

Year Ended December 31, 2005

	Domestic Contract Drilling Services	International Contract Drilling Services	Domestic Marine Services	International Marine Services	Corporate and Other	Total
Revenues	$ 103,422	$	$ 55,740	$ 2,172	$	$ 161,334
Operating expenses, excluding depreciation and amortization	48,330		28,413	1,071		77,814
Depreciation and amortization	5,547		8,031	176	36	13,790
General and administrative, excluding depreciation and amortization	5,486		1,888	336	6,161	13,871
Operating income (loss)	44,059		17,408	589	(6,197)	55,859
Interest expense	(6,980)		(2,825)		(75)	(9,880)
Loss on early retirement of debt	(2,683)		(1,395)			(4,078)
Other, net	541		96		287	924
Income (loss) before income taxes	34,937		13,284	589	(5,985)	42,825
Income tax (expense) benefit	(6,900)		(8,828)	(100)	459	(15,369)

Net income (loss)	$ 28,037	$	$ 4,456	$ 489	$ (5,526)	$ 27,456
Total assets (at end of period)	$ 157,756	$	$ 137,865	$ 19,682	$ 39,522	$ 354,825
Capital expenditures and deferred drydocking expenditures	$ 90,347	$	$ 67,460	$ 17,600	$	$ 175,407

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Period From Inception to December 31, 2004

	Domestic Contract Drilling Services	International Contract Drilling Services	Domestic Marine Services	International Marine Services	Corporate and Other	Total
Revenues	$ 24,006	$	$ 7,722	$	$	$ 31,728
Operating expenses, excluding depreciation and amortization	12,799		4,198			16,997
Depreciation and amortization	1,070		946			2,016
General and administrative, excluding depreciation and amortization	1,972		581		255	2,808
Operating income (loss)	8,165		1,997		(255)	9,907
Interest expense	(1,648)		(422)			(2,070)
Other, net	158		64		6	228
Net income (loss)	$ 6,675	$	$ 1,639	$	$ (249)	$ 8,065
Total assets (at end of period)	$ 60,399	$	$ 61,094	$	$ 10,663	$ 132,156
Capital expenditures and deferred drydocking expenditures	$ 40,728	$	$ 54,316	$	$	$ 95,044

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

	Revenue			Long-Lived Assets	
	Year Ended December 31, 2006	Year Ended December 31, 2005	Period From Inception to December 31, 2004	As of December 31, 2006	As of December 31, 2005
United States	$ 294,690	$ 159,162	$ 31,728	$ 266,850	$ 187,897
International:					
Nigeria	18,440	2,172		76,377	17,424
United Arab Emirates					26,588
Malaysia					15,534
India	12,392			37,539	
Qatar	18,068			35,071	
Cameroon	722				
Cayman Island				27	
Total	49,622	2,172		149,014	59,546
Total	$ 344,312	$ 161,334	$ 31,728	$ 415,864	$ 247,443

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NOTE 13 COMMITMENTS AND CONTINGENCIES

Operating Leases

The Company has operating lease commitments that expire at various dates through 2011. As of December 31, 2006, future minimum lease payments related to operating leases were as follows (in thousands):

Years ended December 31,	
2007	$ 729
2008	354
2009	287
2010	286
2011	33
Thereafter	
Total	$ 1,689

Rental expense for all operating leases was $1,576,752, $571,836 and $34,572 for the years ended December 31, 2006 and 2005 and the period from inception to December 31, 2004, respectively.

Legal Proceedings

The Company is involved in various claims and lawsuits in the normal course of business. Management does not believe any accruals are necessary in accordance with SFAS No. 5, Accounting for Contingencies .

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, maritime employers liability, general liability, vessel pollution and other coverages. 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 $580,000,000; however, coverage for U.S. Gulf of Mexico named windstorm damage is subject to an annual aggregate limit on liability of $75,000,000. The policies are subject to deductibles and other conditions. Deductibles for events that are not U.S. Gulf of Mexico named windstorm events are $1,500,000 per occurrence for drilling rigs, and range from $250,000 to $1,000,000 per occurrence for liftboats, depending on the insured value of the particular vessel. The deductibles for drilling rigs in a U.S. Gulf of Mexico named windstorm event are $1,500,000 per rig for each occurrence plus an additional $5,000,000 for each U.S. Gulf of Mexico named windstorm. The protection and indemnity coverage under the primary marine package has a $5,000,000 limit per occurrence with excess liability coverage up to $100,000,000. 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 general domestic liability, employer s liability, domestic auto liability and non-owned aircraft liability, with customary deductibles and coverage. Insurance premiums and fees for coverage of the Company s operations, assets and personnel base (as the same existed at June 30, 2006) are expected to be approximately $23,900,000 for the twelve-month policy period ending July 1, 2007, an increase of approximately 151% over the previous policy period on an annualized basis.

In connection with the renewal of certain of the Company s insurance policies, the Company entered into an agreement to finance a portion of the annual insurance premiums. Approximately $17,900,000 was financed

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through this arrangement. The interest rate is 5.75%, and the note matures in April 2007. Approximately $6,058,000 was outstanding at December 31, 2006.

2005 Hurricanes

In August 2005, two of the Company s jackup rigs, *Rig 21* and *Rig 25*, sustained damage during Hurricane Katrina. *Rig 25* was insured for $50,000,000, and the Company reached a settlement with its insurance underwriters and received net insurance proceeds of $48,750,000 related to this claim in 2006, which represents the insured value less the negotiated salvage value of $1,250,000. 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 $29,580,283 in March 2006 related to its insurance claim on *Rig 25*, which represented the gross proceeds of $50,000,000 expected to be received, less the rig book value of $20,116,178 and less $303,539 of items related to the salvage operation of the rig not reimbursed by the Company s insurance carriers. *Rig 21* 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 Hurricane Katrina had been paid.

NOTE 14 UNAUDITED INTERIM FINANCIAL DATA

Unaudited interim financial information for the years ended December 31, 2006 and 2005, and the period from inception to December 31, 2004 is as follows (in thousands, except per share amounts):

	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

	Quarter Ended			
	March 31	**June 30**	**September 30**	**December 31**
2005				
Operating revenues	$ 34,055	$ 37,075	$ 42,185	$ 48,019
Operating income	13,571	13,369	12,601	16,318
Net income (loss)	11,402	8,150	10,110	(2,206)
Net income (loss) per share:				
Basic	$ 0.48	$ 0.34	$ 0.42	$ (0.08)
Diluted	$ 0.48	$ 0.34	$ 0.41	$ (0.08)

	Quarter Ended	
	September 30	**December 31**
2004		
Operating revenues	$ 8,405	$ 23,323
Operating income	2,726	7,181
Net income	2,141	5,924
Net income per share:		
Basic	$ 0.29	$ 0.40
Diluted	$ 0.29	$ 0.40

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NOTE 15 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 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.

A former manager of the Company who resigned in 2005 is a principal in Bassoe Offshore USA. The Company paid $200,000 in the year ended December 31, 2005 to Bassoe Offshore USA for rig brokerage fees in connection with the acquisition by the Company of a jackup rig. The Company paid $442,250 in the period from inception to December 31, 2004 for such rig brokerage fees. The services were bid under competitive marketplace conditions. The Company believes that these transactions were on terms that were reasonable and in the best interest of the Company.

In January 2005, the Company purchased *Rig 30* 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 *Rig 30* 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 $211,209, $211,209 and $422,338, respectively.

During 2006 and 2005, a subsidiary of the Company purchased an aggregate of approximately $345,000 and $167,000, respectively, in rig equipment monitoring products and services from MBH Datasource, Inc. Thomas E. Hord, a former Vice President, Operations and Chief Operating Officer of the subsidiary, holds a 50% ownership interest in MBH Datasource, Inc. The Company believes that the transactions were on terms that were reasonable and in its best interest, although the transactions may not have been on or have terms as favorable to the Company as it could have obtained from unaffiliated third-parties in arms-length transactions.

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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 Chief Executive Officer and President, and Lisa W. Rodriguez, who is currently performing the duties of our Chief Financial Officer on an interim basis, of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934 as of the end of the period covered by this annual report. Based upon that evaluation, Mr. Stilley and Ms. Rodriguez, acting in their capacities as our principal executive officer and our principal financial officer, concluded that, as of December 31, 2006, 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, for 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, 2006. 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, 2006, 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, 2006, 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, to the extent not set forth in Executive Officers in Item 4, 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 of the end of our fiscal year on December 31, 2006.

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 under Corporate Governance in the Investor Relations 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 11 Greenway Plaza, Suite 2950, 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 under Corporate Governance in the Investor Relations 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 of the end of our fiscal year on December 31, 2006.

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 of the end of our fiscal year on December 31, 2006.

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 of the end of our fiscal year on December 31, 2006.

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 of the end of our fiscal year on December 31, 2006.

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.

(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 Registration Statement), originally filed on July 8, 2005).
3.1	Certificate of Incorporation of Hercules Offshore, Inc. (incorporated by reference to Exhibit 3.1 to Hercules Current Report on Form 8-K dated November 1, 2005 (File No. 0-51582) (the Form 8-K)).
3.2	Bylaws of Hercules Offshore, Inc. (incorporated by reference to Exhibit 3.2 to the Form 8-K).
4.1	Form of specimen common stock certificate (incorporated by reference to Exhibit 4.1 to the 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 Form 8-K).
4.3	Certificate of Designations of Series A Junior Participating Preferred Stock (incorporated by reference to Exhibit 4.2 to the Form 8-K).
4.4	Credit Agreement dated as of June 30, 2005 (the Credit Agreement) among Hercules Offshore, LLC, as Borrower, Comerica Bank, as Administrative Agent, Citicorp North America, Inc., as Syndication Agent, Credit Suisse, as Documentation Agent, and the Lenders party thereto (incorporated by reference to Exhibit 4.2 to the Registration Statement).

Exhibit Number	Description
4.5	Consent, Release, Waiver and Amendment to the Credit Agreement, dated as of January 25, 2006, among Hercules, as Borrower, Comerica Bank, as Administrative Agent, Citicorp North America, Inc., as Syndication Agent, Credit Suisse, Cayman Islands Branch, as Documentation Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to Hercules Current Report on Form 8-K dated January 25, 2006 (File No. 0-51582)).
4.6	Second Amendment to the Credit Agreement, dated as of January 25, 2006, among Hercules, as Borrower, Comerica Bank, as Administrative Agent, Citicorp North America, Inc., as Syndication Agent, Credit Suisse, Cayman Islands Branch, as Documentation Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.2 to Hercules Current Report on Form 8-K dated January 25, 2006 (File No. 0-51582)).
4.7	Third Amendment to the Credit Agreement, dated June 12, 2006, among Hercules, as borrower, Comerica Bank as Administrative Agent, Citigroup North America, Inc., as Syndication Agent, Credit Suisse Cayman Islands Branch, as Documentation Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to Hercules Current Report on Form 8-K dated June 14, 2006 (File No. 0-51582)).
*4.8	Fourth Amendment to the Credit Agreement, dated as of February 13, 2007, among Hercules, as borrower, Comerica Bank as Administrative Agent, Citigroup North America, Inc., as Syndication Agent, Credit Suisse Cayman Islands Branch, as Documentation Agent, and the Lenders party thereto.
10.1	Executive Employment Agreement, dated November 3, 2006, between Hercules Offshore, Inc. 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)).
10.2	Executive Employment Agreement, dated November 3, 2006, between Hercules Offshore, Inc. and Steven A. Manz (incorporated by reference to Exhibit 10.3 to Hercules Current Report on Form 8-K dated November 3, 2006 (File No. 0-51582)).
10.3	Executive Employment Agreement, dated November 3, 2006, between Hercules Offshore, Inc. and John T. Rynd (incorporated by reference to Exhibit 10.2 to Hercules Current Report on Form 8-K dated November 3, 2006 (File No. 0-51582)).
10.4	Executive Employment Agreement, dated November 3, 2006, between Hercules Offshore, Inc. and Randal R. Reed (incorporated by reference to Exhibit 10.4 to Hercules Current Report on Form 8-K dated November 3, 2006 (File No. 0-51582)).
10.5	Executive Employment Agreement, dated November 3, 2006, between Hercules Offshore, Inc. and James W. Noe (incorporated by reference to Exhibit 10.5 to Hercules Current Report on Form 8-K dated November 3, 2006 (File No. 0-51582)).
10.6	Expatriate Employment Agreement, dated November 1, 2006, between Hercules Offshore, Inc. and Don P. Rodney incorporated by reference to Exhibit 10.2 to Hercules Current Report on Form 8-K dated November 2, 2006 (File No. 0-51582)).
10.7	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)).
10.8	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 Registration Statement).
10.9	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 November 2, 2006 (File No. 0-51582)).

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Exhibit Number	Description
10.10	Amendment to Stock Option Award Agreement, dated October 31, 2006, between Hercules Offshore, Inc. and Thomas E. Hord (incorporated by reference to Exhibit 10.3 to Hercules Current Report on Form 8-K dated November 2, 2006 (File No. 0-51582)).
10.11	Hercules Offshore 2004 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.5 to the Registration Statement).
* 10.12	Form of Stock Option Agreement.
* 10.13	Form of Restricted Stock Agreement for Employees and Consultants.
* 10.14	Form of Restricted Stock Agreement for Directors.
*10.15	Schedule of executive officer and director compensation arrangements.
10.16	Registration Rights Agreement, dated as of July 8, 2005, between the Company and the holders listed on the signature page thereto (incorporated by reference to Exhibit 10.9 to the Company s Annual Report on Form 10-K for the year ended December 31, 2005, filed on March 8, 2006).
10.17	Asset and Securities Purchase Agreement dated as of January 13, 2005 among Hercules Drilling, the Company, Porterhouse Offshore, LP and Filet Ltd. (incorporated by reference to Exhibit 10.11 to the Registration Statement).
10.18	Rig Sale Agreement dated as of May 13, 2005 among Transocean Offshore Deepwater Drilling Inc. and the Company (incorporated by reference to Exhibit 10.12 to the Registration Statement).
10.19	Vessel Purchase Agreement dated as of May 19, 2005 among Superior Energy Services, L.L.C. and the Company (incorporated by reference to Exhibit 10.13 to the Registration Statement).
10.20	Vessel Purchase Agreement dated as of August 4, 2005 between C.S. Liftboats, Inc. and the Company (incorporated by reference to Exhibit 10.14 to the Registration Statement).
10.21	Rig Sale Agreement dated as of August 8, 2005 between Hydrocarbon Capital II LLC and the Company (incorporated by reference to Exhibit 10.15 to the Registration Statement).
10.22	Asset Purchase Agreement dated as of September 16, 2005 by and among Hercules Liftboat Company, LLC, Danos Marine, Inc. and Danos & Curole Marine Contractors, LLC. (incorporated by reference to Exhibit 10.16 to the Registration Statement).
10.23	Asset Purchase Agreement, dated April 3, 2006, by and between Hercules Liftboat Company, LLC and Laborde Marine Lifts, Inc. (incorporated by reference to Exhibit 10.1 to Hercules Current Report on Form 8-K dated April 4, 2006 (File No. 0-51582)).
10.24	Asset Purchase Agreement, dated as of August 23, 2006, by and among Hercules International Holdings, Ltd., Halliburton West Africa Ltd. and Halliburton Energy Services Nigeria Limited (incorporated by reference to Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, filed on November 7, 2006).
10.25	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 the Company s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, filed on November 7, 2006).

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Exhibit Number	**Description**
10.26	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 13, 2006 (File No. 0-51582)).
*21	Subsidiaries of Hercules.
*23	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 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.
Compensatory plan, contract or arrangement.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Houston, State of Texas, on February 27, 2007.

HERCULES OFFSHORE, INC.

By: /s/ RANDALL D. STILLEY
Randall D. Stilley
President and Chief Executive Officer

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 27, 2007.

Signatures	Title
/s/ RANDALL D. STILLEY **Randall D. Stilley**	President, Chief Executive Officer and Director (Principal Executive Officer)
/s/ LISA W. RODRIGUEZ **Lisa W. Rodriguez**	Principal Financial Officer
/s/ JOHN T. REYNOLDS **John T. Reynolds**	Chairman of the Board
/s/ THOMAS R. BATES, JR. **Thomas R. Bates, Jr.**	Director
/s/ THOMAS J. MADONNA **Thomas J. Madonna**	Director
/s/ F. GARDNER PARKER **F. Gardner Parker**	Director
/s/ THIERRY PILENKO **Thierry Pilenko**	Director
/s/ STEVEN A. WEBSTER **Steven A. Webster**	Director

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