TODCO
Form 10-K
February 28, 2006

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, 2005

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

Class A 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. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer þ Accelerated filer 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 Class A common stock held by non-affiliates of the Registrant as of June 30, 2005, was $1,554,526,222.

As of February 21, 2006, the Registrant had 61,510,165 shares of Class A 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, 2005, for its 2006 annual general meeting of stockholders are incorporated by reference into Part III of this Form 10-K.

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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 and believe that, as a result of our leading position and geographic focus, we are well-positioned to continue to benefit from any further increase in drilling activity associated with the search for natural gas in this region.

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, 48 of these rigs are located in shallow and inland waters of the United States with the remainder in Angola, Colombia, Mexico, Trinidad and Venezuela. We also operate a fleet of 49 inland tugs, 22 offshore tugs, 36 crew boats, 33 deck barges, 17 shale barges, five spud barges and two offshore barges.

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 mainly 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 those 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 U.S. Gulf of Mexico shallow water market which begins at the outer limit of the transition zone and extends to water depths of about 350 feet. Our jackup rigs in this market 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 operating in this market 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.

Other International Segment Our other operations are currently conducted in Angola, Colombia, Mexico, Trinidad and Venezuela. We operate one jackup rig in Angola and one in Colombia. In Mexico, we operate two jackup rigs and a platform rig. Additionally, we have two jackup rigs and one land rig in Trinidad and eight land rigs in Venezuela. We may pursue selected opportunities in other international areas from time to time.

Delta Towing Segment Delta Towing LLC (Delta Towing) operates 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.

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 17 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 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 in a shipyard 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, 2006.

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.	Cold Stacked
THE 155	ILC	1980	150	20,000	U.S.	Cold Stacked
THE 156	ILC	1983	150	20,000	Colombia	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 Contract
THE 201	MC	1981	200	20,000	U.S.	Under Contract
THE 202(a)	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.	Under Contract
THE 205	MC	1979	200	20,000	Mexico	Under Contract
THE 206	MC	1980	200	20,000	Mexico	Under Contract
THE 207	MC	1981	200	20,000	U.S.	Under Contract
THE 208(b)	MC	1980	200	20,000	Trinidad	Cold Stacked
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.	Reactivating
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.	Reactivating

(a) This rig is currently under repair in a shipyard for leg damage incurred during a jacking operation. It is expected to return to work under its contract in May 2006.

(b) 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.

The following table contains information regarding our barge drilling rig fleet as of February 20, 2006.

Rig	Type	Original Year Entered Service	Horsepower Rating	Rated Drilling Depth (In feet)	Location	Status
1	Conv.	1980	2,000	20,000	U.S.	Reactivating
7	Posted	1981	2,000	25,000	U.S.	Cold Stacked
9	Posted	1975	2,000	25,000	U.S.	Under Contract
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. See Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Continuing Operations Years Ended December 31, 2004 and 2003.

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.

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, 2006.

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.	Reactivating
THE 78	Subm.	1983	N/A	30,000	U.S.	Reactivating
Rig 3	Plat.	1993	N/A	25,000	Mexico	Under Contract
26	Land	1980	750	6,500	Venezuela	Warm Stacked
27	Land	1981	900	8,000	Venezuela	Warm Stacked
36	Land	1982	2,000	18,000	Trinidad	Under Contract
37	Land	1982	2,000	18,000	Venezuela	Warm Stacked
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

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 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, due to current market conditions, a declining supply of jackup rigs in the U.S. Gulf of Mexico and our recent rig reactivations, we have been entering into longer term drilling contracts. As of February 20, 2006, we had an estimated 4,899 rig days in 2006 and an estimated 1,236 rig days in 2007 contracted for under term contracts (as opposed to well-by-well contracts) of varying duration. These estimates include rig days expected to be completed under contracts the term of which begins upon reactivation of a cold stacked rig, as discussed further below. Included in these estimates are the remaining terms for three contracts we have executed with Pemex Exploration and Production Company (Pemex) for rigs *THE 205* (209 days), *THE 206* (503 days) and *Platform Rig 3* (798 days).

Rig Reactivations Against Term Drilling Contracts

Since December 31, 2004, we reactivated or began reactivation of eight cold stacked rigs consisting of three jackup rigs, two submersible rigs and three barge rigs. In each case, these reactivations are supported by term drilling contracts at dayrates sufficient to recover over the term of the contract all of our expected operating expenses of performing the contract plus all, or a substantial portion of, the anticipated costs of reactivating the rig. These completed or planned rig reactivations are described below.

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 and upgrade the rig is estimated at $18.6 million consisting of approximately $12.4 million of reactivation costs that will be expensed over the 150-day reactivation period and an additional $6.2 million for capital upgrades to the rig. *THE 256* is expected to begin drilling operations in July 2006 at a dayrate of approximately $105,000 per day.

In December 2005, we reached an agreement to reactivate *THE 252*, a jackup drilling rig. The cost to reactivate and upgrade the rig is anticipated to be approximately $13.5 million, including $4.2 million for capital upgrades to the rig. Upon the completion of the reactivation, expected to be May 2006, the rig will commence operations under a one year contract at a dayrate of approximately $85,000 per day.

In November 2005, we signed term contracts for a barge rig and two submersible drilling rigs. *Rig 1*, a conventional inland barge, will be reactivated for a cost of approximately $5.7 million, including $2.3 million of capital expenditures against a one-year term contract. The reactivation is expected to be completed in March 2006, at which time the rig will begin drilling operations at a dayrate of approximately $28,000 per day. *THE 77*, an offshore submersible drilling rig, will be reactivated and upgraded against a nine-month term contract. The completion of the reactivation is anticipated to be May 2006 at a cost of approximately $18.0 million, including $6.0 million of capital expenditures. At that time, drilling operations are expected to commence at a dayrate of approximately $85,000 per day. The offshore submersible drilling rig, *THE 78*, will be reactivated and upgraded at a cost of approximately $11.7 million, of which $5.2 million will be capitalized and $6.5 million will be expensed during the reactivation period. This reactivation is expected to be completed in May 2006. Drilling operations under the six-month term contract will be at a dayrate of approximately $73,000 per day.

In October 2005, we signed a six-month contract with an independent oil and gas company for our cold stacked inland barge, *Rig 49.* The total cost to reactivate the rig was approximately $3 million. *Rig 49* began drilling operations in the inland waterways of Texas and Louisiana in December 2005 at a dayrate of approximately $36,000 per day.

In June 2005, we signed a seven-month contract with an independent oil and gas company for the reactivation of our cold stacked inland barge rig, *Rig 28.* The rig reactivation was completed in late July 2005 at a cost of $2.6 million. The reactivation costs included $2.4 million of repairs and maintenance, which was expensed as incurred, and $0.2 million of capital equipment. Operations began in July 2005 at a dayrate of $26,000 per day.

In May 2005, we signed a contract with Angola Drilling Company Limited (ADC) to reactivate our cold stacked jackup rig, *THE 185*, for a two-year drilling contract with two one-year options. Following a shipyard reactivation and mobilization to Angola, *THE 185* began drilling operations in September 2005 at a dayrate of approximately $59,500 per day. We spent $7.3 million to reactivate *THE 185*, which was expensed as incurred. Additionally, we spent $3.4 million to mobilize the rig to Angola, which was deferred and is being amortized to expense over the two-year term of the drilling contract. We received reimbursement from ADC of $7 million for the reactivation and mobilization costs, which was treated as deferred revenue and is being amortized to revenue over the two-year term of the drilling contract.

We anticipate that market conditions should provide us an opportunity to obtain in 2006 term contracts with customers for the reactivation and return to service of all five of our remaining cold stacked U.S. Gulf of Mexico jackup rigs. Approximately $55 to $60 million in the aggregate would be required to return these rigs to service, based on our cost projections for these future reactivations. Additionally, we anticipate that we should be able to obtain in 2006 term contracts with customers to reactivate and return to service two or three of our 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 these two or three inland barge rigs for service would be approximately $6 to $10 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 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.

Customers

Our customers are primarily independent oil and gas companies, although we also work for large international oil companies and government-controlled oil companies. One customer, Applied Drilling Technologies, Inc., accounted for 11% of both our 2004 and 2003 operating revenues. No other customers accounted for 10% or greater of our operating revenues in 2004 or 2003. No customer accounted for 10% or greater of our operating revenues in 2005. 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 U.S. Gulf of Mexico shallow water and U.S. inland marine markets in which we operate are highly competitive. We believe we are the largest jackup rig contractor in the U.S. Gulf of Mexico shallow water market and the largest inland barge contractor in the U.S. inland marine market. In the U.S. inland marine market, our principal competitor is Parker Drilling Co. In the U.S. Gulf of Mexico shallow water market, 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 U.S. Gulf of Mexico shallow water market 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 and Other Assets

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. Delta Towing utilizes rig moving tugs, utility barges, service tugs and crew boats 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 20, 2006, Delta Towing s operating assets consisted of 49 inland tugs, 22 offshore tugs, 36 crewboats, 33 deck barges, 17 shale barges, five spud barges and two offshore barges.

At December 31, 2005, we had a 25% equity interest in Delta Towing, which operates a U.S. inland and shallow water marine support vessel business. Affiliates of Edison Chouest Inc. (Chouest) owned the remaining 75% equity interest in Delta Towing. In connection with its formation, Delta Towing issued notes to us with principal amounts totaling $144 million, secured by Delta Towing s assets described in the following paragraph. In 2001, we valued these notes at $80 million. Delta Towing has defaulted on its scheduled quarterly interest and principal payments on these notes. See Management s Discussion and Analysis of Financial Condition and Results of Operations Variable Interest Entity 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 $2.9 million related party note to Chouest. As a result of the consolidation of Delta Towing in our consolidated financial statements in accordance with Financial Accounting Standards Board (FASB) Interpretation No. 46, *Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51* (FIN 46), beginning December 31, 2003, the purchase of the additional interest in Delta Towing is not expected to have a material effect 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.

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.

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.

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, 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 specified substances into the navigable waters of the United States without a permit. The regulations implementing the Clean Water Act require permits to be obtained by an operator before specified exploration activities occur. Offshore facilities must also prepare plans addressing spill prevention control and countermeasures. Violations of monitoring, reporting and permitting requirements can result in the imposition of civil and criminal penalties.

The U.S. Oil Pollution Act of 1990 (OPA) and related regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. Few defenses exist to the liability imposed by OPA, and the liability could be substantial. Failure to comply with ongoing requirements or inadequate cooperation in the event of a spill could subject a responsible party to civil or criminal enforcement action.

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, 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 2005, we renewed our principal insurance coverages for property damage, liability and occupational injury and illness for a one-year term. Generally, our deductible levels under the new 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 applies in the event of a windstorm. Previously, our deductible level under these policies was $1.0 million per occurrence with no windstorm limits. In addition, in an effort to control premium costs, we reduced our insurance coverage to 70% of our losses in excess of the applicable deductible and we are uninsured for 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.

Our premium cost increased from approximately $8 million to approximately $15 million under these new policies, which also included an increase of approximately $340 million for insured values. 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.

Employees

As of December 31, 2005, we had approximately 2,420 employees. We require highly skilled personnel to operate and provide technical services and support for our drilling units. As a result, we conduct extensive personnel recruiting, training and safety programs.

As of December 31, 2005, approximately 219 (or 9%) of our employees worldwide were working under collective bargaining agreements, approximately 53 of whom were working in Trinidad and 166 of whom were working in Venezuela. The union agreement in Trinidad officially expired in August 2005 and negotiations are currently continuing on a new three year contract which, upon ratification, will be in effect until August 2008. None of the other union agreements are expected to expire in 2006. 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, a Tax Sharing Agreement which allocated certain rights and responsibilities with respect to pre- and post-IPO taxes, a Registration Rights Agreement pursuant to which we are required to file Registration Statements to assist Transocean in selling its shares of our common stock, an Employee Matters Agreement which governed the application of the separation of our employees from Transocean and its benefit plans and a Transition Services Agreement under which Transocean provided certain services to us during the initial phases of our separation from Transocean.

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, 6, 12 and 20 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 materials with, or furnish those materials 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 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 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) where we are active. Oil and gas prices and our customers expectations of potential changes in these prices significantly affect this level of activity. In particular, changes in the price of natural gas materially affect our operations because 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 gas prices are extremely volatile and are affected by numerous factors, including the following:

the demand for oil and 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 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 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 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 lower rate contracts 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 U.S. Gulf of Mexico shallow water and inland marine market segments 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 of supply of rigs in the Gulf of Mexico could create an excess supply of jackup rigs in the Gulf of Mexico 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 51 jackup rigs on order with delivery dates ranging from 2006 to 2009. 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.

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 a rig move 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. 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, semisubmersible drilling rigs or drillships. This trend is expected to continue and could result in a decline in demand for lower specification jackup rigs like ours.

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 oil and gas companies. 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 2005, we renewed our principal insurance coverages for property damage, liability and occupational injury and illness for a one-year term. Our premium cost increased from approximately $8 million to approximately $15 million under these new policies, which also included an increase of approximately $340 million for insured values. Additionally, we reduced our insurance coverage to 70% of our losses over the applicable deductibles and we are uninsured with respect to the remaining 30% of such losses. We cannot predict what effect Hurricanes Katrina and Rita, or future storms, may have on our insurance costs. But we may again experience significant premium increases or we may be required to again reduce the percentage of our losses that would be covered by insurance.

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 management could hurt our operations.

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

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 or 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 equipment, and
- the inability to repatriate income or capital.

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 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 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 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 Separation from Transocean

The terms of our separation from Transocean, the related agreements and other transactions with Transocean were determined in the context of a parent-subsidiary relationship and thus may be less favorable to us than the terms we could have obtained from an unaffiliated third party.

Transactions and agreements we entered into after our acquisition by Transocean and on or before the closing of the IPO presented conflicts between our interests and those of Transocean. These transactions and agreements included the following:

- agreements related to the separation of our business from Transocean that provide for, among other things, the assumption by us of liabilities related to our business, the assumption by Transocean of liabilities unrelated to our business, our respective rights, responsibilities and obligations with respect to taxes and tax benefits and the terms of our various interim and ongoing relationships, and

the transfer to Transocean of assets that were not related to our business. See Note 20 to our consolidated financial statements included in Item 8 of this report.

Because these transactions and agreements were entered into in the context of a parent-subsidiary relationship, their terms may be less favorable to us than the terms we could have obtained from an unaffiliated third party.

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.

In connection with the IPO, we entered into a tax sharing agreement with Transocean. Although we are currently disputing the enforceability of the agreement, we may be required to make substantial payments to Transocean, if we are unsuccessful in that dispute. 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 we must pay Transocean for any tax benefit resulting from the delivery by Transocean of its stock to an employee of ours in connection with the exercise of an employee stock option and 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. 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.

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 is 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. Transocean disagrees with our interpretation of the tax sharing agreement as it relates to this issue and believes that we must pay Transocean for the tax benefit received 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 upon 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 cash equal to 35% of the deduction we took. While this would not increase our tax expense, it would defer our utilization of pre-IPO income tax benefits.

As of December 31, 2005, we had approximately $282 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, 2005, the estimated amount that we would have been required to pay Transocean would have been approximately $197 million, or 70% of the pre-IPO tax benefits at December 31, 2005.

The estimated liabilities to Transocean at December 31, 2005 and 2004 and the estimated amount of remaining pre-IPO tax benefits subject to the obligation to reimburse Transocean at December 31, 2005 do not reflect the benefit of the tax deduction for stock option exercises of former employees who were not our employees on the date of the exercise and are presented within accrued income taxes related party in the Company s condensed consolidated balance sheets.

Furthermore, even though Transocean no longer owns any shares of our common stock, the 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 12 to our consolidated financial statements for the period ended December 31, 2005 included in Item 8 of this report.

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 $59.4 million for the year ended December 31, 2005, our net losses from continuing operations before cumulative effect of a change in accounting principle were approximately $29 million and $222 million during the years ended December 31, 2004 and 2003, respectively, 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 market 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.

Our rights agreement and provisions in our charter documents may inhibit a takeover, which could adversely affect the value of our Class A 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; Santa Marta, Colombia; Bogota, Colombia; 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.

Item 3. ***Legal Proceedings***

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.

TODCO vs. Transocean Inc. and Transocean Holdings Inc. (Transocean). In connection with our separation from Transocean, we executed a tax sharing agreement with Transocean. The agreement provides that we must pay Transocean for certain pre-IPO tax benefits utilized or deemed to have been utilized subsequent to the IPO. The agreement also provides that we must pay Transocean for any tax benefit resulting from the delivery by Transocean of its stock to an employee of our tax group that results in a tax benefit to us. In September 2005, Transocean instructed us 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. We believe that the applicable provision of the agreement only requires us to pay Transocean for deductions related to stock option exercises by persons who were employees of our tax group on the date of exercise and we have advised Transocean accordingly. Both parties have issued arbitration demand notices to the other and are in the process of attempting to select a neutral arbitrator to decide the dispute. In addition, we have filed a lawsuit against Transocean in Texas State District Court seeking to have the agreement overturned in its entirety. The dispute is in the early stages of development and it is difficult to predict the eventual outcome. In any event, we do not expect the outcome of this matter to have a material adverse effect on our consolidated results of operations, financial position or cash flows.

Robert E. Aaron et al. vs. Phillips 66 Company et al. Circuit Court, Second Judicial District, Jones County, Mississippi. This is the case name used to refer to several cases that have been filed in the Circuit Courts of the State of Mississippi involving 768 persons that allege personal injury arising out of asbestos exposure in the course of their employment by the defendants between 1965 and 2002. The complaints name as defendants, among others, certain of 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 ranges from approximately 20 to 70. The complaints allege that the defendant drilling contractors used asbestos-containing products in offshore drilling operations, land based drilling operations and in drilling structures, drilling rigs, vessels and other equipment and assert claims based on, among other things, negligence and strict liability, and claims authorized under the Jones Act. The plaintiffs seek, among other things, awards of unspecified compensatory and punitive damages. The trial court granted motions requiring each plaintiff to name the specific defendant or defendants against whom such plaintiff makes a claim and the time period and location of asbestos exposure so that the cases may be properly served. In that regard, a majority of these cases have been assigned to a special master who has approved a form of questionnaire to be completed by plaintiffs so that claims made may be properly served against specific defendants. As of the date of this report, approximately 699 questionnaires had been submitted. Of those, approximately 103 shared periods of employment by us and Transocean which could lead to claims against either company. We have not determined which entity would be responsible for such claims under the master separation agreement between the two companies. 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 the master separation agreement, Transocean has agreed to indemnify us for any losses we incur as a result of the legal proceedings described in the following two paragraphs.

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 2001. 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). 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.

In 1984, in connection with the financing of the corporate headquarters, at that time, for Reading & Bates Corporation (R&B), a predecessor to one of our subsidiaries, in Tulsa, Oklahoma, the Greater Southwestern Funding Corporation (Southwestern) issued and sold, among other instruments, Zero Coupon Series B Bonds due 1999-2009 with an aggregate $189 million value at maturity. Paine Webber Incorporated (Paine Webber) purchased all of the Series B Bonds for resale and in 1985 acted as underwriter in the public offering of most of these bonds. The proceeds from the sale of the bonds were used to finance the acquisition and construction of the headquarters. R&B s rental obligation was the primary source for repayment of the bonds. In connection with the offering, R&B entered into an indemnification agreement indemnifying Southwestern and Paine Webber from loss caused by any untrue statement or alleged untrue statement of a material fact or the omission or alleged omission of a material fact contained or required to be contained in the prospectus or registration statement relating to that offering. Several years after the offering, R&B defaulted on its lease obligations, which led to a default by Southwestern. Several holders of Series B bonds filed an action in Tulsa, Oklahoma in 1997 against several parties, including Paine Webber, alleging fraud and misrepresentation in connection with the sale of the bonds. In response to a demand from Paine Webber in connection with that lawsuit and a related lawsuit, R&B agreed in 1997 to retain counsel for Paine Webber with respect to only that part of the referenced cases relating to any alleged material misstatement or omission relating to R&B made in certain sections of the prospectus or registration statement. The agreement to retain counsel did not amend any rights and obligations under the indemnification agreement. There has been only limited progress on the substantive allegations of the case. The trial court has denied class certification, and the plaintiffs appeal of this denial to a higher court has been denied. The plaintiffs further appealed that decision and that appeal was denied. The case has now been dismissed.

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 2005.

PART II

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

Our Class A 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 June 10, 2005 that he was not aware of any violation by TODCO of NYSE corporate governance listing standards as of that date.

As of February 21, 2006, there were approximately 390 holders of record of our Class A common stock. We have presented in the table below, for the periods indicated, the reported high and low sales prices for our Class A common stock on the NYSE.

	Price per Share of Our Class A Common Stock	
Calendar Period	**High**	**Low**
2005		
First Quarter	$ 28.55	$ 16.84
Second Quarter	27.45	19.67
Third Quarter	43.03	25.85
Fourth Quarter	49.75	35.53
2004		
First Quarter (starting February 5)	$ 16.45	$ 13.10
Second Quarter	16.05	13.38
Third Quarter	17.86	13.40
Fourth Quarter	19.05	16.15

On February 21, 2006, the last reported sales price of our Class A common stock was $37.20 per share.

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 market 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, that 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.

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, 2005, 2004 and 2003, and as of December 31, 2005 and 2004, has been derived from our audited financial statements included elsewhere in this report. The financial information for the year ended December 31, 2002, the one month ended January 31, 2001 and the eleven months ended December 31, 2001, and as of December 31, 2003, 2002 and 2001 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.

On January 31, 2001, we became an indirect wholly-owned subsidiary of Transocean as a result of our merger transaction with Transocean. The merger was accounted for as a purchase, with Transocean as the accounting acquirer. The purchase price was allocated to our assets and liabilities based on their estimated fair values on the date of the merger with the excess accounted for as goodwill. The purchase price adjustments were pushed down to our consolidated financial statements. Accordingly, our financial statements for periods subsequent to January 31, 2001 are not comparable to those of prior periods in material respects since those financial statements report financial position, results of operations and cash flows using a different basis of accounting.

	Pre-Transocean Merger	Post-Transocean Merger				
	One Month Ended January 31, 2001	Eleven Months Ended December 31, 2001	Years Ended December 31, 2002	2003	2004 (g)	2005 (g)
	(In millions, except per share amounts)					
Historical Statement of Operations Data:						
Operating revenues	$ 48.5	$ 441.0	$ 187.8	$ 227.7	$ 351.4	$ 534.2
Operating and maintenance expense	23.2	270.0	185.7	227.4	259.7	323.2
Earnings (loss) from continuing operations before cumulative effect of a change in accounting principle	(90.1)(a)	(96.7)(b)	(529.1)(c)	(222.0)(d)	(28.8)(e)	59.4
Earnings (loss) from continuing operations before cumulative effect of a change in accounting principle:						
Basic	$ (0.43)	$ (7.96)	$ (43.57)	$ (18.28)	$ (0.52)	$ 0.98
Diluted	$ (0.43)	$ (7.96)	$ (43.57)	$ (18.28)	$ (0.52)	$ 0.97

Weighted average common shares outstanding:						
Basic	211.3	12.1	12.1	12.1	55.6	60.7
Diluted	211.3	12.1	12.1	12.1	55.6	61.4
Cash dividends paid:						
Total	$	$	$	$	$	$ 61.2
Per common share	$	$	$	$	$	$ 1.00

	As of December 31,				
	2001	2002	2003	2004	2005
			(In millions)		
Balance Sheet Data:					
Total assets	$ 8,838.8	$ 2,227.2	$ 778.2	$ 761.4	$ 825.0
Long-term debt and redeemable preferred shares(f)	1,538.0	40.7	26.8	25.4	17.0
Long-term debt related party(f)	55.0	1,080.1	525.0	3.0	2.9
Total stockholders equity	6,496.5	561.9	137.7	480.6	495.5

(a) Included in the one month ended January 31, 2001 are $58.1 million of merger related expenses and a $64.0 million impairment loss on long-lived assets related to the disposal of the marine support vessel business.

(b) Included in the eleven months ended December 31, 2001 are a $1.1 million impairment loss on long-lived assets and a $27.5 million loss on retirement of debt.

(c) 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.

(d) 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.

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

(f) Includes current portion.

(g) 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.

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 natural gas drilling services, primarily in the United States (U.S.) Gulf of Mexico shallow water and inland marine region, an area that we refer to as the U.S. Gulf Coast. We provide these services primarily to independent oil and natural gas companies, but we also service major international and government-controlled oil and natural 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 those 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 U.S. Gulf of Mexico shallow water market which begins at the outer limit of the transition zone and extends to water depths of about 350 feet. Our jackup rigs in this market 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 operating in this market 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.

Other International Segment Our other operations are currently conducted in Angola, Colombia, Mexico, Trinidad and Venezuela. We operate one jackup rig in Angola and one jackup rig in Colombia. In Mexico, we operate two jackup rigs and a platform rig. We have two jackup rigs and a land rig in Trinidad and eight land rigs in Venezuela. 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 U.S. marine support vessels consisting primarily of shallow water tugs, crewboats and utility barges. In January 2006, we purchased the 75% interest owned by Chouest. See Notes 4 and 21 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 units in the market segments in which we operate. Supply and demand for drilling units 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.

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.

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.

Industry Background, Trends and Outlook

The drilling industry in the U.S. Gulf Coast is highly cyclical and is typically driven by general economic activity and changes in actual or anticipated oil and gas prices. We believe that both our earnings and demand for our rigs will typically be correlated to our customers expectations of energy prices, particularly natural gas prices, and that sustained energy price increases will generally have a positive impact on our earnings.

We believe there are several trends in our industry that could effect our operations, including:

High Natural Gas Prices. While U.S. natural gas prices are volatile, the rolling twelve-month average price of natural gas has increased from $2.11 in January 1994 to $9.10 in January 2006. High natural gas prices in the United States have resulted in more exploration and development drilling activity and higher utilization and dayrates for drilling companies like us. If high natural gas prices are sustained, we expect this trend to continue.

Need for Increased Natural Gas Drilling Activity. From 1994 to 2004, U.S. demand for natural gas grew at an annual rate of 0.7% while its supply grew at an annual rate of 0.2%. We believe that this supply and demand growth imbalance will continue if demand for natural gas continues to increase and production decline rates continue to accelerate. Even though the number of U.S. gas wells drilled has increased overall in recent years, a corresponding increase in production has not been realized. We believe that an increase in U.S. drilling activity will be required for the natural gas industry to meet the expected increased demand for, and compensate for the slowing production of, natural gas in the United States.

Trend Towards Drilling Deeper Shallow Water Gas Wells. A current trend by oil and gas companies is to drill deep gas wells along the U.S. Gulf Coast in search of new and potentially prolific untapped natural gas reserves. We believe that this trend towards deeper drilling will benefit premium jackup rigs as well as barge rigs and submersible rigs that are capable of drilling deep gas wells. In addition, this trend will indirectly benefit conventional jackup fleets, such as ours, as the use of premium rigs in the U.S. Gulf Coast to drill deep wells should reduce the supply of rigs available to drill shallower wells.

Redeployment of Jackup 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. This favorable supply environment has contributed to increased jackup utilization and dayrates.

New Building of Jackup Rigs. In response to the improved market conditions, our competitors and speculators have recently begun ordering new jackup drilling rigs. We believe there are currently 51 jackup rigs on order with delivery dates ranging from 2006 to 2009. 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 could curtail a further strengthening of utilization and dayrates, or reduce them. 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 when the U.S. Gulf of Mexico experienced two major hurricanes, which destroyed or significantly damaged nine jackup drilling rigs.

Market conditions for our U.S. Gulf Coast jackup fleet improved beginning in the third quarter of 2003 and continued to improve through 2005. As shown in the following table, from the fourth quarter of 2004 through the fourth quarter of 2005, our average revenue per day for U.S. Gulf of Mexico jackups and submersibles improved by 52%. During the same period, average revenue per day for our U.S. inland barges improved by 34%. As of February 20, 2006, 11 of our 16 marketed jackup and submersible rigs working in the U.S. Gulf Coast were operating at dayrates ranging from $55,000 to $105,300. As of February 20, 2006, 16 of our 17 marketed inland barges were operating at dayrates ranging from $20,400 to $41,700. We anticipate that the declining jackup rig supply in the U.S. Gulf Coast due to the recent hurricane damage, the redeployment of rigs to international locations and the trend towards more deep gas well drilling will continue to result in improved utilization and higher dayrates into 2006. As a result, we are actively pursuing long-term contracts with our customers to reactivate our five cold stacked U.S. Gulf of Mexico jackup rigs. Additionally, we are pursuing long-term contracts to reactivate some of our ten cold stacked inland barge rigs.

The following table shows our average rig revenue per day and utilization for the quarterly periods ended on or prior to December 31, 2005 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, as adjusted to include calendar days available for rigs that were held for sale during the periods ended on or prior to December 31, 2003.

	Three Months Ended								
	December 31, 2003	**March 31, 2004**	**June 30, 2004**	**September 30, 2004**	**December 31, 2004**	**March 31, 2005**	**June 30, 2005**	**September 30, 2005**	**Decemb 200**
ge Rig ue Per Day:									
ulf of o Jackups bmersibles	$ 26,700	$ 30,600	$ 30,700	$ 33,800	$ 39,900	$ 44,600	$ 51,000	$ 56,700	$ 60,
nland Barges	18,700	20,300	22,500	22,900	23,000	25,000	27,800	29,600	30,
International	25,600	40,000	37,500	34,600	29,400	28,400	33,900	31,300	37,
ation:									

ulf of								
o Jackups								
bmersibles	50%	43%	50%	54%	56%	56%	56%	56%
nland Barges	40%	40%	42%	45%	46%	46%	51%	53%
International	28%	29%	29%	33%	39%	56%	55%	56%

In response to strengthening demand for drilling rigs, we began reactivating certain of our cold stacked rigs beginning in the second quarter of 2005 and continuing into 2006. We did so, however, only if we first obtained a term drilling contract for each reactivated rig at a dayrate sufficient to recover, over the full term of the contract, all of our expected operating expenses of performing the contract plus all, or a substantial portion of, our anticipated costs of reactivating the rig.

Since December 31, 2004, we have commenced or completed the reactivation of eight drilling rigs, consisting of three jackup rigs, two submersible rigs and three barge rigs. We estimate that the total actual and estimated remaining costs of reactivating these eight rigs will be approximately $82 million but that we will receive $178 million in total historical and estimated future revenues over the full term of the related drilling contracts. For additional information concerning each of our completed and pending rig reactivations and the related term contract, please see Business Reactivation of Rigs Against Term 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. With respect to currently pending rig reactivations, we estimate that $22.3 million of reactivation costs will be capitalized in 2006, and that approximately $42.2 million will be charged to operating and maintenance expense.

We expect that we may reactivate or commit to reactivate additional cold stacked rigs in 2006, 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 anticipation of reactivating cold stacked rigs in 2006, we have ordered certain rig components and equipment that have extended delivery times. See Liquidity and Capital Resources Sources of Liquidity and Capital Resources, below.

In the third quarter of 2003, we were awarded contracts with PEMEX for two of our jackup rigs and a platform rig. After upgrades to comply with contract specifications, one rig, *THE 206*, began operating on a 720-day contract in early November 2003 at a contract dayrate of approximately $42,000. A new 615-day contract was awarded for *THE 206* at dayrates of approximately $64,000 which became effective in late October 2005. The other jackup rig, *THE 205*, began operating in early December 2003 on a 1,081-day contract at a contract dayrate of approximately $39,000. The platform rig contract 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.

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, which will be exceeded in both incidents. Currently, we have recognized $0.8 million of insurance claims expense through the fourth quarter of 2005 for the insurance deductibles related to the damage sustained during Hurricane Katrina. We also incurred $2.6 million in expenses related to damages caused by Hurricane Rita. We recorded $1.6 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 January 2005, we retained Simmons & Company International to explore alternatives for the disposition of our Venezuelan land drilling business, which is not viewed by us as being core to our ongoing offshore drilling business. The evaluation may result in the sale of some or all of our Venezuelan assets.

In October 2005, we renewed our principal insurance coverages for property damage, liability and occupational injury and illness for a one-year term. Generally, our deductible levels under the new 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 applies in the event of a windstorm. Previously, our deductible level under these policies was $1.0 million per occurrence with no windstorm limits. In addition, in an effort to control premium costs, we reduced our insurance coverage to 70% of our losses in excess of the applicable deductible and we are uninsured for 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.

Our premium cost increased from approximately $8 million to approximately $15 million under these new policies, which also included an increase of approximately $340 million for insured values. 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.

IPO and Separation from Transocean

In July 2002, Transocean announced plans to divest its Gulf of Mexico shallow and inland water (Shallow Water) business through an initial public offering of TODCO common stock. During 2003, we completed the transfer to Transocean of all assets not related to our Shallow Water business (Transocean Assets), including the transfer of all revenue-producing Transocean Assets. Accordingly, the Transocean Assets and related operations have been reflected as discontinued operations in our historical financial statements.

In February 2004, we completed our initial public offering in which Transocean sold 13,800,000 shares of our Class A common stock (the IPO). After several stock offerings and a private sale in 2004 and 2005, Transocean had converted all of its unsold shares of Class B common stock into an equal number of shares of Class A common stock and had sold all of its remaining shares of our common stock. As a result of the conversion, no Class B common stock was outstanding as of December 31, 2005 and 2004. We received no proceeds from any of these sales.

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, a Tax Sharing Agreement which allocated certain rights and responsibilities with respect to pre and post IPO taxes, a Registration Rights Agreement pursuant to which we are required to file Registration Statements to assist Transocean in selling its shares of our common stock, an Employee Matters Agreement which governed the application of the separation of our employees from Transocean and its benefit plans and a Transition Services Agreement under which Transocean provided certain services to us during the initial phases of our separation from Transocean. See Notes 1, 3, 6, 12 and 20 in the accompanying Notes to Consolidated Financial Statements included in Item 8 of this report for further discussion concerning our separation from Transocean.

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.

General and administrative expense includes costs related to our corporate executives, corporate accounting and reporting, engineering, health, safety and environment, information technology, marketing, operations management, legal, tax, treasury, risk management and human resource functions. Prior to June 30, 2003 and the transfer of the Transocean Assets to Transocean, general and administrative expense also included an allocation from Transocean for certain administrative support. After June 30, 2003, general and administrative expense includes costs for services provided to us under our transition services agreement with Transocean. In addition, we are incurring additional general and administrative expense associated with the vesting of stock options and restricted stock granted in conjunction with the IPO.

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 replaced 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). Based upon the price per share at date of issuance, the value of the 2005 Plan and the 2004 Plan awards that we will recognize as compensation expense is approximately $24.4 million. During 2005 and 2004 we recognized $7.6 million and $10.6 million, respectively, of compensation expense related to these awards and grants. We will amortize the remaining $6.2 million 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) (see Variable Interest Entity Delta Towing), 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 the approximately $24 million face value of our senior notes payable to third parties, commitment fees on the unused portion of our line of credit and the amortization of financing costs. During 2005, the face value of our senior notes payable was further reduced to approximately $16 million. Our debt levels and, correspondingly, our interest expense were substantially lower in 2005 and 2004 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 is 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. Transocean disagrees with our interpretation of the tax sharing agreement as it relates to this issue and 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 upon 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 in cash for an amount equal to 35% for the deduction. While this would not increase our tax expense, it would defer utilization of pre-IPO income tax benefits.

During the years ended December 31, 2005 and 2004, we utilized pre-IPO income tax benefits to offset our current federal income tax obligation resulting in a liability to Transocean of $43.8 million and $7.6 million, respectively. Additionally, during the years ended December 31, 2005 and 2004, we utilized pre-IPO state tax benefits resulting in a liability to Transocean of $0.1 million and $0.8 million, respectively. We also utilized pre-IPO foreign tax benefits during 2005 resulting 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, 2004. As of December 31, 2005 and 2004, we estimate our liability to Transocean to be $44.9 million and $8.4 million, respectively, for pre-IPO federal, state and foreign income tax benefits utilized.

As of December 31, 2005, we had approximately $282 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, 2005, the estimated amount that we would have been required to pay Transocean would have been approximately $197 million, or 70% of the pre-IPO tax benefits at December 31, 2005.

The estimated liabilities to Transocean at December 31, 2005 and 2004 and the estimated amount of remaining pre-IPO income tax benefits subject to the obligation to reimburse Transocean at December 31, 2005 do not reflect the benefit of the tax deduction for stock option exercises of former employees who were not our employees on the date of the exercise and are presented within accrued income taxes related party in our condensed 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 59% of our total assets as of December 31, 2005. 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 Statement of Financial Accounting Standards (SFAS) 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.

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,		
	2005	2004	2003
	(In millions, except per day data)		
U.S. Gulf of Mexico Segment:			
Operating days	4,465	4,134	4,388
Available days(a)	8,166	8,144	9,914
Utilization(b)	55%	51%	44%
Average rig revenue per day(c)	$ 53,000	$ 34,200	$ 23,100
Operating revenues	$ 236.7	$ 141.2	$ 101.2
Operating and maintenance expenses(d)	116.4	93.4	98.6
Depreciation	50.2	49.5	55.3
Impairment loss on long-lived assets			10.6
Gain on disposal of assets, net	(19.7)	(1.5)	(0.1)
Operating income (loss)	89.8	(0.2)	(63.2)
U.S. Inland Barge Segment:			
Operating days	5,147	4,764	4,558
Available days(a)	10,049	10,980	11,101
Utilization(b)	51%	43%	41%
Average rig revenue per day(c)	$ 28,400	$ 22,200	$ 18,500
Operating revenues	$ 146.1	$ 105.9	$ 84.2
Operating and maintenance expenses(d)	94.1	82.6	95.8
Depreciation	23.6	22.5	23.3
Gain on disposal of assets, net	(4.8)	(2.4)	(0.4)
Operating income (loss)	33.2	3.2	(34.5)
Other International Segment:			
Operating days	3,088	2,097	2,007
Available days(a)	5,339	6,496	5,591
Utilization(b)	58%	32%	36%
Average rig revenue per day(c)	$ 33,000	$ 35,000	$ 21,100
Operating revenues	$ 101.8	$ 73.3	$ 42.3
Operating and maintenance expenses(d)	87.0	62.2	33.0
Depreciation	17.5	19.0	13.6
Impairment loss on long-lived assets		2.8	0.7
(Gain) loss on disposal of assets, net	0.6	(0.3)	(0.3)
Operating loss	(3.3)	(10.4)	(4.7)

	For the Years Ended December 31,		
	2005	2004	2003
	(In millions, except per day data)		
Delta Towing Segment:			
Operating revenues	$ 49.6	$ 31.0	$
Operating and maintenance expenses(d)	25.7	21.5	
Depreciation	4.7	4.7	
General and administrative expenses	4.4	4.2	
Gain on disposal of assets	(1.2)	(2.3)	
Operating income	16.0	2.9	
Total Company:			
Rig operating days	12,700	10,995	10,953
Rig available days(a)	23,554	25,620	26,606
Rig utilization(b)	54%	43%	41%
Average rig revenue per day(c)	$ 38,200	$ 29,100	$ 20,800
Operating revenues	$ 534.2	$ 351.4	$ 227.7
Operating and maintenance expenses(d)	323.2	259.7	227.4
Depreciation	96.0	95.7	92.2
General and administrative expenses	37.7	34.0	16.3
Impairment loss on long-lived assets		2.8	11.3
Gain on disposal of assets, net	(25.1)	(6.5)	(0.8)
Operating income (loss)	102.4	(34.3)	(118.7)

(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.

Our consolidated results of operations for the years ended December 31, 2005 and December 31, 2004 reflect the consolidation of our 25% ownership interest in Delta Towing effective December 31, 2003 in accordance with FIN 46. Accordingly, our results for 2005 and 2004 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 our consolidated statements of operations and also recognized interest income related party related to Delta Towing s notes payable to us. See Variable Interest Entity Delta Towing for a discussion of the effects of FIN 46 on our investment in Delta Towing.

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 market conditions 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 market demand. Results for 2005 also reflect higher utilization for our current rig fleet in this market, 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 market conditions.

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 is 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.

Years Ended December 31, 2004 and 2003

Operating Revenues. Total operating revenues increased $123.7 million, or 54%, during 2004 as compared to 2003. The increase in operating revenues is primarily attributable to higher overall average rig revenue per day earned in 2004, and the inclusion of revenues from the operation of Delta Towing s fleet of marine support vessels. Overall average rig revenue per day increased from $20,800 for 2003 to $29,100 for 2004. The increase in average rig revenue per day reflects the continued improvement of market conditions in the U.S. Gulf Coast, as well as the addition of two of our jackup rigs which began operating offshore Mexico in late 2003 and a jackup rig that recently completed its contract offshore Venezuela. Average rig utilization of 43% for 2004 is up slightly from 41% average rig utilization in 2003. The increased utilization is principally due to a decrease in total available rig operating days in the 2004 period as a result of the removal of five jackup rigs from drilling service in the second quarter of 2003, partially offset by the effect of lower land rig utilization in Venezuela during 2004.

Operating revenues for our U.S. Gulf of Mexico segment increased $40.0 million, or 40%, during 2004 as compared to 2003. In 2004, we achieved higher average rig revenue per day for our jackup and submersible drilling fleet as a result of our success in obtaining contracts with our customers at higher dayrates in response to increased market demand and decreased jackup drilling rig supply in the U.S. Gulf of Mexico. Average revenue per day increased to $34,200 for 2004, up from $23,100 for 2003, which resulted in an additional $45.7 million in operating revenues for 2004 as compared to 2003. Results for 2004 also reflect higher utilization for our current rig fleet in this market, after giving effect to the transfers of the jackup drilling units *THE 156*, *THE 205* and *THE 206* to our Other International segment in the fourth quarter of 2003. This increase in utilization resulted in $8.9 million in additional rig revenues in 2004 as compared to 2003. The drilling units transferred to our Other International segment generated revenues of $14.6 million in 2003.

Operating revenues for our U.S. Inland Barge segment increased $21.7 million, or 26%, in 2004 as compared to 2003, primarily due to higher average rig revenue per day. Average rig revenue per day increased from $18,500 for 2003 to $22,200 for 2004, as a result of our successful marketing efforts in negotiating higher dayrates for our fleet of inland barges during 2004. The increase in average rig revenue per day resulted in additional revenues of $17.9 million for 2004 as compared to 2003. This market has continued to improve in 2004 resulting in improved utilization of our inland barge fleet compared to utilization levels experienced beginning in the last half of 2003. Utilization of our inland barge fleet was 43% for 2004, as compared to 41% for 2003, which resulted in a $3.8 million increase in operating revenues in 2004.

Operating revenues for our Other International segment were $73.3 million for 2004. The $31.0 million, or 73%, increase over operating revenues for 2003 reflects the operation of two of our jackup rigs, (*THE 205* and *THE 206*), which began working offshore Mexico in late 2003 under long-term contracts and the operation of *THE 156*, which began operating under a multi-well contract with ConocoPhillips in late December 2003. The operation of these rigs in 2004 contributed an additional $41.9 million in operating revenues during 2004. The favorable contribution by these jackup rigs was partially offset by lower utilization for our land rigs in Venezuela and a platform rig in Trinidad that completed its contract in the third quarter of 2003. The lower utilization for our land rigs in Venezuela resulted in a $5.2 million decrease in operating revenues for 2004 as compared to 2003. Our platform rig, which was operating in Trinidad until the third quarter of 2003, generated $7.4 million of operating revenues in 2003.

Our operating revenues for 2004 included $31.0 million related to the operation of Delta Towing s fleet of U.S. marine support vessels.

Operating and Maintenance Expenses. Total operating and maintenance expenses increased $32.3 million, or 14%, in 2004 as compared to operating expenses of $227.4 million for 2003. A decrease in operating expenses for our U.S. Gulf of Mexico and Inland Barge segments was offset by higher operating expenses in our Other International segment, primarily as a result of the three additional jackup rigs working in international locations in 2004 and the inclusion of $21.5 million in operating expenses related to Delta Towing. The decrease in operating expenses for our domestic segments for 2004 as compared to 2003, is primarily due to the transfer of three jackup drilling rigs from the U.S. Gulf of Mexico to international locations, the absence of one-time charges related to a well-control incident and a fire on two of our barge rigs and an insurance provision for damages sustained to the mat finger on one of our jackup rigs in 2003.

Operating and maintenance expenses for our U.S. Gulf of Mexico segment declined $5.2 million, or 5%, in 2004 as compared to 2003, primarily due to the transfer of three of our jackup rigs to locations in Mexico and Venezuela in the fourth quarter of 2003 ($16.0 million) and an insurance provision in 2003 for damages sustained to one of our jackup rigs ($2.3 million). These favorable variances in operating costs were partly offset by higher costs for maintenance of our jackup rig fleet in the U.S. Gulf of Mexico ($6.1 million), increased labor costs ($2.7 million), higher reimbursable mobilization costs ($2.5 million), and increased personnel-related charges for labor and health benefits claims ($1.7 million) in 2004 as compared to 2003.

Operating and maintenance expenses for our U.S. Inland Barge segment were $82.6 million for 2004 as compared to $95.8 million for 2003. Our results for 2003 included one-time charges of $7.5 million and $3.5 million related to a June 2003 well-control incident on *Rig 62* and a September 2003 fire on *Rig 20*, respectively. The further decrease in operating expenses for this segment in 2004 as compared to 2003, was due primarily to lower operating costs related to support vessels and other equipment rentals ($3.6 million), lower write-downs of other receivables ($0.7 million) and lower personal injury claims ($0.5 million). These favorable decreases were partly offset by $3.1 million in higher maintenance costs in 2004.

Operating and maintenance expenses for our Other International segment for 2004 increased $29.2 million as compared to 2003, primarily due to $23.7 million of additional operating expenses as a result of our jackup drilling operations in Mexico. Operating expenses in 2004 also included $10.1 million of costs related to the operation of *THE*

156 offshore Venezuela through the third quarter of 2004. Our results for this segment in 2003 included $5.5 million of additional operating costs related to our platform rig in Trinidad, which completed its contract in the third quarter of 2003. Our platform rig began operating under a new contract in Mexico in late December 2004.

General and Administrative Expenses. General and administrative expenses were $34.0 million for 2004 as compared to $16.3 million for 2003. The $17.7 million increase in general and administrative expenses was due primarily to the inclusion of $10.6 million of stock compensation expense associated with post-IPO grants of stock options and restricted stock awards, $1.5 million in stock compensation expense related to the modification of Transocean stock options held by some of our employees, $4.2 million in general and administrative expenses for Delta Towing and $2.4 million in higher other overhead costs, primarily related to corporate insurance policies and professional fees. These unfavorable variances in general and administrative expenses in 2004, as compared to 2003, were partly offset by lower administrative charges of $1.0 million for 2004 under our transition services agreement with Transocean, which became effective in the third quarter of 2003. See Related Party Transactions Allocation of Administrative Costs.

Impairment Loss on Long-Lived Assets. During the fourth quarter of 2004, we recorded a $2.8 million non-cash impairment charge related to our decision to decommission our three Venezuelan lake barges and to salvage any remaining useable equipment. During the second quarter of 2003, we recorded a non-cash impairment charge of $10.6 million resulting from our decision to take five jackup rigs out of drilling service and market the rigs for alternative uses. We do not anticipate returning these rigs to drilling service, as we believe it would be cost prohibitive to do so. In conjunction with these decisions, and in accordance with SFAS 144, the carrying value of these assets was adjusted to fair market value. The fair market value of the drilling equipment on board the lake barges and the non-drilling rigs was primarily based on third party valuations. Additionally in the second quarter of 2003, we recorded a $1.0 million non-cash impairment resulting from our determination that assets of entities in which we had an investment did not support our recorded investment. The impairment was determined and measured based upon the remaining book value of the assets and our assessment of the fair value at the time the decision was made. In December 2003, we received $0.3 million in proceeds from certain assets sold by the entities, which was recorded as a reduction to the impairment charge. The entities were liquidated in early 2004.

Gain on Disposal of Assets, Net. 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 sales and disposals of used drill pipe ($2.1 million). Net gains (losses) on disposal of assets were not significant in 2003.

Interest Expense. Third party interest expense and interest expense-related party decreased $39.0 million in 2004 as compared to 2003, primarily due to lower debt balances owed to third parties and Transocean, partly offset by $1.2 million in bank commitment fees related to our $75 million line of credit entered into in December 2003. In 2003, we repaid $15.2 million of third party debt and, in conjunction with the transfer of the Transocean Assets, we retired $529.7 million in related party debt payable to Transocean. Additionally, prior to the closing of our IPO, we completed a debt-for-equity exchange of all our remaining outstanding related party debt payable to Transocean.

Loss on Retirement of Debt. In conjunction with the retirement of debt held by Transocean in 2003, we recorded losses on retirement of related party debt in 2003 of $79.5 million. In the first quarter of 2004, we wrote off the remaining balance of unamortized fees of approximately $1.9 million associated with the exchange of Transocean debt for our outstanding senior notes in March 2002 due to the retirement of the debt in conjunction with the IPO. See Related Party Transactions Long-Term Debt Transocean.

Impairment of Investment in and Advance to Joint Venture. Based on cash flow projections and industry conditions, we recorded a $21.3 million impairment of our notes receivable from Delta Towing during the second quarter of 2003. See Variable Interest Entity Delta Towing.

Other, Net. Other expense, net was $2.8 million for 2003, including a $2.4 million loss on revaluation of our local currency in Venezuela. In January 2003, Venezuela implemented foreign exchange controls that limited our ability to convert local currency into U.S. dollars and transfer excess funds out of Venezuela. The exchange controls caused an artificially high value to be placed on the local currency. As a result, we recognized a loss on revaluation of the local currency into functional U.S. dollars during the second quarter of 2003. In 2004, other income, net included $1.7 million in foreign currency exchange gains.

Income Tax Benefit. The income tax benefit of $12.5 million for 2004 reflects an effective tax rate (ETR) of 30.2%, as compared to $50.1 million for 2003, based on an ETR of 18.5%. The increased ETR is primarily the result of providing a valuation allowance on net operating losses generated in 2003. During 2003, we recorded a valuation allowance on net operating loss carry forwards and foreign tax credits generated during the year. In 2004, to the extent we utilized net operating losses carry forwards (NOL s) to reduce taxable income, we owe Transocean for the utilization of these NOL s, in accordance with the tax sharing agreement. As of December 31, 2004, accrued income taxes payable to Transocean under the tax sharing agreement was $8.4 million. See Related Party Transactions Other Transactions Between Us and Transocean.

Discontinued Operations

In July 2002, Transocean announced plans to divest its Shallow Water business through an initial public offering of TODCO common stock. During 2003, we completed the transfer to Transocean of certain assets, including all revenue-producing Transocean Assets. Accordingly, the Transocean Assets and related operations have been reflected as discontinued operations in our historical financial statements. See Note 20 to our consolidated financial statements included in Item 8 of this report for a discussion of discontinued operations.

Cumulative Effect of a Change in Accounting Principle

As a result of our adoption of FIN 46 as of December 31, 2003, we recognized a $0.8 million gain as a cumulative effect of a change in accounting principle related to our consolidation of Delta Towing. See Variable Interest Entity Delta Towing. See Note 4 to our consolidated financial statements included in Item 8 of this report.

Financial Condition

At December 31, 2005 and December 31, 2004, we had total assets of $825.0 million and $761.4 million, respectively. The $63.6 million increase in assets during 2005 is primarily attributable to an increase in cash and cash equivalents resulting from the increased dayrates and utilizations experienced throughout 2005 ($97.9 million), a $44.6 million increase in our accounts receivable primarily due to the increased dayrates, capital expenditures of $22.4 million and the recognition of an additional $4.9 million in deferred income tax assets in 2005. These increases were partly offset by depreciation of $96.0 million, $1.2 million in net amortization of deferred preparation and mobilization cost and the sale of assets with a net book value of $10.7 million. See Liquidity and Capital Resources. Total assets by business segment were as follows for the periods indicated below:

	December 31,		
	2005	**2004**	**2003**
U.S. Gulf of Mexico Segment	$ 252.2	$ 354.1	$ 334.6
U.S. Inland Barge Segment	161.3	160.8	170.4
Other International Segment	164.6	154.5	171.3
Delta Towing Segment	55.6	51.8	61.3
Corporate and Other	191.3	40.2	40.6
Total assets	$ 825.0	$ 761.4	$ 778.2

Working capital at December 31, 2005 was $143.1 million, as compared to a working capital of $61.2 million at December 31, 2004. The increase in working capital during 2005 is primarily attributable increases in cash and accounts receivable resulting from higher dayrates and utilization rates for our drilling rigs for the year ended December 31, 2005.

Liquidity and Capital Resources

Sources and Use of Cash

2005 Compared to 2004. Net cash provided by operating activities was $136.4 million for the year ended December 31, 2005, as compared to $57.7 million in 2004. The $78.7 million increase in net cash provided by operating activities is primarily attributable to the increase in net income of $88.2 million. Adjustments to reconcile net income to net cash provided by operating activities were lower in 2005, primarily due to unfavorable variances related to an increase in deferred income taxes of $10.0 million, a $4.5 million decrease in stock compensation expense recognized by us in 2005 as compared to 2004, the $4.7 million loss in 2004 related to impairment of three lake barges in Venezuela and the retirement of related party debt and the additional $18.6 million in gains recognized from asset sales in 2005. These were partially offset by a favorable variance resulting from an increase in deferred income recognized during 2005 of $9.0 million. Changes in operating assets and liabilities, net of effect of distributions to Transocean, resulted in a $14.4 million increase in cash in 2005, compared to a $4.3 million reduction in 2004. This $18.7 million favorable increase is primarily the result of the increase in net taxes payable due to current year income ($29.8 million) and the increase in accounts payable and other current liabilities resulting from the increased levels of activity ($32.0 million). These increases were partly offset by the increase in accounts receivable which had an unfavorable impact of $36.0 million when reconciling net income to net cash provided by operating activities. Higher revenues, the result of increasing dayrates and utilizations, during 2005 resulted in a significantly higher receivable balance at year end when compared to year end 2004.

Net cash provided by investing activities was $13.4 million for the year ended December 31, 2005 compared to $0.4 million for the same period in 2004. The $13.0 million increase in net cash provided by investing activities relates primarily to the higher proceeds recognized from asset sales during the year of $23.0 million offset by the increase in capital expenditures of $10.0 million.

Net cash used in financing activities was $51.9 million for the year ended December 31, 2005, as compared to $13.0 million for the same period in 2004. Financing activities in 2005 included the special cash dividend of $61.2 million, the $7.7 million repayment of our 6.75% notes, the receipt of $17.8 million related to the issuance of common stock under our long-term incentive plans and the repayment of capital leases totaling $0.8 million. Financing activities in 2004 included an increase in restricted cash of $11.9 million related to performance bonds for our Mexico operations and capital lease payments of $1.1 million.

Sources of Liquidity and Capital Expenditures

Our cash flows from operations, asset sales and existing cash balances were our primary sources of liquidity for the years ended December 31, 2005 and 2004.

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. For the year ended December 31, 2004, our primary uses of cash were capital expenditures of $12.4 million related to upgrades and replacements of equipment, the use of $11.9 million for restricted cash to support our three performance bonds related to our Mexico operations and the retirement of amounts owed under capital lease obligations. At December 31, 2005, we had $163.0 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 2003, we entered into a two-year $75 million floating-rate secured revolving credit facility (the 2003 Facility) that declined to $60 million in December 2004. The 2003 Facility expired in December 2005 at which time we entered into a two-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 milli