TODCO
Form 10-K
March 01, 2007

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2006

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission File Number 1-31983

TODCO
(Exact name of registrant as specified in its charter)

Delaware	**76-0544217**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
2000 W. Sam Houston Parkway South, Suite 800 Houston, Texas	**77042-3615**
(Address of principal executive offices)	*(Zip Code)*

(713) 278-6000
Registrant s telephone number, including area code:

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

Title of Each Class	**Name of Each Exchange on Which Registered**

Common stock, par value $.01 per share	New York Stock Exchange
Preferred stock purchase rights	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes **þ** No **o**

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. **o**

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 **o** Non-accelerated filer **o**

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

The aggregate market value of the registrant s common stock held by non-affiliates of the Registrant as of June 30, 2006, was $2,527,831,824.

As of February 20, 2007, the Registrant had 57,718,239 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant s definitive Proxy Statement to be filed with the Securities and Exchange Commission within 120 days of December 31, 2006, for its 2007 annual meeting of stockholders are incorporated by reference into Part III of this Form 10-K.

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Amended and Restated By-Laws
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PART I

Item 1. *Business*

Overview

TODCO is a leading provider of contract oil and gas drilling services, primarily in the U.S. Gulf of Mexico shallow water and inland marine region, an area that we refer to as the U.S. Gulf Coast. We have the largest fleet of drilling rigs in the U.S. Gulf Coast.

We operate a fleet of 64 drilling rigs consisting of 27 inland barge rigs, 24 jackup rigs, three submersible rigs, one platform rig, and nine land rigs. Currently, 50 of these rigs are located in United States with the remainder in Angola, Brazil, Mexico, Trinidad, Venezuela and other international locations. We also operate through our wholly-owned subsidiary, Delta Towing LLC (Delta Towing), a fleet of U.S. marine support vessels consisting primarily of shallow water tugs, crewboats and utility barges along the U.S. Gulf Coast and in the U.S. Gulf of Mexico.

Our core business is to contract our drilling rigs, related equipment and work crews on a dayrate basis to customers who are drilling oil and gas wells. We provide these services primarily to independent oil and gas companies, but we also service major international and government-controlled oil and gas companies. Our customers in the U.S. Gulf Coast typically focus on drilling for natural gas.

We provide our services and report the results of our operations in four business segments which, for our contract drilling services, correspond to the principal geographic regions in which we operate:

> *U.S. Gulf of Mexico Segment* We currently have 18 jackup and three submersible rigs in the shallow water U.S. Gulf of Mexico which begins at the outer limit of the transition zone and extends to water depths of about 350 feet. Our jackup rigs in this segment consist of independent leg cantilever type units, mat-supported cantilever type rigs and mat-supported slot type jackup rigs that can operate in water depths up to 250 feet.

> *U.S. Inland Barge Segment* Our barge rig fleet currently consists of 12 conventional and 15 posted barge rigs. These units operate in marshes, rivers, lakes and shallow bay or coastal waterways that are known as the transition zone. This area along the U.S. Gulf Coast, where jackup rigs are unable to operate, is the world s largest market for this type of equipment.

> *International and Other Segment* Our other operations are currently conducted in Angola, Brazil, Mexico, Trinidad, the United States and Venezuela. We operate one jackup rig in Angola and one in Brazil. In Mexico, we have two jackup rigs and a platform rig. Additionally, we have one jackup rig and one land rig in Trinidad and six land rigs in Venezuela. One jackup rig is currently under tow to Southeast Asia for reactivation. We also have two land rigs in the United States. We may pursue selected opportunities in other international areas from time to time.

> *Delta Towing Segment* Delta Towing operates a fleet of 42 inland tugs, 19 offshore tugs, 36 crewboats, 30 deck barges, 17 shale barges, four spud barges and one offshore barge along the U.S. Gulf Coast and in the U.S. Gulf of Mexico.

For information about the revenues, operating income, assets and other information relating to our business segments and the geographic areas in which we operate, see Management s Discussion and Analysis of Financial Condition and

Results of Operations and Notes 2 and 16 to our consolidated financial statements included in Item 8 of this report. For information about the risks and uncertainties relating to our business, see Item 1A. Risk Factors.

Drilling Rig Fleet

Our drilling rig fleet consists of jackup rigs, barge rigs, and other rigs, which include submersible rigs, a platform drilling rig and land drilling rigs.

There are several factors that determine the type of rig most suitable for a particular drilling operation. The most significant factors are water depth and seabed conditions (in offshore and inland marine environments), whether drilling is being done over a platform or other structure, and the intended well depth. Our fleet allows us to meet a broad range of needs in the shallow water along the U.S. Gulf Coast. Most of our drilling equipment is suitable for both exploration and development drilling, and we are normally engaged in both types of drilling activity. All of our mobile offshore drilling units are designed for operations away from port for extended periods of time and have living quarters for the crews, a helicopter landing deck and storage space for pipe and drilling supplies.

Following are brief descriptions of the types of rigs we operate. Rigs described in the following charts as under contract are operating under contract, including rigs being prepared or mobilized under contract. Rigs described as under repair are rigs that are currently in a shipyard for planned maintenance or repair. Rigs described as warm stacked are not under contract but are actively marketed and may require the hiring of additional crew (and, in some cases, an entire crew), but are generally ready for service with little or no capital expenditures. Rigs described as cold stacked are not actively marketed, generally cannot be ready for service immediately and normally require the hiring of an entire crew. Cold stacked rigs will also require a varying degree of maintenance and significant refurbishment before they can be operated. Rigs described as reactivating were cold stacked rigs that are currently being reactivated against term contracts that they will operate under upon completion of their reactivation. We include information in the following charts for rated drilling depth, which means drilling depth stated by the manufacturer of the drilling equipment. A rig may not have the actual capacity to drill to the rated drilling depth.

Jackup Drilling Rigs (24)

Jackup rigs are mobile self-elevating drilling platforms equipped with legs that can be lowered to the ocean floor until a foundation is established to support the drilling platform. Once a foundation is established, the drilling platform is jacked further up the legs so that the platform is above the highest expected waves. The rig hull includes the drilling rig, jacking 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. Independent leg rigs are better suited for harder or uneven seabed conditions while mat rigs are better suited for soft bottom conditions. Some of our jackup rigs have a cantilever design, a feature that permits the drilling platform to be extended out from the hull, allowing it to perform drilling or workover operations over some types of preexisting platforms or structures. Our other jackup rigs have a slot-type design, permitting the rig to be configured for drilling operations to take place through a slot in the hull. Slot-type rigs are usually used for exploratory drilling, since it is difficult to position them over existing platforms or structures. In the table below ILC means an independent leg cantilevered jackup rig, MC means a mat-supported cantilevered jackup rig and MS means a mat-supported slot-type jackup rig.

The following table contains information regarding our jackup rig fleet as of February 20, 2007.

Rig	Type	Original Year Entered Service	Water Depth Capacity (In feet)	Rated Drilling Depth (In feet)	Location	Status
THE 110	MC	1982	100	20,000	Trinidad	Under Contract
THE 150	ILC	1979	150	20,000	U.S.	Under Contract
THE 152	MC	1980	150	20,000	U.S.	Under Contract
THE 153	MC	1980	150	20,000	U.S.	Warm Stacked
THE 155	ILC	1980	150	20,000	U.S.	Cold Stacked
THE 156	ILC	1983	150	20,000	Brazil	Under Contract
THE 185	ILC	1982	120	20,000	Angola	Under Contract
THE 191	MS	1978	160	20,000	U.S.	Cold Stacked
THE 200	MC	1979	200	20,000	U.S.	Under Repair
THE 201	MC	1981	200	20,000	U.S.	Under Repair
THE 202	MC	1982	200	20,000	U.S.	Under Contract
THE 203	MC	1981	200	20,000	U.S.	Under Contract
THE 204	MC	1981	200	20,000	U.S.	Warm stacked
THE 205	MC	1979	200	20,000	Mexico	Under Repair
THE 206	MC	1980	200	20,000	Mexico	Under Contract
THE 207	MC	1981	200	20,000	U.S.	Under Contract
THE 208(a)	MC	1980	200	20,000	Under Tow	Reactivating
THE 250	MS	1974	250	20,000	U.S.	Under Contract
THE 251	MS	1978	250	20,000	U.S.	Under Contract
THE 252	MS	1978	250	20,000	U.S.	Under Contract
THE 253	MS	1982	250	20,000	U.S.	Under Contract
THE 254	MS	1976	250	20,000	U.S.	Cold Stacked
THE 255	MS	1976	250	20,000	U.S.	Cold Stacked
THE 256	MS	1975	250	20,000	U.S.	Cold Stacked

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

Barge Drilling Rigs (27)

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

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The following table contains information regarding our barge drilling rig fleet as of February 20, 2007.

Rig	Type	Original Year Entered Service	Horsepower Rating	Rated Drilling Depth (In feet)	Location	Status
1	Conv.	1980	2,000	20,000	U.S.	Under Contract
7	Posted	1981	2,000	25,000	U.S.	Cold Stacked
9	Posted	1975	2,000	25,000	U.S.	Under Repair
10	Posted	1981	2,000	25,000	U.S.	Cold Stacked
11	Conv.	1982	3,000	30,000	U.S.	Under Contract
15	Conv.	1981	2,000	25,000	U.S.	Under Contract
17	Posted	1981	3,000	30,000	U.S.	Under Contract
19	Conv.	1996	1,000	14,000	U.S.	Under Contract
20(a)	Conv.	1998	1,000	14,000	U.S.	Cold Stacked
21	Conv.	1982	1,500	15,000	U.S.	Cold Stacked
23	Conv.	1995	1,000	14,000	U.S.	Cold Stacked
27	Posted	1978	3,000	30,000	U.S.	Under Contract
28	Conv.	1979	3,000	30,000	U.S.	Under Contract
29	Conv.	1980	3,000	30,000	U.S.	Under Contract
30	Conv.	1981	3,000	30,000	U.S.	Cold Stacked
31	Conv.	1981	3,000	30,000	U.S.	Cold Stacked
32	Conv.	1982	3,000	30,000	U.S.	Cold Stacked
41	Posted	1981	3,000	30,000	U.S.	Under Contract
46	Posted	1981	3,000	30,000	U.S.	Under Contract
47	Posted	1982	3,000	30,000	U.S.	Cold Stacked
48	Posted	1982	3,000	30,000	U.S.	Under Contract
49	Posted	1980	3,000	30,000	U.S.	Under Contract
52	Posted	1981	2,000	25,000	U.S.	Under Contract
55	Posted	1981	3,000	30,000	U.S.	Under Contract
57	Posted	1978	2,000	25,000	U.S.	Under Contract
61	Posted	1978	3,000	30,000	U.S.	Cold Stacked
64	Posted	1979	3,000	30,000	U.S.	Under Contract

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

Other Drilling Rigs (13)

A submersible rig is a mobile drilling platform that is towed to the well site where it is submerged by flooding its lower hull tanks until it rests on the sea floor, with the upper hull above the water surface. After completion of the drilling operation, the rig is refloated by pumping the water out of the lower hull, so that it can be towed to another location. Submersible rigs typically operate in water depths of 12 to 85 feet. Our three submersible rigs are suitable for deep gas drilling.

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

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Our nine land drilling rigs are completely equipped to drill oil and gas wells. These rigs are designed to be transported by truck and assembled by crane. They require a firm, level area to be erected and sometimes require foundation work to be performed to support the drill floor and derrick. The following table contains information regarding our other rigs as of February 20, 2007.

Rig	Type	Original Year Entered Service	Horsepower Rating	Rated Drilling Depth (In feet)	Location	Status
THE 75	Subm.	1983	N/A	25,000	U.S.	Under Contract
THE 77	Subm.	1983	N/A	30,000	U.S.	Under Contract
THE 78	Subm.	1983	N/A	30,000	U.S.	Under Contract
Rig 3	Plat.	1993	N/A	25,000	Mexico	Under Contract
26	Land	1980	750	6,500	U.S.	Reactivating
27	Land	1981	900	8,000	U.S.	Warm Stacked
36	Land	1982	2,000	18,000	Trinidad	Under Contract
37	Land	1982	2,000	18,000	Venezuela	Under Contract
40	Land	1980	2,000	25,000	Venezuela	Under Contract
42	Land	1981	2,000	25,000	Venezuela	Under Contract
43	Land	1981	2,000	25,000	Venezuela	Under Contract
54	Land	1981	3,000	30,000	Venezuela	Under Contract
55	Land	1983	3,000	35,000	Venezuela	Under Contract

We also own additional offshore equipment that consists of two mat-supported jackup rigs ranging in water depth capacity from 100 feet to 160 feet, that we currently do not anticipate returning to drilling service as we believe doing so would be cost prohibitive. In May 2003, we decided to market these units for non-drilling uses such as production platforms or accommodation units.

Drilling Contracts

Our contracts to provide drilling services are individually negotiated and vary in their terms and provisions. We obtain most of our contracts through competitive bidding against other contractors. Drilling contracts generally provide for payment on a dayrate basis, with higher rates while the drilling unit is operating and potentially lower rates for periods of mobilization or when drilling operations are interrupted or restricted by equipment breakdowns, adverse environmental 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. The contract term in some instances may be extended by the customer exercising options for the drilling of additional wells or for an additional term, or by exercising a right of first refusal.

Historically, most of our drilling contracts have been short-term or on a well-to-well basis. However, we have been able to enter into some longer term contracts. As of February 20, 2007, we had an estimated 3,057 rig days in 2007 and an estimated 836 rig days in later years contracted for under term contracts (as opposed to well-by-well contracts). Included in these estimates are the remaining terms for two contracts we have executed with Pemex Exploration and Production Company (Pemex) for rigs *THE 206* (854 days) and *Platform Rig 3* (433 days) which can be terminated by the customer on five days notice.

Rig Reactivations Against Term Drilling Contracts

We reactivated five of our cold stacked rigs in 2006. In each case, except for *THE 153*, our rig reactivations were supported by term drilling contracts at dayrates sufficient to recover, over the term of the contract, a substantial portion of our expected operating expenses of performing the contract and the anticipated costs of reactivating the rig.

Reactivations of *THE 77, THE 78,* and *THE 252* were completed in 2006 and the reactivation of *THE 153* was completed in January 2007. Rig reactivation expenses for these four rigs totaled $65.9 million as of December 31, 2006. Included in the total for these rigs are $22.3 million in expense to complete *THE 77*, $12.3 million in expense to complete *THE 78* and $12.1 million in expense to complete *THE 252. THE 153* had incurred $19.2 million in expense as of December 31, 2006. Delayed completions and cost overruns caused reactivation expenses to be higher than originally anticipated. In addition*, Rig 1*, a conventional inland barge, incurred reactivation expenses totaling $2.0 million.

In February 2006, we signed a contract to reactivate *THE 256*, a jackup drilling rig, against a one-year term contract. The cost to reactivate the rig was estimated at $18.6 million. In May 2006, while reactivation work was in progress, *THE 256* suffered fire damage. As a result of the fire, the contract was rescinded in July 2006. The damage and repair costs are estimated to be in excess of $20 million for which we have made a claim under our insurance policies. We have also filed a lawsuit against the shipyard to recover the cost of the damages incurred. While we cannot be certain about the amount of recovery from the shipyard, we believe that under our insurance policies we should be able to recover approximately $7 to $11 million, net of our deductible and 30% quota share depending upon whether the rig is determined to be a partial loss or a total constructive loss. The timing of the actual repairs to the rig will be based upon final resolution of our insurance claim and future market demand for reactivation of the rig. As of December 31, 2006, we had incurred $6.5 million of expense related to this reactivation prior to the fire.

Our *THE 208* drilling rig, a 200-foot mat-supported cantilevered jackup rig, was constructed in 1980 and has been cold stacked in Trinidad since March, 2002. The rig is currently being transported to a shipyard in Southeast Asia where it will undergo an extensive shipyard reactivation and upgrade which will include conversion from a mechanically driven rig to a conventionally powered SCR rig. While final reactivation and upgrade costs as well as the exact timing for reactivation of *THE 208* remain uncertain as we are in the process of finalizing bids from several shipyards, it is anticipated, subject to final award of the drilling contract, that the rig will begin drilling operations under a three-year drilling program in Malaysia by the end of 2007.

We plan to continue our efforts to obtain term contracts with our customers to reactivate and return to service all five of our remaining cold stacked rigs in the U.S. Gulf of Mexico. The willingness of a customer to enter into a rig reactivation term contract with us generally depends, however, on the presence of strong market demand for jackup rigs and, more importantly, on the customer s expectation that jackup rig dayrates and utilization levels are likely to remain strong or increase during the customer s upcoming drilling program. Demand for our jackup rigs in the Gulf of Mexico, as measured by the dayrates we are able to charge on new drilling contracts, weakened beginning in the second quarter of 2006 and currently remains slightly lower than the dayrates we charged during the first quarter of 2006. We believe this is primarily attributable to the lower prices for natural gas and to our customers uncertainty about the future price of natural gas. Due to this weakened demand, we expect that any further reactivations of our cold stacked jackup rigs will not begin until late 2007 or into 2008. By then, we believe that customers may be more willing to enter into term contracts because the supply of jackup rigs in the Gulf of Mexico may be reduced by previously announced departures of rigs for international waters.

We estimate that approximately $20 to $30 million would be required to return each of our five cold stacked jackup rigs to service for the U.S. Gulf of Mexico. Additionally, if we are able to obtain term contracts with customers, we will reactivate and return to service our remaining cold stacked 2,000 or 3,000 horsepower inland barge rigs. Based upon our historical experience and previous rig reactivation assessments we believe the estimated costs to prepare our inland barge rigs for service would be approximately $10 to $15 million per rig. The amounts we estimate for restoring cold stacked rigs to service are based on our projections of the costs of equipment, supplies and services, which have been rising and are becoming more difficult to project. In order to provide better estimates of the costs that will be incurred to reactivate rigs, we have performed rig reactivation assessment surveys on four of these rigs, *THE 254*, *THE 191*, *THE 155* and *THE 255*, in 2006 at an aggregate cost of $9.4 million. In addition to the uncertainty of projecting costs in a time of increasing prices, our estimates of rig reactivation costs are also subject to numerous other variables including further rig deterioration over time, the availability and cost of shipyard facilities, customer specifications, and the actual extent of required repairs and maintenance and optional upgrading of the rigs. The actual amounts we ultimately pay for returning these rigs to service could, therefore, vary substantially from our estimates.

Delta Towing

Delta Towing owns and operates towing vessels and barges used primarily to transport and store equipment and material to support jackup and barge rig drilling operations and also to transport the associated operating personnel. Delta Towing utilizes rig moving tugs, utility barges, service tugs and crewboats in connection with its operations. Although these assets can be deployed for other uses, a significant downturn in oil and gas activity in the transition zone would have a negative impact on Delta Towing s business that could not be fully offset by deployment of such assets to other markets. As of February 16, 2007, Delta Towing s operating assets consisted of 42 inland tugs, 19 offshore tugs, 36 crewboats, 30 deck barges, 17 shale barges, four spud barges and one offshore barge. Vessels are generally contracted on a rate per day or rate per hour of service basis pursuant to short-term contracts.

Prior to January 1, 2006, we owned a 25% equity interest in Delta Towing. In January 2006, we purchased the remaining 75% interest in Delta Towing for $1.1 million, including the extinguishment of Delta Towing s $2.9 million related party note payable held by Edison Chouest Inc. (Chouest). For further discussion refer to Management s Discussion and Analysis of Financial Condition and Results of Operations Delta Towing and Notes 4 and 5 to our consolidated financial statements included in Item 8 of this report.

Customers

No customer accounted for 10% or greater of our operating revenues in 2006. Nonetheless, the loss of any significant customer could, at least in the short term, have a material adverse effect on our results of operations.

Competitors

The shallow water U.S. Gulf of Mexico and U.S. inland marine drilling businesses in which we operate are highly competitive. We believe we are the largest jackup rig contractor in the shallow water U.S. Gulf of Mexico and the largest inland barge contractor in the U.S. Our principal competitor in the inland marine barge drilling business is Parker Drilling Co. In the shallow water U.S. Gulf of Mexico, we compete with numerous industry participants, none of which has a dominant market share. Drilling contracts are traditionally awarded on a competitive bid basis. Pricing is often the primary factor in determining which qualified contractor is awarded a job, although rig availability, safety record, crew quality and technical capability of service and equipment may also be considered. Many of our competitors in the shallow water U.S. Gulf of Mexico 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.

Delta Towing also operates in a very competitive business. Vessels are generally contracted on a rate per day or rate per hour basis and pricing is based on suitability and availability of equipment, which can be very competitive. Most of our competitors are privately held companies.

Regulation

Our operations are affected in varying degrees by governmental laws and regulations. The drilling industry is dependent on demand for services from the oil and gas industry and, accordingly, is also affected by changing tax and other laws relating to the energy business generally. Our operations are affected by requirements of a number of governmental agencies with authority to regulate our marine and onshore activities, including various requirements to develop security plans to address terrorism risks and plans to prevent and respond to releases to the environment.

The transition zone and shallow water areas of the U.S. Gulf of Mexico are ecologically sensitive. Environmental issues have led to higher drilling costs, a more difficult and lengthy well permitting process and, in general,

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have adversely affected decisions of oil and gas companies to drill in these areas. In the United States, regulations applicable to our operations include regulations controlling the discharge of materials into the environment, requiring removal and cleanup of materials that may harm the environment or otherwise relating to the protection of the environment. For example, as an operator of mobile offshore drilling 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 requirements could have a material adverse effect on our consolidated results of operations, financial position or cash flows.

The U.S. Federal Water Pollution Control Act of 1972, commonly referred to as the Clean Water Act, prohibits the discharge of pollutants into the navigable waters of the United States without a permit. The regulations implementing the Clean Water Act require permits to be obtained by an operator before specified exploration activities occur. Offshore facilities must also prepare plans addressing spill prevention control and countermeasures. Challenges arising largely out of foreign invasive species contained in discharges of ballast water resulted in a 2006 court order that vacated, as of September 30, 2008, an exemption from Clean Water Act discharge permit requirements for discharges incidental to normal operation of a vessel. This decision may result in imposition of permit or other requirements on the discharges of ballast water and other vessel wastewaters. Violations of monitoring, reporting and permitting requirements can result in the imposition of civil and criminal penalties.

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, including those relating to proof of financial responsibility, or inadequate cooperation in the event of a spill could subject a responsible party to civil or criminal enforcement action.

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 (CERCLA), also known as 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 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. We could be subject to liability under CERCLA principally in connection with our onshore activities. 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.

Our non-U.S. contract drilling operations are subject to various laws and regulations in countries in which we operate, including laws and regulations relating to the importation of and operation of drilling units, currency conversions and repatriation, oil and gas exploration and development, environmental protection, taxation of offshore earnings and earnings of expatriate personnel, the use of local employees and suppliers by foreign contractors and duties on the importation and exportation of drilling 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 gas and other aspects of the oil and 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 gas companies and may continue to do so. Operations in less developed countries can be subject to legal systems that are not as mature or predictable as those in more developed countries, which can lead to greater uncertainty in legal matters and proceedings.

Although significant capital expenditures may be required to comply with these governmental laws and regulations, such compliance has not materially adversely affected our earnings or competitive position.

Insurance

In October 2006, we extended our principal insurance coverages for property damage, liability and occupational injury and illness for a five month term. Generally, our deductible levels under the hull and machinery policies are 15% of individual insured asset values per occurrence except in the event of a total loss only where the deductible would be zero. An annual limit of $75.0 million and a minimum deductible of $5.0 million per occurrence apply in the event of a windstorm. In an effort to control premium costs, our insurance coverage will continue to cover 70% of our losses in excess of the applicable deductible and we will self insure the remaining 30% of any such losses. The primary marine package also provides coverage for cargo, control of well, seepage, pollution and property in our care, custody and control. Our deductible for this coverage varies between $250,000 and $1.0 million per occurrence depending upon coverage line. In addition to our marine package, we have separate policies providing coverage for general domestic liability, employer s liability, domestic auto liability and non-owned aircraft liability with $1.0 million deductibles per occurrence. We also have an excess liability policy that extends our coverage to an aggregate of $200.0 million under all of these policies. Our insurance program also includes separate policies that cover certain liabilities in foreign countries where we operate.

The five-month extension did not increase our premium cost, which remained at approximately $15.0 million per annum under these policies, nor did it change our hull and machinery insured value from approximately $1.1 billion. We believe our current insurance coverage, deductibles and the level of risk involved is adequate and reasonable. However, insurance premiums and/or deductibles could be increased or coverages may be unavailable in the future.

Effective March 1, 2007, we renewed our hull and machinery insurance with essentially the same terms and conditions as our previous policy. However, we increased our insured values from $1.1 billion to $1.8 billion and decreased our deductible per occurrence from 15% of insured asset values to 10% of insured asset values except in the event of a total loss in which case the deductible is zero. Total premiums for our new hull and machinery policy are $13.3 million.

Employees

As of December 31, 2006, the Company had approximately 3,030 employees. Approximately 378 (or 12.5%) of the Company s employees worldwide were working under collective bargaining agreements, approximately 84 of whom were working in Trinidad and 294 of whom were working in Venezuela. The company s union agreement in Trinidad is in effect through August 31, 2008. The union agreement in Venezuela expired on December 31, 2006. However, the government has refused to start any negotiation with the union until the second quarter of 2007. Until then, the employees continue to work under the terms of the previous union agreement. Efforts have been made from time to time to unionize other portions of our workforce, including workers in the U.S. Gulf of Mexico.

IPO and Separation from Transocean

Before our initial public offering in February 2004 (the IPO), we were a wholly-owned subsidiary of Transocean Inc. (Transocean). In the IPO, Transocean sold 13,800,000 shares of our Class A common stock. Subsequently, secondary stock offerings were completed in September 2004, December 2004 and May 2005 in which Transocean sold an additional 17,940,000, 14,950,000 and 13,310,000 shares, respectively, of our Class A common stock. At the closing of the December 2004 stock offering, Transocean converted all of its unsold shares of our Class B common stock into an equal number of shares of Class A common stock. By June 30, 2005, Transocean had sold all of its remaining shares of our common stock. We did not receive any proceeds from the IPO, the secondary offerings or other sales of our common stock by Transocean.

Prior to the IPO, we entered into several agreements with Transocean defining the terms of the separation of our business from Transocean s business. These agreements included a Master Separation Agreement which defined our separate businesses and provided for allocations of responsibilities and rights in connection therewith and a Tax Sharing Agreement which allocated certain rights and responsibilities with respect to pre- and post-IPO taxes.

We were incorporated in Delaware in 1997 as R&B Falcon Corporation and became a wholly-owned subsidiary of Transocean in 2001. Our name was changed to TODCO in preparation for the IPO in December 2002. See Notes 1, 3, 5, and 11 in the accompanying Notes to Consolidated Financial Statements included in Item 8 of this report for further discussion concerning the general development of our business and our separation from Transocean.

Available Information

Our website address is *www.theoffshoredrillingcompany.com.* We make available on this website, free of charge, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports as soon as reasonably practicable after we electronically file those reports with, or furnish those reports to, the Securities and Exchange Commission (SEC). We make our website content available for information purposes only. It should not be relied upon for investment purposes, nor is it incorporated by reference in this Form 10-K. The SEC maintains an Internet site (*www.sec.gov*) that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC, including us.

Our website also includes our Corporate Governance Guidelines, our Code of Business Conduct and Ethics and the charters for the Audit Committee, the Executive Compensation Committee and the Corporate Governance Committee of our Board of Directors. Each of these documents is also available in print to any stockholder who requests a copy by addressing a request to our executive offices located at 2000 W. Sam Houston Parkway South, Suite 800, Houston, Texas 77042, Attention: Corporate Secretary. Our telephone number is (713) 278-6000.

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

Our business, financial condition, results of operations and the trading prices of our securities can be materially and adversely affected by many events and conditions including the following:

Risks Related to Our Business

Our business depends primarily on the level of activity in the oil and gas industry in the U.S. Gulf Coast, which is significantly affected by often volatile oil and natural gas prices.

Our business depends on the level of activity in oil and gas exploration, development and production primarily in the U.S. Gulf Coast (our term for the U.S. Gulf of Mexico shallow water and inland marine region). Oil and natural gas prices and our customers expectations of potential changes in these prices significantly affect this level of activity. In particular, as the price of natural gas has decreased, we have recently experienced a weakened demand for our services because we primarily drill in the U.S. Gulf Coast where the focus of drilling has tended to be on the search for natural gas. Oil and natural gas prices are extremely volatile and are affected by numerous factors, including the following:

- the demand for oil and natural gas in the United States and elsewhere,
- economic conditions in the United States and elsewhere,

weather conditions in the United States and elsewhere,

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 gas reserves, and

the worldwide military and political environment, including uncertainty or instability resulting from an escalation or additional outbreak of armed hostilities or other crises in the Middle East or the geographic areas in which we operate or further acts of terrorism in the United States, or elsewhere.

Depending on the market prices of oil and natural gas, companies exploring for oil and gas may cancel or curtail their drilling programs, thereby reducing demand for drilling services. In the U.S. Gulf Coast, drilling contracts are generally short-term, and oil and gas companies tend to respond quickly to upward or downward changes in oil and natural gas prices. Any reduction in the demand for drilling services may materially erode dayrates and utilization rates for our rigs and adversely affect our financial results.

The U.S. Gulf Coast is a mature oil and gas production region that has experienced substantial seismic survey and exploration activity for many years. Because a large number of oil and gas prospects in this region have already been drilled, additional prospects of sufficient size and quality could be more difficult to identify. In addition, oil and gas companies may be unable to obtain financing necessary to drill prospects in this region. This could result in reduced drilling activity in the U.S. Gulf Coast region. We expect demand for our drilling services in this area to continue to fluctuate with the cycles of reduced and increased overall domestic rig demand, and demand at similar points in future cycles could be lower than levels experienced in past cycles.

Our industry is highly cyclical, and our results of operations may be volatile.

Our industry is highly cyclical, with periods of high demand and high dayrates followed by periods of low demand and low dayrates. Periods of low rig demand intensify the competition in the industry and often result in rigs being idle for long periods of time. We may be required to idle rigs or enter into contracts at lower rates in response to market conditions in the future. Due to the short-term nature of most of our drilling contracts, changes in market conditions can quickly affect our business. As a result of the cyclical nature of our industry, our results of operations have been volatile, and we expect this volatility to continue.

Our industry is highly competitive, with intense price competition.

The shallow water U.S. Gulf of Mexico and inland marine drilling businesses in which we operate are highly competitive. Drilling contracts are traditionally awarded on a competitive bid basis. Pricing is often the primary factor in determining which qualified contractor is awarded a job. The competitive environment has intensified as recent mergers among oil and gas companies have reduced the number of available customers. Many other offshore drilling companies are larger than we are and have more diverse fleets, or fleets with generally higher specifications, and greater resources than we have. This allows them to better withstand industry downturns, better compete on the basis of price and build new rigs or acquire existing rigs, all of which could affect our revenues and profitability. We believe that competition for drilling contracts will continue to be intense in the foreseeable future.

The increase in the number of rigs in the Gulf of Mexico could create an excess supply of jackup rigs in this area and adversely affect utilization rates and dayrates for our rigs.

If, as a result of improved industry conditions in the Gulf of Mexico, inactive rigs that are currently not being marketed continue to be reactivated, jackup rigs or other mobile offshore drilling units are moved into the U.S. Gulf Coast from other regions or increased rig construction or rig upgrade programs by our competitors continue, a significant increase in the supply of jackups in the Gulf of Mexico could occur. Some of our competitors and speculators have ordered new jackup drilling rigs. We believe there are currently 66 jackup rigs on order with delivery dates ranging from 2007 to 2010. Most of the rigs on order are premium, cantilevered drilling units with 350 to 400 foot water depth capability. This trend of new jackup construction or other increases in the supply of jackup or other mobile offshore drilling units could curtail a further strengthening of utilization rates and dayrates, or reduce them.

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Rig upgrade, refurbishment, repair and reactivation 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 significant upgrade, refurbishment and repair expenditures for our fleet from time to time, particularly in light of the aging nature of our rigs. Some of these expenditures are unplanned. All of these projects may be subject to the risks of delay or cost overruns, including cost overruns or delays resulting from the following:

- unexpectedly long delivery times for, or shortages of, 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 design or engineering problems,
- unanticipated actual or purported change orders,
- disputes with shipyards and suppliers,
- work stoppages,
- financial or other difficulties at shipyards,
- adverse weather conditions, and
- inability to obtain required permits or approvals.

Significant cost overruns or delays could materially affect our financial condition and results of operations. Additionally, capital expenditures for rig upgrade, refurbishment and reactivation projects could materially exceed our planned capital expenditures. Moreover, our rigs undergoing upgrade, refurbishment and reactivation may not earn a dayrate during the period they are out of service.

Our ability to move our rigs to other regions is limited.

Most jackup and submersible rigs can be moved from one region to another, and in this sense the marine contract drilling market is a global market. Nevertheless, the demand/supply balance for jackup and submersible rigs may vary somewhat from region to region. This is because the cost of moving a rig is significant and there is limited availability of rig-moving vessels. Additionally, some rigs are designed to work in specific regions, in certain water depths or over certain types of seafloor conditions. Significant variations between regions tend not to exist on a long-term basis due to the ability to move rigs. However, because many of our rigs were designed for drilling in the U.S. Gulf Coast, our ability to move our rigs to other regions in response to changes in market conditions is limited.

Our jackup rigs are at a relative disadvantage to higher specification rigs.

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 jackups and other rigs may be more likely to obtain contracts than lower specification jackups. As a result, our lower specification jackups have in the past been stacked earlier in the cycle of decreased rig demand than most of our competitors   jackups and have been reactivated later in the cycle. This pattern has adversely impacted our business and could be repeated. In addition, higher specification rigs have greater flexibility to move to areas of demand in response to changes in market conditions. Furthermore, in recent years, an increasing amount of exploration and production expenditures have been concentrated in deep water drilling programs and deeper formations, including deep gas prospects, requiring higher specification jackups, semi-submersible 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.

Our business involves numerous operating hazards, and we are not fully insured against all of them.

Our operations are subject to the usual hazards inherent in the drilling of oil and 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 operations, claims by the operator, damage to or destruction of the equipment involved and injury or death to rig personnel. We may also be subject to personal injury and other claims of rig personnel as a result of our drilling operations. Operations also may be suspended because of machinery breakdowns, abnormal drilling conditions, failure of subcontractors to perform or supply goods or services and personnel shortages. In addition, offshore and inland marine drilling operators are subject to perils peculiar to marine operations, including capsizing, grounding, collision and loss or damage from severe weather. Damage to the environment could also 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 the government, oil and gas companies and other private parties. 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.

In October 2006, we extended our principal insurance coverages for property damage, liability and occupational injury and illness for a five month term. The five-month extension did not increase our premium cost, which remained at approximately $15.0 million per annum under these policies, nor did it change our hull and machinery insured value from approximately $1.1 billion. Our insurance continues to cover 70% of our losses over the applicable deductibles and we self insure the remaining 30% of such losses. In the future, we may experience significant premium increases or we may be required to reduce the percentage of our losses that would be covered by insurance.

Effective March 1, 2007, we renewed our hull and machinery insurance with essentially the same terms and conditions as our previous policy. However, we increased our insured values from $1.1 billion to $1.8 billion and decreased our deductible per occurrence from 15% of insured asset values to 10% of insured asset values except in the event of a total loss in which case the deductible is zero. Total premiums for our new hull and machinery policy are $13.3 million.

If a significant accident or other event, including terrorist acts, war, civil disturbances, pollution or environmental damage, occurs that is not fully covered by insurance or a recoverable indemnity from a customer, it could adversely affect our consolidated results of operation, financial position and cash flows. 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 litigation.

We are also from time to time involved in a number of litigation matters, including, among other things, contract disputes, personal injury, environmental, asbestos and other toxic tort, employment, tax and securities litigation, and other litigation that arises in the ordinary course of our business. Litigation may have an adverse effect on us because of potential adverse outcomes, the costs associated with defending the lawsuits, the diversion of our management s resources and other factors.

Failure to retain key personnel could hurt our operations.

We require highly skilled personnel to operate and provide technical services and support for our drilling rigs. To the extent that demand for drilling services and the number of operating rig increases, shortages of qualified personnel could arise, creating upward pressure on wages and difficulty in staffing rigs.

Loss of key members of our management team could hurt our operations.

Our success is to a considerable degree dependent on the services of key members of our management team, including Jan Rask, our President and Chief Executive Officer. The loss of any key member of our management team could adversely affect our results of operations.

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Unionization efforts could increase our costs or limit our flexibility.

A small percentage of our employees worldwide work under collective bargaining agreements, all of whom work in Venezuela and Trinidad. Efforts have been made from time to time to unionize other portions of our workforce, including workers in the Gulf of Mexico. Any such unionization could increase our costs and limit our flexibility.

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

Our operations are affected in varying degrees by governmental laws and regulations. The drilling industry is dependent on demand for services from the oil and gas industry and, accordingly, is also affected by changing tax and other laws relating to the energy business generally. We may be required to make significant capital expenditures to comply with laws and regulations. It is also possible that these laws and regulations may in the future add significantly to operating costs or may limit drilling activity.

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 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 or the adoption of new requirements could have a material adverse effect on our consolidated results of operations, financial position or cash flows.

Our non-U.S. operations involve additional risks not associated with our U.S. operations.

We operate in regions that may expose us to political and other uncertainties, including risks of:

- terrorist acts, war and civil disturbances,
- expropriation or nationalization of property and equipment,
- the inability to repatriate income or capital, and
- foreign currency devaluations and the inability to convert foreign currency into U.S. dollars.

Our insurance policies and indemnity provisions in our drilling contracts generally do not protect us from loss of revenue. If a significant accident or other event occurs and is not fully covered by insurance or a recoverable indemnity from a customer, it could adversely affect our consolidated results of operations, financial position or cash flows.

Many governments favor or effectively require the awarding of drilling contracts to local contractors or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. These practices may adversely affect our ability to compete.

Our non-U.S. contract drilling operations are subject to various laws and regulations in countries in which we operate, including, but not limited to, laws and regulations relating to the equipment and operation of drilling units, currency conversions and repatriation, oil and 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 drilling rigs 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 gas and other aspects of the oil and 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 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.

Another risk inherent in our operations is the possibility of currency exchange losses where revenues are received and expenses are paid in foreign currencies. 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.

Our Venezuela operations are subject to adverse political and economic conditions.

A portion of our operations is conducted in the Republic of Venezuela, which has been experiencing political and economic turmoil, including labor strikes and demonstrations. The implications and results of the political, economic and social instability in Venezuela are uncertain at this time, but the instability could have an adverse effect on our business. Depending on future developments, we could decide to cease operations in Venezuela. Venezuela also imposes foreign exchange controls that limit our ability to convert local currency into U.S. dollars and transfer excess funds out of Venezuela. Although our current drilling contracts in Venezuela call for a significant portion of our dayrates to be paid in U.S. dollars, changes in existing regulation or the interpretation or enforcement of those regulations could further restrict our ability to receive U.S. dollar payments. The exchange controls could also result in an artificially high value being placed on the local currency.

Risks Related to Our Tax Sharing Agreement

Our tax sharing agreement with Transocean could require substantial payments by us if an event occurs that accelerates the utilization or deemed utilization of pre-IPO tax benefits or an event could occur that may delay the utilization of the pre-IPO tax benefits.

We and Transocean, our former parent corporation, are parties to a tax sharing agreement that was originally entered into in connection with our February 2004 IPO. The tax sharing agreement was amended and restated in November 2006 in a negotiated settlement of certain disputes between Transocean and us over the terms of the original tax sharing agreement. The tax sharing agreement may require us to make substantial payments to Transocean. For example, the agreement provides that we must pay Transocean for substantially all pre-IPO tax benefits utilized or deemed to have been utilized subsequent to the IPO. It also provides that if any person other than Transocean or its subsidiaries becomes the beneficial owner of greater than 50% of the total voting power of our outstanding voting stock, we will be deemed to have utilized all of the pre-IPO tax benefits, and we will be required to pay Transocean an amount for the deemed utilization of these tax benefits adjusted by a specified discount factor. This payment is required even if we are unable to utilize the pre-IPO tax benefits. As of December 31, 2006, we had approximately $195 million of estimated pre-IPO income tax benefits subject to the obligation to reimburse Transocean. If an acquisition of beneficial ownership had occurred on December 31, 2006, the estimated amount we would have been required to pay Transocean would have been approximately $137 million, or 70% of the pre-IPO tax benefits at December 31, 2006. As of January 1, 2007, we will be required, under the terms of the Amended and Restated Tax Sharing Agreement, to pay Transocean 80% of the pre-IPO tax benefits if an acquisition of beneficial ownership occurs. Our requirement to make this payment could have the effect of delaying or preventing a change of control. Our obligation to make a potentially substantial payment to Transocean may deter transactions that would trigger a payment under the tax sharing agreement, such as a merger in which we are not the surviving company or a merger in which more than 50% of the aggregate voting power of our stock becomes owned by a single person or group of related persons. Even if we complete such a transaction, our obligation to make a substantial payment to Transocean could result in a lower economic benefit of such a transaction to our other stockholders than those stockholders could have received if we had not entered into the tax sharing agreement. We are also obligated to make certain other payments to Transocean under the tax sharing agreement. See Management s Discussion and Analysis of Financial

Condition and Results of Operations Transactions with Former Parent Tax Sharing Agreement .

Furthermore, even though Transocean no longer owns any shares of our common stock, the tax sharing agreement provides that Transocean will continue to have substantial control over our filing of tax returns so long as there remains a present or potential obligation for us to pay Transocean for pre-IPO tax benefits. See Note 11 to our consolidated financial statements for the period ended December 31, 2006 included in Item 8 of this report and Management s Discussion and Analysis of Financial Condition and Results of Operations Transactions with Former Parent Tax Sharing Agreement .

The tax sharing agreement with Transocean also provides that if any of our subsidiaries that join with us in the filing of consolidated returns ceases to do so, we will be deemed to have used that portion of any pre-IPO tax benefits that will be allocable to the subsidiary following that cessation, and we will generally be required to pay Transocean the amount of this deemed tax benefit, adjusted by a specified discount factor, at the time the subsidiary ceases to join in the filing of these returns.

Payment of amounts for the deemed utilization of tax benefits by us could require additional financing. The amount of our payments to Transocean will not be adjusted for any difference between the tax benefits that we are deemed to utilize and the tax benefits that we actually utilize, and the difference between these amounts could be substantial. Among other considerations, applicable tax laws may significantly limit our use of these tax benefits, and these limitations are not taken into account in determining the amount of the payment to Transocean.

Our tax sharing agreement with Transocean could delay or preclude us from realizing post-IPO tax benefits.

The tax sharing agreement with Transocean provides that if the utilization of a pre-IPO tax benefit defers or precludes our utilization of any post-IPO tax benefit, our payment obligation with respect to the pre-IPO tax benefit generally will be deferred until we actually utilize that post-IPO tax benefit. This payment deferral will not apply with respect to, and we will have to pay currently for the utilization of pre-IPO tax benefits to the extent of (a) up to 20% of any deferred or precluded post-IPO tax benefit arising out of our payment of foreign income taxes, and (b) 100% of any deferred or precluded post-IPO tax benefit arising out of a carryback from a subsequent year. Therefore, we may not realize the full economic value of tax deductions, credits and other tax benefits that arise post-IPO until we have utilized all of the pre-IPO tax benefits, if ever.

Other Risks

We could incur substantial losses during industry downturns and may need additional financing to withstand industry downturns.

Although we recognized net income of $183.6 million and $59.4 million for the years ended December 31, 2006 and 2005, respectively, our net loss was $28.8 million for the year ended December 31, 2004, and we could incur substantial losses during future cyclical downturns in our industry. During cyclical downturns in our industry, we may need additional financing in order to satisfy our cash requirements. If we are not able to obtain financing in sufficient amounts and on acceptable terms, we may be required to reduce our business activities, seek financing on unfavorable terms or pursue a business combination with another company.

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

We have no plans to pay regular dividends on our common stock. We generally intend to invest our future earnings, if any, to fund our growth. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends, and other considerations that our board of directors deems relevant. Our credit facility also includes limitations on our payment of dividends. In 2005, due to favorable business conditions, our unrestricted cash balances grew to levels that exceeded our foreseeable needs for cash held for reinvestment and unknown contingencies. We secured the approval of our lenders and our board of directors declared a special cash dividend of $1.00 per share that was paid in 2005. This special cash dividend is not indicative of a change in our basic dividend policy nor does it guarantee that any future dividends will be paid. Accordingly, investors may have to sell some or all of their common stock in order to generate cash flow from their investment. Investors may not receive a gain on their investment when they sell our common stock and may lose the entire amount of the investment.

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Our rights agreement and provisions in our charter documents may inhibit a takeover, which could adversely affect the value of our common stock.

Our amended and restated certificate of incorporation and bylaws contain provisions that could delay or prevent a change of control or changes in our management that a stockholder might consider favorable. These provisions include:

classification of the members of our board of directors into three classes, with each class serving a staggered three-year term,

requiring our stockholders to give advance notice of their intent to make nominations for the election of directors or to submit a proposal at an annual meeting of the stockholders,

limitations on the ability of our stockholders to amend specified provisions of our amended and restated certificate of incorporation and bylaws,

the denial of any right of our stockholders to act by unanimous written consent in lieu of a meeting,

the denial of any right of our stockholders to remove members of our board of directors except for cause, and

the denial of any right of our stockholders to call special meetings of the stockholders.

We are also party to a rights agreement that could delay or prevent a change of control that a stockholder might consider favorable.

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

None.

Item 2. ***Properties***

We maintain our principal executive offices in Houston, Texas and have operational offices in Houma, Louisiana; Maturin, Venezuela; La Romaine, Trinidad; Luanda, Angola; Rio de Janeiro, Brazil; and Ciudad del Carmen, Mexico. We also have warehouse and yard facilities in Houma, Louisiana, La Romaine, Trinidad and Maturin, Venezuela. We lease all of these facilities, except for the warehouse and yard facilities in Maturin, Venezuela.

Item 3. ***Legal Proceedings***

TODCO vs. Transocean Inc. and Transocean Holdings Inc.. We were engaged in an arbitration proceeding against our former parent corporation, Transocean Inc. (NYSE: RIG) and its subsidiary, Transocean Holdings Inc. (collectively, Transocean), over disputes arising out of the Tax Sharing Agreement that we entered into with Transocean in connection with our initial public offering in 2004. A negotiated settlement of that dispute was reached on November 27, 2006. As a result of the settlement, we and Transocean executed an Amended and Restated Tax Sharing Agreement reflecting the terms of the settlement. For more information concerning this dispute and its negotiated settlement see Management s Discussion and Analysis of Financial Condition and Results of Operations Transactions with Former Parent Tax Sharing Agreement .

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

Robert E. Aaron et al. vs. Phillips 66 Company et al. Circuit Court, Second Judicial District, Jones County, Mississippi. This is the case name used to refer to several cases filed in the Circuit Courts of the State of Mississippi involving 768 persons that alleged personal injury arising out of asbestos exposure in the course of their employment by the defendants between 1965 and 2002. The complaints named as defendants, among others, certain

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of our subsidiaries and certain of Transocean s subsidiaries to whom we may owe indemnity and other unaffiliated defendant companies, including companies that allegedly manufactured drilling related products containing asbestos that are the subject of the complaints. The number of unaffiliated defendant companies involved in each complaint ranged from approximately 20 to 70. The complaints allege that the defendant drilling contractors used asbestos-containing products in offshore drilling operations, land based drilling operations and in drilling structures, drilling rigs, vessels and other equipment and assert claims based on, among other things, negligence and strict liability, and claims authorized under the Jones Act. The plaintiffs seek, among other things, awards of unspecified compensatory and punitive damages. All of these cases were assigned to a special master who approved a form of questionnaire to be completed by plaintiffs so that claims made would be properly served against specific defendants. As of the date of this report, approximately 699 questionnaires were returned and the remaining plaintiffs, who did not submit a questionnaire reply, have had their suits dismissed without prejudice. Of the respondents, approximately 103 shared periods of employment by Transocean and us which could lead to claims against either company, even though many of these plaintiffs did not state in their questionnaire answers that the employment actually involved exposure to asbestos. After providing the questionnaire, each plaintiff was further required to file a separate and individual amended complaint naming only those defendants against whom they had a direct claim as identified in the questionnaire answers. Defendants not identified in the amended complaints were dismissed from the plaintiffs litigation. To date, three plaintiffs named us as a defendant in their amended complaints. It is possible that some of the plaintiffs who have filed amended complaints and have not named us as a defendant may attempt to add us as a defendant in the future when case discovery begins and greater attention is given to each individual plaintiff s employment background. We continue to monitor a small group of these other cases. We have not determined which entity would be responsible for such claims under the Master Separation Agreement between Transocean and us. We have not yet had an opportunity to conduct any additional discovery to verify the number of plaintiffs, if any, that were employed by our subsidiaries or Transocean s subsidiaries or otherwise have any connection with our or Transocean s drilling operations. We intend to defend ourselves vigorously and, based on the limited information available at this time, we do not expect the ultimate outcome of these lawsuits to have a material adverse effect on our consolidated results of operations, financial position or cash flows.

Under a master separation agreement entered into in connection with our IPO, Transocean has agreed to indemnify us for any losses we incur as a result of the legal proceedings described in the following paragraph.

In December 2002, we received an assessment for corporate income taxes from SENIAT, the national Venezuelan tax authority, of approximately $20.7 million (based on current exchange rates and inclusive of penalties) relating to calendar years 1998 through 2000. In March 2003, we paid approximately $2.6 million of the assessment, plus approximately $0.3 million in interest, and are contesting the remainder of the assessment. After we made the partial assessment payment, we received a revised assessment in September 2003 of approximately $16.7 million (based on current exchange rates and inclusive of penalties). Thereafter, we filed an administrative tax appeal with SENIAT and the tax authority rendered a decision that reduced the tax assessment to $8.1 million based on the current exchange rates at the time of the decision). We then initiated a judicial tax court appeal with the Venezuelan Tax Court to set aside the $8.1 million administrative tax assessment. We do not expect the ultimate resolution of this assessment to have an impact on our consolidated results of operations, financial condition or cash flows.

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

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

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

None during the fourth quarter of 2006.

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PART II

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

Our common stock is listed on the New York Stock Exchange (NYSE) under the symbol THE. As required by the listed company rules of the NYSE, our Chief Executive Officer certified to the NYSE on May 16, 2006, that he was not aware of any violation by TODCO of NYSE corporate governance listing standards as of that date.

On May 9, 2006, our stockholders approved certain amendments to the TODCO Third Amended and Restated Certificate of Incorporation that included the elimination of the Class B common stock. As a result, we now only have one class of our common stock. As of February 26, 2007, there were approximately 268 holders of record of our common stock. We have presented in the table below, for the periods indicated, the reported high and low sales prices for our common stock on the NYSE.

	Common Stock of Our Price per Share	
Calendar Period	**High**	**Low**
2006		
Fourth Quarter	$ 40.91	$ 30.05
Third Quarter	41.00	31.81
Second Quarter	53.86	33.00
First Quarter	47.20	32.40
2005		
Fourth Quarter	$ 49.75	$ 35.53
Third Quarter	43.03	25.85
Second Quarter	27.45	19.67
First Quarter	28.55	16.84

On February 21, 2007, the last reported sales price of our common stock was $33.03 per share.

Issuer Purchases of Equity Securities

In August 2006, our Board of Directors authorized the repurchase of up to $150.0 million of our common stock. We repurchased and retired $150.0 million of our common stock, which amounted to 4.2 million shares at an average price of $35.55 per share. The repurchase was funded with existing cash balances. Total consideration of $150.2 million paid to repurchase the shares and the related brokerage commissions was recorded in stockholders equity as a reduction in common stock and additional paid-in capital. Currently, we have no further plans nor authorization to repurchase additional company stock.

We sometimes accept the surrender of shares of our common stock to offset tax withholding obligations in connection with the vesting of restricted stock issued to employees under our stockholder-approved long-term incentive plans. The following table sets forth information concerning these surrenders of our common stock for the periods indicated in 2006:

Period	(a) Total Number of Shares Purchased(1)		(b) Average Price Paid per Share(1)	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
February 2006	25,744	$	42.07	NA	NA

(1) Based upon the closing price of our common stock on the New York Stock Exchange on the date of surrender.

Common Stock Dividends

We have no plans to pay regular dividends on our common stock. We generally intend to invest our future earnings, if any, to fund our growth. Subject to Delaware law, any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends, and other considerations that our board of directors deems relevant. Our credit facility also includes limitations on our payment of dividends. However, during 2005, due to favorable business conditions, our unrestricted cash balances grew to levels that exceeded our foreseeable needs for cash held for reinvestment and unknown contingencies. After we secured the approval of our lenders, our board of directors declared a special cash dividend of $1.00 per share, totaling $61.2 million, which was paid in August 2005. This special cash dividend is not indicative of a change in our basic dividend policy nor does it guarantee that any future dividends will be paid. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Sources of Liquidity and Capital Expenditures.

Performance Graph

The chart below presents a comparison of the cumulative total return, assuming $100 invested on February 5, 2004 (the date the Common Stock first became publicly traded) through December 31, 2006, and the reinvestment of dividends, if any, for the Common Stock, the Standard & Poor s 500 Index and the Philadelphia Stock Exchange Oil Service Sector Index.

The Philadelphia Stock Exchange Oil Service Sector Index (OSX) is a price-weighted index composed of 15 companies that provide oil drilling and production services, oil field equipment, support services and geophysical/reservoir services.

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Item 6. *Selected Financial Data*

The following table sets forth selected financial information for our company. The financial information for the years ended December 31, 2006, 2005 and 2004, and as of December 31, 2006 and 2005, has been derived from our audited financial statements included elsewhere in this report. The financial information for the years ended December 31, 2003 and 2002, and as of December 31, 2004, 2003 and 2002 has been derived from our audited financial statements not included in this report.

The following selected historical financial data should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and our consolidated financial statements and the related notes included in Item 8 of this report.

	Years Ended December 31,				
	2002	2003	2004(f)	2005(f)	2006(f)
Historical Statement of Operations Data:					
Operating revenues	$ 187.8	$ 227.7	$ 351.4	$ 534.2	$ 912.1
Operating and maintenance expense	185.7	227.4	259.7	323.2	510.2
Earnings (loss) from continuing operations before cumulative effect of a change in accounting principle	(529.1)(a)	(222.0)(b)	(28.8)(c)	59.4	183.5(d)
Earnings (loss) from continuing operations before cumulative effect of a change in accounting principle:					
Basic	$ (43.57)	$ (18.28)	$ (0.52)	$ 0.98	$ 3.06
Diluted	$ (43.57)	$ (18.28)	$ (0.52)	$ 0.97	$ 3.04
Weighted average common shares outstanding:					
Basic	12.1	12.1	55.6	60.7	60.1
Diluted	12.1	12.1	55.6	61.4	60.5
Cash dividends paid:					
Total	$	$	$	$ 61.2	$
Per common share	$	$	$	$ 1.00	$

	As of December 31,				
	2002	2003	2004	2005	2006
			(In millions)		
Balance Sheet Data:					
Total assets	$ 2,227.2	$ 778.2	$ 761.4	$ 825.0	$ 889.2
Long-term debt and redeemable preferred shares(e)	40.7	26.8	25.4	17.0	16.4
Long-term debt related party(e)	1,080.1	525.0	3.0	2.9	
Total stockholders equity	561.9	137.7	480.6	495.5	563.9

(a) Included in 2002 are a $17.5 million impairment loss on long-lived assets, a $381.9 million goodwill impairment and a $18.8 million loss on retirement of debt.

(b) Included in 2003 are an $11.3 million impairment loss on long-lived assets, a $21.3 million impairment loss on a note receivable from an unconsolidated joint venture and a $79.5 million loss on retirement of debt.

(c) Included in 2004 are a $2.8 million impairment loss on long-lived assets and a $1.9 million loss on retirement of debt.

(d) Included in 2006 is a $0.4 million impairment loss on long-lived assets.

(e) Includes current portion.

(f) Our consolidated results of operations for the years ended December 31, 2005 and December 31, 2004 reflect the consolidation of our ownership interest in Delta Towing effective December 31, 2003 in accordance with Financial Accounting Standards Board Interpretation No. 46, *Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51* (FIN 46). Accordingly, our results for 2004 and 2005 include revenues and expenses for Delta Towing. Prior to the adoption of FIN 46, we recorded our 25% interest in the results of Delta Towing as equity in income (loss) of joint venture. In January 2006, we purchased the remaining 75% interest in Delta Towing. Our 2006 results reflect the consolidation of Delta Towing as a wholly-owned subsidiary.

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

The following discussion should be read in conjunction with our historical consolidated financial statements and the related notes included in Item 8 of this report. Except for the historical financial information contained herein, the matters discussed below may be considered forward-looking statements. Please see Cautionary Statement About Forward-Looking Statements, for a discussion of the uncertainties, risks and assumptions associated with these statements.

Overview of Our Business

We are a leading provider of contract oil and gas drilling services, primarily in the U.S. Gulf Coast. We provide these services primarily to independent oil and gas companies, but we also service major international and government-controlled oil and gas companies. Our customers in the U.S. Gulf Coast typically focus on drilling for natural gas.

We provide contract oil and gas drilling and other support services and report the results of our operations in four business segments which, for our contract drilling services, correspond to the principal geographic regions in which we operate:

U.S. Gulf of Mexico Segment We currently operate 18 jackup and three submersible rigs in the shallow water U.S. Gulf of Mexico which begins at the outer limit of the transition zone and extends to water depths of about 350 feet. Our jackup rigs in this segment consist of independent leg cantilever type units, mat-supported cantilever type rigs and mat-supported slot type jackup rigs that can operate in water depths up to 250 feet.

U.S. Inland Barge Segment Our barge rig fleet currently consists of 12 conventional and 15 posted barge rigs. These units operate in marshes, rivers, lakes and shallow bay or coastal waterways that are known as the transition zone . This area along the U.S. Gulf Coast, where jackup rigs are unable to operate, is the world s largest market for this type of equipment.

International and Other Segment Our other operations are currently conducted in Angola, Brazil, Mexico, Trinidad, the United States and Venezuela. We operate one jackup rig in Angola and one jackup rig in Brazil. In Mexico, we have two jackup rigs and a platform rig. We have one jackup rig and a land rig in Trinidad, two land rigs in the United States and six land rigs in Venezuela. An additional jackup rig is currently being towed to a shipyard in Southeast Asia for reactivation. We may pursue selected opportunities in other international areas from time to time.

Delta Towing Segment During 2005, we had a 25% interest in Delta Towing, a joint venture that operates a fleet of 42 inland tugs, 19 offshore tugs, 36 crewboats, 30 deck barges, 17 shale barges, four spud barges and one offshore barge along the U.S. Gulf Coast and in the U.S. Gulf of Mexico. In January 2006, we purchased the remaining 75% interest owned by Chouest. See Note 4 to our consolidated financial statements included in Item 8 of this report.

Our operating revenues for our drilling segments are based on dayrates received for our drilling services and the number of operating days during the relevant periods. The level of our operating revenues depends on dayrates, which in turn are primarily a function of industry supply and demand for drilling rigs in the business segments in which we operate. Supply and demand for drilling rigs in the U.S. Gulf Coast, which is our primary operating region, has historically been volatile. During periods of high demand, our rigs typically achieve higher utilization and dayrates than during periods of low demand. Delta Towing revenues are generally contracted on a rate per day or rate per hour of service basis pursuant to short-term contracts.

Our operating and maintenance costs for our drilling segments represent all direct and indirect costs associated with the operation and maintenance of our drilling rigs. The principal elements of these costs are direct and indirect labor and benefits, freight costs, repair and maintenance, insurance, general taxes and licenses, boat and helicopter rentals, communications, tool rentals and services. Labor, repair and maintenance and insurance costs represent the most significant components of our operating and maintenance costs.

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Operating and maintenance expenses may not necessarily fluctuate in proportion to changes in operating revenues because we generally seek to preserve crew continuity and maintain equipment when our rigs are idle. In general, labor costs increase primarily due to higher salary levels, rig staffing requirements and inflation. Equipment maintenance expenses fluctuate depending upon the type of activity the unit is performing and the age and condition of the equipment.

Current Conditions and Outlook

Demand for our U.S. Gulf of Mexico jackup and submersible drilling services and U.S. inland barge drilling services both began to improve in the third quarter of 2003 and continued to improve through May 2006 with respect to the U.S. Gulf of Mexico jackup and submersible fleet, and through the end of 2006 with respect to the U.S. inland barge fleet. As shown in the table below, which sets forth the average rig revenue per day and utilization, from the fourth quarter of 2005 through the fourth quarter of 2006 our average revenue per day for U.S. Gulf of Mexico jackups and submersibles improved by 60%. During the same period, our average revenue per day for U.S. inland barges improved by 45% and our average revenue per day for our International and Other segment improved by 19%.

Beginning in June 2006, however, we began to experience weakening demand in the U.S. Gulf of Mexico for jackups, as evidenced by a decline in the dayrates we have been able to obtain under new drilling contracts for our jackup and submersible drilling rigs. Consequently, the average rig revenue per day we received for U.S. Gulf of Mexico jackup and submersible rigs remained the same from the second quarter to the third quarter of 2006, but then declined in the fourth quarter for the first time in the previous thirteen quarters. Softening demand also adversely affected our ability to obtain term contracts (as opposed to well-by-well contracts) for our jackup and submersible rigs operating in the U.S. Gulf Coast. Our total rig days in backlog under term contracts decreased from 6,135 rig days at February 20, 2006, to 3,893 days rig days at February 20, 2007, or a 37% decrease. We believe this weakened demand is principally attributable to reduced prices for natural gas in the Gulf of Mexico and to customer uncertainty regarding future prices of natural gas. These factors, we believe, strongly influence the drilling activity of our customers who are predominantly independent oil and gas companies that sometimes delay or curtail their drilling activities to manage their cash flow.

Demand for our barge rigs has shown signs of weakening as evidenced by a flattening of the average utilization rate for our barge rigs in early 2007 compared to the fourth quarter of 2006. While we have not experienced any decline in dayrates for barge rigs thus far in 2007, dayrates may decline if utilization rates remain the same or decrease.

As of February 20, 2007, 12 of our 16 marketed jackup and submersible rigs in the U.S. Gulf of Mexico were operating with dayrates ranging from $61,200 to $126,100. Dayrates for single well and prompt starting date contracts were at the lower end of this range, or approximately, $61,200 to $101,200 per day. As of February 20, 2007, 16 of our 17 marketed inland barges were operating with dayrates ranging from $29,700 to $62,100.

The following table shows our average rig revenue per day and utilization for the quarterly periods ended on or prior to December 31, 2006 with respect to each of our three drilling segments. Average rig revenue per day is defined as operating revenue earned per revenue earning day in the period. Utilization in the table below is defined as the total actual number of revenue earning days in the period as a percentage of the total number of calendar days in the period for all drilling rigs in our fleet.

Three Months Ended								
December 31, 2004	March 31, 2005	June 30, 2005	September 30, 2005	December 31, 2005	March 31, 2006	June 30, 2006	September 30, 2006	Decem 20

e Rig									
e Per Day:									
lf of									
Jackups									
omersibles	$ 39,900	$ 44,600	$ 51,000	$ 56,700	$ 60,800	$ 78,700	$ 104,100	$ 104,100	$ 97
and Barges	23,000	25,000	27,800	29,600	30,800	33,700	37,200	42,900	44
ional and									
	29,400	28,400	33,900	31,300	37,100	45,700	43,200	42,100	44
ion:									
lf of									
Jackups									
omersibles	56%	56%	56%	56%	51%	50%	53%	56%	
and Barges	46%	46%	51%	53%	55%	60%	61%	62%	
ional and									
	39%	56%	55%	56%	63%	67%	71%	70%	

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Our customers in the U.S. Gulf Coast typically focus on drilling for natural gas. Although U.S. natural gas prices have generally declined since late 2005, prices nevertheless remain relatively high compared to historical levels. The rolling twelve-month average price of natural gas has increased from $2.11 in January 1994 to $6.74 in December 2006. However, the twelve-month average price of natural gas for 2006 was $6.74 as compared to $8.89 for 2005.

We believe there are currently 66 jackup rigs on order with delivery dates ranging from 2007 to 2010. Most of the rigs on order are premium, cantilevered drilling units with 350 to 400 foot water depth capability. This trend of new jackup construction, principally on speculation, could result in the creation of a worldwide oversupply of jackup rigs. This could ultimately cause dayrates and utilization percentages to decline. However, the worldwide jackup fleet is aging and will need to be replaced at some point. Currently, the average age worldwide is approximately 24 years old. In addition, attrition continues and was recently accelerated in 2005 when the U.S. Gulf of Mexico experienced two major hurricanes, which destroyed or significantly damaged nine jackup drilling rigs.

Greater demand for jackup rigs in international areas over the last three years has reduced the overall supply of jackups in the U.S. Gulf of Mexico. This has created a more favorable supply environment for the remaining jackups, including ours, which has contributed to increased jackup utilization and dayrates in prior periods. As of February 2007, there are six jackup rigs that have announced departures for international contracts during the first and second quarters of 2007. This is expected to further tighten the jackup rig supply in the U.S. Gulf of Mexico.

In the past, we were awarded contracts with PEMEX for two of our jackup rigs and a platform rig. *THE 206* is currently operating under a 615-day contract at dayrates of approximately $64,000 which became effective in late October 2005. A new two-year contract will commence in late June 2007, following the completion of the current drilling contract, at a dayrate of approximately $112,500. Currently, *THE 205*, our other jackup rig, is undergoing repairs in Mexico and is anticipated to return to work for PEMEX in the second quarter of 2007 under a new two-year contract. The contract for *Platform Rig 3* is 1,289 days in duration and began operating in December 2004 at a contract dayrate of approximately $29,000. Each of the contracts can be terminated by PEMEX on five days notice, subject to certain conditions.

Rig Reactivations

Since December 31, 2004, we have commenced or completed the reactivation of nine drilling rigs, consisting of four jackup rigs, two submersible rigs and three barge rigs. For additional information concerning each of our completed and pending rig reactivations and the related term contract, please see Business Rig Reactivations Against Term Drilling Contracts. Approximately $5.0 million was capitalized and $12.2 million was charged to operating and maintenance expense in connection with rig reactivations in 2005. During 2006, approximately $73.0 million was charged to operating and maintenance expense and an additional $16.4 million was capitalized in connection with rig reactivations.

We plan to continue our efforts to obtain term contracts with customers to reactivate and return to service all five of our remaining cold stacked U.S. Gulf of Mexico jackup rigs. We also plan to continue seeking term contracts with customers to reactivate and return to service our remaining cold stacked 2,000 or 3,000 horsepower inland barge rigs. Due to recent market softness, we currently expect that our reactivation program may be further delayed into late 2007 or into 2008. We estimate that once commenced, these rig reactivations will take four to five months to complete and that the cost will be $10.0 million to $15.0 million for each inland barge rig and seven to eight months to complete and $20.0 million to $30.0 million for each jackup rig. We expect that we may reactivate or commit to reactivate additional cold stacked rigs in 2007, but only if we are able to obtain suitable term contracts on the reactivated rig or if we are confident that we will be able to do so in view of then favorable market conditions.

In the second quarter 2006, we mobilized two land rigs from Venezuela to the United States for the purpose of reactivating the rigs. As of December 31, 2006, we have incurred expenses totaling $2.8 million and we expect to incur approximately $2.0 million in expenses during the first quarter of 2007 for this mobilization and reactivation.

Our *THE 208* drilling rig, a 200-foot mat-supported cantilevered jackup rig, was constructed in 1980 and has been cold stacked in Trinidad since March, 2002. The rig is currently being transported to a shipyard in Southeast Asia where it will undergo an extensive shipyard reactivation and upgrade which will include conversion from a mechanically driven rig to a conventionally powered SCR rig. While final reactivation and upgrade costs as well as the exact timing for reactivation of *THE 208* remain uncertain since we are in the process of finalizing bids from several shipyards, it is anticipated, subject to final award of the drilling contract, that the rig will begin drilling operations under a three-year drilling program in Malaysia by the end of 2007.

Repairs and Scheduled Maintenance

THE 205, currently in Mexico, is undergoing repairs at an estimated cost of $2.7 million. In addition to scheduled repairs, additional repairs expected to cost approximately $8.0 million which resulted from *THE 205* being struck by a cargo vessel, will be performed. We have initiated in rem proceedings against the cargo vessel and a lawsuit has been filed against the vessel owners to recover the cost of these additional repairs which proceedings will extend into the second quarter of 2007.

THE 202 returned to service in June 2006 after sustaining damage during a jacking incident in the fourth quarter of 2005. Related thereto, we incurred a total of $13.9 million in costs, of which $6.9 million was recognized as repair expense for *THE 202* and $7.0 million was recorded as an insurance claim receivable pending under our insurance.

Our jackup rig, *THE 200*, went to the shipyard in mid-July 2006 for leg and hull refurbishments related to a regulatory survey. The work was completed in mid-October at a total cost of approximately $5.3 million. Another jackup rig, *THE 250*, also completed surveys and refurbishments in October at a total cost of approximately $3.8 million. In addition, leg and hull refurbishments on *THE 251* were completed in October at a total cost of approximately $3.1 million.

During the reactivation of *THE 153* in 2006, two unplanned events occurred that resulted in additional repairs. A crane incident resulted in a change out of one our cranes at a cost of $2.1 million and additional mat damage, caused by Hurricane Rita in 2005 and discovered during the dry docking phase, cost $3.6 million. *THE 153* completed its repairs and reactivation in January 2007 and is currently idle.

In addition to the above, *THE 201* and *THE 204*, neither currently under contract, will undergo repairs in the first quarter of 2007 totaling approximately $4.5 million. *Rig 9* will be out of service for 30 days in the first quarter for repairs. In addition, *Rig 41* and *Rig 52* are scheduled to be out of service for repairs for approximately 42 days combined in the first quarter of 2007. Estimated costs to complete the repairs on these three inland barge rigs are approximately $4.2 million. *THE 200* will be out of service for 110 to 120 days undergoing mat and additional repairs for damage suffered during Hurricane Katrina in 2005. Approximately $8.7 million of the estimated $10.5 million of total repair costs on *THE 200* is expected to be covered by our insurance.

During the third quarter of 2005, hurricanes Katrina and Rita impacted our offshore and inland water operations. All of the damage caused by these two hurricanes is covered under our hull and machinery insurance policy with a total incident deductible of $1.0 million. Currently, we have recognized expense of $0.8 million through 2006 for damage sustained during Hurricane Katrina. We also incurred $6.1 million in expenses related to damages caused by Hurricane Rita. We recorded $5.1 million of claims receivable for the repair amount incurred above the $1.0 million insurance deductible related to losses sustained during Hurricane Rita. Any remaining expenses incurred related to damage caused by Hurricane Rita will be recorded as a claims receivable.

In October 2006, we extended our principal insurance coverages for property damage, liability and occupational injury and illness for a five month term. Generally, our deductible levels under the hull and machinery policies are 15% of individual insured asset values per occurrence except in the event of a total loss only where the deductible would be zero. An annual limit of $75.0 million and a minimum deductible of $5.0 million per occurrence apply in the event of a windstorm. In an effort to control premium costs, our insurance coverage continues to cover 70% of our losses in excess of the applicable deductible and we self insure the remaining 30% of any such losses. The primary marine package also provides coverage for cargo, control of well, seepage, pollution and property in our care, custody and control. Our deductible for this coverage varies between $250,000 and $1.0 million per occurrence depending upon the coverage line. In addition to our marine package, we have separate policies providing coverage for general domestic liability, employer s liability, domestic auto liability and non-owned aircraft liability with $1.0 million deductibles per occurrence. We also have an excess liability policy that extends our coverage to an aggregate of $200.0 million under all of these policies. Our insurance program also includes separate policies that cover certain liabilities in foreign countries where we operate.

The five-month extension did not increase our premium cost, which remained at approximately $15.0 million per annum under these policies, nor did it change our hull and machinery insured value from approximately $1.1 billion. We believe our current insurance coverage, deductibles and the level of risk involved is adequate and reasonable. However, insurance premiums and/or deductibles could be increased or coverages may be unavailable in the future.

Effective March 1, 2007, we renewed our hull and machinery insurance with essentially the same terms and conditions as our previous policy. However, we increased our insured values from $1.1 billion to $1.8 billion and decreased our deductible per occurrence from 15% of insured asset values to 10% of insured asset values except in the event of a total loss in which case the deductible is zero. Total premiums for our new hull and machinery policy are $13.3 million.

Changes in Results of Operations Related to our Separation from Transocean

As a result of our separation from Transocean, including the transfer of the Transocean Assets to Transocean in 2003 and the completion of our IPO in February 2004, our reporting of certain aspects of our results of operations differs from our historical reporting of results of operations. The following discussion describes these and other differences.

In February 2004, we adopted a long-term incentive plan for certain of our employees and non-employee directors in order to provide additional incentives through the grant of awards (the 2004 Plan). In conjunction with the closing of the IPO, we granted restricted stock and stock options to certain employees and non-employee directors. Additional awards were made during 2004 from the 2004 Plan which has since been modified for equity award purposes by a new plan. In 2005, a new plan was adopted to continue to provide employees, non-employee directors and our consultants with additional incentives and increase their personal stake in our success (the 2005 Plan). During 2006, 2005 and 2004, we recognized $6.5 million, $7.6 million and $10.6 million, respectively, of compensation expense related to these awards and grants. Based upon the fair value price per share at date of issuance per Financial Accounting Standards Board s (FASB) Statement of Financial Accounting Standards (SFAS) No. 123 (revised 2004), *Share-Based Payment* (SFAS 123R), the value of the 2005 Plan and the 2004 Plan awards that we will recognize as compensation expense in future years for awards previously granted is approximately $11.2 million. This expense will be amortized to compensation expense over the vesting period of the awards and options. In addition to these grants under the 2005 Plan and the 2004 Plan, we expect to make additional grants of restricted stock, deferred performance units, deferred stock units and stock options annually. The value of any additional awards under the 2005 Plan will be recognized as compensation expense over the vesting period of the awards.

In addition, certain of our employees held options to acquire Transocean ordinary shares that were granted prior to the IPO. In accordance with the employee matters agreement, the employees holding such options were treated as terminated for the convenience of Transocean on the IPO date. As a result, these options became fully vested and were modified to remain exercisable over the original contractual life. In connection with the modification of the options, we recognized $1.5 million in additional compensation expense in the first quarter of 2004. No further compensation expense will be recognized related to the Transocean options.

Interest income consists of interest earned on our cash balances and, for periods before December 31, 2003, on notes receivable from Delta Towing. Because of the adoption of the Financial Accounting Standards Board s (FASB) Interpretation No. 46, *Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51* (FIN 46), and the resulting consolidation of Delta Towing in our consolidated balance sheet effective December 31, 2003, we expect future interest income to consist of interest earned on our cash balances. For periods before the IPO, interest expense consisted of financing cost amortization and interest associated with our senior notes, other debt and other related party debt as described in the notes to our consolidated financial statements. After the closing of the IPO, interest expense primarily included interest on our senior notes payable to third parties, commitment fees on the unused portion of our line of credit and the amortization of financing costs. Our debt levels and, correspondingly, our interest expense were substantially lower in 2006 and 2005 compared to prior years as a result of the notes payable to Transocean prior to the IPO.

In connection with the IPO, we entered into a tax sharing agreement with Transocean. The agreement provides that we must pay Transocean for substantially all pre-IPO tax benefits utilized or deemed to have been utilized subsequent to the closing of the IPO. It also provides that we must pay Transocean for any tax benefit resulting from the delivery by Transocean of its stock to one of our active employees in connection with the exercise of an employee stock option. In return, Transocean agreed to indemnify us against substantially all pre-IPO income tax liabilities.

Additionally, the tax sharing agreement provides that if any person other than Transocean or its subsidiaries becomes the beneficial owner of greater than 50% of the total voting power of our outstanding voting stock, we will be deemed to have utilized all of the pre-IPO tax benefits, and we will be required to pay Transocean an amount for the deemed utilization of these tax benefits adjusted by a specified discount factor. This payment is required even if we are unable to utilize the pre-IPO tax benefits.

Under the tax sharing agreement with Transocean, if the utilization of a pre-IPO tax benefit defers or precludes our utilization of any post-IPO tax benefit, our payment obligation with respect to the pre-IPO tax benefit generally will be deferred until we actually utilize that post-IPO tax benefit. This payment deferral will not apply with respect to, and we will have to pay currently for the utilization of pre-IPO tax benefits to the extent of (a) up to 20% of any deferred or precluded post-IPO tax benefit arising out of our payment of foreign income taxes, and (b) 100% of any deferred or precluded post-IPO tax benefit arising out of a carryback from a subsequent year. Therefore, we may not realize the full economic value of tax deductions, credits and other tax benefits that arise post-IPO until we have utilized all of the pre-IPO tax benefits, if ever.

Upon consummation of the IPO, we recorded the tax sharing agreement to eliminate the valuation allowance associated with the pre-IPO tax benefits and reflect the associated liability to Transocean for the pre-IPO tax benefits as a corresponding obligation within the deferred income tax accounts. The net effect was a $181.4 million reduction in additional paid-in capital. In addition, we recorded as a credit to additional paid-in capital $10.3 million for Transocean s indemnification for pre-IPO liabilities that existed as of the IPO date with a corresponding offset to a related party receivable from Transocean.

During the first quarter of 2005, we recorded an additional $7.7 million in pre-IPO deferred state tax liabilities that existed at the IPO date. The recognition of these pre-IPO deferred state tax liabilities resulted in a $7.7 million reduction in additional paid-in capital, $0.9 million of deferred state tax benefit and a $6.8 million increase in deferred tax liabilities.

In September 2005, Transocean instructed us, pursuant to a provision in the tax sharing agreement, to take a tax deduction for profits realized by our current and former employees and directors from the exercise of Transocean stock options during calendar 2004. Transocean also indicated that it expected us to take a similar deduction in future years to the extent there were profits realized by our current and former employees and directors during those future periods.

It was our belief that the tax sharing agreement only required us to pay Transocean for deductions related to stock option exercises by persons who were our employees on the date of exercise. Transocean disagreed with our interpretation of the tax sharing agreement as it related to this issue and believed that we must pay for all stock option exercises, regardless of whether any employment or other service provider relationship may have terminated prior to the exercise of the employee stock option. As such, Transocean initiated dispute resolution proceedings against us.

A negotiated settlement of that dispute was reached on November 27, 2006. As a result of the settlement, we and Transocean executed an Amended and Restated Tax Sharing Agreement reflecting the terms of the settlement. Under the terms of the settlement, we will now pay Transocean for only 55% of the value of the tax deductions arising from the exercise of the Transocean stock options by our current and former employees and directors, or a 45% discount from the September 2005 demand by Transocean. This discounted payment rate applies retroactively to amounts we previously accrued and to future payments. Further, under the terms of the original Tax Sharing Agreement, our use of certain state and foreign tax assets reduced our ability to receive the federal tax benefit for the use of such tax assets that otherwise would have been available in the amount of $2.9 million. The Amended and Restated Tax Sharing Agreement gives us credit for the federal tax benefit that otherwise would have been available in connection with the use of such assets for past and future periods.

During the dispute with Transocean, we continued to accrue liabilities based on Transocean s interpretation of the Tax Sharing Agreement. As a result, upon settlement of this dispute, we eliminated $44.5 million in liability to Transocean by paying it $22.0 million, increasing additional paid-in capital by $20.9 million, reducing current tax expense by $2.9 million and recording net interest expense and other of $1.3 million. In the future, as Transocean stock option deductions are generated under the Amended Tax Sharing Agreement, we will reduce current taxes payable by the entire amount of the Transocean stock option deduction, pay Transocean for 55% of the deduction and increase additional paid-in capital by 45% of the deduction.

We utilized pre-IPO income tax benefits to offset our current federal income tax obligation during the years ended December 31, 2006 and 2005. After accounting for payments made to Transocean, we had a liability to Transocean of $51.3 million and $43.8 million as of December 31, 2006 and 2005, respectively. Additionally, during the years ended December 31, 2006 and 2005, we utilized pre-IPO state tax benefits which, after payments made to Transocean, resulted in a liability to Transocean of $0.4 million and $0.1 million, respectively. We also utilized pre-IPO foreign tax benefits during 2005 which, after payments made to Transocean, resulted in a liability to Transocean of $1.0 million at December 31, 2005. There was no liability due to Transocean for the utilization of foreign tax benefits at December 31, 2006. As of December 31, 2006 and 2005, we estimate that we owe Transocean $51.7 million and $44.9 million, respectively, for pre-IPO federal, state and foreign income tax benefits utilized.

As of December 31, 2006, we had approximately $195 million of estimated pre-IPO income tax benefits subject to the obligation to reimburse Transocean. If an acquisition of beneficial ownership had occurred on December 31, 2006, the estimated amount we would have been required to pay Transocean would have been approximately $137 million, or 70% of the pre-IPO tax benefits at December 31, 2006. As of January 1, 2007, we will be required, under the terms of the Amended and Restated Tax Sharing Agreement, to pay 80% of the pre-IPO tax benefits if an acquisition of beneficial ownership occurs.

The estimated liabilities to Transocean at December 31, 2006 and 2005 and the estimated amount of remaining pre-IPO income tax benefits subject to the obligation to reimburse Transocean at December 31, 2006 are presented within accrued income taxes former parent in our consolidated balance sheets.

We had an ownership change for purposes of Section 382 of the Internal Revenue Code of 1986, as amended, in connection with our secondary offering in September 2004. As a result, our ability to utilize certain of our tax benefits is subject to an annual limitation. However, we believe that, in light of the amount of the annual limitation, it should not have a material effect on our ability to utilize these tax benefits for the foreseeable future.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations is based on our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, operating revenues, expenses and related disclosure of contingent assets and liabilities. On an ongoing basis, we evaluate our estimates, including those related to bad debts, materials and supplies obsolescence, investments, property, equipment and other long-lived assets, income taxes, workers injury claims, employment benefits and contingent liabilities. We base our estimates on historical experience and on various other assumptions we believe are reasonable under the circumstances. The results of these estimates form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources.

Actual results may differ from these estimates.

We believe the following are our most critical accounting policies. These policies require significant judgments and estimates used in the preparation of our consolidated financial statements.

Property and Equipment. Our property and equipment represent approximately 51% of our total assets as of December 31, 2006. We determine the carrying value of these assets based on our property and equipment accounting policies, which incorporate our estimates, assumptions and judgments relative to capitalized costs, useful lives and salvage values of our rigs. We review our property and equipment for impairment when events or changes in circumstances indicate that the carrying value of these assets or asset groups may be impaired or when reclassifications are made between property and equipment and assets held for sale as prescribed by the FASB s SFAS No. 144, *Accounting for Impairment or Disposal of Long-Lived Assets* (SFAS 144). Asset impairment evaluations are based on estimated undiscounted cash flows for the assets being evaluated. 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 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 drilling rigs.

Allowance for Doubtful Accounts. We establish reserves for doubtful accounts on a case-by-case basis when we believe the collection of specific amounts owed to us is unlikely to occur. Our operating revenues are principally derived from services to U.S. independent oil and natural gas companies and international and government-controlled oil companies and our receivables are concentrated in the United States. We generally do not require collateral or other security to support customer receivables. If the financial condition of our customers deteriorates, we may be required to establish additional reserves.

Provision for Income Taxes. Our tax provision is based on expected taxable income, statutory rates and tax planning opportunities available to us in the various jurisdictions in which we operate. Determination of taxable income in any jurisdiction requires the interpretation of the related tax laws. Our effective tax rate is expected to fluctuate from year to year as our operations are conducted in different taxing jurisdictions and the amount of pre-tax income fluctuates. Currently payable income tax expense represents either nonresident withholding taxes or the liabilities expected to be reflected on our income tax returns for the current year while the net deferred tax expense or benefit represents the changes in the balance of deferred tax assets and liabilities as reported on the balance sheet.

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

Contingent Liabilities. We establish reserves for estimated loss contingencies when we believe a loss is probable and we can reasonably estimate the amount of the loss. Revisions to contingent liabilities are reflected in income in the period in which different facts or information become known or circumstances change that affect our previous assumptions with respect to the likelihood or amount of loss. Reserves for contingent liabilities are based upon our assumptions and estimates regarding the probable outcome of the matter. Should the outcome differ from our assumptions and estimates, we would make revisions to the estimated reserves for contingent liabilities, and such revisions could be material.

Stock-Based Compensation Expense. Effective January 1, 2003, we adopted the fair value method of accounting for stock-based compensation using the prospective method of transition under SFAS No. 123, *Accounting for Stock-based Compensation* (SFAS 123). Under the prospective method and in accordance with the provisions of SFAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure* (SFAS 148), the recognition provisions were applied to all employee awards granted, modified or settled after January 1, 2003. Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS 123R using the modified prospective transition method and therefore have not restated results for prior periods. Under this transition method, stock-based compensation expense for the year ended December 31, 2006 includes compensation expense for all stock-based compensation awards granted prior to, but not yet vested as of January 1, 2006, based on the grant date fair value estimated in accordance with the original provision of SFAS 123. Stock-based compensation expense for all stock-based compensation awards granted after January 1, 2006 is based on the grant-date fair value estimated in accordance with the provisions of SFAS 123R. As a result of adopting SFAS 123 in an earlier period, the adoption of SFAS 123R in the first quarter of 2006 had an immaterial income effect. Under the

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fair value recognition provisions of SFAS 123R, we recognize stock-based compensation net of an estimated forfeiture rate and only recognize compensation cost for those shares expected to vest on a straight-line basis over the requisite service period of the award, which is generally a vesting term of three years. Under the guidelines of SFAS 123, we recognized forfeitures in the period in which they occurred. As a result of our adoption of SFAS 123R, the estimate of forfeitures resulted in a one-time cumulative adjustment credit to income of $0.1 million, net of tax.

Determining the appropriate fair value model and calculating the fair value of share-based payment awards require the input of highly subjective assumptions, including the expected life of the share-based payment awards and stock price volatility. The assumptions used in calculating the fair value of share-based payment awards represent management s best estimates, but these estimates involve inherent uncertainties and the application of management judgment. As a result, if factors change and we use different assumptions, our stock-based compensation expense could be materially different in the future. As of December 31, 2006, there was $11.2 million of total unrecognized compensation cost related to nonvested share-based compensation arrangements that have been granted. That cost is expected to be recognized over a weighted-average period of 2.8 years. In addition, we are required to estimate the expected forfeiture rate and only recognize expense for those shares expected to vest. If our actual forfeiture rate is materially different from our estimate, the stock-based compensation expense could be significantly different from what we have recorded in the current period. See Notes 2 and 13 to the Consolidated Financial Statements for a further discussion on stock-based compensation.

FIN 48. In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109* (FIN 48). FIN 48 seeks to reduce the diversity in practice associated with certain aspects of measurement and recognition in 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. Additionally, FIN 48 provides guidance on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006, which is our 2007 fiscal year, and its provisions are to be applied to all tax positions upon initial adoption. Upon adoption of FIN 48, only tax positions that meet a more likely than not threshold at the effective date may be recognized or continue to be recognized. The cumulative effect of applying FIN 48, if any, is to be reported as an adjustment to the opening balance of retained earnings in the year of adoption. We are evaluating the impact that FIN 48 will have on our financial statements.

Results of Continuing Operations

The following table sets forth our operating days, average rig utilization rates, average rig revenue per day, revenues and operating expenses by operating segment for the periods indicated:

	For the Years Ended December 31,		
	2006	**2005**	**2004**
	(Dollars in millions, except per day data)		
U.S. Gulf of Mexico Segment:			
Operating days	4,301	4,465	4,134
Available days(a)	7,665	8,166	8,144
Utilization(b)	56%	55%	51%
Average rig revenue per day(c)	$ 96,500	$ 53,000	$ 34,200
Operating revenues	$ 415.0	$ 236.7	$ 141.2
Operating and maintenance expenses(d)	224.1	116.4	93.4
Depreciation	38.2	50.2	49.5

Operating income (loss)	152.7	70.1	(1.7)

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	For the Years Ended December 31, 2006	2005	2004
	(Dollars in millions, except per day data)		
U.S. Inland Barge Segment:			
Operating days	6,007	5,147	4,764
Available days(a)	9,855	10,049	10,980
Utilization(b)	61%	51%	43%
Average rig revenue per day(c)	$ 39,700	$ 28,400	$ 22,200
Operating revenues	$ 238.6	$ 146.1	$ 105.9
Operating and maintenance expenses(d)	123.7	94.1	82.6
Depreciation	22.9	23.6	22.5
Operating income	92.0	28.4	0.8
International and Other Segment:			
Operating days	4,132	3,088	2,097
Available days(a)	5,840	5,339	6,496
Utilization(b)	71%	58%	32%
Average rig revenue per day(c)	$ 43,800	$ 33,000	$ 35,000
Operating revenues	$ 180.8	$ 101.8	$ 73.3
Operating and maintenance expenses(d)	130.0	87.0	62.2
Depreciation	21.1	17.5	19.0
Impairment loss on long-lived assets	0.4		2.8
Operating income (loss)	29.3	(2.7)	(10.7)
Delta Towing Segment:			
Operating revenues	$ 77.7	$ 49.6	$ 31.0
Operating and maintenance expenses(d)	32.4	25.7	21.5
Depreciation	4.0	4.7	4.7
General and administrative expenses	4.8	4.4	4.2
Operating income	36.5	14.8	0.6
Total Company:			
Rig operating days	14,440	12,700	10,995
Rig available days(a)	23,360	23,554	25,620
Rig utilization(b)	62%	54%	43%
Average rig revenue per day(c)	$ 57,800	$ 38,200	$ 29,100
Operating revenues	$ 912.1	$ 534.2	$ 351.4
Operating and maintenance expenses(d)	510.2	323.2	259.7
Depreciation	86.2	96.0	95.7
General and administrative expenses	41.3	37.7	34.0
Impairment loss on long-lived assets	0.4		2.8
Operating income (loss)	274.0	77.3	(40.8)

(a) Available days are the total number of calendar days in the period for all drilling rigs in our fleet.

(b) Utilization is the total number of operating days in the period as a percentage of the total number of calendar days in the period for all drilling rigs in our fleet.

(c)

Average rig revenue per day is defined as revenue earned per operating day for the applicable segment, and as total U.S. Gulf of Mexico, U.S. Inland Barge and Other International revenues per rig operating days for Total Company.

(d) Excludes depreciation, amortization and general and administrative expenses.

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Years Ended December 31, 2006 and 2005

Operating Revenues. Total operating revenues increased $377.9 million, or 71%, during 2006 as compared to 2005, primarily due to higher overall average rig revenue per day earned in 2006, as compared to 2005. Overall average rig revenue per day increased from $38,200 for 2005 to $57,800 for 2006, as a consequence of the continued improvement of customer demand in the U.S. Gulf of Mexico and transition zone along the U.S. Gulf Coast and the commencement of operations in Angola in the last half of 2005 which extended through 2006, in Colombia from December 2005 through June 2006 and in Brazil which began in November 2006. Additional land rigs operating in Trinidad and Venezuela and the reactivation of three inland barge rigs, two submersible rigs and one jackup rig in the U.S. Gulf of Mexico have increased average rig utilization to 62% for the year ended December 31, 2006, as compared to 54% for the year ended December 31, 2005.

Operating revenues for our U.S. Gulf of Mexico segment increased $178.3 million, or 75%, in 2006, as compared to 2005. In 2006, we achieved higher average rig revenue per day for our jackup and submersible drilling fleet, improving from $53,000 per day to $96,500 per day. This resulted in an additional $186.2 million in operating revenues for 2006 as compared to the same period in 2005. The increase in average rig revenue per day is the result of our success in obtaining contracts with our customers at higher dayrates in response to increased demand during the majority of 2006 which have recently begun to decline due to weakening demand. Results for 2006 also reflect higher utilization for our current rig fleet in this segment, after giving effect to the transfer of the jackup drilling unit *THE 156* from to our International and Other segment in the fourth quarter of 2005. This increase in utilization resulted in $6.5 million in additional rig revenues in 2006 as compared to the same period in 2005. The transfer of *THE 156* resulted in a $14.4 million decrease in operating revenues for the year ended December 31, 2006, as compared to year ended December 31, 2005.

Operating revenues for our U.S. Inland Barge segment increased $92.5 million, or 63%, in 2006, as compared to the same period in the prior year, primarily due to higher average rig revenue per day achieved in 2006, as compared to 2005. Average rig revenue per day increased from $28,400 for 2005 to $39,700 for 2006, as a result of our successful marketing efforts in negotiating higher dayrates for our fleet of inland barges during 2006. The increase in average rig revenue per day resulted in additional revenues of $68.1 million for 2006 as compared to 2005. Utilization of our inland barge fleet was 61% for 2006, as compared to 51% for 2005, which resulted in $24.4 million additional operating revenues in 2006 as compared to 2005. The increase in utilization was favorably affected by the three reactivations that were begun in 2005 and completed in the first quarter of 2006.

Operating revenues for our International and Other segment were $180.8 million for 2006. The 78%, or $79.0 million, increase over operating revenues reported for 2005 reflects commencement of operations in Angola and Colombia during the last half of 2005. *THE 156*, which operated in Colombia through June 2006, moved to Brazil and began contributing to operating revenues in November 2006. Additionally, a land rig began operating in Trinidad in the last quarter of 2005 and two additional land rigs began operations in Venezuela during 2006. The operations in Angola, Brazil and Colombia contributed an additional $40.3 million in operating revenues for the year ended December 31, 2006 as compared to the year ended December 31, 2005. The additional land rigs in Trinidad and Venezuela resulted in additional operating revenues of $18.5 million for 2006 as compared to 2005. Increased average daily revenue for all other operations resulted in a favorable variance of $24.5 million offset by a decrease of $2.8 million due to slightly lower utilizations for our other operations.

Our operating revenues for 2006 included $77.7 million related to the operation of Delta Towing s fleet of U.S. marine support vessels which increased from $49.6 million recognized in 2005 due to increased vessel utilization in response to improved demand.

Operating and Maintenance Expenses. Total operating and maintenance expenses increased $187.0 million, or 58%, in 2006 as compared to operating expenses of $323.2 million for 2005.

Operating and maintenance expenses for our U.S. Gulf of Mexico segment were $107.7 million higher for 2006 as compared to 2005. This 93% increase was principally due to increases of $72.1 million in repair and maintenance costs and $28.1 in personnel costs principally due to more operating rigs and payroll increases. These increases were primarily the result of $72.4 million of rig reactivation expense related to the reactivation of cold stacked rigs *THE 77, THE 78, THE 252, THE 256*, and *THE 153* and $10.2 million of additional repair and maintenance costs incurred on *THE 200, THE 250* and *THE 251*, principally due to scheduled rig repairs. We also incurred $9.4 million in rig reactivation assessment costs on *THE 155*, *THE 191*, *THE 254* and *THE 255* in 2006. Additionally, when comparing 2006 to 2005, insurance premiums increased by $2.7 million and insurance claim expense increased $2.2 million, primarily related to the damage sustained on *THE 202.* Personal injury claim expense increased by $5.9 million for the year ended December 31, 2006 as compared to the year ended December 31, 2005, principally due to a write-off of a third party receivable and higher actuarial factors used in 2006 to develop our personal injury claims. These increases were offset by the $6.2 million of operating and maintenance expenses incurred by *THE 156* during 2005 which has since been transferred to our International and Other segment.

Operating and maintenance expenses for our U.S. Inland Barge segment were $123.7 million for 2006 as compared to $94.1 million for 2005. This $29.6 million, or 31%, increase was primarily the result of increasing personnel costs ($15.8 million) and an increase in the costs incurred by shore-based support, principally due to costs incurred to repair the bulkhead at our Houma facility ($5.2 million). In addition, higher costs were incurred during 2006 as compared to 2005 due to an increase in support vessel costs, a result of rate increases and increased utilization ($3.5 million), an increase of $3.8 million in repair and maintenance expense primarily due to increased utilization and an increase in our personal injury claim expense of $5.1 million which was due to higher actuarial factors used to develop our personal injury claims in 2006 as compared to 2005. These increases were partially offset by lower insurance claims expense of $4.5 million when comparing the year ended December 31, 2006 to the year ended December 31, 2005, due principally to the property litigation settlement of $4.0 million received from a contractor to the operator on our inland barge *Rig 62* related to a blowout and fire that occurred in June 2003. The settlement was a partial reimbursement for damages to the rig and personal injury claims paid to our employees on board the rig.

Operating and maintenance expenses for our International and Other segment for 2006 increased $43.0 million, or 49%, as compared to 2005. This increase in expense was due principally to a full year of operations in Angola in 2006 which resulted in an increase of $2.1 million for the year ended December 31, 2006 as compared to the year ended December 31, 2005. Operations in Colombia, which began in December 2005 and concluded in June 2006, contributed an additional $10.4 million in operating expenses for the year ended December 31, 2006 as compared to the year ended December 31, 2005. After moving from Colombia to Brazil, *THE 156* incurred an additional $4.2 million in operating and maintenance expense. The full year operations of a land rig in Trinidad and one in Venezuela together with an additional land rig beginning operations in Venezuela during 2006 contributed $18.9 million in additional operating and maintenance expense for the year ended December 31, 2006, as compared to the year ended December 31, 2005. Additional costs of $3.1 million were incurred to prepare two land rigs for service in the United States for the year ended December 31, 2006 as compared to the year ended December 31, 2005.

Delta Towing operations incurred $32.4 million in operating costs for 2006. This represented a $6.7 million, or 26%, increase over operating costs of $25.7 million recognized in 2005 which was principally due to increased marine support vessel utilization.

General and Administrative Expenses. General and administrative expenses were $41.3 million for 2006 as compared to $37.7 million for 2005. General and administrative expenses for 2006 increased $3.6 million as compared to 2005, due primarily to higher payroll costs of $3.6 million. This increase was principally due to the additional personnel required to manage and provide support for the rig reactivation projects and increased rig utilization during 2006. In addition, Delta Towing and other general and administrative expenses increased $2.3 million for the year ended December 31, 2006 as compared to the year ended December 31, 2005. These increases were partially offset by a decrease in our stock compensation expense of $2.3 million. This was primarily due to the expense recognized in 2005 from the vesting of certain awards granted at the initial public offering.

Gain on Disposal of Assets, Net. During 2006, we realized net gains on disposal of assets of $11.6 million. Included in the gain on disposal of assets was the sale of drill pipe and miscellaneous equipment which realized a gain of

$6.1 million on proceeds of $8.0 million. In addition, nine support vessels owned by Delta Towing were sold for $6.5 million which resulted in a net gain of $5.5 million. During 2005, we realized net gains on disposal of assets of $25.1 million related to the sale of three out-of-service jackup rigs, *THE 154* ($9.3 million), *THE 151*

($6.7 million) and *THE 192* ($3.8 million), the sale of drill pipe and miscellaneous equipment ($4.1 million) and the sale of five marine support vessels owned by Delta Towing ($1.2 million).

Interest Expense/Income. Third party interest expense and interest expense-related party increased $0.9 million in 2006 as compared to 2005, primarily due to interest expense of $1.8 million paid to Transocean as part of the tax sharing agreement settlement. Due to continued operating improvement, our cash balances were overall higher throughout all of 2006 as compared to 2005. Coupled with higher interest rates, interest income increased $6.3 million when comparing the year ended December 31, 2006 to the year ended December 31, 2005.

Income Tax Expense (Benefit). The income tax expense of $108.0 million for 2006 reflects a 37.0% effective tax rate (ETR) and is comprised of our obligation to Transocean under the tax sharing agreement for the utilization of pre-IPO federal and state tax benefits and the recognition of foreign deferred tax liabilities in certain foreign tax jurisdictions where we have a low tax basis in our assets. The ETR is higher than the federal rate of 35% principally due to foreign and state tax expense.

In September 2005, Transocean instructed us, pursuant to a provision in the tax sharing agreement, to take a tax deduction for profits realized by our current and former employees and directors from the exercise of Transocean stock options during calendar 2004. Transocean also indicated that it expected us to take a similar deduction in future years to the extent there were profits realized by our current and former employees and directors during those future periods.

It was our belief that the tax sharing agreement only required us to pay Transocean for deductions related to stock option exercises by persons who were our employees on the date of exercise. Transocean disagreed with our interpretation of the tax sharing agreement as it related to this issue and believed that we must pay for all stock option exercises, regardless of whether any employment or other service provider relationship may have terminated prior to the exercise of the employee stock option. As such, Transocean initiated dispute resolution proceedings against us.

A negotiated settlement of that dispute was reached on November 27, 2006. As a result of the settlement, we and Transocean executed an Amended and Restated Tax Sharing Agreement reflecting the terms of the settlement. Under the terms of the settlement, we will now pay Transocean for only 55% of the value of the tax deductions arising from the exercise of the Transocean stock options by our current and former employees and directors, or a 45% discount from the September 2005 demand by Transocean. This discounted payment rate applies retroactively to amounts we previously accrued and to future payments. Further, under the terms of the original Tax Sharing Agreement, our use of certain state and foreign tax assets reduced our ability to receive federal tax benefit for the use of such tax assets that otherwise would have been available in the amount of $2.9 million. The Amended and Restated Tax Sharing Agreement gives us credit for the federal tax benefit that otherwise would have been available in connection with the use of such assets for past and future periods.

During the dispute with Transocean, we continued to accrue liabilities based on Transocean s interpretation of the Tax Sharing Agreement. As a result, upon settlement of this dispute, we eliminated $44.5 million in liability to Transocean by paying it $22.0 million, increasing additional paid-in capital by $20.9 million, reducing current tax expense by $2.9 million and recording net interest expense and other of $1.3 million. In the future, as Transocean stock option deductions are generated under the Amended Tax Sharing Agreement, we will reduce current taxes payable by the entire amount of the Transocean stock option deduction, pay Transocean for 55% of the deduction and increase additional paid-in capital by 45% of the deduction.

We utilized pre-IPO income tax benefits to offset our current federal income tax obligation during the years ended December 31, 2006 and 2005. After accounting for payments made to Transocean, we had a liability to Transocean of $51.3 million and $43.8 million as of December 31, 2006 and 2005, respectively. Additionally, during the years ended

December 31, 2006 and 2005, we utilized pre-IPO state tax benefits which, after payments made to Transocean, resulted in a liability to Transocean of $0.4 million and $0.1 million, respectively. We also utilized pre-IPO foreign tax benefits during 2005 which, after payments made to Transocean, resulted in a liability to Transocean of $1.0 million at December 31, 2005. There was no liability due to Transocean for the utilization of foreign tax benefits at December 31, 2006. As of December 31, 2006 and 2005, we estimate that we owe Transocean $51.7 million and $44.9 million, respectively, for pre-IPO federal, state and foreign income tax benefits utilized.

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As of December 31, 2006, we had approximately $195 million of estimated pre-IPO income tax benefits subject to the obligation to reimburse Transocean. If an acquisition of beneficial ownership had occurred on December 31, 2006, the estimated amount we would have been required to pay Transocean would have been approximately $137 million, or 70% of the pre-IPO tax benefits at December 31, 2006. As of January 1, 2007, we will be required, under the terms of the Amended and Restated Tax Sharing Agreement, to pay 80% of the pre-IPO tax benefits if an acquisition of beneficial ownership occurs.

Years Ended December 31, 2005 and 2004

Operating Revenues. Total operating revenues increased $182.8 million, or 52%, during 2005 as compared to 2004, primarily due to higher overall average rig revenue per day earned in 2005, as compared to 2004. Overall average rig revenue per day increased from $29,100 for 2004 to $38,200 for 2005, as a consequence of the continued improvement of customer demand in the U.S. Gulf of Mexico and transition zone along the U.S. Gulf Coast, the revenue contribution from our platform rig which began operating in Mexico in December 2004, the commencement of operations in Angola and three land rigs which began operating in Venezuela in the last half of 2004. Average rig utilization of 54% for 2005 was up from 43% in 2004.

Operating revenues for our U.S. Gulf of Mexico segment increased $95.5 million, or 68%, in 2005, as compared to 2004. In 2005, we achieved higher average rig revenue per day for our jackup and submersible drilling fleet, improving from $34,200 per day to $53,000 per day. This resulted in an additional $80.1 million in operating revenues for 2005, as compared to the same period in 2004. The increase in average rig revenue per day is the result of our success in obtaining contracts with our customers at higher dayrates in response to increased demand. Results for 2005 also reflect higher utilization for our current rig fleet in this segment, after giving effect to the transfer of the jackup drilling unit *THE 156* from our Other International segment in the fourth quarter of 2004. This increase in utilization resulted in $4.6 million in additional rig revenues in 2005, as compared to the same period in 2004. The transfer of *THE 156* generated operating revenues of $10.8 million in 2005 before it was transferred to Colombia in the last quarter of 2005.

Operating revenues for our U.S. Inland Barge segment increased $40.2 million, or 38%, in 2005, as compared to the same period in the prior year, primarily due to higher average rig revenue per day achieved in 2005, as compared to 2004. Average rig revenue per day increased from $22,200 for 2004 to $28,400 for 2005, as a result of our successful marketing efforts in negotiating higher dayrates for our fleet of inland barges during 2005. The increase in average rig revenue per day resulted in additional revenues of $31.7 million for 2005 as compared to 2004. Utilization of our inland barge fleet was 51% for 2005, as compared to 43% for 2004, which resulted in $8.5 million additional operating revenues in 2005 as compared to 2004.

Operating revenues for our Other International segment were $101.8 million for 2005. The 39%, or $28.5 million, increase over operating revenues reported for 2004 reflects commencement of operation of our platform rig in Mexico in late 2004 under a long-term contract, the commencement of operations in Angola in September 2005 and the commencement of operations in Venezuela of three land rigs in the last half of 2004. The operation of the platform rig contributed an additional $12.7 million in operating revenues during 2005. Higher land rig utilization in Venezuela contributed an additional $16.7 million in operating revenues in 2005 compared to 2004. In addition, the commencement of operations in Angola in September 2005 contributed an additional $8.1 million to 2005 operating revenues. Also, *THE 156* was transferred from the U.S. Gulf of Mexico to Colombia in the last quarter of 2005 and generated $0.7 million revenue after beginning operations in December. These favorable contributions were offset by the transfer of *THE 156* from Venezuela to the U.S. Gulf of Mexico which generated $15.6 million in operating revenues for 2004.

Our operating revenues for 2005 included $49.6 million related to the operation of Delta Towing s fleet of U.S. marine support vessels which increased from $31.0 million recognized in 2004 due to increased vessel utilization in response to improved demand.

Operating and Maintenance Expenses. Total operating and maintenance expenses increased $63.5 million, or 24%, in 2005 as compared to operating expenses of $259.7 million for 2004.

Operating and maintenance expenses for our U.S. Gulf of Mexico segment were $23.0 million higher for 2005 as compared to 2004. The factors contributing to this 25% increase were additional personnel costs of $6.4 million relating to the higher utilizations and wage increases in 2005, the relocation of *THE 156* back to the U.S. Gulf of Mexico ($4.7 million) and increased mobilization expense ($0.7 million). Repair and maintenance expense resulting from the higher utilizations increased $6.0 million for 2005 as compared to 2004. Our insurance claims expense increased $3.8 million from damages sustained during Hurricanes Katrina and Rita and also from damage to *THE 202* during a jacking incident. Our 2004 expenses were also favorably impacted by a $0.5 million reduction in our reserve for uncollectible accounts receivable and a $0.7 million recovery of insurance claims related to one of our jackup drilling rigs.

Operating and maintenance expenses for our U.S. Inland Barge segment were $94.1 million for 2005 as compared to $82.6 million for 2004. This $11.5 million, or 14%, increase was primarily the result of increasing personnel costs ($8.6 million) and higher repair and maintenance expenses ($3.1 million), primarily on *Rig 64* hull repairs and the reactivation of *Rig 28,* which was cold stacked and began operations in the third quarter of 2005. Mobilization expense and rental recharges increased $1.1 million when comparing results from 2005 to 2004 as a result of increased activity and utilization. Insurance claims expense related to hurricane damage in 2005 of $0.6 million was more than offset by a $1.1 million decrease in personal injury claim expense and insurance costs when comparing 2005 to 2004, primarily the result of an improvement in the actuarial factors used to develop our personal injury claims.

Operating and maintenance expenses for our Other International segment for 2005 increased $24.8 million, or 40%, as compared to 2004. This increase was due to our platform rig in Mexico which began operations in December 2004 and incurred $8.7 million of expenses in 2005, an increase of $5.8 million over 2004. In addition, we incurred higher expenses on our other Mexico operations of $1.7 million during 2005 as compared to 2004. Higher land rig utilization and increasing costs in Venezuela resulted in an increase of $11.5 million when comparing 2005 to 2004. Reactivation of *THE 185* for operations in Angola resulted in an additional $12.6 million in expense being incurred during 2005. The commencement of operations of a land rig in Trinidad in the last quarter of 2005 contributed an additional $1.7 million in expenses. The relocation of *THE 156* from the U.S. Gulf of Mexico segment to Colombia in the last quarter of 2005 contributed an additional $0.6 million in operating expenses. These additional expenses were partially offset by the transfer of *THE 156* from Venezuela in the last quarter of 2004 to our U.S. Gulf of Mexico operations which lowered expenses in our Other International segment by $10.4 million for 2005 as compared to 2004 and a $0.8 million reduction in a Venezuelan labor claim legal reserve due to favorable settlements.

Delta Towing operations incurred $25.7 million in operating costs for 2005. This represented a $4.2 million, or 20%, increase over operating costs of $21.5 million recognized in 2004 which was principally due to increased marine support vessel utilization and increased repairs and maintenance expenses.

General and Administrative Expenses. General and administrative expenses were $37.7 million for 2005 as compared to $34.0 million for 2004. General and administrative expenses for 2005 increased $3.7 million as compared to 2004, due primarily to higher payroll costs of $3.8 million and an increase in Delta Towing and other general and administrative expenses of $1.9 million. Additional audit fees, a secondary offering in May 2005 and Sarbanes-Oxley compliance work contributed to an increase of $2.9 million in our professional, legal and accounting fees. These increases were offset by a decrease in stock option and restricted stock award expense of $4.5 million. The stock option expense of $12.1 million recognized in 2004 included $10.6 million of stock compensation expense associated with post-IPO grants of stock options and restricted stock awards. Comparable stock compensation expense for 2005 was $7.6 million which also included expense related to deferred performance units and deferred stock units. Additionally in 2004, we recognized a one-time $1.5 million stock compensation expense related to the modification of Transocean stock options held by some of our employees. In addition, we incurred no administrative charges under our transition services agreement with Transocean in 2005 as compared to $0.4 million in 2004.

Gain on Disposal of Assets, Net. During 2005, we realized net gains on disposal of assets of $25.1 million related to the sale of three out-of-service jackup rigs, *THE 154* ($9.3 million), *THE 151* ($6.7 million) and *THE 192* ($3.8 million), the sale of drill pipe and miscellaneous equipment ($4.1 million) and the sale of five marine support vessels by Delta Towing ($1.2 million). During 2004, we realized gains on disposal of assets of $6.5 million, primarily related to the sale of six marine support vessels by Delta Towing ($2.3 million), the settlement of an October 2000 insurance claim for one of our jackup rigs ($1.5 million) and the sale of drill pipe and miscellaneous equipment ($2.1 million).

Interest Expense. Third party interest expense and interest expense-related party decreased $3.7 million in 2005 as compared to 2004, primarily due to lower debt balances owed to third parties and Transocean. In the first quarter of 2004, we completed the debt-for-equity exchange of all our remaining outstanding related party debt payable to Transocean and in the second quarter of 2005 we made payments of $7.7 million to retire our 6.75% Senior Notes.

Income Tax Expense (Benefit). The income tax expense of $44.5 million for 2005 reflects a 42.8% effective tax rate (ETR) and is comprised of our obligation to Transocean under the tax sharing agreement for the utilization of pre-IPO federal and state tax benefits and the recognition of foreign deferred tax liabilities in certain foreign tax jurisdictions where we have a low tax basis in our assets. The ETR is higher than the federal rate of 35% principally due to foreign tax expense, state tax expense and a 2004 tax return adjustment. Tax expense for 2005 also includes the effect of recognizing an additional $7.7 million in pre-IPO deferred state tax liabilities that existed at the IPO date. The recognition of these pre-IPO deferred state tax liabilities resulted in a $7.7 million reduction in additional paid-in capital, $0.9 million of deferred state tax benefit and a $6.8 million increase in deferred tax liabilities.

Under the tax sharing agreement, we are unable to reduce our federal tax benefit obligation owed to Transocean for the state tax benefits utilized. For 2004, our net loss generated a tax benefit of $12.5 million, or a 30.2% ETR, which was lower than the federal tax rate due to a valuation allowance on the Delta Towing tax benefits generated during 2004.

During 2005, Transocean instructed us, pursuant to a provision in the tax sharing agreement, to take a tax deduction for profits realized by current and former employees and directors who exercised Transocean stock options during calendar 2004. Transocean also indicated that it expected us to take a similar deduction in future years to the extent there were profits realized by our current and former employees and directors during those future periods.

It was our belief that the tax sharing agreement only requires us to pay Transocean for deductions related to stock option exercises by persons who were our employees on the date of exercise. The payment obligation is generally 35% of the tax deduction. Transocean disagrees with our interpretation of the tax sharing agreement as it relates to this issue and it believes that we must pay for all stock option exercises, irrespective of whether any employment or other service provider relationship may have terminated prior to the exercise of the employee stock option. As such, Transocean initiated dispute resolution proceedings against us.

We recorded our obligation to Transocean based on our interpretation of the tax sharing agreement. However, due to the uncertainty of the outcome of this dispute, we established a reserve equal to the benefit derived from stock option deductions relating to persons who were not our employees on the date of the exercise. For the tax year ending December 31, 2004, the deduction related to all of our current and former employees and directors was $8.8 million with only $1.1 million attributable to persons who were our employees on the date of exercise. Additionally, we have been informed by Transocean that from January 1, 2005 to December 31, 2005, our current and former employees and directors have realized $85.3 million of gains from the exercise of Transocean stock options with $4.3 million relating to persons who were our employees on the date of exercise. If Transocean s interpretation of the tax sharing agreement prevails, we would recognize a tax benefit for former employee and director stock option exercises and pay Transocean 35% for the deduction. While this would not increase our tax expense, it would defer utilization of pre-IPO income tax benefits.

Cumulative Effect of a Change in Accounting Principle

We adopted SFAS No. 123(R) in the first quarter of 2006. As a result of adopting SFAS 123 in an earlier period, the adoption of SFAS 123R in the first quarter of 2006 had an immaterial income effect. Under the fair value recognition provisions of SFAS 123R, we recognize stock-based compensation net of an estimated forfeiture rate and only recognize compensation cost for those shares expected to vest on a straight-line basis over the requisite service period of the award, which is generally a vesting term of three years. Under the guidelines of SFAS 123, we recognized forfeitures in the period in which they occurred. As a result of our adoption of SFAS 123R, the estimate of forfeitures resulted in a one-time cumulative adjustment credit to income of $0.1 million, net of tax.

Financial Condition

At December 31, 2006 and December 31, 2005, we had total assets of $889.2 million and $825.0 million, respectively. The $64.2 million increase in assets during 2006 is primarily attributable to a $102.2 million increase in our accounts receivable, primarily due to the increased dayrates and utilization we experienced in 2006 as compared to 2005. Cash balances increased $6.3 million, a result of the improving of the dayrates and utilization offset by the $150.2 million stock repurchase completed during the third quarter of 2006. These were partially offset by a net decrease in our property and equipment of $31.7 million, primarily resulting from depreciation expense of $86.2 million offset by net capital expenditures of $59.7 million and a net decrease in our deferred mobilization of $9.1 million which resulted from amortization exceeding additions to this account for the year. See Liquidity and Capital Resources. Total assets by business segment were as follows for the periods indicated below:

	December 31,		
	2006	**2005**	**2004**
U.S. Gulf of Mexico Segment	$ 287.3	$ 252.2	$ 354.1
U.S. Inland Barge Segment	194.6	161.3	160.8
International and Other Segment	164.3	164.6	154.5
Delta Towing Segment	48.6	55.6	51.8
Corporate and Other	194.4	191.3	40.2
Total assets	$ 889.2	$ 825.0	$ 761.4

Working capital at December 31, 2006 was $228.8 million, as compared to a working capital of $156.7 million at December 31, 2005. The increase in working capital during 2006 is primarily attributable to increases in accounts receivable offset by increases in accounts payable and taxes payable. Our accounts receivable has increased as dayrates and utilization have increased. Accounts payable increased as we returned rigs to service during the year for the year ended December 31, 2006. Our increase in taxes payable is attributable to our net income of $183.6 million for 2006.

Liquidity and Capital Resources

Sources and Use of Cash

2006 Compared to 2005. Net cash provided by operating activities was $190.2 million for the year ended December 31, 2006, as compared to $136.4 million in 2005. The $53.8 million increase in net cash provided by operating activities is primarily attributable to the increase in net income of $124.2 million. Our net income was favorably affected by the improvement in the demand for shallow water drilling services which resulted in our dayrates increasing from $38,200 to $57,800 and our rig utilization percentages increasing from 54% to 62%. Adjustments to reconcile net income to net cash provided by operating activities decreased in 2006, primarily due to unfavorable variances related to an increase in deferred income taxes of $6.0 million, a decrease in depreciation expense of $9.8 million and a $28.9 million decrease in deferred income. These were partially offset by a decrease in gains realized on asset sales of $13.5 million and an increase in deferred expenses of $7.9 million in 2006. Changes in operating assets and liabilities resulted in a $27.3 million decrease in cash in 2006, compared to a $14.4 million increase in 2005. This $41.7 million unfavorable decrease is primarily the result of the increase in accounts receivable of $57.3 million. Higher revenues, the result of increasing dayrates and utilizations, during 2006 resulted in a significantly higher receivable balance at year end when compared to year end 2005. Partially offsetting this unfavorable variance were increases in our net taxes payable ($4.7 million) and accounts payable and other current liabilities ($6.7 million).

Net cash used in investing activities was $39.3 million for the year ended December 31, 2006 compared to net cash provided by investing activities of $13.1 million for the same period in 2005. The $52.4 million increase in net cash used in investing activities relates primarily to an increase in capital expenditures of $37.3 million and a decrease in the cash proceeds from the sale of assets of $21.3 million. These unfavorable effects on cash were partially offset by a decrease in our restricted cash balances, due to a reduction of collateral requirements related to our PEMEX required performance bonds in Mexico, resulting in a favorable variance of $6.2 million for 2006 when compared to 2005.

Net cash used in financing activities was $144.6 million for the year ended December 31, 2006, as compared to $51.6 million for the same period in 2005. Financing activities in 2006 included the repurchase of 4.2 million shares of our common stock for $150.2 million and net repayments of short-term borrowings of $1.5 million. In addition, we received $3.2 million related to the issuance of our common stock under our long-term incentive plans in 2006, compared to the $17.8 million we received in 2005. Additional financing activities in 2005 included the special cash dividend of $61.2 million, the $7.7 million repayment of our 6.75% notes and the repayment of capital leases totaling $0.8 million.

Sources of Liquidity and Capital Expenditures

Our cash flows from operations and existing cash balances were our primary sources of liquidity for the years ended December 31, 2006 and 2005.

For the year ended December 31, 2006, our primary uses of cash were operating costs, including rig reactivations, the stock repurchase of 4.2 million shares of our common stock for $150.2 million and capital expenditures of $59.7 million. For the year ended December 31, 2005, our primary uses of cash were operating costs, the special cash dividend payment of $61.2 million, capital expenditures of $22.4 and debt repayments of $7.7 million. At December 31, 2006, we had $169.3 million in cash and cash equivalents.

We anticipate that we will rely primarily on internally generated cash flows to maintain liquidity. From time to time, we may also make use of our revolving line of credit for cash liquidity. In December 2005 we entered into a four-year, $200 million floating-rate secured revolving credit facility (the 2005 Facility). The 2005 Facility is secured by most of our drilling rigs, receivables, the stock of most of its U.S. subsidiaries and is guaranteed by some of its subsidiaries. Borrowings under the 2005 Facility bear interest at our option at either (1) the higher of (A) the prime rate and (B) the federal funds rate plus 0.5%, plus a margin in either case of 1.25% or (2) the London Interbank Offering Rate (LIBOR) plus a margin of 1.60%. Commitment fees on the unused portion of the 2005 Facility are 0.55% of the average daily available portion and are payable quarterly. Borrowings and letters of credit issued under the 2005 Facility may not exceed the lesser of $200 million or one third of the fair market value of the drilling rigs securing the facility, as determined from time to time by a third party approved by the agent under the facility.

Financial covenants include maintenance of the following:

- a working capital ratio of (1) current assets plus unused availability under the facility to (2) current liabilities of at least 1.2 to 1,
- a ratio of total debt to total capitalization of not more than 0.35 to 1.00,
- tangible net worth of not less than $375 million, and
- in the event availability under the facility is less than $50 million, a ratio of (1) EBITDA (earnings before interest, taxes, depreciation and amortization) minus capital expenditures to (2) interest expense of not less than

2 to 1, for the previous four fiscal quarters.

The revolving credit facility provides, among other things, for the issuance of letters of credit that we may utilize to guarantee performance under some drilling contracts, as well as insurance, tax and other obligations in various jurisdictions. The 2005 Facility also provides for customary fees and expense reimbursements and includes other covenants (including limitations on the incurrence of debt, mergers and other fundamental changes, asset sales and dividends) and events of default (including a change of control) that are customary for similar secured non-investment grade facilities.

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At December 31, 2006 and 2005, we had no borrowings outstanding under our credit facility.

In the third quarter of 2004, we entered into an unsecured line of credit with a bank in Venezuela to provide a maximum of 4.5 million Venezuela Bolivars which was subsequently increased to 6.0 billion Venezuela Bolivars ($2.8 million U.S. dollars at the current exchange rate at December 31, 2006) in order to manage local currency liquidity. Each draw on the line of credit is denominated in Venezuela Bolivars and is evidenced by a 30-day promissory note that bears interest at the then market rate as designated by the bank. The promissory notes are pre-payable at any time at our option. However, if not repaid within 30 days, the promissory notes may be renewed at mutually agreeable terms for an additional 30-day period at the then designated interest rate. There are no commitment fees payable on the unused portion of the line of credit, and the facility is reviewed annually by the bank s board of directors. At December 31, 2005, we had a balance of $0.4 million outstanding under this line of credit. There were no borrowings outstanding under this line of credit at December 31, 2006.

We expect capital expenditures primarily for rig refurbishments and the purchase of capital equipment to be approximately $59.0 million in 2007, including approximately $20.0 million for potential rig reactivations. The timing and amounts we actually spend in connection with our plans to upgrade and refurbish other selected rigs is subject to our discretion and will depend on our view of market conditions and our cash flows. We would expect capital expenditures to increase as market conditions improve. Our cold stacked rigs requiring refurbishment to be ready for service are noted in the tables in Business Drilling Rig Fleet. From time to time we may review possible acquisitions of drilling rigs or businesses, joint ventures, mergers or other business combinations and may in the future make significant capital commitments for such purposes. Any such transactions could involve the issuance of a substantial number of additional shares or other securities or the payment by us of a substantial amount of cash. We would likely fund the cash portion, if any, of such transactions through cash balances on hand, the incurrence of additional debt, sales of assets, shares or other securities or a combination thereof. In addition, from time to time we may consider dispositions of drilling rigs. 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 the revolving credit facility described above.

The amounts we estimate for reactivating cold stacked rigs to service are based on our projections of the costs of equipment, supplies and services, which have been rising. We estimate that once commenced, rig reactivations will take four to five months to complete and that the cost will be $10.0 million to $15.0 million for each inland barge rig and seven to eight months to complete and $20.0 million to $30.0 million for each jackup rig. Our estimates of rig reactivation costs are subject to numerous other variables including further rig deterioration over time, the availability and cost of shipyard facilities, customer specifications, and the actual extent of required repairs and maintenance and optional upgrading of the rigs. The actual amounts we ultimately pay for returning these rigs to service could, therefore, vary substantially from our estimates. In anticipation of reactivating cold stacked rigs, we have placed orders for equipment with long lead times in the amount of approximately $28.0 million. This includes approximately $6 million for four top-drives and approximately $22 million of drill pipe for delivery in 2007 for reactivations and capital upgrades.

We anticipate that our available funds, together with our cash generated from operations and amounts that we may borrow, will be sufficient to fund our required capital expenditures, working capital and debt service requirements for the foreseeable future. Future cash flows and the availability of outside funding sources, however, are subject to a number of uncertainties, especially the condition of the oil and natural gas industry. Accordingly, these resources may not be available or sufficient to fund our cash requirements.

Investment in oil and gas partnerships

During the second quarter of 2006, we invested in two oil and gas exploration and production limited partnerships operating in the inland waterway of the U.S. Gulf Coast and Offshore U.S. Gulf of Mexico. We committed $9.5 million and funded $6.3 million in these two partnerships. Our investment in these oil and gas partnerships was the result of customer relationships and is not indicative of a strategy change, nor do we believe that the investments will be long-term in nature. In November 2006, we sold our investment in one of the partnerships for $6.3 million and recognized a $1.4 million gain on the sale of the partnership.

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Our total investment in the remaining partnership is classified in Other Assets on the Consolidated Balance Sheets at December 31, 2006. Currently, the partnership has no producing wells. Additional contributions to the partnership are limited to the initial commitment with provisions for optional assessments.

Repurchase of Common Stock

In August 2006, our Board of Directors authorized the repurchase of up to $150.0 million of our common stock. We repurchased and retired $150.0 million of our common stock, which amounted to 4.2 million shares at an average price of $35.55 per share. The repurchase was funded with existing cash balances. Total consideration of $150.2 million paid to repurchase the shares and the related brokerage commissions was recorded in stockholders equity as a reduction in common stock and additional paid-in capital.

Payment of Dividends

We have no plans to pay regular dividends on our common stock. We generally intend to invest our future earnings, if any, to fund our growth. Subject to Delaware law, any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends, and other considerations that our board of directors deems relevant. Our credit facility also includes limitations on our payment of dividends. However, due to favorable business conditions, our unrestricted cash balances grew to levels that exceeded our foreseeable needs for cash held for reinvestment and unknown contingencies. After we secured the approval of our lenders, our board of directors declared a special cash dividend of $1.00 per share, totaling $61.2 million, which was paid in August 2005. This special cash dividend is not indicative of a change in our basic dividend policy nor does it guarantee that any future dividends will be paid.

In connection with the special cash dividend and as contemplated by our long term incentive plans, our Executive Compensation Committee awarded special cash bonuses to holders of stock options under our long term incentive plans in the aggregate amount of $0.7 million to compensate them for any potential loss in option value. These bonuses were paid in the third quarter of 2006.

Contractual Obligations

As of December 31, 2006, our scheduled debt maturities and other contractual obligations are presented in the table below with debt obligations presented at face value:

	For the Years Ended December 31,				
	Total	2007	2008 to 2009	2010 to 2011	Thereafter
	(In millions)				
Contractual Obligations					
Debt	$ 15.9	$	$ 12.4	$	$ 3.5
Operating Leases	8.1	1.2	2.4	2.4	2.1
Purchase Obligations(a)	34.1	34.1			
Accrued Income Taxes Former Parent	51.7	51.7			
Total Contractual Obligations	$ 109.8	$ 87.0	$ 14.8	$ 2.4	$ 5.6

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

At December 31, 2006, we had other commitments that we are contractually obligated to fulfill with cash should the obligations be called. These obligations represent surety bonds that guarantee our performance as it relates to our drilling contracts, insurance, tax and other obligations in various jurisdictions. These obligations could be called at any time prior to their expiration dates. The obligations that are the subject of these surety bonds are geographically concentrated primarily in Mexico and Venezuela.

	For the Years Ended December 31,				
	Total	2007	2008 to 2009	2010 to 2011	Thereafter
	(In millions)				
Other Commercial Commitments					
Surety Bonds(a)	$ 38.8	$ 16.0	$ 10.2	$ 12.6	$

(a) Relates to bonds issued primarily in connection with our contracts with PEMEX, PDVSA and Trinidad.

Derivative Instruments

We have established policies and procedures for derivative instruments that have been approved by our board of directors. These policies and procedures provide for the prior approval of derivative instruments by our Chief Financial Officer and periodic review by the Audit Committee of our board of directors. From time to time, we may enter into a variety of derivative financial instruments in connection with the management of our exposure to fluctuations in foreign exchange rates and interest rates. We do not plan to enter into derivative transactions for speculative purposes; however, for accounting purposes, certain transactions may not meet the criteria for hedge accounting.

Gains and losses on foreign exchange derivative instruments that qualify as accounting hedges are deferred as accumulated other comprehensive income and recognized when the underlying foreign exchange exposure is realized. Gains and losses on foreign exchange derivative instruments that do not qualify as hedges for accounting purposes are recognized currently based on the change in market value of the derivative instruments. At December 31, 2006, we did not have any outstanding foreign exchange derivative instruments.

From time to time, we may use interest rate swaps to manage the effect of interest rate changes on future income. Interest rate swaps would be designated as a hedge of underlying future interest payments and would not be used for speculative purposes. The interest rate differential to be received or paid under the swaps is recognized over the lives of the swaps as an adjustment to interest expense. If an interest rate swap is terminated, the gain or loss is amortized over the life of the underlying debt. At December 31, 2006, we did not have any outstanding interest rate swaps.

Delta Towing

In January 2006, we purchased Chouest s 75% interest in Delta Towing for one dollar and paid $1.1 million to retire Delta Towing s related party debt to Chouest. As a result of the consolidation of Delta Towing in our consolidated financial statements in accordance with FIN 46 beginning December 31, 2003, the purchase of the additional interest in Delta Towing did not have a material impact on our consolidated results of operations, financial position or cash flows. See Note 4 to our consolidated financial statements included in Item 8 of this report.

Prior to January 1, 2006, we owned a 25% equity interest in Delta Towing, which was formed to own and operate our U.S. marine support vessel business consisting primarily of shallow water tugs, crewboats and utility barges. We contributed this business to Delta Towing in return for a 25% ownership interest and secured notes issued by Delta

Towing with a face value of $144.0 million. The remaining 75% ownership interest was held by Chouest which also loaned Delta Towing $3.0 million. See Related Party Transactions Long-Term Debt Chouest.

In January 2003, the FASB issued FIN 46 which requires that an enterprise consolidate a variable interest entity (VIE) if the enterprise has a variable interest that will absorb a majority of the entity s expected losses and/or receives a majority of the entity s expected residual returns as a result of ownership, contractual or other financial interests in the entity, if such loss or residual return occurs. If one enterprise absorbs a majority of a VIE s expected losses and another enterprise receives a majority of that entity s expected residual returns, the enterprise absorbing a majority of the expected losses is required to consolidate the VIE and will be deemed the primary beneficiary for accounting purposes.

Under FIN 46, Delta Towing was considered a VIE because its equity was not sufficient to absorb the joint venture s expected future losses. TODCO was deemed to be the primary beneficiary of Delta Towing for accounting purposes because we had the largest percentage of investment at risk through the secured notes held by us and would thereby absorb the majority of the expected losses of Delta Towing. We consolidated Delta Towing in accordance with FIN 46 as of December 31, 2003. Upon the purchase of Delta Towing s outstanding 75% interest in January 2006, we began consolidating Delta Towing as a wholly-owned subsidiary.

As of December 31, 2006 and 2005, we have eliminated in consolidation all intercompany account balances with Delta Towing, as well as the elimination of all intercompany transactions during the years ended December 31, 2006, 2005 and 2004.

Related Party Transactions

Long-Term Debt Chouest

In connection with the acquisition of the marine business, Delta Towing entered into a $3.0 million note agreement with Chouest dated January 30, 2001. As of December 31, 2005, the balance outstanding under the note was $2.9 million. The note bore interest at 8%, payable quarterly. In January 2004, Delta Towing failed to make its scheduled principal payment to Chouest and the $2.9 million principal amount of the note payable was classified as a current obligation in our consolidated balance sheet. In conjunction with our purchase of Chouest s 75% in Delta Towing in January 2006, we paid $1.1 million to retire the $2.9 million note payable. Interest expense related to the note payable to Chouest was $0.2 million for the year ended December 31, 2005. No interest expense related to the note payable to Chouest was recognized for the year ended December 31, 2006.

Transactions With Former Parent

Long-Term Debt Transocean

We have been party to several long-term debt agreements with Transocean which no longer exist. See Notes 3 and 5 to the consolidated financial statements for further discussion regarding the issuance and retirement of these notes.

Tax Sharing Agreement

In September 2005, Transocean instructed us, pursuant to a provision in the tax sharing agreement, to take a tax deduction for profits realized by our current and former employees and directors from the exercise of Transocean stock options during calendar 2004. Transocean also indicated that it expected us to take a similar deduction in future years to the extent there were profits realized by our current and former employees and directors during those future periods.

It was our belief that the tax sharing agreement only required us to pay Transocean for deductions related to stock option exercises by persons who were our employees on the date of exercise. Transocean disagreed with our interpretation of the tax sharing agreement as it related to this issue and believed that we must pay for all stock option exercises, regardless of whether any employment or other service provider relationship may have terminated prior to the exercise of the employee stock option. As such, Transocean initiated dispute resolution proceedings against us.

A negotiated settlement of that dispute was reached on November 27, 2006. As a result of the settlement, we and Transocean executed an Amended and Restated Tax Sharing Agreement reflecting the terms of the settlement. Under the terms of the settlement, we will now pay Transocean for only 55% of the value of the tax deductions arising from the exercise of the Transocean stock options by our current and former employees and directors, or a 45% discount from the September 2005 demand by Transocean. This discounted payment rate applies retroactively to amounts we previously accrued and to future payments. Further, under the terms of the original Tax Sharing Agreement, our use of certain state and foreign tax assets reduced our ability to receive the federal tax benefit for the use of such tax assets that otherwise would have been available in the amount of $2.9 million. The Amended and Restated Tax Sharing Agreement gives us credit for the federal tax benefit that otherwise would have been available in connection with the use of such assets for past and future periods.

During the dispute with Transocean, we continued to accrue liabilities based on Transocean s interpretation of the Tax Sharing Agreement. As a result, upon settlement of this dispute, we eliminated $44.5 million in liability to Transocean by paying it $22.0 million, increasing additional paid-in capital by $20.9 million, reducing current tax expense by $2.9 million and recording net interest expense and other of $1.3 million. In the future, as Transocean stock option deductions are generated under the Amended Tax Sharing Agreement, we will reduce current taxes payable by the entire amount of the Transocean stock option deduction, pay Transocean for 55% of the deduction and increase additional paid-in capital by 45% of the deduction.

As part of the tax sharing agreement, we must pay Transocean for substantially all pre-closing income tax benefits utilized or deemed to have been utilized subsequent to the closing of the IPO. We utilized pre-IPO income tax benefits to offset our current federal income tax obligation during the years ended December 31, 2006 and 2005. After accounting for payments made to Transocean, we had a liability to Transocean of $51.3 million and $43.8 million as of December 31, 2006 and 2005, respectively. Additionally, during the years ended December 31, 2006 and 2005, we utilized pre-IPO state tax benefits which, after payments made to Transocean, resulted in a liability to Transocean of $0.4 million and $0.1 million, respectively. We also utilized pre-IPO foreign tax benefits during 2005 which, after payments made to Transocean, resulted in a liability to Transocean of $1.0 million at December 31, 2005. There was no liability due to Transocean for the utilization of foreign tax benefits at December 31, 2006. As of December 31, 2006 and 2005, we estimate that we owe Transocean $51.7 million and $44.9 million, respectively, for pre-IPO federal, state and foreign income tax benefits utilized.

As of December 31, 2006, we had approximately $195 million of estimated pre-IPO income tax benefits subject to the obligation to reimburse Transocean. If an acquisition of beneficial ownership had occurred on December 31, 2006, the estimated amount we would have been required to pay Transocean would have been approximately $137 million, or 70% of the pre-IPO tax benefits at December 31, 2006. As of January 1, 2007, we will be required, under the terms of the Amended and Restated Tax Sharing Agreement, to pay 80% of the pre-IPO tax benefits if an acquisition of beneficial ownership occurs.

In addition, Transocean agreed to indemnify us for certain tax liabilities that existed as of the IPO date which are currently estimated to be $10.3 million. We recorded the tax indemnification by Transocean as a credit to additional paid-in capital with a corresponding offset to a receivable from Transocean.

Cautionary Statement About Forward Looking Statements

This report contains both historical and forward-looking statements. All statements other than statements of historical fact are, or may be deemed to be, forward-looking statements. Forward-looking statements include information concerning our possible or assumed future financial performance and results of operations, including statements about the following subjects:

- our strategy,
- improvement in the fundamentals of the oil and gas industry,
- the supply and demand imbalance in the oil and gas industry,
- the correlation between demand for our rigs, our earnings and our customers expectations of energy prices,
- expected improvement in demand for U.S. Gulf of Mexico jackup rigs in 2007,

our plans, expectations and any effects of focusing on agreements and marine assets and drilling for natural gas along the U.S. Gulf Coast, pursuing efficient, low-cost operations and a disciplined approach to capital spending, maintaining high operating standards and maintaining a conservative capital structure,

future taxes and the estimated tax benefits and estimated payments under our tax sharing agreement with Transocean,

expected capital expenditures,

expected general and administrative expense, expectations regarding rig refurbishments and reactivations including anticipated costs, completion times and our ability to recover refurbishment costs and operating expenses under term contracts,

our ability to take advantage of opportunities for growth and our ability to respond effectively to market downturns,

sources and sufficiency of funds for required capital expenditures, working capital and debt service,

deep gas drilling opportunities,

operating standards,

payment of dividends,

competition for drilling contracts,

matters relating to derivatives,

matters related to our letters of credit and surety bonds,

future restructurings,

future transactions with unaffiliated third parties, including the possible sale of our Venezuelan assets,

matters relating to our future transactions, agreements and relationship with Transocean,

payments under agreements with Transocean,

interests conflicting with those of Transocean,

liabilities under laws and regulations protecting the environment,

expectations regarding the materiality to us of new or modified FASB pronouncements and other changes in generally accepted accounting principles,

results, effects and level of materiality of legal proceedings,

future utilization rates,

the expectations and assumptions we use to determine the fair value of stock options and restricted stock grants,

future dayrates,

expectations regarding improvements in offshore drilling activity,

demand for our drilling rigs and the future supply of rigs in the U.S. Gulf Coast, including the effect of new rigs being built, our plan to operate primarily in the U.S. Gulf Coast, and

operating revenues, operating and maintenance expense, capital expenditures, insurance expense and deductibles, interest expense, debt levels and other matters with regard to our outlook.

Forward-looking statements in this report are identifiable by use of the following words and other similar expressions:

anticipate,

believe,

budget,

could,

estimate,

expect,

- forecast,
- intent,
- may,
- might,
- plan,
- potential,
- predict,
- project, and
- should.

The following factors could affect our future results of operations and could cause those results to differ materially from those expressed in the forward-looking statements included in this Form 10-K:

- worldwide demand for oil and gas,
- exploration success by producers,
- demand for offshore and inland water rigs and marine support vessels,
- our ability to enter into and the terms of future contracts,
- labor relations,
- political and other uncertainties inherent in non-U.S. operations (including exchange controls and currency fluctuations),
- the impact of governmental laws and regulations,
- the adequacy of sources of liquidity,
- uncertainties relating to the level of activity in offshore oil and gas exploration and development,
- oil and natural gas prices (including U.S. natural gas prices),
- competition and market conditions in the contract drilling industry,
- work stoppages,
- increases in operating expenses,

extended delivery times for material and equipment,

the availability of qualified personnel,

operating hazards,

war, terrorism and cancellation or unavailability of insurance coverage,

compliance with or breach of environmental laws,

the effect of litigation and contingencies,

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

our ability to obtain drilling contracts for rigs we reactivate or are planning to reactivate,

the impact on us of newly built rigs,

the matters discussed in Item 1A. Risk Factors, and

other factors discussed in this Form 10-K.

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Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may vary materially from those indicated. Investors and potential investors should not place undue reliance on forward-looking statements. 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***

Interest Rate Risk

The table below presents scheduled debt maturities and related weighted-average interest rates for each of the years ending December 31, relating to debt obligations as of December 31, 2006:

	Scheduled Maturity Date							Fair Value at December 31,
	2007	2008	2009	2010	2011	Thereafter	Total	2006
	(In millions, except interest rate percentages)							
Total Debt								
Fixed Rate(a)	$	$ 12.4	$	$	$	$ 3.5	$ 15.9	$ 17.3
Average interest rate		9.1%				7.4%	8.7%	

(a) Expected maturity amounts are based on the face value of debt and do not reflect fair market value of debt.

A large part of our cash investments would earn commensurately higher rates of return if interest rates increase. Using December 31, 2006 cash investment levels, a one percent increase in interest rates would result in approximately $1.7 million of additional interest income per year.

Foreign Exchange Risk

Our international operations in Angola, Brazil, Mexico, Trinidad and Venezuela expose us to foreign exchange risk. We use a variety of techniques to minimize the exposure to foreign exchange risk. Our primary foreign exchange risk management strategy involves structuring customer contracts to provide for payment in both U.S. dollars and local currency. The payment portion denominated in local currency is based on anticipated local currency requirements over the contract term. We may also use foreign exchange derivative instruments or spot purchases. We do not enter into derivative transactions for speculative purposes. At December 31, 2006, we did not have any outstanding foreign exchange contracts.

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

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Management s Report on Responsibility for Financial Statements

Management is responsible for the Consolidated Financial Statements and the other financial information contained in this Annual Report on Form 10-K. The financial statements have been prepared in accordance with generally accepted accounting principles and are considered by management to present fairly the company s financial position, results of operations and cash flows. The financial statements include some amounts that are based on management s best estimates and judgments. The financial statements have been audited by the company s independent registered public accounting firm, Ernst & Young LLP. The purpose of their audit is to express an opinion as to whether the Consolidated Financial Statements included in this Annual Report on Form 10-K present fairly, in all material respects, the company s financial position, results of operations and cash flows. Their report is presented on the following page.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of TODCO

We have audited the accompanying consolidated balance sheets of TODCO as of December 31, 2006 and 2005, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of TODCO at December 31, 2006 and 2005, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

As described in Notes 2 and 13 to the consolidated financial statements, effective January 1, 2006, the Company adopted the modified prospective provisions of Statement of Financial Accounting Standards No. 123 (revised), Share-Based Payment .

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of TODCO s 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 and our report dated February 27, 2007 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 27, 2007

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of TODCO

We have audited management s assessment, included in the accompanying Management s Report on Responsibility for Internal Control over Financial Reporting, that TODCO 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 (the COSO criteria). TODCO s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. 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 opinion.

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

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

In our opinion, management s assessment that TODCO maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, TODCO maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the COSO criteria.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of TODCO as of December 31, 2006 and 2005, and the related consolidated statements of operations, stockholders equity and cash flows for each of the three years in the period ended December 31, 2006 of TODCO and our report dated February 27, 2007 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas

February 27, 2007

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TODCO

CONSOLIDATED BALANCE SHEETS

	December 31, 2006	December 31, 2005
	(In millions, except share data)	
ASSETS		
Cash and cash equivalents	$ 169.3	$ 163.0
Accounts receivable		
Trade	196.8	107.4
Other	32.5	19.7
Supplies	4.9	4.9
Deferred income taxes	11.0	8.4
Other current assets	12.8	17.9
Total current assets	427.3	321.3
Property and equipment	968.4	919.7
Less accumulated depreciation	517.1	436.7
Property and equipment, net	451.3	483.0
Other assets	10.6	20.7
Total assets	$ 889.2	$ 825.0
LIABILITIES AND STOCKHOLDERS EQUITY		
Trade accounts payable	$ 66.1	$ 42.4
Accrued income taxes	21.8	10.9
Accrued income taxes former parent	51.7	44.9
Debt due within one year		0.4
Debt due within one year related party		2.9
Interest payable related party		0.1
Other current liabilities	58.9	63.0
Total current liabilities	198.5	164.6
Long-term debt	16.4	16.6
Deferred income taxes	110.2	144.8
Other long-term liabilities	0.2	3.5
Total long-term liabilities	126.8	164.9
Commitments and contingencies		

Preferred stock, $0.01 par value, 50,000,000 shares authorized, none outstanding				
Common stock, $0.01 par value, 500,000,000 shares authorized, 57,742,030 shares and 61,521,990 outstanding at December 31, 2006 and 2005, respectively		0.6		0.6
Common stock, Class B, $0.01 par value, no shares authorized at December 31, 2006 and 260,000,000 shares authorized, none issued and outstanding at December 31, 2005				
Additional paid-in capital		6,409.0		6,527.2
Retained deficit		(5,845.7)		(6,029.3)
Unearned compensation				(3.0)
Total stockholders equity		563.9		495.5
Total liabilities and stockholders equity	$	889.2	$	825.0

See accompanying notes.

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TODCO

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2006	2005	2004
	(In millions, except per share amounts)		
Operating revenues	$ 912.1	$ 534.2	$ 351.4
Costs and expenses			
Operating and maintenance	510.2	323.2	259.7
Depreciation	86.2	96.0	95.7
General and administrative	41.3	37.7	34.0
Impairment loss on long-lived assets	0.4		2.8
	638.1	456.9	392.2
Operating income (loss)	274.0	77.3	(40.8)
Other income (expense), net			
Interest income	9.8	3.5	0.6
Interest expense	(4.7)	(3.6)	(4.1)
Interest expense related party		(0.2)	(3.4)
Gain on disposal of assets, net	11.6	25.1	6.5
Loss on retirement of debt			(1.9)
Other, net	0.8	1.8	1.8
	17.5	26.6	(0.5)
Income (loss) before income taxes and cumulative effect of a change in accounting principle	291.5	103.9	(41.3)
Income tax expense (benefit)	108.0	44.5	(12.5)
Income (loss) before cumulative effect of a change in accounting principle	183.5	59.4	(28.8)
Cumulative effect of a change in accounting principle, net of income tax	0.1		
Net income (loss)	$ 183.6	$ 59.4	$ (28.8)
Net income (loss) per common share:			
Basic:			
Income (loss) before cumulative effect of a change in accounting principle	$ 3.06	$ 0.98	$ (0.52)
Cumulative effect of a change in accounting principle, net of income tax			
Net income (loss) per common share	$ 3.06	$ 0.98	$ (0.52)
Diluted:			
Income (loss) before cumulative effect of a change in accounting principle	$ 3.04	$ 0.97	$ (0.52)
Cumulative effect of a change in accounting principle, net of income tax			
Net income (loss) per common share	$ 3.04	$ 0.97	$ (0.52)

Weighted average common shares outstanding:			
Basic	60.1	60.7	55.6
Diluted	60.5	61.4	55.6

See accompanying notes.

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TODCO

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

	Common Stock				Additional			
	Class A		Class B		Paid-in	Retained	Unearned	Total
	Shares	Amount	Shares	Amount	Capital	Deficit	Compensation	Equity
					(In millions)			
Balance at December 31, 2003			12.1	0.1	6,136.3	(5,998.7)		137.7
Net loss						(28.8)		(28.8)
Debt for equity exchange			47.9	0.5	528.4			528.9
Conversation of common stock from Class B to Class A	60.0	0.6	(60.0)	(0.6)				
Net distributions to parent					(181.4)			(181.4)
Equity contribution from parent					13.6			13.6
Issuance of restricted stock, net of forfeitures	0.3				4.4		(4.4)	
Stock options granted					8.7			8.7
Amortization of unearned compensation							1.9	1.9
Balance at December 31, 2004	60.3	0.6			6,510.0	(6,027.5)	(2.5)	480.6
Net income						59.4		59.4
Dividend payment ($1.00 per share)						(61.2)		(61.2)
Net distributions to parent					(7.7)			(7.7)
IPO tax adjustment					0.1			0.1
Stock options exercised, net of tax benefit	1.1				17.8			17.8
Issuance of restricted stock, deferred performance units, and deferred stock awards, net of forfeitures	0.1				3.1		(3.6)	(0.5)
Stock options granted					3.9			3.9
Amortization of unearned compensation							3.1	3.1

Balance at December 31, 2005	61.5	$ 0.6	$	6,527.2	(6,029.3)	(3.0)	495.5
Net income					183.6		183.6
Stock repurchase	(4.2)			(150.2)			(150.2)
Adoption of FAS 123(R)				(3.2)		3.0	(0.2)
Stock based compensation expense				6.5			6.5
Deferred stock award expense				0.7			0.7
Shares issued related to stock-based compensation plans	0.4			3.2			3.2
Excess tax benefits				3.9			3.9
Tax sharing agreement settlement				20.9			20.9
Balance at December 31, 2006	57.7	$ 0.6	$	$ 6,409.0	$ (5,845.7)	$	$ 563.9

See accompanying notes.

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TODCO

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2006	2005	2004
	(In millions)		
Cash Flows from Operating Activities			
Net income (loss)	$ 183.6	$ 59.4	$ (28.8)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Cumulative effect of a change in accounting principle, net of tax	(0.1)		
Depreciation	86.2	96.0	95.7
Deferred income taxes	(37.3)	(31.3)	(21.3)
Stock-based compensation expense	6.5	7.6	12.1
Net gain from disposal of assets	(11.6)	(25.1)	(6.5)
Impairment loss on long-lived assets	0.4		2.8
Amortization of debt fair value adjustments	0.2	0.9	0.2
Deferred income, net	(15.6)	13.3	4.3
Deferred expenses, net	9.1	1.2	1.6
Loss from retirement of debt			1.9
Excess tax benefit from stock based compensation	(3.9)		
Changes in operating assets and liabilities, net of effects of distributions to related parties			
Accounts receivable, net	(102.2)	(44.9)	(8.9)
Accounts payable and other current liabilities	32.4	25.7	(6.3)
Income taxes receivable/payable, net	42.4		