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

Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)**
OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2007

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 001-32936

HELIX ENERGY SOLUTIONS GROUP, INC.
(Exact name of registrant as specified in its charter)

Minnesota	**95-3409686**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
400 North Sam Houston Parkway East Suite 400 Houston, Texas	**77060**
(Address of principal executive offices)	*(Zip Code)*

(281) 618-0400
(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock (no par value)	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 o No

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

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 o No

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

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

Large accelerated filer ☑	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant based on the last reported sales price of the Registrant's Common Stock on June 30, 2007 was approximately $3.4 billion.

The number of shares of the registrant's Common Stock outstanding as of February 26, 2008 was 91,674,430.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement for the Annual Meeting of Shareholders to be held on May 6, 2008, are incorporated by reference into Part III hereof.

HELIX ENERGY SOLUTIONS GROUP, INC. INDEX — FORM 10-K

Forward Looking Statements

This Annual Report on Form 10-K ("Annual Report") contains certain statements that are, or may be deemed to be, "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended ("Exchange Act"). All statements, other than statements of historical facts, included herein or incorporated herein by reference are forward-looking statements. Included among forward-looking statements are, among other things:

- statements regarding our anticipated production volumes, results of exploration, exploitation, development, acquisition or operations expenditures, and current or prospective reserve levels with respect to any property or well, or the ability to replace oil and gas reserves;
- statements related to commodity prices for oil and gas or with respect to the supply of and demand for oil and gas;
- statements relating to our proposed acquisition, exploration, development and/or production of oil and gas properties, prospects or other interests and any anticipated costs related thereto;
- statements regarding any financing transactions or arrangements, or ability to enter into such transactions;
- statements relating to the construction or acquisition of vessels or equipment, including statements concerning the engagement of any engineering, procurement and construction contractor and any anticipated costs related thereto;
- statements that our proposed vessels, when completed, will have certain characteristics or the effectiveness of such characteristics;
- statements regarding projections of revenues, gross margin, expenses, capital costs, earnings or losses or other financial items;
- statements regarding our business strategy, our business plans or any other plans, forecasts or objectives;
- statements regarding any Securities and Exchange Commission ("SEC") or other governmental or regulatory inquiry or investigation;
- statements regarding anticipated legislative, governmental, regulatory, administrative or other public body actions, requirements, permits or decisions;
- statements regarding anticipated developments, industry trends, performance or industry ranking;
- statements related to the underlying assumptions related to any projection or forward-looking statement;
- statements related to environmental risks, exploration and development risks, or drilling and operating risks;
- statements related to the ability of the Company to retain key members of its senior management and key employees;
- statements regarding general economic or political conditions, whether international, national or in the regional and local market areas in which we do business; and
- any other statements that relate to non-historical or future information.

These forward-looking statements are often identified by the use of terms and phrases such as "achieve," "anticipate," "believe," "estimate," "expect," "forecast," "plan," "project," "propose," "strategy," "predict," "envision," "hope," "intend," "will," "continue," "may," "potential," "achieve," "should," "could" and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve assumptions, risks and uncertainties, and these expectations may prove to be incorrect. You should not place undue reliance on these forward-looking statements.

Our actual results could differ materially from those anticipated in these forward-looking statements as a result of a variety of factors, including those discussed in "Risk Factors" beginning on page 19 of this Annual Report. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these risk factors. Forward-looking statements are only as of the date they are made, and other than as required under the securities laws, we assume no obligation to update or revise these forward-looking statements or provide reasons why actual results may differ.

PART I

Item 1. *Business*

OVERVIEW

Helix Energy Solutions Group, Inc. ("Helix") is an international offshore energy company, incorporated in the state of Minnesota in 1979, that provides reservoir development solutions and other contracting services to the energy market as well as to our own oil and gas properties. Our Contracting Services segment utilizes our vessels and offshore equipment that when applied with our methodologies reduce finding and development ("F&D") costs and cover the complete lifecycle of an offshore oil and gas field. Our Oil and Gas segment engages in prospect generation, exploration, development and production activities. We operate primarily in the Gulf of Mexico, North Sea, Asia Pacific and Middle East regions. Unless the context indicates otherwise, as used in this Annual Report, the terms "Company," "we," "us" and "our" refer collectively to Helix and its subsidiaries, including Cal Dive International, Inc. (collectively with its subsidiaries referred to as "Cal Dive" or "CDI"), our majority-owned subsidiary.

Our principal executive offices are located at 400 North Sam Houston Parkway East, Suite 400, Houston, Texas 77060; phone number 281-618-0400. Our stock trades on the New York Stock Exchange under the ticker symbol "HLX." Our Chief Executive Officer (formerly Executive Chairman) submitted the annual CEO certification to the New York Stock Exchange as required under the NYSE listed Company Manual in April 2007. Our principal executive officer and our principal financial officer have made the certifications required under Section 302 of the Sarbanes-Oxley Act, which are included as exhibits to this report.

Please refer to the subsection "— Certain Definitions" on page 7 for definitions of additional terms used in this Annual Report.

CONTRACTING SERVICES OPERATIONS

We provide offshore services and methodologies that we believe are critical to finding and developing offshore reservoirs and maximizing production economics, particularly from marginal fields. By "marginal," we mean reservoirs that are no longer wanted by major operators or are too small to be material to them. Our "life of field" services are organized in five disciplines: construction, well operations, drilling, production facilities, and reservoir and well technology services. We have disaggregated our contracting services operations into three reportable segments in accordance with Financial Accounting Standards Board ("FASB") Statement No. 131 *Disclosures about Segments of an Enterprise and Related Information* ("SFAS No. 131"): Contracting Services (which includes deepwater construction, well operations, reservoir and well technology services and in the future, drilling), Shelf Contracting and Production Facilities.

Construction

Since 1975, we have provided services in support of offshore oil and natural gas infrastructure projects involving the construction and maintenance of pipelines, production platforms, risers and subsea production systems primarily in the Gulf of Mexico, North Sea and Asia Pacific regions. Our deepwater construction services include pipelay and robotics in water depth of more than 1,000 feet. We also provide construction services periodically from our well intervention vessels. We perform traditional subsea services, including air and saturation diving, salvage work and shallow water pipelay on the Outer Continental Shelf ("OCS") of the Gulf of Mexico in water depths up to 1,000 feet through Cal Dive, a majority-owned subsidiary in which we currently own 58.5%. We have consolidated the financial results of Cal Dive as of December 31, 2007. Cal Dive stock publicly trades on the New York Stock Exchange under the ticker symbol "DVR."

Well Operations

We believe we are the global leader in rig alternative subsea well intervention. We engineer, manage and conduct well construction, intervention and decommissioning operations in water depths ranging from 200 to 10,000 feet. With the increased demand for these services caused by the growing number of subsea tree installations, coupled with the shortfall in Deepwater rig availability, we are constructing a newbuild North Sea vessel and have expanded geographically in Australia and Asia with the acquisition of Seatrac Pty Ltd. ("Seatrac"), an established Australian well operations company now called Well Ops SEA Pty Limited ("WOSEA").

Production Facilities

We own interests in certain production facilities in hub locations where there is potential for significant subsea tieback activity. Ownership of production facilities enables us to earn a transmission company type return through tariff charges while providing construction work for our vessels. We own a 50% interest in the Marco Polo tension leg platform ("TLP"), which was installed in 4,300 feet of water in the Gulf of Mexico, through Deepwater Gateway, L.L.C. ("Deepwater Gateway"). We also own a 20% interest in Independence Hub, L.L.C. ("Independence"), an affiliate of Enterprise Products Partners L.P. Independence owns the Independence Hub platform, a 105-foot deep draft, semi-submersible platform, which was installed during 2007. The platform is located in a water depth of 8,000 feet, which serves as a regional hub for up to 1 billion cubic feet of natural gas production per day from multiple ultra-deepwater fields in the previously untapped eastern Gulf of Mexico. Finally, through a consolidated 50% owned entity, we are currently converting a vessel into a floating production unit for use on our Phoenix field in the Gulf of Mexico.

Reservoir and Well Technology Services

In 2005, we acquired Helix Energy Limited, the largest outsource provider of sub-surface technology skills in the North Sea. With a technical staff of over 90 employees, we have the resources to provide valuable well enhancement services, which typically increase production or extend the life of a reservoir, to our own oil and natural gas projects as well as to our clients. Each team we assign to a specific client comprises a diverse set of skills, including reservoir engineering, geology, modeling, flow assurance, completions, well design and production enhancement. With offices in Aberdeen, Perth, London, Kuala Lumpur and Perth, we have an established market presence in regions that we have identified as strategically important to future growth.

Drilling

Contract drilling is a service we have not historically provided but have been contemplating since the construction of our *Q4000* vessel over six years ago. Dayrates for deepwater drilling rigs have increased dramatically in recent years based on the significant oil and natural gas reserves located in deepwater regions and limited availability of rigs capable of drilling such depths. As a result, the drilling and completion cost of a subsea development can be as much as 50% of the total F&D costs. We are currently adding drilling capability to the *Q4000*, a project scheduled for completion in the second quarter of 2008. The type of drilling intended for this vessel is a hybrid slim-bore technology capable of drilling and completing 6-inch slimbore wells to 22,000 feet total depth in up to 6,000 feet of water, which will allow us to drill most of our own deepwater prospects and support the exploration and appraisal efforts of our clients. We expect approval from the MMS for cased well services including completions in 2008 and approval for drilling once we have satisfied MMS requirements.

OIL AND GAS OPERATIONS

We formed our oil and gas operations in 1992 to provide a more efficient solution to offshore abandonment, to expand the off-season asset utilization of our contracting services business and to achieve incremental returns to our contracting services. Over the last 15 years, we have evolved this business model to include not only mature oil and gas properties but also proved reserves yet to be developed. In July 2006, we acquired Remington Oil and Gas Corporation ("Remington"), an exploration, development and production company with operations primarily in the Gulf of Mexico. This acquisition has led to the assembly of services that allow us to create value at key points in the life of a reservoir from exploration through development, life of field management and operating through abandonment. We believe that owning controlling interests in reservoirs, particularly in deepwater, accomplishes the following:

- provides a backlog for our service assets as a hedge against cyclical service asset utilization;

- provides enabling utilization for new non-conventional applications of service assets to hedge against lack of initial market acceptance and utilization risk;
- achieves control of development assets and methodologies to be employed and therefore control costs; and
- adds incremental returns.

As of December 31, 2007 we had 677 Bcfe of proved reserves with 95% of that located in the Gulf of Mexico.

Within oil and gas operations, we have assembled a team of personnel with experience in geology, geophysics, reservoir engineering, drilling, production engineering, facilities management, lease operations and petroleum land management. We seek to maximize profitability by lowering F&D costs, reducing development time, operating our fields more effectively, and extending the reservoir life through well exploitation operations. Our reservoir engineering and geophysical expertise, along with our access to contracting services assets that can positively impact development costs, have made us a preferred partner for many other oil and gas companies in offshore development projects.

Significant financial information relating to our operations by segments and by geographic areas for the last three years is contained in Item 8. *Financial Statements and Supplementary Data* "— Note 19 — Business Segment Information." Within Contracting Services for financial reporting purposes, we have disclosed separately the financial information for Shelf Contracting and Production Facilities.

THE INDUSTRY AND OUR STRATEGY

Demand for our contracting services operations is primarily influenced by the condition of the oil and gas industry, and in particular, the willingness of oil and gas companies to make capital expenditures for offshore exploration, drilling and production operations. Generally, during periods of high commodity prices, oil and gas producers increase spending on our services in an effort to develop new reservoirs and enhance production from existing wells. The performance of our oil and gas operations is largely dependent on the prevailing market prices for oil and natural gas, which are impacted by global economic conditions, hydrocarbon production and excess capacity, geopolitical issues, weather and several other factors.

We believe that the long-term industry fundamentals are positive based on the following factors: (1) increasing world demand for oil and natural gas; (2) peaking global production rates; (3) globalization of the natural gas market; (4) increasing number of mature and small reservoirs; (5) increasing ratio of contribution to global production from marginal fields; (6) increasing offshore activity, particularly in Deepwater; and (7) increasing number of subsea developments. Our two-stranded strategy of combining contracting services operations and oil and gas operations allows us to focus on trends (4) through (7) in that we pursue long-term sustainable growth by applying specialized subsea services to the broad external offshore market but with a complementary focus on marginal fields and new reservoirs in which we have an equity stake.

Our primary goal is to provide services and methodologies to the industry which we believe are critical to finding and developing offshore reservoirs and maximizing the economics from marginal fields. A secondary goal is for our oil and gas operations to generate prospects and find and develop oil and gas employing our key services and methodologies resulting in a reduction in F&D costs. Meeting these objectives drives our ability to achieve our primary goal of achieving a return on invested capital of 15% or greater. In order to achieve these goals we will:

Continue Expansion of Contracting Services Capabilities. We will focus on providing offshore services that deliver the highest financial return to us. We will make strategic investments in capital projects that expand our services capabilities or add capacity to existing services in our key operating regions. Our capital investments have included adding offshore drilling capability to our *Q4000* vessel, converting a vessel into a dynamically positioned floating production unit (*Helix Producer I)*, converting a former dynamically positioned cable lay vessel into a deepwater pipelay vessel (the *Caesar)*, and constructing the *Well Enhancer* vessel with greater well servicing capabilities in the North Sea.

Monetize Oil and Gas Reserves and Non-Core Assets. We intend to sell down interests in oil and gas reserves once value has been created via prospect generation, discovery and/or development engineering. Through this approach we seek to lower reservoir and commodity risk, lower capital expenditures and increase third party contracting services profits.

As stated previously, we will focus on services which are critical to lowering F&D costs, particularly on marginal fields in the deepwater. As the strategy of our Shelf Contracting segment does not focus on minimizing F&D cost, in December 2006, a minority stake (26.5%) in this business was sold through a carve-out initial public offering. Our interest in CDI was further reduced to 58.5% through CDI's acquisition in December 2007 of Horizon Offshore, Inc. ("Horizon"). See Item 8. *Financial Statements and Supplementary Data* "— Note 5 — Acquisition of Horizon Offshore, Inc." We believe the Shelf Contracting segment is better positioned for growth as a separately traded entity.

Generate Prospects and Focus Exploration Drilling on Select Deepwater Prospects. We will continue to generate prospects and drill in areas where we believe our contracting services assets can be utilized and incremental returns will be achieved through control of and application of our development services and methodologies. To minimize our F&D costs, we intend to utilize the *Q4000* for most of our deepwater drilling needs after the drilling upgrade is completed and regulatory approval has been obtained. Additionally, we plan to seek partners on these prospects to enhance financial results on the drilling and development work as well as to mitigate risk.

Continue Exploitation Activities and Converting PUD/PDNP Reserves into Production. Over the years, our oil and gas operations have been able to achieve a significant return on capital due in part to our ability to convert proved undeveloped reserves ("PUD") and proved developed non-producing reserves ("PDNP") into producing assets through successful exploitation drilling and well work. As of December 31, 2007, we had 67% of our proved reserves, or approximately 453 Bcfe, in the PUD category. We will focus on cost effectively developing these reserves to generate oil and gas production, or alternatively, selling full or partial interests in them to fund our growth initiatives and/or retire outstanding debt.

International Expansion of the Business Model. Based on attractive opportunities outside the Gulf of Mexico, we will continue to export our unique Gulf of Mexico business model to international offshore regions. We regard the North Sea and certain offshore areas of Southeast Asia as the primary regional targets for expansion. We have built a strong service presence in the North Sea and in December 2006 acquired our first mature oil and gas property in that area. In the Asia Pacific region, we completed two important service acquisitions in 2006 and will seek to grow our business there in a measured way over the near term.

Certain Definitions

Defined below are certain terms helpful to understanding our business:

Bcfe: One billion cubic feet equivalent, with one barrel of oil being equivalent to six thousand cubic feet of natural gas.

Deepwater: Water depths beyond 1,000 feet.

Dive Support Vessel (DSV): Specially equipped vessel that performs services and acts as an operational base for divers, remotely operated vehicles ("ROV") and specialized equipment.

Dynamic Positioning (DP): Computer-directed thruster systems that use satellite-based positioning and other positioning technologies to ensure the proper counteraction to wind, current and wave forces enabling the vessel to maintain its position without the use of anchors.

DP-2: Two DP systems on a single vessel pursuant to which the redundancy allows the vessel to maintain position even with the failure of one DP system; required for vessels which support both manned diving and robotics and for those working in close proximity to platforms. DP-2 are necessary to provide the redundancy required to support safe deployment of divers, while only a single DP system is necessary to support ROV operations.

EHS: Environment, Health and Safety programs to protect the environment, safeguard employee health and eliminate injuries.

E&P: Oil and gas exploration and production activities.

F&D: Total cost of finding and developing oil and gas reserves.

G&G: Geological and geophysical.

IMR: Inspection, maintenance and repair activities.

Life of Field Services: Services performed on offshore facilities, trees and pipelines from the beginning to the end of the economic life of an oil field, including installation, inspection, maintenance, repair, contract operations, well intervention, recompletion and abandonment.

MBbl: When describing oil or other natural gas liquid, refers to 1,000 barrels containing 42 gallons each.

Minerals Management Service (MMS): The federal regulatory body for the United States having responsibility for the mineral resources of the United States OCS.

Mcf: When describing natural gas, refers to 1 thousand cubic feet.

MMcf: When describing natural gas, refers to 1 million cubic feet.

Moonpool: An opening in the center of a vessel through which a saturation diving system or ROV may be deployed, allowing safe deployment in adverse weather conditions.

MSV: Multipurpose support vessel.

Outer Continental Shelf (OCS): For purposes of our industry, areas in the Gulf of Mexico from the shore to 1,000 feet of water depth.

Peer Group-Contracting Services: Defined in this Annual Report as comprising Global Industries, Ltd. (NASDAQ: GLBL), Oceaneering International, Inc. (NYSE: OII), Cameron International Corporation (NYSE: CAM), Pride International, Inc. (NYSE: PDE), Oil States International, Inc. (NYSE: OIS), Grant Prideco, Inc. (NYSE: GRP), Rowan Companies, Inc. (NYSE: RDC), Complete Production Services, Inc. (NYSE: CPX), and Tidewater Inc. (NYSE: TDW).

Oil and Gas: Defined in this Annual Report as comprising ATP Oil & Gas Corp (NASDAQ: ATPG), W&T Offshore, Inc. (NYSE: WTI), Energy Partners, Ltd. (NYSE:EPL), and Mariner Energy, Inc. (NYSE: ME).

Proved Developed Non-Producing (PDNP): Proved developed oil and gas reserves that are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells that require additional completion work or future recompletion prior to the start of production.

Proved Developed Reserves: Reserves that geological and engineering data indicate with reasonable certainty to be recoverable today, or in the near future, with current technology and under current economic conditions.

Proved Undeveloped Reserves (PUD): Proved undeveloped oil and gas reserves that are expected to be recovered from a new well on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Remotely Operated Vehicle (ROV): Robotic vehicles used to complement, support and increase the efficiency of diving and subsea operations and for tasks beyond the capability of manned diving operations.

ROVDrill: ROV deployed coring system developed to take advantage of existing ROV technology. The coring package, deployed with the ROV system, is capable of taking cores from the seafloor in water depths up to 3000m. Because the system operates from the seafloor there is no need for surface drilling strings and the larger support spreads required for conventional coring.

Saturation Diving: Saturation diving, required for work in water depths between 200 and 1,000 feet, involves divers working from special chambers for extended periods at a pressure equivalent to the pressure at the work site.

Spar: Floating production facility anchored to the sea bed with catenary mooring lines.

Spot Market: Prevalent market for subsea contracting in the Gulf of Mexico, characterized by projects that are generally short in duration and often on a turnkey basis. These projects often require constant rescheduling and the availability or interchangeability of multiple vessels.

Stranded Field: Smaller PUD reservoir that standing alone may not justify the economics of a host production facility and/or infrastructure connections.

Subsea Construction Vessels: Subsea services are typically performed with the use of specialized construction vessels which provide an above-water platform that functions as an operational base for divers and ROVs. Distinguishing characteristics of subsea construction vessels include DP systems, saturation diving capabilities, deck space, deck load, craneage and moonpool launching. Deck space, deck load and craneage are important features of a vessel's ability to transport and fabricate hardware, supplies and equipment necessary to complete subsea projects.

Tension Leg Platform (TLP): A floating production facility anchored to the seabed with tendons.

Trencher or Trencher System: A subsea robotics system capable of providing post lay trenching, inspection and burial (PLIB) and maintenance of submarine cables and flowlines in water depths of 30 to 7,200 feet across a range of seabed and environmental conditions.

Ultra-Deepwater: Water depths beyond 4,000 feet.

Working Interest: The interest in an oil and natural gas property (normally a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property and to a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

CONTRACTING SERVICES OPERATIONS

We provide a full range of contracting services primarily in the Gulf of Mexico, North Sea, Asia Pacific and Middle East regions in both the shallow water and deepwater. Our services include:

- *Exploration support.* Pre-installation surveys; rig positioning and installation assistance; drilling inspection; subsea equipment maintenance; reservoir engineering; G&G services; modeling; well design; and engineering;
- *Development.* Installation of small platforms on the OCS, installation of subsea pipelines, flowlines, control umbilicals, manifolds, risers; pipelay and burial; installation and tie-in of riser and manifold assembly; commissioning, testing and inspection; and cable and umbilical lay and connection;
- *Production.* Inspection, maintenance and repair of production structures, risers, pipelines and subsea equipment; well intervention; life of field support; reservoir management; providing production technology; and intervention engineering; and
- *Decommissioning.* Decommissioning and remediation services; plugging and abandonment services; platform salvage and removal services; pipeline abandonment services; and site inspections.

We provide offshore services and methodologies that we believe are critical to finding and developing offshore reservoirs and maximizing production economics, particularly from marginal fields. Those "life of field" services are organized in five disciplines: reservoir and well technology services, drilling, production facilities, construction and well operations. As of December 31, 2007, our contracting services operations had backlog of approximately $1.1 billion, of which approximately $630 million was expected to be completed in 2008.

Construction

Deepwater

Construction services which we believe are critical to the development of marginal fields in the deepwater are pipelay and robotics. We currently own three deepwater umbilical and pipelay vessels. The *Intrepid* is a 381 foot DP-2 vessel capable of laying rigid and flexible pipe (up to 8 inch) and umbilicals. The *Express*, which was acquired in 2005, is a 502 foot DP-2 vessel also capable of laying rigid and flexible pipe (up to 14 inch) and umbilicals. In January 2006, we acquired the *Caesar*, a mono-hull built in 2002 for the cable lay market. The vessel is 485 feet long and has a state-of-the-art DP-2 system. We are currently converting this vessel to a deepwater pipelay asset capable of laying rigid pipe up to 42 inch in diameter. The total estimated cost to acquire and convert the vessel is $172.5 million and the conversion is expected to be completed in third quarter 2008. We also periodically provide construction services from our well intervention vessels, *Seawell* and *Q4000*.

We operate ROVs, trenchers and ROV Drills designed for offshore construction, rather than supporting drilling rig operations. As marine construction support in the Gulf of Mexico and other areas of the world moves to deeper waters, ROV systems play an increasingly important role. Our vessels add value by supporting deployment of our ROVs. We have positioned ourselves to provide our customers with vessel availability and schedule flexibility to meet the technological challenges of these deepwater construction developments in the Gulf of Mexico and internationally. Our 35 ROVs and four trencher systems operate in three regions: the Americas, Europe/West Africa and Asia Pacific. We are in the process of building a new 2,000 HP trencher and a portable reeled pipelay system for the installation of rigid pipe with a diameter up to 6 inch.

The results of our Deepwater division are reported under our Contracting Services segment. See Item 8. *Financial Statements and Supplementary Data* "— 19 — Business Segment Information."

Shelf Contracting

Our Shelf Contracting segment consists of CDI, our consolidated, majority-owned subsidiary. In shallower waters we provide manned diving, pipelay and pipe burial services, and platform installation and salvage services to the offshore oil and natural gas industry. Based on the size of our fleet, we believe that we are the market leader in the diving support business, which involves services such as construction, inspection, maintenance, repair and decommissioning of offshore production and pipeline infrastructure, on the Gulf of Mexico OCS. We also provide these services directly or through partnering relationships in select international offshore markets, such as the Middle East and Asia Pacific. Within this segment we currently own and operate a diversified fleet of 31 vessels, including 21 surface and saturation diving support vessels, six pipelay/pipebury barges, one dedicated pipebury barge, one combination derrick/pipelay barge and two derrick barges. Pipelay and pipe burial operations typically require extensive use of our diving services; therefore, we consider these services to be complementary.

Shelf Contracting performs saturation, surface and mixed gas diving which enable us to provide a full complement of marine contracting services in water depths of up to 1,000 feet. We provide our saturation diving services in water depths of 200 to 1,000 feet through our fleet of nine saturation diving vessels and ten portable saturation diving systems. We also believe that our fleet of diving support vessels is among the most technically advanced in the industry because a number of these vessels have features such as dynamic positioning, hyperbaric rescue chambers, multi-chamber systems for split-level operations and moon pool deployment, which allow us to operate effectively in challenging offshore environments. We provide surface and mixed gas diving services in water depths typically less than 300 feet through our 15 surface diving vessels.

On December 11, 2007, CDI completed its previously announced acquisition of Horizon, through the merger of Horizon with and into a wholly owned subsidiary of CDI, which resulted in Horizon becoming a wholly owned subsidiary of CDI. Under the terms of the merger, each share of common stock, par value $0.00001 per share, of Horizon was converted into the right to receive $9.25 in cash and 0.625 shares of CDI's common stock. All shares of Horizon restricted stock that had been issued but had not vested prior to the effective time of the merger became fully vested at the effective time of the merger and converted into the right to receive the merger consideration. CDI issued an aggregate of approximately 20.3 million shares of common stock and paid approximately $300 million in cash in the merger. The cash portion of the merger consideration was paid from CDI's cash on hand and from borrowings under its new $675 million credit facility consisting of a $375 million senior secured term loan and a $300 million senior secured revolving credit facility. See Item 8. *Financial Statements and Supplementary Data* "— Note 11 — Long-Term Debt."

We have substantially increased the size of our Shelf Contracting fleet and expanded our operating capabilities on the Gulf of Mexico OCS through strategic acquisitions of Horizon (2007), Acergy US, Inc. ("Acergy") (2006), and the assets of Torch (2005). We also acquired Fraser Diving International Limited ("Fraser") (2006).

Shelf Contracting retained our former name of "Cal Dive," and completed a carve-out initial public offering in December 2006. It trades on the New York Stock Exchange under the ticker symbol of "DVR." We received pre-tax net proceeds of $464.4 million from the initial public offering ("IPO"), which included the sale of a 26.5% interest and transfer of debt to CDI. After the consummation of the Horizon acquisition, we currently own 58.5% of CDI.

Well Operations

We believe we are the global leader in rig alternative subsea well intervention. We engineer, manage and conduct well construction, intervention, and decommissioning operations in water depths ranging from 200 to 10,000 feet. The increased number of subsea wells installed, the increasing value of the product, and the shortfall in both rig availability and equipment have resulted in an increased demand for Well Operations services in both the Gulf of Mexico and the North Sea.

As major and independent oil and gas companies expand operations in the deepwater basins of the world, development of these reserves will often require the installation of subsea trees. Historically, drilling rigs were typically necessary for subsea well operations to troubleshoot or enhance production, shift zones or perform recompletions. Two of our vessels serve as work platforms for well operations services at costs significantly less than drilling rigs. In the Gulf of Mexico, our multi-service semi-submersible vessel, the *Q4000*, has set a series of well operations "firsts" in increasingly deeper water without the use of a traditional drilling rig. In the North Sea, the *Seawell* has provided intervention and abandonment services for over 500 North Sea subsea wells since 1987. Competitive advantages of our vessels are derived from their lower operating costs, together with an ability to mobilize quickly and to maximize production time by performing a broad range of tasks for intervention, construction, inspection, repair and maintenance. These services provide a cost advantage in the development and management of subsea reservoir developments. With the increased demand for these services due to the growing number of subsea tree installations coupled with the shortfall in rig availability, we have significant backlog for both working assets and are constructing a newbuild North Sea vessel, the *Well Enhancer*. The expected cost of the new vessel is $198 million. We also expanded our operations geographically in Australia and Asia with the 2006 acquisition of Seatrac, an established Australian well operations company now called Well Ops SEA Pty. Limited.

The results of Well Operations are reported under our Contracting Services segment. See Item 8. *Financial Statements and Supplementary Data* "— Note 19 — Business Segment Information."

Production Facilities

We own interests in certain production facilities in hub locations where there is potential for significant subsea tieback activity. There are a significant number of small discoveries that cannot justify the economics of a dedicated host facility. These discoveries are typically developed as subsea tie backs to existing facilities when capacity through the facility is available. We invest in over-sized facilities that allow operators of these fields to tie back without burdening the operator of the hub reservoir. We are well positioned to facilitate the tie back of the smaller reservoir to these hubs through our services and production groups. Ownership of production facilities enables us to earn a transmission company type return through tariff charges while providing construction work for our vessels. We own a 50% interest in Deepwater Gateway, L.L.C., which owns the Marco Polo TLP, which was installed in 4,300 feet of water in the Gulf of Mexico in order to process production from Anadarko Petroleum Corporation's Marco Polo field discovery. We also own a 20% interest in Independence Hub, LLC, an affiliate of Enterprise Products Partners L.P., which owns the Independence Hub platform, a 105-foot deep draft, semi-submersible platform located in a water depth of 8,000 feet that serves as a regional hub for up to 1 billion cubic feet of natural gas production per day from multiple ultra-deepwater fields in the previously untapped eastern Gulf of Mexico.

When a hub is not feasible, we intend to apply an integrated application of our services in a manner that cumulatively lowers development costs to a point that allows for a small dedicated facility to be used. This strategy will permit the development of some fields that otherwise would be non-commercial to develop. The commercial risk is mitigated because we have a portfolio of reservoirs and the assets to redeploy the facility. For example, through a consolidated 50%-owned entity, we are currently converting a vessel into a dynamically positioned floating production unit. This unit will first be utilized on the Phoenix field (formerly known as Typhoon) which we acquired in 2006 after the hurricanes of 2005 destroyed the TLP which was being used to produce the field. Once production in the Phoenix area ceases, this re-deployable facility is expected to be moved to a new location, contracted to a third party, or used to produce other internally-owned reservoirs.

Reservoir and Well Technolgy Services

In 2005, we acquired Helix Energy Limited, the largest outsource provider of sub-surface technology skills in the North Sea. With a technical staff of over 90 employees, we have the resources to provide valuable well enhancement services, which typically increase production or extend the life of a reservoir, to our own oil and natural gas projects as well as provide these services to our clients. Each team we assign to a specific client comprises a diverse set of skills, including reservoir engineering, geology, modeling, flow assurance, completions, well design and production enhancement. With offices in Aberdeen, London, Kuala Lumpur and Perth, we have an established market presence in regions that we have identified as strategically important to future growth. The results of reservoir and well technology services are reported under our Contracting Services segment. See Item 8. *Financial Statements and Supplementary Data* "— Note 19 — Business Segment Information."

Drilling

Contract drilling is a service we have not historically provided but have been contemplating since the construction of our *Q4000* vessel over six years ago. Dayrates for deepwater drilling rigs have increased dramatically in recent years based on the significant oil and natural gas reserves located in deepwater regions and limited availability of rigs capable of drilling such depths. As a result, the drilling cost of a subsea development can be as much as 50% of the total F&D costs. We are currently adding drilling capability to the *Q4000*, a project scheduled for completion in the second quarter of 2008. The type of drilling intended for this vessel is a hybrid slim-bore technology capable of drilling and completing 6-inch slimbore wells to 22,000 feet total depth in up to 6,000 feet of water, which will allow us to drill most of our own deepwater prospects and support the exploration and appraisal efforts of our clients. We expect approval from the MMS for cased well services including completions in 2008 and approval for drilling once we have satisfied MMS requirements.

OIL & GAS OPERATIONS

We formed our oil and gas operations in 1992 to provide a more efficient solution to offshore abandonment, to expand our off-season asset utilization of our contracting services business and to achieve incremental additional returns to our contracting services. Over the last 15 years, we have evolved this business model to include not only mature oil and gas properties but also proved reserves yet to be developed. In July 2006, we acquired Remington, an exploration, development and production company with operations primarily in the Gulf of Mexico, for approximately $1.4 billion in cash and Helix stock and the assumption of $358.4 million of liabilities. This acquisition led to the assembly of services that allows us to create value at key points in the life of a reservoir from exploration through development, life of field management and operating through abandonment. As of December 31, 2007, we had 677 Bcfe of proved reserves with 95% located in the Gulf of Mexico.

We believe that owning controlling interests in reservoirs, particularly in deepwater, accomplishes the following:

- provides a backlog for our service assets as a hedge against cyclical service asset utilization;
- provides enabling utilization for new non-conventional applications of service assets to hedge against lack of initial market acceptance and utilization risk;
- achieves control of development assets and methodologies to be employed and therefore control costs; and
- adds incremental returns.

Our oil and gas operations now seek to be involved in the reservoir at any stage of its life if we can apply our methodologies. The cumulative effect of our model is the ability to meaningfully improve the economics of a reservoir that would otherwise be considered non-commercial or non-impact, as well as making us a value adding partner to producers. Our expertise, along with similarly aligned interests, allows us to develop more efficient relationships with other producers. With a focus on acquiring non-impact reservoirs or mature fields, our approach taken as a whole is, itself, a service in demand by our producer clients and partners. As a result, we have been successful in acquiring equity interests in several deepwater undeveloped reservoirs. Developing these fields over the next few years will require meaningful capital commitments but will also provide significant backlog for our construction assets.

Our oil and gas operations have a significant prospect inventory, mostly in the deepwater, which we believe will generate significant life of field services for our vessels. To minimize F&D costs, we intend to utilize the *Q4000* for most of our deepwater drilling needs after the drilling upgrade is completed and regulatory approval has been obtained. Our Oil and Gas segment has a proven track record of cost effectively turning prospects into production on the OCS, and we believe similar success will continue to occur in the deepwater. Of the prospects we currently have in the deepwater, we intend to utilize the *Q4000* for most of our drilling needs once the drilling upgrade is completed and regulatory approval has been granted. We plan to seek partners on these prospects to enhance financial results on the drilling and development work as well as mitigate risk.

We identify prospective oil and gas properties primarily by using 3-D seismic technology. After acquiring an interest in a prospective property, our strategy is to drill one or more exploratory wells with partners. If the exploratory well(s) find commercial oil and/or gas reserves, we complete the well(s) and install the necessary infrastructure to begin producing the oil and/or gas. Because most of our operations are located offshore Gulf of Mexico, we must install facilities such as offshore platforms and gathering pipelines in order to produce the oil and gas and deliver it to the marketplace. Certain properties require additional drilling to fully develop the oil and gas reserves and maximize the production from a particular discovery.

Within our oil and gas operations, we have assembled a team of personnel with experience in geology, geophysics, reservoir engineering, drilling, production engineering, facilities management, lease operations and petroleum land management. We seek to maximize profitability by lowering F&D costs, lowering development time and cost, operating the field more effectively, and extending the reservoir life through well exploitation operations. When a company sells an OCS property, it retains the financial responsibility for plugging and decommissioning if its purchaser becomes financially unable to do so. Thus, it becomes important that a property be sold to a purchaser that has the financial wherewithal to perform its contractual obligations. Although there is significant competition in this mature field market, our oil and gas operations' reputation, supported by our financial strength, has made us the purchaser of choice of many major and independent oil and gas companies. In addition, our reservoir engineering and geophysical expertise, along with our access to contracting service assets that can positively impact development costs, have made us a preferred partner for many other oil and gas companies in offshore development projects. We share ownership in our oil and gas properties with various industry participants. We currently operate the majority of our offshore properties. An operator is generally able to maintain a greater degree of control over the timing and amount of capital expenditures than a non-operating interest owner. See Item 2. *Properties* "— Summary of Natural Gas and Oil Reserve Data" for detailed disclosures of our oil and gas properties.

GEOGRAPHIC AREAS

Revenue by geographic region during the years ended December 31, 2007, 2006 and 2005 were as follows (in thousands):

	Year Ended December 31,		
	2007	2006	2005
United States	$ 1,261,844	$ 1,063,821	$630,227
United Kingdom	230,189	190,064	83,239
Other	275,412	113,039	86,006
Total	$ 1,767,445	$ 1,366,924	$799,472

Property and equipment, net of depreciation, by geographic region during the years ended December 31, 2007, 2006 and 2005 were as follows (in thousands):

	Year Ended December 31,		
	2007	2006	2005
United States	$ 2,915,655	$ 2,046,043	$843,304
United Kingdom	189,117	110,451	72,932
Other	139,916	55,964	126
Total	$ 3,244,688	$ 2,212,458	$916,362

CUSTOMERS

Our customers include major and independent oil and gas producers and suppliers, pipeline transmission companies and offshore engineering and construction firms. The level of construction services required by any particular contracting customer depends on the size of that customer's capital expenditure budget devoted to construction plans in a particular year. Consequently, customers that account for a significant portion of contract revenues in one fiscal year may represent an immaterial portion of contract revenues in subsequent fiscal years. The percent of consolidated revenue of major customers was as follows: 2007 — Louis Dreyfus Energy Services (13%) and Shell Offshore, Inc. (10%); 2006 — Louis Dreyfus Energy Services (10%) and Shell Offshore, Inc. (10%); and 2005 — Louis Dreyfus Energy Services (10%) and Shell Trading (US) Company (10%). All of these customers were purchasers of our oil and gas production. We estimate that in 2007 we provided subsea services to over 200 customers.

Our contracting services projects have historically been of short duration and are generally awarded shortly before mobilization. As a result, no significant backlog existed prior to 2007. In 2007, we entered into several long-term contracts, for certain of our Deepwater and Well Operations vessels. In addition, our production portfolio inherently provides a backlog of work for our services that we can complete at our option based on market conditions.

COMPETITION

The marine contracting industry is highly competitive. While price is a factor, the ability to acquire specialized vessels, attract and retain skilled personnel, and demonstrate a good safety record are also important. Our competitors on the OCS include Global Industries, Ltd., Oceaneering International, Inc. and a number of smaller companies, some of which only operate a single vessel and often compete solely on price. For Deepwater projects, our principal competitors include Acergy, Allseas, Subsea 7, and Technip-Coflexip.

Our oil and gas operations compete with large integrated oil and gas companies as well as independent exploration and production companies for offshore leases on properties. We also encounter significant competition for the acquisition of mature oil and gas properties. Our ability to acquire additional properties depends upon our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. Many of our competitors may have significantly more financial, personnel, technological, and other resources available. In addition, some of the larger integrated companies may be better able to respond to industry changes including price fluctuation, oil and gas demands, and governmental regulations. Small or mid-sized producers, and in some cases financial players, with a focus on acquisition of proved developed and undeveloped reserves are often competition on development properties.

TRAINING, SAFETY AND QUALITY ASSURANCE

We have established a corporate culture in which EHS remains among the highest of priorities. Our corporate goal, based on the belief that all accidents can be prevented, is to provide an injury-free workplace by focusing on correct and safe behavior. Our EHS procedures, training programs and management system were developed by management personnel, common industry work practices and by employees with on-site experience who understand the physical challenges of the ocean work site. As a result, management believes that our EHS programs are among the best in the industry. We have introduced a company-wide effort to enhance and provide continual improvements to our behavioral based safety process, as well as our training programs, that continue to focus on safety through open communication. The process includes the documentation of all daily observations, collection of data and data treatment to provide the mechanism of understanding both safe and unsafe behaviors at the worksite. In addition, we initiated scheduled Hazard Hunts by project management on each vessel, complete with assigned responsibilities and action due dates. To further this effort, progressive auditing is done to continuously improve our EHS management system.

GOVERNMENT REGULATION

Many aspects of the offshore marine construction industry are subject to extensive governmental regulations. We are subject to the jurisdiction of the U.S. Coast Guard (“USCG”), the U.S. Environmental Protection Agency, the MMS and the U.S. Customs Service, as well as private industry organizations such as the American Bureau of Shipping (“ABS”). In the North Sea, international regulations govern working hours and a specified working environment, as well as standards for diving procedures, equipment and diver health. These North Sea standards are some of the most stringent worldwide. In the absence of any specific regulation, our North Sea branch adheres to standards set by the International Marine Contractors Association and the International Maritime Organization. In addition, we operate in other foreign jurisdictions that have various types of governmental laws and regulations to which we are subject.

We support and voluntarily comply with standards of the Association of Diving Contractors International. The Coast Guard sets safety standards and is authorized to investigate vessel and diving accidents, and to recommend improved safety standards. The Coast Guard also is authorized to inspect vessels at will. We are required by various governmental and quasi-governmental agencies to obtain various permits, licenses and certificates with respect to our operations. We believe that we have obtained or can obtain all permits, licenses and certificates necessary for the conduct of our business.

In addition, we depend on the demand for our services from the oil and gas industry, and therefore, our business is affected by laws and regulations, as well as changing tax laws and policies relating to the oil and gas industry generally. In particular, the development and operation of oil and gas properties located on the OCS of the United States is regulated primarily by the MMS.

The MMS requires lessees of OCS properties to post bonds or provide other adequate financial assurance in connection with the plugging and abandonment of wells located offshore and the removal of all production facilities. Operators on the OCS are currently required to post an area-wide bond of $3.0 million, or $500,000 per producing lease. We have provided adequate financial assurance for our offshore leases as required by the MMS.

We acquire production rights to offshore mature oil and gas properties under federal oil and gas leases, which the MMS administers. These leases contain relatively standardized terms and require compliance with detailed MMS regulations and orders pursuant to the Outer Continental Shelf Lands Act (“OCSLA”). These MMS directives are subject to change. The MMS has promulgated regulations requiring offshore production facilities located on the OCS to meet stringent engineering and construction specifications. The MMS also has issued regulations restricting the flaring or venting of natural gas and prohibiting the burning of liquid hydrocarbons without prior authorization.

Similarly, the MMS has promulgated other regulations governing the plugging and abandonment of wells located offshore and the removal of all production facilities. Finally, under certain circumstances, the MMS may require any operations on federal leases to be suspended or terminated or may expel unsafe operators from existing OCS platforms and bar them from obtaining future leases. Suspension or termination of our operations or expulsion from operating on our leases and obtaining future leases could have a material adverse effect on our financial condition and results of operations.

Under the OCSLA and the Federal Oil and Gas Royalty Management Act, MMS also administers oil and gas leases and establishes regulations that set the basis for royalties on oil and gas. The regulations address the proper way to value production for royalty purposes, including the deductibility of certain post-production costs from that value. Separate sets of regulations govern natural gas and oil and are subject to periodic revision by MMS.

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 (“NGPA”), and the regulations promulgated thereunder by the Federal Energy Regulatory Commission (“FERC”). In the past, the federal government has regulated the prices at which oil and gas could be sold. While sales by producers of natural gas, and all sales of crude oil, condensate and natural gas liquids currently can be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead sales in the natural gas industry began with the enactment of the NGPA. In 1989, the Natural Gas Wellhead Decontrol Act was enacted. This act amended the NGPA to remove both price and non-price controls from natural gas sold in “first sales” no later than January 1, 1993.

Sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation remain subject to extensive federal and state regulation. Several major regulatory changes have been implemented by Congress and FERC since 1985 that affect the economics of natural gas production, transportation and sales. In addition, FERC continues to promulgate revisions to various aspects of the rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to FERC jurisdiction. Changes in FERC rules and regulations may also affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry. We cannot predict what further action FERC will take on these matters, but we do not believe any such action will materially adversely affect us differently from other companies with which we compete.

Additional proposals and proceedings before various federal and state regulatory agencies and the courts could affect the oil and gas industry. We cannot predict when or whether any such proposals may become effective. In the past, the natural gas industry has been heavily regulated. There is no assurance that the regulatory approach currently pursued by FERC will continue indefinitely. Notwithstanding the foregoing, we do not anticipate that compliance with existing federal, state and local laws, rules and regulations will have a material effect upon our capital expenditures, financial conditions, earnings or competitive position.

ENVIRONMENTAL REGULATION

Our operations are subject to a variety of national (including federal, state and local) and international laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often complex and costly to comply with and that carry substantial administrative, civil and possibly criminal penalties for failure to comply. Under these laws and regulations, we may be liable for remediation or removal costs, damages and other costs associated with releases of hazardous materials (including oil) into the environment, and such liability may be imposed on us even if the acts that resulted in the releases were in compliance with all applicable laws at the time such acts were performed. Some of the environmental laws and regulations that are applicable to our business operations are discussed in the following paragraphs, but the discussion does not cover all environmental laws and regulations that govern our operations.

The Oil Pollution Act of 1990, as amended (“OPA”), imposes a variety of requirements on “Responsible Parties” related to the prevention of oil spills and liability for damages resulting from such spills in waters of the

United States. A "Responsible Party" includes the owner or operator of an onshore facility, a vessel or a pipeline, and the lessee or permittee of the area in which an offshore facility is located. OPA imposes liability on each Responsible Party for oil spill removal costs and for other public and private damages from oil spills. Failure to comply with OPA may result in the assessment of civil and criminal penalties. OPA establishes liability limits of $350 million for onshore facilities, all removal costs plus $75 million for offshore facilities, and the greater of $800,000 or $950 per gross ton for vessels other than tank vessels. The liability limits are not applicable, however, if the spill is caused by gross negligence or willful misconduct; if the spill results from violation of a federal safety, construction, or operating regulation; or if a party fails to report a spill or fails to cooperate fully in the cleanup. Few defenses exist to the liability imposed under OPA. Management is currently unaware of any oil spills for which we have been designated as a Responsible Party under OPA that will have a material adverse impact on us or our operations.

OPA also imposes ongoing requirements on a Responsible Party, including preparation of an oil spill contingency plan and maintaining proof of financial responsibility to cover a majority of the costs in a potential spill. We believe that we have appropriate spill contingency plans in place. With respect to financial responsibility, OPA requires the Responsible Party for certain offshore facilities to demonstrate financial responsibility of not less than $35 million, with the financial responsibility requirement potentially increasing up to $150 million if the risk posed by the quantity or quality of oil that is explored for or produced indicates that a greater amount is required. The MMS has promulgated regulations implementing these financial responsibility requirements for covered offshore facilities. Under the MMS regulations, the amount of financial responsibility required for an offshore facility is increased above the minimum amounts if the "worst case" oil spill volume calculated for the facility exceeds certain limits established in the regulations. We believe that we currently have established adequate proof of financial responsibility for our onshore and offshore facilities and that we satisfy the MMS requirements for financial responsibility under OPA and applicable regulations.

In addition, OPA requires owners and operators of vessels over 300 gross tons to provide the Coast Guard with evidence of financial responsibility to cover the cost of cleaning up oil spills from such vessels. We currently own and operate 19 vessels over 300 gross tons. We have provided satisfactory evidence of financial responsibility to the Coast Guard for all of our vessels.

The Clean Water Act imposes strict controls on the discharge of pollutants into the navigable waters of the United States and imposes potential liability for the costs of remediating releases of petroleum and other substances. The controls and restrictions imposed under the Clean Water Act have become more stringent over time, and it is possible that additional restrictions will be imposed in the future. Permits must be obtained to discharge pollutants into state and federal waters. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System Program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the exploration for, and production of, oil and gas into certain coastal and offshore waters. The Clean Water Act provides for civil, criminal and administrative penalties for any unauthorized discharge of oil and other hazardous substances and imposes liability on responsible parties for the costs of cleaning up any environmental contamination caused by the release of a hazardous substance and for natural resource damages resulting from the release. Many states have laws that are analogous to the Clean Water Act and also require remediation of releases of petroleum and other hazardous substances in state waters. Our vessels routinely transport diesel fuel to offshore rigs and platforms and also carry diesel fuel for their own use. Our vessels transport bulk chemical materials used in drilling activities and also transport liquid mud which contains oil and oil by-products. Offshore facilities and vessels operated by us have facility and vessel response plans to deal with potential spills. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

OCSLA provides the federal government with broad discretion in regulating the production of offshore resources of oil and gas, including authority to impose safety and environmental protection requirements applicable to lessees and permittees operating in the OCS. Specific design and operational standards may apply to OCS vessels, rigs, platforms, vehicles and structures. Violations of lease conditions or regulations issued pursuant to OCSLA can result in substantial civil and criminal penalties, as well as potential court injunctions curtailing operations and cancellation of leases. Because our operations rely on offshore oil and gas exploration and production, if the government were to exercise its authority under OCSLA to restrict the availability of offshore oil and gas leases, such action could have a material adverse effect on our financial condition and results of operations. As of this date, we believe we are not the subject of any civil or criminal enforcement actions under OCSLA.

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") contains provisions requiring the remediation of releases of hazardous substances into the environment and imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons including owners and operators of contaminated sites where the release occurred and those companies who transport, dispose of, or arrange for disposal of hazardous substances released at the sites. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. Third parties may also file claims for personal injury and property damage allegedly caused by the release of hazardous substances. Although we handle hazardous substances in the ordinary course of business, we are not aware of any hazardous substance contamination for which we may be liable.

We operate in foreign jurisdictions that have various types of governmental laws and regulations relating to the discharge of oil or hazardous substances and the protection of the environment. Pursuant to these laws and regulations, we could be held liable for remediation of some types of pollution, including the release of oil, hazardous substances and debris from production, refining or industrial facilities, as well as other assets we own or operate or which are owned or operated by either our customers or our sub-contractors.

Management believes that we are in compliance in all material respects with all applicable environmental laws and regulations to which we are subject. We do not anticipate that compliance with existing environmental laws and regulations will have a material effect upon our capital expenditures, earnings or competitive position. However, changes in the environmental laws and regulations, or claims for damages to persons, property, natural resources or the environment, could result in substantial costs and liabilities, and thus there can be no assurance that we will not incur significant environmental compliance costs in the future.

EMPLOYEES

We rely on the high quality of our workforce. As of January 31, 2008, we had over 3,370 employees, nearly 1,000 of which were salaried personnel. Of the total employees, approximately 2,000 were employees of Cal Dive. As of December 31, 2007, we also contracted with third parties to utilize approximately 300 non-U.S. citizens to crew our foreign flag vessels. None of our employees belong to a union nor are employed pursuant to any collective bargaining agreement or any similar arrangement. We believe our relationship with our employees and foreign crew members is favorable.

WEBSITE AND OTHER AVAILABLE INFORMATION

We maintain a website on the Internet with the address of www.HelixESG.com. Copies of this Annual Report for the year ended December 31, 2007, and copies of our Quarterly Reports on Form 10-Q for 2007 and 2008 and any Current Reports on Form 8-K for 2007 and 2008, and any amendments thereto, are or will be available free of charge at such website as soon as reasonably practicable after they are filed with, or furnished to, the Securities and Exchange Commission ("SEC"). We make our website content available for informational purposes only. Information contained on our website is not part of this report and should not be relied upon for investment purposes. Please note that prior to March 6, 2006, the name of the Company was Cal Dive International, Inc.

The general public may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. We are an electronic filer, and the SEC maintains an Internet website that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC, including us. The Internet address of the SEC's website is www.sec.gov.

Item 1A. *Risk Factors.*

Shareholders should carefully consider the following risk factors in addition to the other information contained herein. You should be aware that the occurrence of the events described in these risk factors and elsewhere in this Annual Report could have a material adverse effect on our business, results of operations and financial position.

Risks Relating to our Contracting Services Operations

Our contracting services operations are adversely affected by low oil and gas prices and by the cyclicality of the oil and gas industry.

Our contracting services operations are substantially dependent upon the condition of the oil and gas industry, and in particular, the willingness of oil and gas companies to make capital expenditures for offshore exploration, drilling and production operations. The level of capital expenditures generally depends on the prevailing view of future oil and gas prices, which are influenced by numerous factors affecting the supply and demand for oil and gas, including, but not limited to:

- worldwide economic activity;
- demand for oil and natural gas, especially in the United States, China and India;
- economic and political conditions in the Middle East and other oil-producing regions;
- actions taken by the Organization of Petroleum Exporting Countries (“OPEC”);
- the availability and discovery rate of new oil and natural gas reserves in offshore areas;
- the cost of offshore exploration for and production and transportation of oil and gas;
- the ability of oil and natural gas companies to generate funds or otherwise obtain external capital for exploration, development and production operations;
- the sale and expiration dates of offshore leases in the United States and overseas;
- technological advances affecting energy exploration, production, transportation and consumption;
- weather conditions;
- environmental and other governmental regulations; and
- tax laws, regulations and policies.

The level of offshore construction has continued to improve during 2007, following higher commodity prices from 2003 to 2007. We cannot assure you that activity levels for offshore construction will remain the same or increase. A sustained period of low drilling and production activity or the return of lower commodity prices would likely have a material adverse effect on our financial position, cash flows and results of operations.

The operation of marine vessels is risky, and we do not have insurance coverage for all risks.

Marine construction involves a high degree of operational risk. Hazards, such as vessels sinking, grounding, colliding and sustaining damage from severe weather conditions, are inherent in marine operations. These hazards can cause personal injury or loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage, and suspension of operations. Damage arising from such occurrences may result in lawsuits asserting large claims. We maintain insurance protection as we deem prudent, including Jones Act employee coverage, which is the maritime equivalent of workers’ compensation, and hull insurance on our vessels. We cannot assure you that any such insurance will be sufficient or effective under all circumstances or against all hazards to which we may be subject. A successful claim for which we are not fully insured could have a material adverse effect on us. Moreover, we cannot assure you that we will be able to maintain adequate insurance in the future at rates that we consider reasonable. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased substantially and could escalate further. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. For example, insurance carriers are now requiring broad exclusions for losses due to war risk and terrorist acts and limitations for wind storm damages. As construction activity expands into deeper water in the Gulf of Mexico and other deepwater basins of the world and with our partial divestiture of Cal Dive, a greater percentage of our revenues may be from deepwater construction projects that are larger and more complex, and thus riskier, than shallow water projects. As a result, our revenues and profits are increasingly dependent on our larger vessels. The current insurance on our vessels, in some cases, is in amounts approximating book value, which could be less than replacement value. In the event of property loss due to a catastrophic marine disaster, mechanical failure, collision or other event, insurance may not cover a substantial loss of revenues, increased costs and other liabilities, and therefore, the loss of any of our large vessels could have a material adverse effect on us.

Our contracting business typically declines in winter, and bad weather in the Gulf or North Sea can adversely affect our operations.

Marine operations conducted in the Gulf of Mexico and North Sea are seasonal and depend, in part, on weather conditions. Historically, we have enjoyed our highest vessel utilization rates during the summer and fall when weather conditions are favorable for offshore exploration, development and construction activities. We typically have experienced our lowest utilization rates in the first quarter. As is common in the industry, we typically bear the risk of delays caused by some adverse weather conditions. Accordingly, our results in any one quarter are not necessarily indicative of annual results or continuing trends.

Certain areas in and near the Gulf of Mexico and North Sea experience unfavorable weather conditions including hurricanes and other extreme weather conditions on a relatively frequent basis. Substantially all of our facilities and assets offshore and along the Gulf of Mexico and the North Sea, including our vessels and structures on our offshore oil and gas properties, are susceptible to damage and/or total loss by these storms. Damage caused by high winds and turbulent seas could potentially cause us to curtail both service and production operations for significant periods of time until damage can be assessed and repaired. Moreover, even if we do not experience direct damage from any of these storms, we may experience disruptions in our operations because customers may curtail their development activities due to damage to their platforms, pipelines and other related facilities.

If we bid too low on a turnkey contract, we suffer adverse economic consequences.

A significant amount of our projects are performed on a qualified turnkey basis where described work is delivered for a fixed price and extra work, which is subject to customer approval, is billed separately. The revenue, cost and gross profit realized on a turnkey contract can vary from the estimated amount because of changes in offshore job conditions, variations in labor and equipment productivity from the original estimates, the performance of third parties such as equipment suppliers, or other factors. These variations and risks inherent in the marine construction industry may result in our experiencing reduced profitability or losses on projects.

Delays or cost overruns in our construction projects could adversely affect our business, or the expected cash flows from these projects upon completion may not be timely or as high as expected.

We currently have the following significant construction projects in our contracting services operations:

- the construction of the *Well Enhancer*, a North Sea well services vessel;
- the conversion of the *Caesar* into a deepwater pipelay asset;
- the addition of a modular-based drilling system on the *Q4000*; and
- the construction of the *Helix Producer I*, a minimal floating production unit to be utilized on the Phoenix field, through a consolidated 50% owned variable interest entity.

Although the construction contracts provide for delay penalties, these projects are subject to the risk of delay or cost overruns inherent in construction projects. These risks include, but are not limited to:

- unforeseen quality or engineering problems;

- work stoppages;
- weather interference;
- unanticipated cost increases;
- delays in receipt of necessary equipment; and
- inability to obtain the requisite permits or approvals.

Significant delays could also have a material adverse effect on expected contract commitments for these assets and our future revenues and cash flow. We will not receive any material increase in revenue or cash flows from these assets until they are placed in service and customers enter into binding arrangements for the assets, which can potentially be several months after the construction or conversion projects are completed. Furthermore, we cannot assure you that customer demand for these assets will be as high as currently anticipated, and, as a result, our future cash flows may be adversely affected. In addition, new assets from third-parties may also enter the market in the future and compete with us.

Risks Relating to our Oil and Gas Operations

Exploration and production of oil and natural gas is a high-risk activity and is subject to a variety of factors that we cannot control.

Our oil & gas business is subject to all of the risks and uncertainties normally associated with the exploration for and development and production of oil and natural gas, including uncertainties as to the presence, size and recoverability of hydrocarbons. We may not encounter commercially productive oil and natural gas reservoirs. We may not recover all or any portion of our investment in new wells. The presence of unanticipated pressures or irregularities in formations, miscalculations or accidents may cause our drilling activities to be unsuccessful and/or result in a total loss of our investment, which could have a material adverse effect on our financial condition, results of operations and cash flows. In addition, we often are uncertain as to the future cost or timing of drilling, completing and operating wells.

Projecting future natural gas and oil production is imprecise. Producing oil and gas reservoirs eventually have declining production rates. Projections of production rates rely on certain assumptions regarding historical production patterns in the area or formation tests for a particular producing horizon. Actual production rates could differ materially from such projections. Production rates also can depend on a number of additional factors, including commodity prices, market demand and the political, economic and regulatory climate.

Our business is subject to all of the operating risks associated with drilling for and producing oil and natural gas, including:

- fires;
- title problems;
- explosions;
- pressures and irregularities in formations;
- equipment availability;
- blow-outs and surface cratering;
- uncontrollable flows of underground natural gas, oil and formation water;
- natural events and natural disasters, such as loop currents, and hurricanes and other adverse weather conditions;
- pipe or cement failures;
- casing collapses;
- lost or damaged oilfield drilling and service tools;

- abnormally pressured formations; and
- environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases.

If any of these events occurs, we could incur substantial losses as a result of injury or loss of life, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties, suspension of our operations and repairs to resume operations.

Natural gas and oil prices are volatile, which makes future revenue uncertain.

Our financial condition and results of operations depend in part on the prices we receive for the oil and gas we produce. The market prices for oil and gas are subject to fluctuation in response to events beyond our control, such as:

- supply of and demand for oil and gas;
- market uncertainty;
- worldwide political and economic instability; and
- government regulations.

Oil and gas prices have historically been volatile, and such volatility is likely to continue. Our ability to estimate the value of producing properties for acquisition and to budget and project the financial returns of exploration and development projects is made more difficult by this volatility. In addition, to the extent we do not forward sell or enter into costless collars in order to hedge our exposure to price volatility, a dramatic decline in such prices could have a substantial and material effect on:

- our revenues;
- results of operations;
- cashflow;
- financial condition;
- our ability to increase production and grow reserves in an economically efficient manner; and
- our access to capital.

Our commodity price risk management related to some of our oil and gas production may reduce our potential gains from increases in oil and gas prices.

Oil and gas prices can fluctuate significantly and have a direct impact on our revenues. To manage our exposure to the risks inherent in such a volatile market, from time to time, we have forward sold for future physical delivery a portion of our future production. This means that a portion of our production is sold at a fixed price as a shield against dramatic price declines that could occur in the market. In addition, we have entered into costless collar contracts related to some of our future oil and gas production. We may from time to time engage in other hedging activities that limit our upside potential from price increases. These sales activities may limit our benefit from dramatic price increases.

Estimates of crude oil and natural gas reserves depend on many factors and assumptions, including various assumptions that are based on conditions in existence as of the dates of the estimates. Any material changes in those conditions, or other factors affecting those assumptions, could impair the quantity and value of our crude oil and natural gas reserves.

This Annual Report contains estimates of our proved oil and gas reserves and the estimated future net cash flows therefrom based upon reports for the years ended December 31, 2007 and 2006, audited by our independent petroleum engineers. These reports rely upon various assumptions, including assumptions required by the SEC, as to oil and gas prices, drilling and operating expenses, capital expenditures, abandonment costs, taxes and availability of funds. The process of estimating oil and gas reserves is complex, requiring significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. As a result, these estimates are inherently imprecise. Actual future production, cash flows, development and production expenditures, operating and abandonment expenses and quantities of recoverable oil and gas reserves may vary from those estimated in these reports. Any significant variance in these assumptions could materially affect the estimated quantity and value of our proved reserves. You should not assume that the present value of future net cash flows from our proved reserves referred to in this Annual Report is the current market value of our estimated oil and gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the net present value estimate. In addition, if costs of abandonment are materially greater than our estimates, they could have an adverse effect on financial position, cash flows and results of operations.

Approximately 79% of our total estimated proved reserves are either PDNP or PUD and those reserves may not ultimately be produced or developed.

As of December 31, 2007, approximately 12% of our total estimated proved reserves were PDNP and approximately 67% were PUD. These reserves may not ultimately be developed or produced. Furthermore, not all of our PUD or PDNP may be ultimately produced during the time periods we have planned, at the costs we have budgeted, or at all, which in turn may have a material adverse effect on our results of operations.

Reserve replacement may not offset depletion.

Oil and gas properties are depleting assets. We replace reserves through acquisitions, exploration and exploitation of current properties. Approximately 79% of our proved reserves at December 31, 2007 are PUDs and PDNP. Further, our proved producing reserves at December 31, 2007 are expected to experience annual decline rates ranging from 30% to 40% over the next ten years. If we are unable to acquire additional properties or if we are unable to find additional reserves through exploration or exploitation of our properties, our future cash flows from oil and gas operations could decrease.

We are in part dependent on third parties with respect to the transportation of our oil and gas production and in certain cases, third party operators who influence our productivity.

Notwithstanding our ability to produce hydrocarbons, we are dependent on third party transporters to bring our oil and gas production to the market. In the event a third party transporter experiences operational difficulties, due to force majeure, pipeline shut-ins, or otherwise, this can directly influence our ability to sell commodities that we are able to produce. In addition, with respect to oil and gas projects that we do not operate, we have limited influence over operations, including limited control over the maintenance of safety and environmental standards. The operators of those properties may, depending on the terms of the applicable joint operating agreement:

- refuse to initiate exploration or development projects;
- initiate exploration or development projects on a slower or faster schedule than we prefer;
- delay the pace of exploratory drilling or development; and/or
- drill more wells or build more facilities on a project than we can afford, whether on a cash basis or through financing, which may limit our participation in those projects or limit the percentage of our revenues from those projects.

The occurrence of any of the foregoing events could have a material adverse effect on our anticipated exploration and development activities.

Our oil and gas operations involve significant risks, and we do not have insurance coverage for all risks.

Our oil and gas operations are subject to risks incident to the operation of oil and gas wells, including, but not limited to, uncontrollable flows of oil, gas, brine or well fluids into the environment, blowouts, cratering, mechanical difficulties, fires, explosions or other physical damage, pollution and other risks, any of which could result in substantial losses to us. We maintain insurance against some, but not all, of the risks described above. As a result, any damage not covered by our insurance could have a material adverse effect on our financial condition, results of operations and cash flows.

Risks Relating to General Corporate Matters

Our substantial indebtedness could impair our financial condition and our ability to fulfill our debt obligations.

As of December 31, 2007, we had approximately $1.8 billion of consolidated indebtedness outstanding. The significant level of combined indebtedness may have an adverse effect on our future operations, including:

- limiting our ability to obtain additional financing on satisfactory terms to fund our working capital requirements, capital expenditures, acquisitions, investments, debt service requirements and other general corporate requirements;
- increasing our vulnerability to general economic downturns, competition and industry conditions, which could place us at a competitive disadvantage compared to our competitors that are less leveraged;
- increasing our exposure to rising interest rates because a portion of our borrowings are at variable interest rates;
- reducing the availability of our cash flow to fund our working capital requirements, capital expenditures, acquisitions, investments and other general corporate requirements because we will be required to use a substantial portion of our cash flow to service debt obligations;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- limiting our ability to expand our business through capital expenditures or pursuit of acquisition opportunities due to negative covenants in senior secured credit facilities that place annual and aggregate limitations on the types and amounts of investments that we may make, and limit our ability to use proceeds from asset sales for purposes other than debt repayment (except in certain circumstances where proceeds will be reinvested under criteria defined by our credit agreements).

If we fail to comply with the covenants and other restrictions in the agreements governing our debt, it could lead to an event of default and the acceleration of our repayment of outstanding debt. Our ability to comply with these covenants and other restrictions may be affected by events beyond our control, including prevailing economic and financial conditions.

We may not be able to compete successfully against current and future competitors.

The businesses in which we operate are highly competitive. Several of our competitors are substantially larger and have greater financial and other resources than we have. If other companies relocate or acquire vessels for operations in the Gulf or the North Sea, levels of competition may increase and our business could be adversely affected. In the exploration and production business, some of the larger integrated companies may be better able to respond to industry changes including price fluctuations, oil and gas demands, political change and government regulations.

The loss of the services of one or more of our key employees, or our failure to attract and retain other highly qualified personnel in the future, could disrupt our operations and adversely affect our financial results.

Our industry has lost a significant number of experienced professionals over the years due to, among other reasons, the volatility in commodity prices. Our continued success depends on the active participation of our key employees. The loss of our key people could adversely affect our operations.

In addition, the delivery of our products and services require personnel with specialized skills and experience. As a result, our ability to remain productive and profitable will depend upon our ability to employ and retain skilled workers. Our ability to expand our operations depends in part on our ability to increase the size of our skilled labor force. The demand for skilled workers in our industry is high, and the supply is limited. In addition, although our employees are not covered by a collective bargaining agreement, the marine services industry has in the past been targeted by maritime labor unions in an effort to organize Gulf of Mexico employees. A significant increase in the wages paid by competing employers or the unionization of our Gulf of Mexico employees could result in a reduction of our skilled labor force, increases in the wage rates that we must pay or both. If either of these events were to occur, our capacity and profitability could be diminished and our growth potential could be impaired.

If we fail to effectively manage our growth, our results of operations could be harmed.

We have a history of growing through acquisitions of large assets and acquisitions of companies. We must plan and manage our acquisitions effectively to achieve revenue growth and maintain profitability in our evolving market. If we fail to effectively manage current and future acquisitions, our results of operations could be adversely affected. Our growth has placed, and is expected to continue to place, significant demands on our personnel, management and other resources. We must continue to improve our operational, financial, management and legal/compliance information systems to keep pace with the growth of our business.

We may need to change the manner in which we conduct our business in response to changes in government regulations.

Our subsea construction, intervention, inspection, maintenance and decommissioning operations and our oil and gas production from offshore properties, including decommissioning of such properties, are subject to and affected by various types of government regulation, including numerous federal, state and local environmental protection laws and regulations. These laws and regulations are becoming increasingly complex, stringent and expensive to comply with, and significant fines and penalties may be imposed for noncompliance. We cannot assure you that continued compliance with existing or future laws or regulations will not adversely affect our operations.

Government regulation may affect our ability to conduct operations, and the nature of our business exposes us to environmental liability.

Numerous federal and state regulations affect our operations. Current regulations are constantly reviewed by the various agencies at the same time that new regulations are being considered and implemented. In addition, because we hold federal leases, the federal government requires us to comply with numerous additional regulations that focus on government contractors. The regulatory burden upon the oil and gas industry increases the cost of doing business and consequently affects our profitability.

Our operations are subject to a variety of national (including federal, state and local) and international laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental agencies issue rules and regulations to implement and enforce such laws that are often complex and costly to comply with and that carry substantial administrative, civil and possibly criminal penalties for failure to comply. Under these laws and regulations, we may be liable for remediation or removal costs, damages and other costs associated with releases of hazardous materials including oil into the environment, and such liability may be imposed on us even if the acts that resulted in the releases were in compliance with all applicable laws at the time such acts were performed.

We operate in foreign jurisdictions that have various types of governmental laws and regulations relating to the discharge of oil or hazardous substances and the protection of the environment. Pursuant to these laws and regulations, we could be held liable for remediation of some types of pollution, including the release of oil, hazardous substances and debris from production, refining or industrial facilities, as well as other assets we own or operate or which are owned or operated by either our customers or our sub-contractors.

In addition, changes in environmental laws and regulations, or claims for damages to persons, property, natural resources or the environment, could result in substantial costs and liabilities, and thus there can be no assurance that we will not incur significant environmental compliance costs in the future. Such environmental liability could substantially reduce our net income and could have a significant impact on our financial ability to carry out our operations.

Certain provisions of our corporate documents and Minnesota law may discourage a third party from making a takeover proposal.

In addition to the 55,000 shares of preferred stock issued to Fletcher International, Ltd. under the First Amended and Restated Agreement dated January 17, 2003, but effective as of December 31, 2002, by and between Helix and Fletcher International, Ltd., our board of directors has the authority, without any action by our shareholders, to fix the rights and preferences on up to 4,945,000 shares of undesignated preferred stock, including dividend, liquidation and voting rights. In addition, our by-laws divide the board of directors into three classes. We are also subject to certain anti-takeover provisions of the Minnesota Business Corporation Act. We also have employment contracts with most of our senior officers that require cash payments in the event of a “change of control.” Any or all of the provisions or factors described above may discourage a takeover proposal or tender offer not approved by management and the board of directors and could result in shareholders who may wish to participate in such a proposal or tender offer receiving less for their shares than otherwise might be available in the event of a takeover attempt.

Our operations outside of the United States subject us to additional risks.

Our operations outside of the United States are subject to risks inherent in foreign operations, including, without limitation:

- the loss of revenue, property and equipment from expropriation, nationalization, war, insurrection, acts of terrorism and other political risks;
- increases in taxes and governmental royalties;
- changes in laws and regulations affecting our operations;
- renegotiation or abrogation of contracts with governmental entities;
- changes in laws and policies governing operations of foreign-based companies;
- currency restrictions and exchange rate fluctuations;
- world economic cycles;
- restrictions or quotas on production and commodity sales;
- limited market access; and
- other uncertainties arising out of foreign government sovereignty over our international operations.

In addition, laws and policies of the United States affecting foreign trade and taxation may also adversely affect our international operations.

Our ability to market oil and natural gas discovered or produced in any future foreign operations, and the price we could obtain for such production, depends on many factors beyond our control, including:

- ready markets for oil and natural gas;
- the proximity and capacity of pipelines and other transportation facilities;
- fluctuating demand for crude oil and natural gas;
- the availability and cost of competing fuels; and
- the effects of foreign governmental regulation of oil and gas production and sales.

Pipeline and processing facilities do not exist in certain areas of exploration and, therefore, any actual sales of our production could be delayed for extended periods of time until such facilities are constructed.

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

None.

Item 2. ***Properties.***

We own a fleet of 41 vessels and 33 ROVs, 4 trenchers, and 2 ROVDrills. We also lease four vessels, one trencher and one ROV. We believe that the market in the Gulf of Mexico requires specially designed and/or equipped vessels to competitively deliver subsea construction and well operations services. Eleven of our vessels have DP capabilities specifically designed to respond to the deepwater market requirements. Fifteen of our vessels (thirteen of which are based in the Gulf of Mexico) have the capability to provide saturation diving services.

Acquisitions in 2007

On December 11, 2007, our majority-owned subsidiary, CDI, completed its previously announced acquisition of Horizon through the merger of Horizon with and into a wholly owned subsidiary of CDI, which resulted in Horizon becoming a wholly owned subsidiary of CDI. Under the terms of the merger, each share of common stock, par value $0.00001 per share, of Horizon was converted into the right to receive $9.25 in cash and 0.625 shares of CDI's common stock. All shares of Horizon restricted stock that had been issued but had not vested prior to the effective time of the merger became fully vested at the effective time of the merger and converted into the right to receive the merger consideration. CDI issued an aggregate of approximately 20.3 million shares of common stock and paid approximately $300 million in cash in the merger. The cash portion of the merger consideration was paid from CDI's cash on hand and from borrowings under CDI's new $675 million credit facility consisting of a $375 million senior secured term loan and a $300 million senior secured revolving credit facility. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations "— Liquidity and Capital Resources."

In July 2007, we acquired the remaining 42% interest in Well Ops SEA Pty Ltd (formerly Seatrac) for total consideration of approximately $10.1 million (see "Note 6 — Other Acquisitions" in Item 8. *Financial Statements and Supplementary Data* for a detailed discussion of Seatrac). We changed the name of the entity to Well Ops SEA Pty Ltd in October 2006 when we purchased the initial 58% interest.

Divestitures in 2007

On September 30, 2007, we sold a 30% working interest in the Phoenix oilfield (Green Canyon Blocks 236/237), the Boris oilfield (Green Canyon Block 282) and the Little Burn oilfield (Green Canyon Block 238) to Sojitz GOM Deepwater, Inc. ("Sojitz"), a wholly owned subsidiary of Sojitz Corporation, for a cash payment of $40 million and the proportionate recovery of all past and future capital expenditures related to the re-development of the fields, excluding the conversion of the *Helix Producer I*, which we plan to use as a redeployable floating production unit ("FPU"). Proceeds of $51.2 million from the sale were collected in October 2007. Sojitz will also pay its proportionate share of the operating costs including fees payable for the use of the FPU. A gain of approximately $40.4 million was recorded in 2007 as a result of this sale.

In December 2006, we acquired a 100% working interest in the Camelot gas field in the North Sea in exchange for the assumption of certain decommissioning liabilities estimated at approximately $7.6 million. In June 2007, we sold a 50% working interest in this property for approximately $1.8 million cash and the assumption by the purchaser of 50% of the decommissioning liability of approximately $4.0 million. We recognized a gain of approximately $1.6 million as a result of this sale.

OUR VESSELS

Listing of Vessels, Barges and ROVs Related to Contracting Services Operations(1)

	Flag State	Placed in Service(2)	Length (Feet)	Berths	SAT Diving	DP or Anchor Moored	Crane Capacity (tons)
CONTRACTING SERVICES:							
Pipelay —							
Caesar (3)(4)	Vanuatu	1/2006	482	220	—	DP	300 and 36
Express (4)	Vanuatu	8/2005	520	132	—	DP	500 and 120
Intrepid (4)	Bahamas	8/1997	381	50	—	DP	400
Talisman (4)	U.S.	11/2000	195	14	—	—	—
Floating Production Unit —							
Helix Producer I (5)	Bahamas	—	528	95	—	DP	26 and 26
Well Operations —							
Q4000 (6)(7)	U.S.	4/2002	312	135	Capable	DP	160 and 360; 600 Derrick
Seawell	U.K.	7/2002	368	129	Capable	DP	130
Robotics —							
33 ROVs, 4 Trenchers and 2 ROVDrills (8)(9)	—	Various	—	—	—	—	—
Northern Canyon (10)	Bahamas	6/2002	276	58	—	DP	50
Olympic Canyon (10)	Norway	5/2007	304	80	—	DP	140
Olympic Triton (10)	Norway	11/2007	311	80	—	DP	150
Seacor Canyon (10)	Majuro Marshall Island	11/2007	221	40	—	DP	20
SHELF CONTRACTING (CAL DIVE INTERNATIONAL, INC.):							
Pipelay/Pipebury —							
Brave (11)	U.S.	11/2005	275	80	—	Anchor	30 and 50
Rider (11)	U.S.	11/2005	260	80	—	Anchor	50
American (11)	U.S.	12/2007	180	74	—	Anchor	90
Lone Star (11)	Vanuatu	12/2007	313	177	—	Anchor	88
Brazos (11)	Vanuatu	12/2007	210	119	—	Anchor	90
Pecos (11)	U.S.	12/2007	256	102	—	Anchor	114
Pipebury —							
Canyon (11)	U.S.	12/2007	330	110	—	Anchor	88
Derrick/Pipelay —							
Sea Horizon	Vanuatu	12/2007	360	255	—	Anchor	1,200
Derrick —							
Atlantic (11)	U.S.	12/2007	420	158	—	Anchor	500
Pacific (11)	U.S.	12/2007	350	109	—	Anchor	1,000
Saturation Diving —							
DP DSV *Eclipse* (11)	Bahamas	3/2002	367	109	Capable	DP	5; 4.3; 92/43; 20.4 A-Frame
DP DSV *Kestrel* (11)	Vanuatu	9/2006	323	80	Capable	DP	40; 15; 10; Hydralift HLR 308
DP DSV *Mystic Viking* (11)	Bahamas	6/2001	253	60	Capable	DP	50
DP MSV *Texas Horizon* (11)	Vanuatu	12/2007	341	96	Capable	DP	113
DP MSV *Uncle John* (11)	Bahamas	11/1996	254	102	Capable	DP	2×100
DSV *American Constitution* (11)	Panama	11/2005	200	46	Capable	4 point	20.41
DSV *Cal Diver I* (11)	U.S.	7/1984	196	40	Capable	4 point	20
DSV *Cal Diver II* (11)	U.S.	6/1985	166	32	Capable	4 point	40 A-Frame
DSV Midnight Star (11)(12)	Vanuatu	6/2006	197	42	—	4 point	20 and 40
Surface Diving —							
American Diver (11)	U.S.	11/2005	105	22	—	—	—
American Liberty (11)	U.S.	11/2005	110	22	—	—	1.588

	Flag State	Placed in Service(2)	Length (Feet)	Berths	SAT Diving	DP or Anchor Moored	Crane Capacity (tons)
Cal Diver IV (11)	U.S.	3/2001	120	24	—	—	—
DSV *American Star* (11)	U.S.	11/2005	165	30	—	4 point	9.072
DSV *American Triumph* (11)	U.S.	11/2005	164	32	—	4 point	13.61
DSV *American Victory* (11)	U.S.	11/2005	165	34	—	4 point	9.072
DSV *Cal Diver V* (11)	U.S.	9/1991	166	34	—	4 point	20 A-Frame
DSV *Dancer* (11)	U.S.	3/2006	173	34	—	4 point	30
DSV *Mr. Fred* (11)	U.S.	3/2000	166	36	—	4 point	25
Fox (11)	U.S.	10/2005	130	42	—	—	—
Mr. Jack (11)	U.S.	1/1998	120	22	—	—	10
Mr. Jim (11)	U.S.	2/1998	110	19	—	—	—
Polo Pony (11)	U.S.	3/2001	110	25	—	—	—
Sterling Pony (11)	U.S.	3/2001	110	25	—	—	—
White Pony (11)	U.S.	3/2001	116	25	—	—	—

(1) Under government regulations and our insurance policies, we are required to maintain our vessels in accordance with standards of seaworthiness and safety set by government regulations and classification organizations. We maintain our fleet to the standards for seaworthiness, safety and health set by the ABS, Bureau Veritas (“BV”), Det Norske Veritas (“DNV”), Lloyds Register of Shipping (“Lloyds”), and the USCG. The ABS, BV, DNV and Lloyds are classification societies used by ship owners to certify that their vessels meet certain structural, mechanical and safety equipment standards.

(2) Represents the date we placed the vessel in service and not the date of commissioning.

(3) Currently under conversion into a deepwater pipelay asset by mid 2008.

(4) Subject to vessel mortgages securing our Senior Credit Facilities described in Item 8. *Financial Statements and Supplementary Data* “— Note 11 — Long-term Debt.”

(5) Former ferry vessel undergoing conversion into DP floating production unit for initial use on our Phoenix field. See Production Facilities on page 30.

(6) Expected to complete drilling capabilities upgrade on the vessel in second quarter 2008.

(7) Subject to vessel mortgage securing our MARAD debt described in Item 8. *Financial Statements and Supplementary Data* “— Note 11 — Long-term Debt.”

(8) Owned and operated by our domestic subsidiary under a secured lien.

(9) Average age of our fleet of ROVs, trenchers and ROV Drills is approximately 4.07 years.

(10) Leased.

(11) Subject to vessel mortgages securing CDI’s $675 million credit facility described in Item 8. *Financial Statements and Supplementary Data* “— Note 11 — Long-term Debt.”

(12) Expected to be converted in 2008 to full saturation diving capabilities.

In addition to CDI’s saturation diving vessels, CDI currently owns ten portable saturation diving systems, including six acquired from Fraser.

The following table details the average utilization rate for our vessels by category (calculated by dividing the total number of days the vessels in this category generated revenues by the total number of calendar days in the applicable period) for the years ended December 31, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
Contracting Services:			
Pipelay	90%	86%	86%
Well operations	71%	81%	84%
ROVs	76%	76%	70%
Shelf Contracting	65%	84%	65%

We incur routine drydock, inspection, maintenance and repair costs pursuant to Coast Guard regulations and in order to maintain our vessels in class under the rules of the applicable class society. In addition to complying with these requirements, we have our own vessel maintenance program that we believe permits us to continue to provide our customers with well maintained, reliable vessels. In the normal course of business, we charter in other vessels on a short-term basis, such as tugboats, cargo barges, utility boats and dive support vessels.

PRODUCTION FACILITIES

Through our interest in Deepwater Gateway, L.L.C., a limited liability company in which Enterprise Products Partners L.P. is the other member, we own a 50% interest in the Marco Polo TLP, which was installed on Green Canyon Block 608 in 4,300 feet of water. Deepwater Gateway, L.L.C. was formed to construct, install and own the Marco Polo TLP in order to process production from Anadarko Petroleum Corporation's Marco Polo field discovery at Green Canyon Block 608. Anadarko required 50,000 barrels of oil per day and 150 million feet per day of processing capacity for Marco Polo. The Marco Polo TLP was designed to process 120,000 barrels of oil per day and 300 million cubic feet of gas per day and payload with space for up to six subsea tie backs.

We also own a 20% interest in Independence Hub, LLC, an affiliate of Enterprise Products Partners L.P., that owns the Independence Hub platform, a 105 foot deep draft, semi-submersible platform located in Mississippi Canyon block 920 in a water depth of 8,000 feet that serves as a regional hub for natural gas production from multiple ultra-Deepwater fields in the previously untapped eastern Gulf of Mexico. First production began in July 2007. The Independence Hub facility is capable of processing 1 billion cubic feet (bcf) per day of gas.

We own a 20% interest in the Gunnison truss spar facility, together with the operator Kerr-McGee Oil & Gas Corporation ("Kerr-McGee"), which owns a 50% interest, and Nexen, Inc., which owns the remaining 30% interest. The Gunnison spar, which is moored in 3,150 feet of water and located on Garden Banks Block 668, has daily production capacity of 40,000 barrels of oil and 200 million cubic feet of gas. This facility is designed with excess capacity to accommodate production from satellite prospects in the area.

Further, in October 2006, we invested $15 million for a 50% interest in Kommandor LLC to convert a ferry vessel into a dynamically-positioned minimal floating production system to be named *Helix Producer I*. Upon completion of the initial conversion, this vessel will be leased under a bareboat charter to us for further conversion and subsequent use as a floating production system in the Deepwater Gulf of Mexico, initially for the Phoenix field. Conversion of the vessel is expected to be completed in two phases. The first phase is expected to be completed in the second quarter of 2008 for approximately $87 million. The second phase of the conversion is expected to be completed in the third quarter of 2008. Estimated cost of conversion for the second phase is approximately $117 million, of which we expect to fund 100%.

SUMMARY OF NATURAL GAS AND OIL RESERVE DATA

We employ full-time experienced reserve engineers and geologists who are responsible for determining proved reserves in conformance with SEC guidelines. Engineering reserve estimates were prepared by us based upon our interpretation of production performance data and sub-surface information derived from the drilling of existing wells. Our internal reservoir engineers and independent petroleum engineers analyzed 100% of our United States oil and gas fields on an annual basis (143 fields as of December 31, 2007). We consider any field with discounted future net revenues of 1% or greater of the total discounted future net revenues of all our fields to be significant. An “engineering audit,” as we use the term, is a process involving an independent petroleum engineering firm’s (Huddleston & Co., Inc. (“Huddleston”)) extensive visits, collection and examination of all geologic, geophysical, engineering and economic data requested by the independent petroleum engineering firm. Our use of the term “engineering audit” is intended only to refer to the collective application of the procedures which Huddleston was engaged to perform and may be defined and used differently by other companies.

The engineering audit of our reserves by the independent petroleum engineers involves their rigorous examination of our technical evaluation, interpretation and extrapolations of well information such as flow rates and reservoir pressure declines as well as other technical information and measurements. Our internal reservoir engineers interpret this data to determine the nature of the reservoir and ultimately the quantity of proved oil and gas reserves attributable to a specific property. Our proved reserves in this Annual Report include only quantities that we expect to recover commercially using current prices, costs, existing regulatory practices and technology. While we are reasonably certain that the proved reserves will be produced, the timing and ultimate recovery can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and changes in projections of long-term oil and gas prices. Revisions can include upward or downward changes in the previously estimated volumes of proved reserves for existing fields due to evaluation of (1) already available geologic, reservoir or production data or (2) new geologic or reservoir data obtained from wells. Revisions can also include changes associated with significant changes in development strategy, oil and gas prices, or the related production equipment/facility capacity. Huddleston also examined our estimates with respect to reserve categorization, using the definitions for proved reserves set forth in Regulation S-X Rule 4-10(a) and subsequent SEC staff interpretations and guidance.

In the conduct of the engineering audit, Huddleston did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties or sales of production. However, if in the course of the examination something came to the attention of Huddleston which brought into question the validity or sufficiency of any such information or data, Huddleston did not rely on such information or data until they had satisfactorily resolved their questions relating thereto or had independently verified such information or data. Furthermore, in instances where decline curve analysis was not adequate in determining proved producing reserves, Huddleston evaluated our volumetric analysis, which included the analysis of production and pressure data. Each of the PUDs analyzed by Huddleston included volumetric analysis, which took into consideration recovery factors relative to the geology of the location and similar reservoirs. Where applicable, Huddleston examined data related to well spacing, including potential drainage from offsetting producing wells in evaluating proved reserves for un-drilled well locations.

The engineering audit by Huddleston included 100% of our producing properties together with a percentage of our non-producing and undeveloped properties. Properties for analysis were selected by us and Huddleston based on discounted future net revenues. All of our significant properties were included in the engineering audit and such audited properties constituted 97% of the total discounted future net revenues. Huddleston audited approximately 96% of our total reserve base in the United States, including what was deemed to be the most valuable properties. Huddleston audited 92% of proved developed reserves and 98% of the proved undeveloped reserves totaling 96% of both categories combined. Huddleston also analyzed the methods utilized by us in the preparation of all of the estimated reserves and revenues. Huddleston represents in its audit report that they believe our methodologies are consistent with the methodologies required by the SEC, Society of Petroleum Engineers (“SPE”) and FASB. There were no limitations imposed, nor limitations encountered by us or Huddleston.

The table below sets forth information, as of December 31, 2007, with respect to estimates of net proved reserves. Proved reserves cannot be measured exactly because the estimation of reserves involves numerous judgmental determinations. Accordingly, reserve estimates must be continually revised as a result of new information obtained from drilling and production history, new geological and geophysical data and changes in economic conditions.

	As of December 31, 2007		
	Proved Developed Reserves	Proved Undeveloped Reserves	Total Proved Reserves
United States:			
Gas (Bcf)	134	291	425
Oil (MMBbls)	15	25	40
Total (Bcfe)	222	440	662
United Kingdom:			
Gas (Bcf)	2	13	15
Oil (MMBbls)	—	—	—
Total (Bcfe)	2	13	15
Total:			
Gas (Bcf)	136	304	440
Oil (MMBbls)	15	25	40
Total (Bcfe)	224	453	677

For additional information regarding estimates of oil and gas reserves, including estimates of proved and proved developed reserves, the standardized measure of discounted future net cash flows, and the changes in discounted future net cash flows, see Item 8. *Financial Statements and Supplementary Data* "— Note 21— Supplemental Oil and Gas Disclosures."

Significant Oil and Gas Properties

Our oil and gas properties consist primarily of interests in developed and undeveloped oil and gas leases. As of December 31, 2007, we had exploration, development and production operations in the United States, primarily in the Gulf of Mexico. In December 2006, we acquired the Camelot field, located in the North Sea, in which we subsequently sold a 50% interest in June 2007. This is our only oil and gas property in the United Kingdom.

Our U.S. operations accounted for 99% of our 2007 production and approximately 98% of total proved reserves at December 31, 2007 (79% of such total reserves are PUDs and PDNP). Further, our proved producing reserves at December 31, 2007 are expected to experience annual decline rates ranging from 30% to 40% over the next ten years. The following table provides a brief description of our domestic and international oil and gas properties we consider most significant to us at December 31, 2007:

	Development Location	Net Total Proved Reserves (Bcfe)	Net Proved Reserves Mix		2007 Net Production (Bcfe)	Average WI%	Expected First Production
			Oil%	Gas%			
United States Offshore:							
Deepwater							
Bushwood (1)	U.S. GOM	206	21%	79%	—	100%	2008
Phoenix (2)	U.S. GOM	45	79%	21%	—	70%	2008
Gunnison (3)	U.S. GOM	27	46%	54%	6	19%	Producing
Bass Lite (4)	U.S. GOM	24	—	100%	—	17.5%	2008

	Development Location	Net Total Proved Reserves (Bcfe)	Net Proved Reserves Mix Oil%	Gas%	2007 Net Production (Bcfe)	Average WI%	Expected First Production
Outer Continental Shelf							
East Cameron 346	U.S. GOM	39	81%	19%	4	75%	Producing
South Timbalier 86/63	U.S. GOM	34	31%	69%	1	95%	Producing
South Pass 89	U.S. GOM	26	42%	58%	1	27%	Producing
Mobile 863	U.S. GOM	20	—	100%	—	83%	2008
West Cameron 170	U.S. GOM	20	31%	69%	1	55%	Producing
East Cameron 339	U.S. GOM	13	81%	19%	1	100%	Producing
South Marsh Island 130	U.S. GOM	13	70%	30%	4	100%	Producing
United States — Onshore:							
Parker Creek	Mississippi	16	99%	1%	1	67%	Producing
United Kingdom Offshore (5)	UK Offshore	15	2%	98%	—	50%	Producing

(1) Garden Banks 506 (formerly Noonan/Danny).

(2) Green Canyon blocks 236, 237, 238 and 282.

(3) An outside operated property comprised of Garden Banks blocks 625, 667, 668 and 669.

(4) Atwater Valley block 426.

(5) Consists of our only property in the United Kingdom, *Camelot*.

United States Offshore

Deepwater

We have proved reserves of approximately 304 Bcfe in five fields in the Gulf of Mexico Deepwater which comprised approximately 45% of our total proved reserves as of December 31, 2007. The working interests in these fields range from 17.5% to 100%. We are the operator of two of the five fields, which comprised approximately 82% of our Deepwater proved reserves (approximately 37% of total proved reserves). Gunnison, a non-operated field, has been producing since December 2003. Our net production in Deepwater totaled approximately 13 Bcfe in 2007. We continue to be active in Deepwater with an ongoing exploration and development program.

Outer Continental Shelf

We have proved reserves of approximately 336 Bcfe in over 130 fields in the Gulf of Mexico on the OCS which comprised approximately 50% of total proved reserves as of December 31, 2007. Our net production on the OCS totaled approximately 50 Bcfe in 2007. The working interests in our OCS fields range from 3% to 100%. Our largest field based on proved reserves is East Cameron 346, with approximately 11% of OCS reserves (approximately 6% of total proved reserves). No other individual OCS field comprised over 5% of total proved reserves. We are the operator of 75% of our OCS proved reserves. We continue to be active on the OCS with an ongoing exploration and development program. Based on current market conditions, we plan to drill approximately 11 wells on the OCS in 2008.

United States Onshore

We have proved reserves of approximately 22 Bcfe in over 17 onshore fields in Mississippi, Alabama, Louisiana and Texas, with net production totaling approximately two Bcfe in 2007. Our U.S. onshore proved reserves comprised approximately 3% of total proved reserves as of December 31, 2007. The working interests in our onshore properties range from 7% to 93.6%. We are not the operator of most of the onshore fields. One onshore non-operated field (Parker Creek) in Mississippi comprised over 71% of our U.S. onshore reserves, but only approximately 2% of our total proved reserves. There are no significant developments scheduled for the onshore fields.

United Kingdom Offshore

In December 2006, we acquired the Camelot field, located in the North Sea, in which we subsequently sold a 50% interest in June 2007. This is our only oil and gas property in the United Kingdom.

Production, Price and Cost Data

Production, price and cost data for our oil and gas operations in the United States are as follows:

	Year Ended December 31,		
	2007	2006	2005
Production:			
Gas — including natural gas liquids (Bcf)	42	28	18
Oil (MMBbls)	4	3	3
Total (Bcfe)	65	48	33
Average sales prices realized (including hedges):			
Gas — including natural gas liquids (per Mcf)	$ 7.69	$ 7.86	$ 8.08
Oil (per Bbl)	$67.68	$60.41	$49.15
Total (per Mcfe)	$ 8.93	$ 8.79	$ 8.13
Average production cost per Mcfe	$ 1.83	$ 1.85	$ 1.71
Average depletion and amortization per Mcfe (including accretion)	$ 3.54	$ 2.79	$ 2.14

No production data is available for our oil and gas operations in the United Kingdom in 2005 and 2006 as we acquired Camelot in December 2006 (which was not then producing). Production in 2007 was insignificant (0.3 Bcfe of gas).

Productive Wells

The number of productive oil and gas wells in which we held interest as of December 31, 2007 is as follows:

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
United States — Offshore	292	226	380	207	672	433
United States — Onshore	28	11	74	16	102	27
Total	320	237	454	223	774	460

Productive wells are producing wells and wells capable of production. A gross well is a well in which a working interest is owned. The number of gross wells is the total number of wells in which a working interest is owned. A net well is deemed to exist when the sum of fractional ownership working interests in gross wells equals one. The number of net wells is the sum of the fractional working interests owned in gross wells expressed as whole numbers and fractions thereof. One or more completions in the same borehole are counted as one well in this table.

The following table summarizes multiple completions and non-producing wells as of December 31, 2007:

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Non-producing	58	39	138	73	196	112
Multiple Completions	220	168	314	173	534	341

Developed and Undeveloped Acreage

The developed and undeveloped acreage (including both leases and concessions) that we held at December 31, 2007 is as follows:

	Undeveloped		Developed	
	Gross	Net	Gross	Net
United States —				
Offshore	470,885	333,444	666,819	391,763
Onshore	5,762	4,466	18,544	6,470
Total United States	476,647	337,910	685,363	398,233
United Kingdom — offshore	25,406	12,703	9,778	4,889
Total	502,053	350,613	695,141	403,122

Developed acreage is acreage spaced or assignable to productive wells. A gross acre is an acre in which a working interest is owned. A net acre is deemed to exist when the sum of fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof. Undeveloped acreage is considered to be those leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and natural gas regardless of whether or not such acreage contains proved reserves. Included within undeveloped acreage are those leased acres (held by production under the terms of a lease) that are not within the spacing unit containing, or acreage assigned to, the productive well so holding such lease. The current terms of our leases on undeveloped acreage are scheduled to expire as shown in the table below (the terms of a lease may be extended by drilling and production operations):

	Offshore		Onshore		Total	
	Gross	Net	Gross	Net	Gross	Net
2008	139,462	81,181	4,292	2,996	143,754	84,177
2009	121,237	77,745	1,470	1,470	122,707	79,215
2010	90,966	68,979	—	—	90,966	68,979
2011	25,112	19,112	—	—	25,112	19,112
2012	27,275	19,594	—	—	27,275	19,594
2013	—	—	—	—	—	—
2014	17,280	17,280	—	—	17,280	17,280
2015	5,760	5,760	—	—	5,760	5,760
Total	427,092	289,651	5,762	4,466	432,854	294,117

Drilling Activity

The following table shows the results of oil and gas wells drilled in the United States for each of the years ended December 31, 2007, 2006 and 2005:

	Net Exploratory Wells			Net Development Wells		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2007	10.8	1.1	11.9	6.4	1.0	7.4
Year ended December 31, 2006	6.5	2.1	8.6	4.6	—	4.6
Year ended December 31, 2005	0.4	—	0.4	1.2	—	1.2

No wells were drilled in the United Kingdom in 2007, 2006 and 2005.

A productive well is an exploratory or development well that is not a dry hole. A dry hole is an exploratory or development well determined to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

An exploratory well is a well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir. A development well, for purposes of the table above and as defined in the rules and regulations of the SEC, is a well drilled within the proved area of a crude oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive. The number of wells drilled refers to the number of wells completed at any time during the respective year, regardless of when drilling was initiated. Completion refers to the installation of permanent equipment for the production of crude oil or natural gas, or in the case of a dry hole, to the reporting of abandonment to the appropriate agency.

At December 31, 2007, our oil and gas operations were completing one development well and one exploration well. See Item 8. *Financial Statements and Supplementary Data* "— Note 7 — Oil and Gas Properties." These wells are located in the Gulf of Mexico.

FACILITIES

Our corporate headquarters are located at 400 N. Sam Houston Parkway E., Suite 400, Houston, Texas. The corporate headquarters of CDI are located at 2500 CityWest Boulevard, Suite 2200, Houston Texas. Our primary subsea and marine services operations are based in Port of Iberia, Louisiana. We own the Aberdeen (Dyce), Scotland facility and CDI owns approximately 6 1/2 acres of the Port of Iberia, Louisiana facility and its Port Arthur and Sabine, Texas facilities. All other facilities are leased.

Properties and Facilities Summary

Location	Function	Size
Houston, Texas	<u>Helix Energy Solutions Group, Inc.</u> Corporate Headquarters, Project Management, and Sales Office <u>Energy Resource Technology GOM, Inc.</u> Corporate Headquarters <u>Well Ops Inc.</u> Corporate Headquarters, Project Management, and Sales Office <u>Kommandor LLC (1)</u> Corporate Headquarters	92,300 square feet
Houston, Texas	<u>Canyon Offshore, Inc.</u> Corporate, Management and Sales Office	27,000 square feet
Dallas, Texas	<u>Energy Resource Technology GOM, Inc.</u> Dallas Office	25,000 square feet
Dulac, Louisiana	<u>Energy Resource Technology GOM, Inc.</u> Shore Base	20 acres 1,720 square feet
Aberdeen (Dyce), Scotland	<u>Well Ops (U.K.) Limited</u> Corporate Offices and Operations <u>Canyon Offshore Limited</u> Corporate Offices, Operations and Sales Office	3.9 acres (Building: 42,463 square feet)

Location	Function	Size
Aberdeen (Westhill), Scotland	Helix RDS Limited Corporate Offices ERT (UK) Limited Corporate Offices	11,333 square feet
London, England	Helix RDS Limited Corporate Offices	3,365 square feet
Kuala Lumpur, Malaysia	Helix RDS Sdn Bhd Corporate Offices	2,227 square feet
Perth, Australia	Well Ops SEA Pty Ltd Corporate Offices	1.0 acre (Building: 12,040 square feet)
Perth, Australia	Helix RDS Pty Ltd Corporate Offices Helix ESG Pty Ltd. Corporate Offices	8,202 square feet
Rotterdam, The Netherlands	Helix Energy Solutions BV Corporate Offices	17,000 square feet
Singapore	Canyon Offshore International Corp Corporate, Operations and Sales Well Ops PTE Ltd Corporate Headquarters	13,180 square feet
Houston, Texas	Cal Dive International, Inc. (2) Corporate Headquarters, Project Management, and Sales Office	89,000 square feet
Port Arthur, Texas	Cal Dive International, Inc. (2) Marine, Spoolbase	23 acres (Buildings: 6,000 square feet)
Sabine, Texas	Cal Dive International, Inc. (2) Marine, Warehouse	26 acres (Buildings: 59,000 square feet)
Port of Iberia, Louisiana	Cal Dive International, Inc. (2) Operations, Offices and Warehouse	23 acres (Buildings: 68,602 square feet)
Fourchon, Louisiana	Cal Dive International, Inc. (2) Marine, Operations, Living Quarters	10 acres (Buildings: 2,300 square feet)
New Orleans, Louisiana	Cal Dive International, Inc. (2) Sales Office	2,724 square feet
Dubai, United Arab Emirates	Cal Dive International, Inc. (2) Sales Office and Warehouse	29,013 square feet
Perth, Australia	Cal Dive International, Inc. (2) Operations, Offices and Project Management	22,970 square feet
Singapore	Cal Dive International, Inc. (2) Marine, Operations, Offices, Project Management and Warehouse	30,484 square feet
Del Carmen, Mexico	Cal Dive International, Inc. (2) Operations, Offices and dock	8,165 sq. ft.
Jakarta, Indonesia	Cal Dive International, Inc. (2) Sales Offices and dock	1,733 sq. ft.

Location	Function	Size
Vietnam	Cal Dive International, Inc. (2) Sales Office	603 sq. ft.
Nigeria	Cal Dive International, Inc. (2) Project Management	13,136 sq. ft.

(1) Kommandor LLC is a joint venture in which we owned 50% at December 31, 2007. Kommandor LLC is included in our consolidated results as of December 31, 2007.

(2) Cal Dive International, Inc. is our Shelf Contracting subsidiary, of which we owned 58.5% at December 31, 2007.

Item 3. *Legal Proceedings.*

Insurance and Litigation

Our operations are subject to the inherent risks of offshore marine activity, including accidents resulting in personal injury and the loss of life or property, environmental mishaps, mechanical failures, fires and collisions. We insure against these risks at levels consistent with industry standards. We also carry workers' compensation, maritime employer's liability, general liability and other insurance customary in our business. All insurance is carried at levels of coverage and deductibles that we consider financially prudent. Our services are provided in hazardous environments where accidents involving catastrophic damage or loss of life could occur, and litigation arising from such an event may result in our being named a defendant in lawsuits asserting large claims. Although there can be no assurance that the amount of insurance we carry is sufficient to protect us fully in all events, or that such insurance will continue to be available at current levels of cost or coverage, we believe that our insurance protection is adequate for our business operations. A successful liability claim for which we are underinsured or uninsured could have a material adverse effect on our business. We also are involved in various legal proceedings, primarily involving claims for personal injury under the General Maritime Laws of the United State and the Jones Act as a result of alleged negligence. In addition, we from time to time incur other claims, such as contract disputes, in the normal course of business.

On December 2, 2005, we received an order from the MMS that the price threshold for both oil and gas was exceeded for 2004 production and that royalties are due on such production notwithstanding the provisions of the Outer Continental Shelf Deep Water Royalty Relief Act of 2005 ("DWRRA"), which was intended to stimulate exploration and production of oil and natural gas in the deepwater Gulf of Mexico by providing relief from the obligation to pay royalty on certain federal leases. Our only oil and gas leases affected by this dispute are Garden Banks Blocks 667, 668 and 669 ("Gunnison"). On May 2, 2006, the MMS issued another order that superseded the December 2005 order, and claimed that royalties on gas production are due for 2003 in addition to oil and gas production in 2004. The May 2006 Order also seeks interest on all royalties allegedly due. We filed a timely notice of appeal with respect to both the December 2005 Order and the May 2006 Order. Other operators in the Deep Water Gulf of Mexico who have received notices similar to ours are seeking royalty relief under the DWRRA, including Kerr-McGee, the operator of Gunnison. In March of 2006, Kerr-McGee filed a lawsuit in federal district court challenging the enforceability of price thresholds in certain deepwater Gulf of Mexico Leases, including ours. On October 30, 2007, the federal district court in the Kerr-McGee case entered judgment in favor of Kerr-McGee and held that the Department of the Interior exceeded its authority by including the price thresholds in the subject leases. The government filed a notice of appeal of that decision on December 21, 2007. We do not anticipate that the MMS director will issue decisions in our or the other companies' administrative appeals until the Kerr-McGee litigation has been resolved in a final decision. As a result of this dispute, we have recorded reserves for the disputed royalties (and any other royalties that may be claimed for production during 2005, 2006 and 2007) plus interest at 5% for our portion of the Gunnison related MMS claim. The total reserved amount at December 31, 2007 was approximately $55.1 million and was included in Other Long Term Liabilities in the accompanying consolidated balance sheet included herein. At this time, it is not anticipated that any penalties would be assessed even if we are unsuccessful in our appeal.

Although the above discussed matters may have the potential for additional liability and may have an impact on our consolidated financial results for a particular reporting period, we believe that the outcome of all such matters and proceedings will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

During the fourth quarter of 2006, Horizon received a tax assessment from the Servicio de Administracion Tributaria ("SAT"), the Mexican taxing authority, for approximately $23 million related to fiscal 2001, including penalties, interest and monetary correction. The SAT's assessment claims unpaid taxes related to services performed among the Horizon subsidiaries that CDI acquired at the time it acquired Horizon. CDI believes under the Mexico and United States double taxation treaty that these services are not taxable and that the tax assessment itself is invalid. On February 14, 2008, CDI received notice from the SAT upholding the original assessment. We believe that CDI's position is supported by law and CDI intends to vigorously defend its position. However, the ultimate outcome of this litigation and CDI's potential liability from this assessment, if any, cannot be determined at this time. Nonetheless, an unfavorable outcome with respect to the Mexico tax assessment could have a material adverse effect on our financial position and results of operations. Horizon's 2002 through 2007 tax years remain subject to examination by the appropriate governmental agencies for Mexico tax purposes, with 2002 and 2003 currently under audit.

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

None.

Executive Officers of the Company

The executive officers of Helix are as follows:

Name	Age	Position
Owen Kratz	53	President and Chief Executive Officer and Director
Bart H. Heijermans	41	Executive Vice President and Chief Operating Officer
Robert P. Murphy	49	Executive Vice President — Oil & Gas
A. Wade Pursell	43	Executive Vice President and Chief Financial Officer
Alisa B. Johnson	50	Senior Vice President, General Counsel and Corporate Secretary
Lloyd A. Hajdik	42	Vice President — Corporate Controller and Chief Accounting Officer

Owen Kratz is President and Chief Executive Officer and the principal executive officer of Helix. He was appointed Chairman in May 1998 and served as our Chief Executive Officer from April 1997 until October 2006, at which time he was appointed Executive Chairman. Mr. Kratz subsequently resumed his role as Chief Executive Officer on February 4, 2008 upon the resignation of Mr. Martin R. Ferron, and was subsequently elected President and Chief Executive Officer on February 28, 2008. Mr. Kratz served as President from 1993 until February 1999, and has been a Director since 1990. He served as Chief Operating Officer from 1990 through 1997. Mr. Kratz joined Helix in 1984 and has held various offshore positions, including saturation diving supervisor, and has had management responsibility for client relations, marketing and estimating. Mr. Kratz has a Bachelor of Science degree in Biology and Chemistry from State University of New York.

Bart H. Heijermans became Executive Vice President and Chief Operating Officer of Helix in September 2005. Prior to joining Helix, Mr. Heijermans worked as Senior Vice President Offshore and Gas Storage for Enterprise Products Partners, L.P. from 2004 to 2005 and previously from 1998 to 2004 was Vice President Commercial and Vice President Operations and Engineering for GulfTerra Energy Partners, L.P. Before his employment with GulfTerra, Mr. Heijermans held various positions with Royal Dutch Shell in the United States, the United Kingdom and the Netherlands. Mr. Heijermans received a Master of Science degree in Civil and Structural Engineering from the University of Delft, the Netherlands and is a graduate of the Harvard Business School Executive Program.

Robert P. Murphy was elected as Executive Vice President — Oil & Gas of Helix on February 28, 2007, and as President and Chief Operating Officer of Helix Oil & Gas, Inc., a wholly owned subsidiary, on November 29, 2006. Mr. Murphy joined Helix on July 1, 2006 when Helix acquired Remington Oil & Gas Corporation, where

Mr. Murphy served as President, Chief Operating Officer and was on the Board of Directors. Prior to joining Remington, Mr. Murphy was Vice President — Exploration of Cairn Energy USA, Inc, of which Mr. Murphy also served on the Board of Directors. Mr. Murphy received a Bachelor of Science degree in Geology from The University of Texas at Austin, and has a Master of Science in Geosciences from the University of Texas at Dallas.

A. Wade Pursell was elected as Executive Vice President and Chief Financial Officer on February 28, 2007, and prior to that, held the office of Senior Vice President and Chief Financial Officer, to which he was appointed in October 2000. Mr. Pursell oversees the finance, treasury, accounting, tax, information technology, administration and corporate planning functions. He joined Helix in May 1997, as Vice President — Finance and Chief Accounting Officer. From 1988 through 1997 he was with Arthur Andersen LLP, lastly as an Experienced Manager specializing in the offshore services industry. Mr. Pursell received a Bachelor of Science degree from the University of Central Arkansas.

Alisa B. Johnson became Senior Vice President, General Counsel and Secretary of Helix in September 2006. Ms. Johnson has been involved with the energy industry for over 17 years. Prior to joining Helix, Ms. Johnson worked for Dynegy Inc. for nine years, at which company she held various legal positions, including Senior Vice President and Group General Counsel — Generation. From 1990 to 1997, Ms. Johnson held various legal positions at Destec Entergy, Inc. Prior to that Ms. Johnson was in private law practice. Ms. Johnson received her Bachelor of Arts degree from Rice University and her law degree from the University of Houston.

Lloyd A. Hajdik joined the Company in December 2003 as Vice President — Corporate Controller and became Chief Accounting Officer in February 2004. From January 2002 to November 2003 he was Assistant Corporate Controller for Houston-based NL Industries, Inc. Prior to NL Industries, Mr. Hajdik served as Senior Manager of SEC Reporting and Accounting Services for Compaq Computer Corporation from 2000 to 2002, and as Controller for Halliburton’s Baroid Drilling Fluids and Zonal Isolation product service lines from 1997 to 2000. Mr. Hajdik served as Controller for Engineering Services for Cliffs Drilling Company from 1995 to 1997 and was with Ernst & Young in the audit practice from 1989 to 1995. Mr. Hajdik graduated from Texas State University — San Marcos (formerly Southwest Texas State University) receiving a Bachelor of Business Administration degree. Mr. Hajdik is a Certified Public Accountant and a member of the Texas Society of CPAs as well as the American Institute of Certified Public Accountants.

Resignation of Martin Ferron

Martin Ferron resigned as our President and Chief Executive Officer effective February 4, 2008. Concurrently, Mr. Ferron resigned from our Board of Directors. Mr. Ferron remained employed by us through February 18, 2008, after which his employment was terminated. At the time of Mr. Ferron’s resignation, Owen Kratz, who served as Executive Chairman, resumed the role and assumed the duties of the President and Chief Executive Officer, and was subsequently elected as President and Chief Executive Officer of Helix,.

PART II

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

Our common stock is traded on the New York Stock Exchange ("NYSE") under the symbol "HLX." Prior to July 18, 2006, our common stock was quoted on the NASDAQ under the symbol "HELX." Prior to March 6, 2006, our common stock traded under the symbol "CDIS" on the NASDAQ. The following table sets forth, for the periods indicated, the high and low closing sale prices per share of our common stock:

	Common Stock Prices	
	High	Low
2006		
First Quarter	$45.61	$32.85
Second Quarter	$45.00	$29.14
Third Quarter	$41.92	$30.00
Fourth Quarter	$37.30	$27.55
2007		
First Quarter	$37.45	$28.00
Second Quarter	$41.44	$35.52
Third Quarter	$42.95	$35.25
Fourth Quarter	$46.84	$39.08
2008		
First Quarter (1)	$42.57	$32.52

(1) Through February 26, 2008

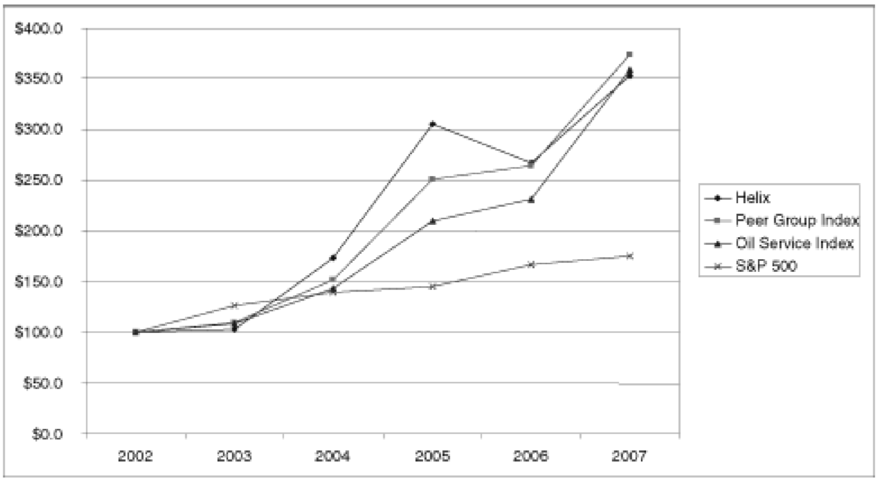
On February 26, 2008, the closing sale price of our common stock on the NYSE was $34.63 per share. As of February 22, 2008, there were an estimated 312 registered shareholders of our common stock.

We have never declared or paid cash dividends on our common stock and do not intend to pay cash dividends in the foreseeable future. We currently intend to retain earnings, if any, for the future operation and growth of our business. In addition, our financing arrangements prohibit the payment of cash dividends on our common stock. See *Management's Discussion and Analysis of Financial Condition and Results of Operations* "— Liquidity and Capital Resources."

Shareholder Return Performance Graph

The following graph compares the cumulative total shareholder return on our common stock for the period since December 31, 2002 to the cumulative total shareholder return for (i)the stocks of 500 large-cap corporations maintained by Standard & Poor's ("S&P 500"), assuming the reinvestment of dividends; (ii) the Philadelphia Oil Service Sector index ("OSX"), a price-weighted index of leading oil service companies, assuming the reinvestment of dividends; and (iii) a peer group selected by us (the "Peer Group") consisting of the following companies: Global Industries, Ltd., Oceaneering International, Inc., Cameron International Corporation, Pride International, Inc., Oil States International, Inc., Grant Prideco, Inc., Rowan Companies, Inc., Complete Production Services, Inc., Tidewater Inc., ATP Oil & Gas Corp, W&T Offshore, Inc., Energy Partners, Ltd., and Mariner Energy, Inc. The returns of each member of the Peer Group have been weighted according to each individual company's equity market capitalization as of December 31, 2007 and have been adjusted for the reinvestment of any dividends. We believe that the members of the Peer Group provide services and products more comparable to us than those companies included in the OSX. The graph assumes $100 was invested on December 31, 2002 in our common stock at the closing price on that date price and on December 31, 2002 in the three indices presented. We paid no cash dividends during the period presented. The cumulative total percentage returns for the period presented were as follows: our stock — 253.2%; the Peer Group — 273.3%; the OSX — 258.9%; and S&P 500- 74.9%. These results are not necessarily indicative of future performance.

Comparison of Five Year Cumulative Total Return among Helix, S&P 500, OSX and Peer Group



	As of December 31,					
	2002	2003	2004	2005	2006	2007
Helix	$100.0	$102.6	$173.4	$305.4	$267.0	$353.2
Peer Group Index	$100.0	$109.6	$152.0	$251.2	$263.8	$373.3
Oil Service Index	$100.0	$109.0	$143.4	$209.9	$231.1	$358.9
S&P 500	$100.0	$126.4	$139.5	$145.7	$166.4	$174.9

Source: Bloomberg

Issuer Purchases of Equity Securities

Period	(a) Total Number of Shares	(b) Average Price Paid	(c) Total Number of Shares Purchased as Part of Publicly Announced Program	(d) Maximum Value of Shares That May Yet Be Purchased Under the Program (In thousands) (2)
October 1 to October 31, 2007 (1)	1,862	$ 44.83	—	$ N/A
November 1 to November 30, 2007	—	$ —	—	N/A
December 1 to December 31, 2007	—	$ —	—	N/A
	1,862	$ 44.83	—	$ —

(1) Represents shares delivered to the Company by employees in satisfaction of withholding taxes and upon forfeiture of restricted shares.

(2) In January 2008, we issued 46,152 shares of our common stock to our employees under our 1998 Employee Stock Purchase Plan to satisfy the employee purchase period from July 1, 2007 to December 31, 2007.

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

The financial data presented below for each of the five years ended December 31, 2007, should be read in conjunction with Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations* and Item 8. *Financial Statements and Supplementary Data* included elsewhere in this Form 10-K.

	Year Ended December 31,				
	2007 (4)	2006 (1)	2005	2004	2003
	(In thousands, except per share amounts)				
Net revenues	$1,767,445	$1,366,924	$799,472	$543,392	$396,269
Gross profit	513,756	515,408	283,072	171,912	92,083
Equity in earnings (losses) of investments	19,698	18,130	13,459	7,927	(87)
Net income before change in accounting principle (2)	320,478	347,394	152,568	82,659	33,678
Cumulative effect of change in accounting principle, net	—	—	—	—	530
Net income (2)	320,478	347,394	152,568	82,659	34,208
Preferred stock dividends and accretion	3,716	3,358	2,454	2,743	1,437
Net income applicable to common shareholders (2)	316,762	344,036	150,114	79,916	32,771
Earnings per common share — Basic (3):					
Earnings per share before change in accounting principle(2)	$ 3.52	$ 4.07	$ 1.94	$ 1.05	$ 0.43
Cumulative effect of change in accounting principle	—	—	—	—	0.01
Earnings per share — Basic (2)	$ 3.52	$ 4.07	$ 1.94	$ 1.05	$ 0.44
Earnings per common share — Diluted (2):					
Earnings per share before change in accounting principle (2)	$ 3.34	$ 3.87	$ 1.86	$ 1.03	$ 0.43
Cumulative effect of change in accounting principle	—	—	—	—	0.01
Earnings per share — Diluted (2)	$ 3.34	$ 3.87	$ 1.86	$ 1.03	$ 0.44

(1) Includes effect of the Remington acquisition since July 1, 2006. See Item 8. *Financial Statements and Supplementary Data* "— Note 4 — Acquisition of Remington Oil and Gas Corporation" for additional information.

(2) Includes the impact of gains on subsidiary equity transactions of $98.5 million and $96.5 million for the year ended December 31, 2007 and 2006, respectively. The gains were derived from the difference in the value of our investment in CDI immediately before and after its issuance of stock as related to its acquisition of Horizon (non-cash gain) and its initial public offering.

(3) All earnings per share information reflects a two-for-one stock split effective as of the close of business on December 8, 2005.

(4) Includes effect of the Horizon acquisition since December 11, 2007. See Item 8. *Financial Statements and Supplementary Data* "— Note 5 — Acquisition of Horizon Offshore, Inc." for additional information.

	As of December 31,				
	2007 (2)	2006 (1)	2005	2004	2003
			(In thousands)		
Total assets	$ 5,452,353	$ 4,290,187	$ 1,660,864	$ 1,038,758	$882,842
Long-term debt and capital leases (including current maturities)	1,800,387	1,480,356	447,171	148,560	222,831
Minority interest	263,926	59,802	—	—	—
Convertible preferred stock	55,000	55,000	55,000	55,000	24,538
Shareholders' equity	1,846,566	1,525,948	629,300	485,292	381,141

(1) Includes effect of the Remington acquisition since July 1, 2006. See Item 8. *Financial Statements and Supplementary Data* "— Note 4— Acquisition of Remington Oil and Gas Corporation" for additional information.

(2) Includes effect of the Horizon acquisition since December 11, 2007. See Item 8. *Financial Statements and Supplementary Data* "— Note 5 — Acquisition of Horizon Offshore, Inc." for additional information.

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

The following management's discussion and analysis should be read in conjunction with our historical consolidated financial statements and their notes included elsewhere in this report. This discussion contains forward-looking statements that reflect our current views with respect to future events and financial performance. Our actual results may differ materially from those anticipated in these forward-looking statements as a result of certain factors, such as those set forth under "Risk Factors" and elsewhere in this report.

Executive Summary

Our Business

We are an international offshore energy company that provides reservoir development solutions and other contracting services to the open energy market as well as to our own oil and gas properties. Our oil and gas business is a prospect generation, exploration, development and production company. Employing our own key services and methodologies we seek to lower finding and development costs, relative to industry norms.

Industry Overview and Major Influences

The offshore oil and gas industry originated in the early 1950s as producers began to explore and develop the new frontier of offshore fields. The industry has grown significantly since the 1970s with service providers taking on greater roles on behalf of the producers. Industry standards were established during this period largely in response to the emergence of the North Sea as a major province leading the way into a new hostile frontier. The methodology of these standards was driven by the requirement of mitigating the risk of developing relatively large reservoirs in a then challenging environment. These standards are still largely adhered to today for all developments even if they are small and the frontier is more understood. There are factors we believe will influence the industry in the coming years: (1) increasing world demand for oil and natural gas; (2) global production rates peaking; (3) globalization of the natural gas market; (4) increasing number of mature and small reservoirs; (5) increasing ratio of contribution to global production from marginal fields; (6) increasing offshore activity; and (7) increasing number of subsea developments.

Our business is substantially dependent upon the condition of the oil and natural gas industry and, in particular, the willingness of oil and natural gas companies to make capital expenditures for offshore exploration, drilling and production operations. The level of capital expenditure generally depends on the prevailing views of future oil and natural gas prices, which are influenced by numerous factors, including but not limited to:

- worldwide economic activity;

- demand for oil and natural gas, especially in the United States, China and India;
- economic and political conditions in the Middle East and other oil-producing regions;
- actions taken by the OPEC;
- the availability and discovery rate of new oil and natural gas reserves in offshore areas;
- the cost of offshore exploration for and production and transportation of oil and gas;
- the ability of oil and natural gas companies to generate funds or otherwise obtain external capital for exploration, development and production operations;
- the sale and expiration dates of offshore leases in the United States and overseas;
- technological advances affecting energy exploration production transportation and consumption;
- weather conditions;
- environmental and other governmental regulations; and
- tax policies.

Activity Summary

Over the last few years we continued to evolve the Helix model by completing a variety of transactions and events that have had, and we believe will continue to have, significant impacts on our results of operations and financial condition. In 2005, we substantially increased the size of our Shelf Contracting fleet and deepwater pipelay fleet through the acquisition of assets from Torch Offshore, Inc. and Acergy US Inc. for a combined purchase price of $210.2 million. We also acquired a significant mature property package on the Gulf of Mexico OCS from Murphy Oil Corporation for $163.5 million cash and assumption of abandonment liability of $32 million. Finally, we established our Reservoir and Well Technology Services group through the acquisition of Helix Energy Limited for $32.7 million and the assumption of $7.5 million of liabilities. In 2006, we acquired Remington, an exploration, development and production company, for approximately $1.4 billion in cash and stock and the assumption of $358.4 million of liabilities. We changed our name from Cal Dive International, Inc. to Helix Energy Solutions Group, Inc., leaving the "Cal Dive" name in our Shelf Contracting subsidiary, and in December 2006 completed a carve-out initial public offering of that company, selling a 26.5% stake and receiving pre-tax net proceeds of $264.4 million from Cal Dive and a pre-tax dividend of $200 million from additional borrowings under the Cal Dive revolving credit facility.

During 2006 we committed to four capital projects which will significantly expand our contracting services capabilities: conversion of the *Caesar* into a deepwater pipelay vessel, upgrading of the *Q4000* to include drilling capability, conversion of a ferry vessel into a DP floating production unit (*Helix Producer I*) and construction of a multi-service DP dive support/well intervention vessel for the North Sea (*Well Enhancer*). During 2007, we successfully completed the drilling of exploratory wells in our 100% owned Noonan and Danny prospects located in Garden Banks Block 506 in the Gulf of Mexico. First production for Noonan is expected in the second half of 2008 and Danny is expected in the first half of 2009.

In June 2007, Cal Dive and Horizon announced that they had entered into an agreement under which Cal Dive would acquire Horizon for approximately $650.0 million. CDI issued an aggregate of approximately 20.3 million shares of common stock and paid approximately $300 million in cash in the merger. The cash portion of the merger consideration was paid from CDI's cash on hand and from borrowings under its new $675 million credit facility consisting of a $375 million senior secured term loan and a $300 million senior secured revolving credit facility, each of which is non-recourse to Helix. As a result of CDI's equity issued, we recorded a $98.6 million gain, net of $53.1 million of taxes. The gain was calculated as the difference in the value of our investment in CDI immediately before and after CDI's stock issuance. The transaction closed on December 11, 2007.

Results of Operations

Our operations are conducted through the following lines of business: contracting services operations and oil and gas operations. We have disaggregated our contracting services operations into three reportable segments in accordance with SFAS No. 131. As a result, our reportable segments consist of the following: Contracting Services, Shelf Contracting, Production Facilities, and Oil and Gas. Contracting Services operations include services such as deepwater pipelay, well operations, robotics and reservoir and well technology services. Shelf Contracting operations represent Cal Dive, in which we owned 58.5% at December 31, 2007. All material intercompany transactions between the segments have been eliminated in our consolidated results of operations.

Comparison of Years Ended December 31, 2007 and 2006

The following table details various financial and operational highlights for the periods presented:

	Year Ended December 31, 2007	Year Ended December 31, 2006	Increase/ (Decrease)
Revenues (in thousands) —			
Contracting Services	$ 708,833	$ 485,246	$223,587
Shelf Contracting (1)	623,615	509,917	113,698
Oil and Gas	584,563	429,607	154,956
Intercompany elimination	(149,566)	(57,846)	(91,720)
	$ 1,767,445	$ 1,366,924	$400,521
Gross profit (in thousands) —			
Contracting Services	$ 188,505	$ 138,516	$ 49,989
Shelf Contracting (1)	227,398	222,530	4,868
Oil and Gas	120,861	162,386	(41,525)
Intercompany elimination	(23,008)	(8,024)	(14,984)
	$ 513,756	$ 515,408	$ (1,652)
Gross Margin —			
Contracting Services	27%	29%	(2) pts
Shelf Contracting (1)	36%	44%	(8) pts
Oil and Gas	21%	38%	(17) pts
Total company	29%	38%	(9) pts
Number of vessels (2)/ Utilization (3) —			
Contracting Services:			
Pipelay	3/90%	3/86%	
Well operations	2/71%	2/81%	
ROVs	42/76%	32/76%	
Shelf Contracting	34/65%	25/84%	

1) Represented by our consolidated, majority owned subsidiary, CDI. At December 31, 2007 and 2006, our ownership interest in CDI was approximately 58.5% and 73.0%, respectively.
2) Represents number of vessels as of the end the period excluding acquired vessels prior to their in-service dates, vessels taken out of service prior to their disposition and vessels jointly owned with a third party.
3) Average vessel utilization rate is calculated by dividing the total number of days the vessels in this category generated revenues by the total number of calendar days in the applicable period.

Intercompany segment revenues during the years ended December 31, 2007 and 2006 were as follows (in thousands):

	Year Ended December 31, 2007	Year Ended December 31, 2006	Increase/ (Decrease)
Contracting Services	$ 115,864	$42,585	$ 73,279
Shelf Contracting	33,702	15,261	18,441
	$ 149,566	$57,846	$ 91,720

Intercompany segment profit (which only relates to intercompany capital projects) during the years ended December 31, 2007 and 2006 were as follows (in thousands):

	Year Ended December 31, 2007	Year Ended December 31, 2006	Increase/ (Decrease)
Contracting Services	$ 10,026	$2,460	$ 7,566
Shelf Contracting	12,982	5,564	7,418
	$ 23,008	$8,024	$ 14,984

The following table details various financial and operational highlights related to our Oil and Gas segment for the periods presented (U.S. operations only as U.K. operations were immaterial for the periods presented):

	Year Ended December 31, 2007	Year Ended December 31, 2006	Increase/ Decrease
Oil and Gas information —			
Oil production volume (MBbls)	3,723	3,400	323
Oil sales revenue (in thousands)	$251,955	$205,415	$ 46,540
Average oil sales price per Bbl (excluding hedges)	$ 70.17	$ 61.08	$ 9.09
Average realized oil price per Bbl (including hedges)	$ 67.68	$ 60.41	$ 7.27
Increase in oil sales revenue due to:			
Change in prices (in thousands)	$ 24,699		
Change in production volume (in thousands)	21,841		
Total increase in oil sales revenue (in thousands)	$ 46,540		
Gas production volume (MMcf)	42,163	27,949	14,214
Gas sales revenue (in thousands)	$324,282	$219,674	$104,608
Average gas sales price per mcf (excluding hedges)	$ 7.46	$ 7.46	$ —
Average realized gas price per mcf (including hedges)	$ 7.69	$ 7.86	$ (0.17)
Increase (decrease) in gas sales revenue due to:			
Change in prices (in thousands)	$ (4,718)		
Change in production volume (in thousands)	109,326		
Total increase in gas sales revenue (in thousands)	$104,608		
Total production (MMcfe)	64,500	48,349	16,151
Price per Mcfe	$ 8.93	$ 8.79	$ 0.14
Oil and Gas revenue information (in thousands) —			
Oil and gas sales revenue	$576,237	$425,089	$151,148
Miscellaneous revenues (1)	$ 5,667	$ 4,518	$ 1,149

(1) Miscellaneous revenues primarily relate to fees earned under our process handling agreements.

Presenting the expenses of our Oil and Gas segment (U.S. operations only) on a cost per Mcfe of production basis normalizes for the impact of production gains/losses and provides a measure of expense control efficiencies. The following table highlights certain relevant expense items in total (in thousands) and on a cost per Mcfe of production basis (with barrels of oil converted to Mcfe at a ratio of one barrel to six Mcf):

	Year Ended December 31,			
	2007		2006	
	Total	Per Mcfe	Total	Per Mcfe
Oil and gas operating expenses (1):				
Direct operating expenses (2)	$ 80,410	$ 1.25	$ 50,930	$ 1.05
Workover	11,840	0.18	11,462	0.24
Transportation	4,560	0.07	3,174	0.07
Repairs and maintenance	12,191	0.19	13,081	0.27
Overhead and company labor	9,031	0.14	10,492	0.22
Total	$ 118,032	$ 1.83	$ 89,139	$ 1.85
Depletion and amortization	$ 217,382	$ 3.37	$126,350	$ 2.61
Abandonment	21,073	0.33	—	—
Accretion	10,701	0.17	8,617	0.18
Impairments	73,950	1.14	—	—
	$ 323,106	$ 5.01	$134,967	$ 2.79

(1) Excludes exploration expense of $16.8 million and $43.1 million for the years ended December 31, 2007 and 2006, respectively. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

Revenues. During the year ended December 31, 2007, our revenues increased by 29% as compared to 2006. Contracting Services revenues increased primarily due to improved contract pricing for the pipelay, well operations and ROV divisions. Shelf Contracting revenues increased primarily as a result of the initial deployment of certain assets we acquired through the Torch, Acergy and Fraser acquisitions that came into service subsequent to the first quarter of 2006 as well as the Horizon assets acquired in late 2007. These increases were partially offset by two vessels CDI did not operate (one owned and one chartered) in 2007 that were in operation in 2006 and an increased number of out-of-service days for regulatory drydock and vessel upgrades for certain vessels in our Shelf Contracting segment.

Oil and Gas revenues increased 36% during 2007 as compared to the prior year. The increase was primarily due to increases in oil and natural gas production. The production volume increase of 33% over 2006 was mainly attributable to properties acquired in connection with the Remington acquisition, which closed on July 1, 2006.

Gross Profit. The Contracting Services gross profit increase was primarily attributable to improved contract pricing for the pipelay, well operations and ROV divisions. The gross profit increase within Shelf Contracting was primarily attributable to increased gross profit derived from the initial deployment of certain assets we acquired subsequent to the first quarter 2006, offset by increased out-of-service days referred to above, lower vessel utilization as a result of seasonal weather in the fourth quarter 2007, and increased depreciation and deferred drydock amortization.

The Oil and Gas gross profit decrease in 2007 as compared to 2006 was primarily due to the following factors:

- impairment expense of approximately $59.4 million (all recorded in fourth quarter 2007) related to our proved oil and gas properties primarily as a result of downward reserve revisions and weak end of life well performance in some of our domestic properties;
- an increase of $91.0 million in depletion expense in 2007 because of higher overall production based on a full year of activity from the Remington acquisition as compared to only half a year of impact in 2006

including approximately $12.5 million of increased fourth quarter 2007 depletion due to certain producing properties experiencing significant proved reserve declines;

- approximately $9.9 million of impairment expense ($9.0 million in fourth quarter 2007) related to our unproved properties primarily due to management's assessment that exploration activities for certain properties will not commence prior to the respective lease expiration dates;
- approximately $9.6 million additional impairment expense in fourth quarter 2007, as we increased our future abandonment liability at December 31, 2007 for work yet to be done for certain properties, partially offset by estimated insurance recoveries of $4.9 million related to properties damaged by hurricanes *Katrina* and *Rita*;
- approximately $25.1 million of plug and abandonment overruns related to properties damaged by the hurricanes, partially offset by insurance recoveries of $4.0 million ($6.6 million of overruns in fourth quarter 2007, offset by $2.1 million of insurance recoveries);
- the gross profit decrease was partially offset by lower dry hole expense in 2007 of $10.3 million, of which $5.9 million was related to our South Marsh Island 123 #1 well, as compared to $38.3 million dry hole expense in 2006 related to the Tulane prospect and two deep shelf wells commenced by Remington prior to the acquisition.

As a result of our unsuccessful development well in January 2008 on Devil's Island, we expect to expense an additional $13 million in the first quarter of 2008. Costs incurred as of December 31, 2007 related to this well were charged to income in 2007 and were included in the 2007 impairment expense described above.

Gain on Sale of Assets, Net. Gain on sale of assets, net, increased by $47.6 million during 2007 as compared to 2006. On September 30, 2007, we sold a 30% working interest in the Phoenix oilfield (Green Canyon Blocks 236/237), the Boris oilfield (Green Canyon Block 282) and the Little Burn oilfield (Green Canyon Block 238) to Sojitz for a cash payment of $51.2 million and recognized a gain of $40.4 million in 2007. We also recognized the following gains in 2007:

- $2.4 million related to the sale of a mobile offshore production unit;
- $1.6 million related to the sale or 50% interest in Camelot; and
- $3.9 million related to the sale of assets owned by CDI.

Selling and Administrative Expenses. Selling and administrative expenses of $151.4 million were $31.8 million higher than the $119.6 million incurred in 2006. The increase was due primarily to higher overhead to support our growth and increased incentive compensation accruals. Further, in June 2007, CDI recorded a $2.0 million charge for a cash settlement with the Department of Justice. Selling and administrative expenses as a percent of revenues were 9% for both 2007 and 2006.

Equity in Earnings of Investments, Net of Impairment Charge. Equity in earnings of investments increased by $1.6 million during 2007 as compared to 2006. Equity in earnings related to our 20% investment in Independence Hub increased $10.5 million as we reached mechanical completion in March 2007 and began receiving demand fees and tariffs as production began in the third quarter. In addition, equity in earnings of our 50% investment in Deepwater Gateway increased by $2.2 million in 2007 as compared to 2006 due to higher throughput at the *Marco Polo* TLP. These increases were offset by second quarter 2007 equity losses from CDI's 40% investment in OTSL and a related non-cash asset impairment charge together totaling $11.8 million.

Net Interest Expense and Other. We reported net interest and other expense of $59.4 million in 2007 as compared to $34.6 million in the prior year. Gross interest expense of $100.4 million during 2007 was higher than the $51.9 million incurred in 2006 as a result of our Term Loan and Revolving Loans, which closed in July 2006, and CDI's revolving credit facility, which closed in December 2006. Offsetting the increase in interest expense was $31.8 million of capitalized interest and $9.5 million of interest income in 2007, compared with $10.6 million of capitalized interest and $6.3 million of interest income in the same prior year period. We expect interest expense to increase in 2008 as a result of the Senior Unsecured Notes we issued in December 2007 and the Term Loan CDI entered into as a result of the Horizon acquisition. See Item 8. *Financial Statements and Supplementary Data* "— Note 11 — Long-Term Debt" for detailed description of these notes.

Gain on Subsidiary Equity Transaction. We recognized a non cash pre-tax gain of $151.7 million ($98.6 million net of taxes of $53.1 million) in 2007 as our share of CDI's underlying equity increased as a result of CDI's issuance of 20.3 million shares of its common stock to former Horizon stockholders in connection with CDI's acquisition of Horizon, which reduced our ownership in CDI to 58.5%. The non-cash gain is derived from the difference in the value of our investment in CDI immediately before and after the acquisition. In 2006, CDI received net proceeds of $264.4 million from the initial public offering of 22.2 million shares of its common stock. Together with CDI's drawdown of its revolving credit facility, CDI paid pre-tax dividends of $464.4 million to us in December 2006. As a result of these transactions, we recorded a pre-tax gain of $223.1 million ($96.5 million net of taxes of $126.6 million) in 2006.

Provision for Income Taxes. Income taxes decreased to $174.9 million in 2007 compared to $257.2 million in the prior year. $126.6 million of the income tax expense decrease was related to the CDI dividends paid to us in 2006. This decrease was partially offset by increased profitability in 2007. The effective tax rate of 33.3% for 2007 was lower than the 42.5% effective tax rate for same period 2006 due primarily to the CDI dividends of $464.4 million received in December 2006. We expect our 2008 income tax rate to be higher than it has historically been as a result of providing a deferred tax liability on the difference between the book and tax basis of our investment in CDI.

Comparison of Years Ended December 31, 2006 and 2005

The following table details various financial and operational highlights for the periods presented:

	Year Ended December 31, 2006	2005	Increase/ (Decrease)
Revenues (in thousands) —			
Contracting Services	$ 485,246	$328,315	$156,931
Shelf Contracting (1)	509,917	223,211	286,706
Oil and Gas	429,607	275,813	153,794
Intercompany elimination	(57,846)	(27,867)	(29,979)
	$ 1,366,924	$799,472	$567,452
Gross profit (in thousands) —			
Contracting Services	$ 138,516	$ 69,381	$ 69,135
Shelf Contracting (1)	222,530	71,215	151,315
Oil and Gas	162,386	142,476	19,910
Intercompany elimination	(8,024)	—	(8,024)
	$ 515,408	$283,072	$232,336
Gross Margin —			
Contracting Services	29%	21%	8 pts
Shelf Contracting (1)	44%	32%	12 pts
Oil and Gas	38%	52%	(14) pts
Total company	38%	35%	3 pts
Number of vessels (2)/ Utilization (3) —			
Contracting Services:			
Pipelay	3/86%	2/86%	
Well operations	2/81%	2/84%	
ROVs	32/76%	30/70%	
Shelf Contracting	25/84%	23/65%	

(1) Shelf Contracting is represented by CDI. At December 31, 2006, our ownership interest in CDI was approximately 73.0%. At December 31, 2005, CDI was a wholly-owned subsidiary.

(2) Represents number of vessels as of the end the period excluding acquired vessels prior to their in-service dates, vessels taken out of service prior to their disposition and vessels jointly owned with a third party.

(3) Average vessel utilization rate is calculated by dividing the total number of days the vessels in this category generated revenues by the total number of calendar days in the applicable period.

Intercompany segment revenues during the years ended December 31, 2006 and 2005 were as follows (in thousands):

	Year Ended December 31,		Increase/
	2006	2005	(Decrease)
Contracting Services	$42,585	$26,431	$ 16,154
Shelf Contracting	15,261	1,436	13,825
	$57,846	$27,867	$ 29,979

Intercompany segment profit (which only relates to intercompany capital projects) during the years ended December 31, 2006 and 2005 were as follows (in thousands):

	Year Ended December 31,		Increase/
	2006	2005	(Decrease)
Contracting Services	$2,460	$ —	$ 2,460
Shelf Contracting	5,564	—	5,564
	$8,024	$ —	$ 8,024

The following table details various financial and operational highlights related to our oil and gas operations for the periods presented (U.S. operations only as U.K. operations were immaterial for the periods presented):

	Year Ended December 31, 2006	2005	Increase/ Decrease
Oil and Gas information —			
Oil production volume (MBbls)	3,400	2,473	927
Oil sales revenue (in thousands)	$205,415	$121,510	$83,905
Average oil sales price per Bbl (excluding hedges)	$ 61.08	$ 51.87	$ 9.21
Average realized oil price per Bbl (including hedges)	$ 60.41	$ 49.15	$ 11.26
Increase in oil sales revenue due to:			
Change in prices (in thousands)	$ 27,840		
Change in production volume (in thousands)	56,065		
Total increase in oil sales revenue (in thousands)	$ 83,905		
Gas production volume (MMcf)	27,949	18,137	9,812
Gas sales revenue (in thousands)	$219,674	$146,591	$73,083
Average gas sales price per mcf (excluding hedges)	$ 7.46	$ 8.48	$ (1.02)
Average realized gas price per mcf (including hedges)	$ 7.86	$ 8.08	$ (0.22)
Increase (decrease) in gas sales revenue due to:			
Change in prices (in thousands)	$ (4,018)		
Change in production volume (in thousands)	77,101		
Total increase in gas sales revenue (in thousands)	$ 73,083		
Total production (MMcfe)	48,349	32,975	15,374
Price per Mcfe	$ 8.79	$ 8.13	$ 0.66

Presenting the expenses of our Oil and Gas segment (U.S. operations only) on a cost per Mcfe of production basis normalizes for the impact of production gains/losses and provides a measure of expense control efficiencies. The following table highlights certain relevant expense items in total (in thousands) and on a cost per Mcfe of production basis (with barrels of oil converted to Mcfe at a ratio of one barrel to six Mcf):

	Year Ended December 31, 2006		2005	
	Total	Per Mcfe	Total	Per Mcfe
Oil and gas operating expense (1):				
Direct operating expenses (2)	$ 50,930	$ 1.05	$26,997	$ 0.82
Workover	11,462	0.24	9,668	0.29
Transportation	3,174	0.07	3,814	0.12
Repairs and maintenance	13,081	0.27	6,030	0.18
Overhead and company labor	10,492	0.22	9,726	0.30
Total	$ 89,139	$ 1.85	$56,235	$ 1.71
Depletion and amortization	$126,350	$ 2.61	$64,938	$ 1.97
Accretion	8,617	0.18	5,699	0.17
	$134,967	$ 2.79	$70,637	$ 2.14

(1) Excludes exploration expense of $43.1 million and $6.5 million for the years ended December 31, 2006 and 2005, respectively. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

Revenues. During the year ended December 31, 2006, our revenues increased by 71% as compared to 2005. Contracting Services revenues increased primarily due to improved market demand (resulting in improved contract pricing for the Pipelay, Well Operations and ROV divisions), and the addition of the *Express* acquired from Torch in 2005 and Helix Energy Limited acquired in 2005. Shelf Contracting revenue increased due to the additional vessels acquired from Acergy and Torch during 2005 and improved market demand, much of which was the result of damages sustained in the 2005 hurricanes in the Gulf of Mexico. This resulted in significantly improved utilization rates and an overall increase in pricing for our Shelf Contracting services.

Oil and Gas revenue increased 56%, during 2006 compared with the prior year. The increase was primarily due to increases in oil and natural gas production. The production volume increase of 47% over 2005 was mainly attributable to the full second half impact of the Remington acquisition, partially offset by continued pipeline shut-ins on certain fields. Oil and Gas revenue also increased due to higher oil prices realized in 2006 as compared to 2005, offset slightly by a $0.22 decline in average realized gas prices.

Gross Profit. Gross profit in 2006 increased 82% as compared to the same period in 2005. The Contracting Services gross profit increase was primarily attributable to improved contract pricing for the Pipelay, Well Operations and ROV divisions, and the addition of the *Express*. The gross profit increase within Shelf Contracting was primarily attributable to additional gross profit derived from the Torch and Acergy acquisitions, improved utilization rates and increased contract pricing as discussed above.

Oil and Gas gross profit increased 14% in 2006 compared to 2005. Gross profit was negatively impacted by $43.1 million of exploration costs incurred during 2006 compared with $6.5 million incurred in 2005. The increase in exploration costs was primarily due to dry hole costs of $21.7 million related to the Tulane prospect as a result of mechanical difficulties experienced in the drilling of this well. The well was subsequently plugged and abandoned in the first quarter of 2006. In addition, we incurred dry hole costs totaling approximately $15.9 million in the third quarter of 2006 associated with two deep shelf wells commenced by Remington prior to the acquisition. We expensed inspection and repair costs of approximately $16.8 million as a result of Hurricanes *Katrina* and *Rita*, partially offset by $9.7 million in insurance recoveries in 2006 compared to $7.1 million of hurricane inspection and repair costs in 2005. In addition, depletion and amortization per Mcfe increased 30% in 2006 compared to 2005 due primarily to the acquisition costs associated with the Remington properties acquired in July 2006. These decreases were offset by higher oil prices realized and higher oil and gas production as discussed above.

In addition, in 2005 we recorded $2.7 million of losses associated with hedge instrument ineffectiveness as a result of production shut-ins caused by the aforementioned hurricanes. No hedge ineffectiveness was recorded in 2006.

Selling and Administrative Expenses. Selling and administrative expenses of $119.6 million were $56.8 million higher than the $62.8 million incurred in 2005. The increase was due primarily to higher overhead to support our growth. Selling and administrative expenses increased slightly to 9% of revenues in 2006 compared to 8% in 2005.

Equity in Earnings of Investments. Equity in earnings of our 50% investment in Deepwater Gateway, L.L.C. increased to $18.4 million in 2006 compared with $10.6 million in 2005 due to increased throughput at the Marco Polo TLP. Further, equity losses in our 40% minority ownership interest in OTSL for 2006 totaled approximately $487,000 compared with equity earnings of $2.8 million in 2005.

Gain on Subsidiary Equity Transaction. Gain on subsidiary equity transaction of $223.1 million is related to the CDI initial public offering of 22,173,000 shares of its common stock in December 2006, together with shares issued to CDI employees immediately after the offering, our ownership reduced to 73.0%. CDI received net proceeds of $264.4 million from its initial public offering. Together with CDI's drawdown of its revolving credit facility, CDI paid pre-tax dividends of $464.4 million to us in December 2006. The gain is as a result of these transactions.

Net Interest Expense and Other. We reported interest and other expense of $34.6 million in 2006 compared to $7.6 million in the prior year. Gross interest expense of $51.9 million during 2006 was higher than the $15.0 million incurred in 2005. Approximately $31.4 million of the increase was related to our Term Loan which closed in July 2006 and $2.4 million of the increase was related to our $300 million Convertible Senior Notes which closed in

March 2005. Offsetting the increase in interest expense was $10.6 million of capitalized interest in 2006, compared with capitalized interest of $2.0 million in the prior year.

Provision for Income Taxes. Income taxes increased to $257.2 million in 2006 compared to $75.0 million in the prior year. $126.6 million of the income tax expense increase was related to the CDI dividends to us. The remaining increase was primarily due to increased profitability. The effective tax rate of 42.5% for 2006 was higher than the 33.0% effective tax rate for same period in 2005 due primarily to the CDI dividends of $464.4 million received in December 2006.

Liquidity and Capital Resources

Overview

The following tables present certain information useful in the analysis of our financial condition and liquidity for the periods presented (in thousands):

	2007	2006
Net working capital	$ 48,290	$ 310,524
Long-term debt (1)	$ 1,725,541	$ 1,454,469

(1) Long-term debt does not include current maturities portion of the long-term debt as amount is included in net working capital.

	Year Ended December 31, 2007	2006	2005
Net cash provided by (used in):			
Operating activities	$ 416,326	$ 514,036	$ 242,432
Investing activities	$ (739,654)	$ (1,379,930)	$ (499,925)
Financing activities	$ 206,445	$ 978,260	$ 288,066

Our primary cash needs are to fund capital expenditures to allow the growth of our current lines of business and to repay outstanding borrowings and make related interest payments. Historically, we have funded our capital program, including acquisitions, with cash flows from operations, borrowings under credit facilities and use of project financing along with other debt and equity alternatives. Some of the significant financings, and corresponding uses, during 2007 were as follows:

- In July 2007, we purchased the remaining 42% of WOSEA for $10.1 million. We now own 100% of this company (see "Note 6 — Other Acquisitions" in Item 8. *Financial Statements and Supplementary Data* for a detailed discussion of WOSEA).
- In December 2007, we issued $550 million of 9.5% Senior Unsecured Notes due 2016 ("Senior Unsecured Notes"). Proceeds from the offering were used to repay outstanding indebtedness under our senior secured credit facilities. For additional information on the terms of the Senior Unsecured Notes, see "Note 11 — Long-term Debt" in Item 8. *Financial Statements and Supplementary data.*
- Also in December 2007, CDI replaced its five-year $250 million revolving credit facility with a secured credit facility consisting of a $375 million term loan and a $300 million revolving credit facility. Proceeds from the CDI term loan were used to fund the cash portion of the Horizon acquisition. CDI expects to use the remaining capacity under the revolving credit facility for its working capital and other general corporate purposes. We do not have access to the unused portion of CDI's revolving credit facility. See "Note 11 — Long-Term Debt" in Item 8. *Financial Statements and Supplementary Data* for additional information.

Some of the significant financings and corresponding uses during 2006 and 2005 were as follows:

- In July 2006, we borrowed $835 million in a term loan ("Term Loan") and entered into a new $300 million revolving credit facility. The proceeds of the Term Loan were used to fund the cash portion of the acquisition of Remington. We also issued 13,032,528 shares of our common stock to the Remington shareholders. See

"Note 11 — Long-Term Debt" in Item 8. *Financial Statements and Supplementary Data* for additional information.

- In December 2006, we completed an IPO of our Shelf Contracting business segment (Cal Dive International, Inc.), selling 26.5% of that company and receiving pre-tax net proceeds of $264.4 million. We may sell additional shares of CDI common stock in the future. Proceeds from the offering were used for general corporate purposes, including the repayment of $71.0 million of our revolving credit facility. See "Note 3 — Initial Public Offering of Cal Dive, International, Inc." in Item 8. *Financial Statements and Supplementary Data* for additional information.
- In connection with the IPO, CDI Vessel Holdings LLC ("CDI Vessel"), a subsidiary of CDI, entered into a secured credit facility for up to $250 million in revolving loans under a five-year revolving credit facility. During December 2006, CDI Vessel borrowed $201 million under the revolving credit facility and distributed $200 million of those proceeds to us as a dividend. This revolving loan was replaced in December 2007 by the $300 million revolving credit facility described above.
- In October 2006, we invested $15 million for a 50% interest in Kommandor LLC, a Delaware limited liability company, to convert a ferry vessel into a dynamically-positioned minimal floating production system. We have consolidated the results of Kommandor LLC in accordance with FASB Interpretation No. 46(R), *Consolidation of Variable Interest Entities* ("FIN 46"). For additional information, see Item 8. *Financial Statements and Supplementary Data* "— Note 10 — Consolidated Variable Interest Entities." We have named the vessel *Helix Producer I*.
- Also in October 2006, we acquired the original 58% interest in WOSEA for total consideration of approximately $12.7 million (including $180,000 of transaction costs), with approximately $9.1 million paid to existing shareholders and $3.4 million for subscription of new WOSEA shares (see "Note 6 — Other Acquisitions" in Item 8. *Financial Statements and Supplementary Data* for a detailed discussion of WOSEA).
- In 2006, our Board of Directors also authorized us to discretionarily purchase up to $50 million of our common stock in the open market. In October and November 2006, we purchased approximately 1.7 million shares under this program for a weighted average price of $29.86 per share, or $50.0 million.
- In March 2005, we issued $300 million of 3.25% Convertible Senior Notes due 2025 ("Convertible Senior Notes"). Proceeds from the offering were used for general corporate purposes including a capital contribution of $72 million (made in March 2005) to Deepwater Gateway to enable it to repay its term loan and to fund the acquisitions described below. For additional information on the terms of the Convertible Senior Notes, see "Note 11 — Long-term Debt" in Item 8. *Financial Statements and Supplementary Data.*
- In June 2005, we were the high bidder for seven vessels in a bankruptcy auction, including the *Express*, and a portable saturation system for approximately $85.9 million, including certain costs incurred related to the transaction.
- In November 2005, we closed the transaction to purchase the diving assets of Acergy that operate in the Gulf of Mexico for approximately $46.1 million. In addition, we purchased the *DLB 801* and *Kestrel* for approximately $78.2 million in the first quarter of 2006 when these assets completed their work campaigns in Trinidadian waters. These vessels were conveyed to CDI in 2006.
- In June 2005, we acquired a mature property package on the Gulf of Mexico shelf from Murphy Oil Corporation ("Murphy"). The acquisition cost included both cash ($163.5 million) and the assumption of the abandonment liability from Murphy of approximately $32.0 million (a non-cash investing activity).

In accordance with our Senior Unsecured Notes, Senior Credit Facilities, the Convertible Senior Notes, the MARAD debt and Cal Dive's credit facilities, we are required to comply with certain covenants and restrictions, including the maintenance of minimum net worth, working capital and debt-to-equity requirements. As of December 31, 2007, we were in compliance with these covenants. The Senior Credit Facilities contain provisions that limit our ability to incur certain types of additional indebtedness. These provisions effectively prohibit us from incurring any additional secured indebtedness or indebtedness guaranteed by the Company. The Senior Credit

Facilities do permit us to incur unsecured indebtedness, and also provide for our subsidiaries to incur project financing indebtedness (such as our MARAD loans) secured by the underlying asset, provided that the indebtedness is not guaranteed by us. Upon the occurrence of certain dispositions or the issuance or incurrence of certain types of indebtedness, we may be required to prepay a portion of the Term Loan equal to the amount of proceeds received from such occurrences. Such prepayments will be applied first to the Term Loan, and any excess will be applied to the Revolving Loans, if any.

As of December 31, 2007, we had approximately $241 million of available borrowing capacity under our credit facilities, and CDI had $273 million of available borrowing under its revolving credit facility. See “Note 11 — Long-term Debt” in Item 8. *Financial Statements and Supplementary Data* for additional information related to our long-term debts, including our obligations under capital commitments.

Working Capital

Cash flow from operating activities decreased $97.7 million in 2007 as compared to 2006 primarily due to negative working capital changes in 2007. Compared to 2006, increased expenditures in other noncurrent assets, net, consisted of an additional $21.6 million in drydock expenses (net of amortization), $8.8 million for an equipment deposit and $14.6 million related to a non-current contract receivable for retainage. Working capital, net of cash, decreased approximately $145.5 million in 2007 when compared to 2006. Cash from operating activities was negatively impacted by higher income taxes paid in 2007 versus 2006 of approximately $146.9 million, of which $126.6 million was related to CDI’s initial public offering. These decreases were partially offset by increase in profitability, excluding the impact of non-cash related items, in 2007 as compared to 2006.

Cash flow from operating activities increased $271.6 million in 2006 as compared to 2005. This increase was primarily due to higher net income and positive working capital changes. Of the $194.8 million increase in net income in 2006, compared with 2005, approximately $96.5 million, net of $126.6 million of taxes, was related to the gain on the CDI initial public offering and related debt push down to CDI. Further, the net income increased due to higher oil and gas production and oil price realized in 2006, and as a result of net income contribution from the Remington, Acergy and Torch acquisitions. Cash from operating activities was more favorable in 2006 as compared to 2005 due to higher income tax payable, which we expect to pay in the first quarter of 2007 and as a result of more favorable accounts receivable turnover.

Investing Activities

Capital expenditures have consisted principally of strategic asset acquisitions related to the purchase or construction of DP vessels, acquisition of select businesses, improvements to existing vessels, acquisition of oil and gas properties and investments in our Production Facilities. Significant sources (uses) of cash associated with investing activities for the years ended December 31, 2007, 2006 and 2005 were as follows (in thousands):

	Year Ended December 31,		
	2007	2006	2005
Capital expenditures:			
Contracting services	$ (287,577)	$ (130,938)	$ (90,037)
Shelf contracting	(30,301)	(38,086)	(32,383)
Oil and gas (1)	(519,632)	(282,318)	(238,698)
Production facilities	(106,086)	(17,749)	(369)
Acquisition of businesses, net of cash acquired:			
Remington Oil and Gas Corporation (2)	—	(772,244)	—
Horizon Offshore Inc. (3)	(137,431)	—	—
Acergy US Inc. (4)	—	(78,174)	(66,586)
Fraser Diving International Ltd. (4)	—	(21,954)	—
WOSEA(4)	(10,067)	(10,571)	—
Kommandor LLC	—	(5,000)	—
(Purchases) sale of short-term investments	285,395	(285,395)	30,000
Investments in production facilities	(17,459)	(27,578)	(112,756)
Distributions from equity investments, net (5)	6,679	—	10,492
Increase in restricted cash	(1,112)	(6,666)	(4,431)
Proceeds from sale of subsidiary stock	—	264,401	—
Proceeds from sale of properties	78,073	32,342	5,617
Other, net	(136)	—	(774)
Cash used in investing activities	$ (739,654)	$ (1,379,930)	$ (499,925)

(1) Includes approximately $10.3 million and $38.3 million of capital expenditures related to exploratory dry holes in 2007 and 2006, respectively. For additional information, see Item 8. *Financial Statements and Supplementary Data* "— Note 7."

(2) For additional information related to the Remington acquisition, see Item 8. *Financial Statements and Supplementary Data* "— Note 4."

(3) For additional information related to the Horizon acquisition, see Item 8. *Financial Statements and Supplementary Data* "— Note 5."

(4) For additional information related to these acquisitions, see Item 8. *Financial Statements and Supplementary Data* "— Note 6."

(5) Distributions from equity investments is net of undistributed equity earnings from our investments. Gross distributions from our equity investments are detailed in Item 8. *Financial Statements and Supplementary Data* "— Note 9."

Short-term Investments

As of December 31, 2006, we held approximately $285.4 million in municipal auction rate securities. We did not hold these types of securities at December 31, 2007 or 2005. These instruments were long-term variable rate bonds tied to short-term interest rates reset through a "Dutch Auction" process which occured every 7 to 35 days and were classified as available-for-sale securities.

Restricted Cash

As of December 31, 2007, we had $34.8 million of restricted cash, included in other assets, net, in the accompanying consolidated balance sheet, all of which related to the escrow funds for decommissioning liabilities associated with the South Marsh Island 130 ("SMI 130") acquisition in 2002 by our Oil and Gas segment. Under the purchase agreement for the acquisition, we are obligated to escrow 50% of production up to the first $20 million and 37.5% of production on the remaining balance up to $33 million in total escrow. We had fully escrowed the requirement as of December 31, 2007. We may use the restricted cash for decommissioning the related field.

Outlook

We anticipate capital expenditures in 2008 will range from $800 million to $900 million. We may increase or decrease these plans based on various economic factors. We believe internally generated cash flow, cash from future sale of oil and gas interests and borrowings under our existing credit facilities will provide the necessary capital to fund our 2008 initiatives.

Contractual Obligations and Commercial Commitments

The following table summarizes our contractual cash obligations as of December 31, 2007 and the scheduled years in which the obligation are contractually due (in thousands):

	Total (1)	Less Than 1 year	1-3 Years	3-5 Years	More Than 5 Years
Convertible Senior Notes (2)	$ 300,000	$ —	$ —	$ —	$ 300,000
Senior Unsecured Notes	550,000	—	—	—	550,000
Term Loan	423,418	4,326	8,652	8,652	401,788
Revolving Loans	18,000	—	—	18,000	—
MARAD debt	127,463	4,014	8,638	9,522	105,289
CDI Term Loan	375,000	60,000	160,000	155,000	—
Loan note	5,002	5,002	—	—	—
Interest related to long-term debt (3)	845,851	113,728	208,918	189,508	333,697
Preferred stock dividends (4)	3,523	3,523	—	—	—
Capital leases	1,504	1,504	—	—	—
Drilling and development costs	113,100	113,100	—	—	—
Property and equipment (5)	169,376	169,376	—	—	—
Operating leases (6)	140,502	58,997	58,096	11,311	12,098
Other (7)	2,765	2,765	—	—	—
Total cash obligations	$ 3,075,504	$ 536,335	$ 444,304	$ 391,993	$ 1,702,872

(1) Excludes unsecured letters of credit outstanding at December 31, 2007 totaling $41.2 million. These letters of credit primarily guarantee various contract bidding, insurance activities and shipyard commitments.

(2) Maturity 2025. Can be converted prior to stated maturity if closing sale price of Helix's common stock for at least 20 days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter exceeds 120% of the closing price on that 30th trading day (i.e. $38.56 per share) and under certain triggering events as specified in the indenture governing the Convertible Senior Notes. To the extent we do not have alternative long-term financing secured to cover the conversion, the Convertible Senior Notes would be classified as a current liability in the accompanying balance sheet. At December 31, 2007, the conversion trigger was met. As we have sufficient financing available under our Revolving Credit Facility and a commitment from a financial institution to fully fund the cash portion of the potential conversion, the Convertible Senior Notes continue to be classified as a long-term liability in the accompanying balance sheet.

(3) Includes total interest obligations of $58.6 million related to CDI's long-term debt.

(4) Amount represents dividend payment for 2008 only. Dividends are paid annually until such time the holder elects to redeem the stock.

(5) Costs incurred as of December 31, 2007 and additional property and equipment commitments (excluding capitalized interest) at December 31, 2007 consisted of the following (in thousands):

	Costs Incurred	Costs Committed	Total Project Cost
Caesar conversion	$ 87,783	$ 35,808	$ 145,000
Q4000 upgrade	79,850	18,596	134,000
Well Enhancer construction	94,142	58,877	198,000
Helix Producer I conversion (a)	138,361	56,095	224,000
Total	$ 400,136	$ 169,376	$ 701,000

(a) Represents 100% of the vessel conversion cost, of which we expect our portion to be approximately $182 million.

(6) Operating leases included facility leases and vessel charter leases. Vessel charter lease commitments at December 31, 2007 were approximately $100.7 million.

(7) Other consisted of scheduled payments pursuant to 3-D seismic license agreements.

Contingencies

In December 2005 and in May 2006, our Oil and Gas segment received notice from the MMS that the price threshold was exceeded for 2004 oil and gas production and for 2003 gas production, respectively, and that royalties are due on such production notwithstanding the provisions of the DWRRA. The total reserved amount at December 31, 2007 was approximately $55.1 million and was included in Other Long Term Liabilities in the accompanying consolidated balance sheet included herein. See Item 3. *Legal Proceedings* and Item 8. *Financial Statements and Supplementary Data* "— Note 18" for a detailed discussion of this contingency.

Critical Accounting Estimates and Policies

Our results of operations and financial condition, as reflected in the accompanying financial statements and related footnotes, are prepared in conformity with accounting principles generally accepted in the United States. As such, we are required to make certain estimates, judgments and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods presented. We base our estimates on historical experience, available information and various other assumptions we believe to be reasonable under the circumstances. These estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. We believe the most critical accounting policies in this regard are those described below. While these issues require us to make judgments that are somewhat subjective, they are generally based on a significant amount of historical data and current market data. For a detailed discussion on the application of our accounting policies, see Item 8. *Financial Statements and Supplementary Data* "— Notes to Consolidated Financial Statements — Note 2"

Revenue Recognition

Contracting Services Revenues

Revenues from Contracting Services and Shelf Contracting are derived from contracts that traditionally have been of relatively short duration; however, during 2007 contract durations started to become longer-term. These contracts contain either lump-sum turnkey provisions or provisions for specific time, material and equipment charges, which are billed in accordance with the terms of such contracts. We recognize revenue as it is earned at estimated collectible amounts.

Unbilled revenue represents revenue attributable to work completed prior to period end that has not yet been invoiced. All amounts included in unbilled revenue at December 31, 2007 and 2006 are expected to be billed and collected within one year.

Dayrate Contracts. Revenues generated from specific time, materials and equipment contracts are generally earned on a dayrate basis and recognized as amounts are earned in accordance with contract terms. In connection with these contracts, we may receive revenues for mobilization of equipment and personnel. In connection with new contracts, revenues related to mobilization are deferred and recognized over the period in which contracted services are performed using the straight-line method. Incremental costs incurred directly for mobilization of equipment and personnel to the contracted site, which typically consist of materials, supplies and transit costs, are also deferred and recognized over the period in which contracted services are performed using the straight-line method. Our policy to amortize the revenues and costs related to mobilization on a straight-line basis over the estimated contract service period is consistent with the general pace of activity, level of services being provided and dayrates being earned over the service period of the contract. Mobilization costs to move vessels when a contract does not exist are expensed as incurred.

Turnkey Contracts. Revenue on significant turnkey contracts is recognized on the percentage-of-completion method based on the ratio of costs incurred to total estimated costs at completion. In determining whether a contract should be accounted for using the percentage-of-completion method, we consider whether:

- the customer provides specifications for the construction of facilities or for the provision of related services;
- we can reasonably estimate our progress towards completion and our costs;
- the contract includes provisions as to the enforceable rights regarding the goods or services to be provided, consideration to be received and the manner and terms of payment;
- the customer can be expected to satisfy its obligations under the contract; and
- we can be expected to perform our contractual obligations.

Under the percentage-of-completion method, we recognize estimated contract revenue based on costs incurred to date as a percentage of total estimated costs. Changes in the expected cost of materials and labor, productivity, scheduling and other factors affect the total estimated costs. Additionally, external factors, including weather and other factors outside of our control, may also affect the progress and estimated cost of a project's completion and, therefore, the timing of income and revenue recognition. We routinely review estimates related to our contracts and reflect revisions to profitability in earnings on a current basis. If a current estimate of total contract cost indicates an ultimate loss on a contract, we recognize the projected loss in full when it is first determined. We recognize additional contract revenue related to claims when the claim is probable and legally enforceable.

Oil and Gas Revenues

We record revenues from the sales of crude oil and natural gas when delivery to the customer has occurred and title has transferred. This occurs when production has been delivered to a pipeline or a barge lifting has occurred. We may have an interest with other producers in certain properties. In this case, we use the entitlements method to account for sales of production. Under the entitlements method, we may receive more or less than our entitled share of production. If we receive more than our entitled share of production, the imbalance is treated as a liability. If we receive less than our entitled share, the imbalance is recorded as an asset. As of December 31, 2007, the net imbalance was a $2.0 million asset and was included in Other Current Assets ($6.7 million) and Accrued Liabilities ($4.7 million) in the accompanying consolidated balance sheet.

Purchase Price Allocation

In connection with a purchase business combination, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Deferred taxes must be recorded for any differences between the assigned values and tax bases of assets and liabilities. Any excess of purchase price over amounts assigned to assets and liabilities is recorded as goodwill. The amount of goodwill recorded in any particular business combination can vary significantly depending upon the value attributed to assets acquired and liabilities assumed.

In December 2007, CDI completed the acquisition of Horizon. This acquisition was accounted for as a business combination. The allocation of the purchase price was based upon preliminary valuations. Estimates and assumptions are subject to change upon the receipt and CDI management's review of the final valuations. The primary area of the purchase price allocation that is not yet finalized relates to post-closing purchase price adjustments. The final valuation of net assets is expected to be completed no later than one year from the acquisition date.

In July 2006, we acquired the assets and assumed the liabilities of Remington in a transaction accounted for as a business combination. In estimating the fair values of Remington's assets and liabilities, we made various assumptions. The most significant assumptions related to the estimated fair values assigned to proved and unproved crude oil and natural gas properties. To estimate the fair values of these properties, we prepared estimates of crude oil and natural gas reserves. We estimated future prices to apply to the estimated reserve quantities acquired, and estimated future operating and development costs, to arrive at estimates of future net revenues. For estimated proved reserves, the future net revenues were discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the merger. The market-based weighted average cost of capital rate was subjected to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved reserves, the estimated probable and possible reserves were reduced by additional risk-weighting factors.

Estimated deferred taxes were based on available information concerning the tax basis of Remington's assets and liabilities and loss carryforwards at the merger date, although such estimates may change in the future as additional information becomes known.

While the estimates of fair value for the assets acquired and liabilities assumed have no effect on our cash flows, they can have an effect on the future results of operations. Generally, higher fair values assigned to crude oil and natural gas properties result in higher future depreciation, depletion and amortization expense, which results in a decrease in future net earnings. Also, a higher fair value assigned to crude oil and natural gas properties, based on higher future estimates of crude oil and natural gas prices, could increase the likelihood of an impairment in the event of lower commodity prices or higher operating costs than those originally used to determine fair value. An impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded.

In 2006, we also completed the acquisition of Acergy, Fraser and Seatrac (58%). These acquisitions were accounted for as business combinations as well. We finalized the purchase price allocation for Acergy and Fraser in the second quarter of 2006 and 2007, respectively. In July 2007, we purchased the remaining 42% of Seatrac. The allocation of purchase price for Seatrac at December 31, 2007 was based on preliminary valuations. Estimates and assumptions are subject to change upon the receipt and management's review of the final valuations. The primary areas of the purchase price allocation that are not yet finalized relate to the identification and valuation of potential intangible assets and valuation of certain equipment.

We complete our valuation of assets and liabilities (including deferred taxes) for the purpose of allocation of the total purchase price amount to assets acquired and liabilities assumed during the twelve-month period following the acquisition date. Any future change in the value of net assets up until the one year period has expired will be offset by a corresponding increase or decrease in goodwill.

Goodwill and Other Intangible Assets

We test for the impairment of goodwill annually and when impairment indicators such as the nature of the assets, the future economic benefit of the assets, any historical or future profitability measurements and other external market conditions are present. Intangible assets with finite useful lives are amortized using the straight-line method over their useful lives. Intangible assets that have indefinite useful lives are not amortized, but are tested for impairment annually and when impairment as described earlier are present. Our goodwill impairment test involves a comparison of the fair value of each of our reporting units with its carrying amount. The fair value is determined using discounted cash flows and other market-related valuation models, such as earnings multiples and comparable asset market values. We completed our annual goodwill impairment test as of November 1, 2007. The changes in the carrying amount of goodwill by the applicable segments are as follows (in thousands):

	Contracting Services	Shelf Contracting	Oil and Gas	Total
Balance at December 31, 2005	$ 73,917	$ 27,814	$ —	$ 101,731
Remington acquisition (Note 4)	—	—	707,596	707,596
Well Ops SEA Pty Ltd. acquisition (Note 6)	7,415	—	—	7,415
Acergy acquisition adjustment (Note 6)	—	(1,148)	—	(1,148)
Helix Energy Ltd. acquisition adjustment (Note 6)	2,634	—	—	2,634
Tax and other adjustments	4,328	—	—	4,328
Balance at December 31, 2006	88,294	26,666	707,596	822,556
Remington acquisition (Note 4)	—	—	4,796	4,796
Well Ops SEA Pty Ltd. acquisition (Note 6)	6,001	—	—	6,001
Horizon acquisition (Note 5)	—	257,340	—	257,340
Tax and other adjustments	(1,071)	136	—	(935)
Balance at December 31, 2007	$ 93,224	$ 284,142	$ 712,392	$ 1,089,758

None of our goodwill was impaired based on the impairment test performed as of November 1, 2007. We will continue to test our goodwill and other indefinite-lived intangible assets annually on a consistent measurement date unless events occur or circumstances change between annual tests that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

Income Taxes

Deferred income taxes are based on the difference between financial reporting and tax bases of assets and liabilities. We utilize the liability method of computing deferred income taxes. The liability method is based on the amount of current and future taxes payable using tax rates and laws in effect at the balance sheet date. Income taxes have been provided based upon the tax laws and rates in the countries in which operations are conducted and income is earned. A valuation allowance for deferred tax assets is recorded when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. For the year ended December 31, 2007, CDI established a $3.0 million valuation allowance related to a non-current deferred tax asset set up during 2007 related to the impairment of CDI's investment in OTSL. Additional valuation allowances may be made in the future if in management's opinion it is more likely than not that the tax benefit will not be utilized.

We consider the undistributed earnings of our principal non-U.S. subsidiaries to be permanently reinvested. At December 31, 2007, our principal non-U.S. subsidiaries had accumulated earnings and profits of approximately $87.6 million. We have not provided deferred U.S. income tax on the accumulated earnings and profits. The deconsolidation of CDI's net income for tax return filing purposes after its initial public offering did not have a material impact on our consolidated results of operations; however, because of our inability to recover our tax basis in CDI tax free, a long term deferred tax liability is provided for any incremental increases to the book over tax basis.

It is our policy to provide for uncertain tax positions and the related interest and penalties based upon management's assessment of whether a tax benefit is more likely than not to be sustained upon examination by tax authorities. At December 31, 2007, we believe we have appropriately accounted for any unrecognized tax benefits. To the extent we prevail in matters for which a liability for an unrecognized tax benefit is established or are required to pay amounts in excess of the liability, our effective tax rate in a given financial statement period may be affected.

See “— Note 12 — Income Taxes” in Item 8. *Financial Statements and Supplementary Data* included herein for discussion of net operating loss carry forwards, deferred income taxes and uncertain tax positions taken by the Company.

Accounting for Oil and Gas Properties

Acquisitions of producing offshore properties are recorded at the fair value exchanged at closing together with an estimate of their proportionate share of the decommissioning liability assumed in the purchase (based upon their working interest ownership percentage). In estimating the decommissioning liability assumed in offshore property acquisitions, we perform detailed estimating procedures, including engineering studies and then reflect the liability at fair value on a discounted basis as discussed below.

We follow the successful efforts method of accounting for our interests in oil and gas properties. Under the successful efforts method, the costs of successful wells and leases containing productive reserves are capitalized. Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized. Capitalized costs of producing oil and gas properties are depleted to operations by the unit-of-production method based on proved developed oil and gas reserves on a field-by-field basis as determined by our engineers. Costs incurred relating to unsuccessful exploratory wells are expensed in the period the drilling is determined to be unsuccessful (see “— Exploratory Drilling Costs” below).

We evaluate the impairment of our proved oil and gas properties on a field-by-field basis at least annually or whenever events or changes in circumstances indicate an asset’s carrying amount may not be recoverable. If an impairment is indicated, the cash flows are discounted at a rate approximate to our cost of capital and compared to the carrying value for determining the amount of the impairment loss to record. Estimated future cash flows are based on management’s expectations for the future and include estimates of crude oil and natural gas reserves and future commodity prices and operating costs. Downward revisions in estimates of reserve quantities or expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future cash flows and could indicate a property impairment. We recorded approximately $59.4 million of impairments in 2007 (all in the fourth quarter), primarily related to downward reserve revisions and weak end of life well performance in some of our domestic properties. During 2006 and 2005, no impairment of proved oil and gas properties was recorded.

We also periodically assess unproved properties for impairment based on exploration and drilling efforts to date on the individual prospects and lease expiration dates. Management’s assessment of the results of exploration activities, availability of funds for future activities and the current and projected political climate in areas in which we operate also impact the amounts and timing of impairment provisions. During 2007, we recorded $9.9 million of impairment expense ($9.0 million in fourth quarter 2007) related to unproved oil and gas properties mainly due to management’s assessment that exploration activities will not commence prior to the respective lease expiration dates. During 2006 and 2005, no impairment of unproved oil and gas properties was recorded.

Exploratory Drilling Costs

In accordance with the successful efforts method of accounting, the costs of drilling an exploratory well are capitalized as uncompleted or “suspended” wells temporarily pending the determination of whether the well has found proved reserves. If proved reserves are not found, these capitalized costs are charged to expense. A determination that proved reserves have been found results in the continued capitalization of the drilling costs of the well and its reclassification as a well containing proved reserves.

At times, it may be determined that an exploratory well may have found hydrocarbons at the time drilling is completed, but it may not be possible to classify the reserves at that time. In this case, we may continue to capitalize the drilling costs as an uncompleted well beyond one year when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project, or the reserves are deemed to be proved. If reserves are not ultimately deemed proved or economically viable, the well is considered impaired and its costs, net of any salvage value, are charged to expense.

Occasionally, we may choose to salvage a portion of an unsuccessful exploratory well in order to continue exploratory drilling in an effort to reach the target geological structure/formation. In such cases, we charge only the unusable portion of the well bore to dry hole expense, and we continue to capitalize the costs associated with the salvageable portion of the well bore and add the costs to the new exploratory well. In certain situations, the well bore may be carried for more than one year beyond the date drilling in the original well bore was suspended. This may be due to the need to obtain, and/or analyze the availability of equipment or crews or other activities necessary to pursue the targeted reserves or evaluate new or reprocessed seismic and geographic data. If, after we analyze the new information and conclude that we will not reuse the well bore or if the new exploratory well is determined to be unsuccessful after we complete drilling, we will charge the capitalized costs to dry hole expense. During the year ended December 31, 2007 and 2006, we incurred $10.3 million and $38.3 million, respectively, of exploratory dry hole expense. No dry hole expense was incurred in 2005.

Estimated Proved Oil and Gas Reserves

The evaluation of our oil and gas reserves is critical to the management of our oil and gas operations. Decisions such as whether development of a property should proceed and what technical methods are available for development are based on an evaluation of reserves. These oil and gas reserve quantities are also used as the basis for calculating the unit-of-production rates for depreciation, depletion and amortization, evaluating impairment and estimating the life of our producing oil and gas properties in our decommissioning liabilities. Our proved reserves are classified as either proved developed or proved undeveloped. Proved developed reserves are those reserves which can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves include reserves expected to be recovered from new wells from undrilled proven reservoirs or from existing wells where a significant major expenditure is required for completion and production. We prepare all of our reserve information, and our independent petroleum engineers' audit, and the estimates of our oil and gas reserves presented in this report (U.S. reserves only) based on guidelines promulgated under generally accepted accounting principles in the United States. See detailed description of our use of the term "engineering audit" and our process of preparing reserve estimates in Item 2. *Properties* "— Summary of Natural Gas and Oil Reserve Data." Our proved reserves in this Annual Report include only quantities that we expect to recover commercially using current prices, costs, existing regulatory practices and technology. While we are reasonably certain that the proved reserves will be produced, the timing and ultimate recovery can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and changes in projections of long-term oil and gas prices. Revisions can include upward or downward changes in the previously estimated volumes of proved reserves for existing fields due to evaluation of (1) already available geologic, reservoir or production data or (2) new geologic or reservoir data obtained from wells. Revisions can also include changes associated with significant changes in development strategy, oil and gas prices, or production equipment/facility capacity.

Accounting for Decommissioning Liabilities

Our decommissioning liabilities consist of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* ("SFAS 143") requires oil and gas companies to reflect decommissioning liabilities on the face of the balance sheet at fair value on a discounted basis. Prior to the Remington acquisition, we have historically purchased producing offshore oil and gas properties that are in the later stages of production. In conjunction with acquiring these properties, we assume an obligation associated with decommissioning the property in accordance with regulations set by government agencies. The abandonment liability related to the acquisitions of these properties is determined through a series of management estimates.

Prior to an acquisition and as part of evaluating the economics of an acquisition, we will estimate the plug and abandonment liability. Our oil and gas operations personnel prepare detailed cost estimates to plug and abandon wells and remove necessary equipment in accordance with regulatory guidelines. We currently calculate the discounted value of the abandonment liability (based on an estimate of the year the abandonment will occur) in accordance with SFAS No. 143 and capitalize that portion as part of the basis acquired and record the related abandonment liability at fair value. The recognition of a decommissioning liability requires that management make numerous estimates, assumptions and judgments regarding factors such as the existence of a legal obligation for liability; estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. Decommissioning liabilities were $217.5 million and $167.7 million at December 31, 2007 and 2006, respectively.

On an ongoing basis, our oil and gas operations personnel monitor the status of wells, and as fields deplete and no longer produce, our personnel will monitor the timing requirements set forth by the MMS for plugging and abandoning the wells and commence abandonment operations, when applicable. On an annual basis, management personnel reviews and updates the abandonment estimates and assumptions for changes, among other things, in market conditions, interest rates and historical experience. In 2007, we incurred $25.1 million of plug and abandonment overruns related to hurricanes *Katrina* and *Rita*, partially offset by insurance recoveries of $4.0 million. In addition, we increased our abandonment liability for work yet to be done for certain properties damaged by the hurricanes totaling $9.6 million, partially offset by estimated insurance recoveries of $4.9 million.

Derivative Instruments and Hedging Activities

Our price risk management activities involve the use of derivative financial instruments to hedge the impact of market price risk exposures primarily related to our oil and gas production, variable interest rate exposure and foreign currency exposure. To reduce the impact of these risks on earnings and increase the predictability of our cash flows, from time to time we have entered into certain derivative contracts, primarily collars, for a portion of our oil and gas production, interest rate swaps and foreign currency forward contracts. Our oil and gas costless collars, interest rate swaps and foreign currency forward exchange contracts generally qualify for hedge accounting and are reflected in our balance sheet at fair value. Hedge accounting does not apply to our normal purchase and sale oil and gas forward sales contracts.

We engage primarily in cash flow hedges. Changes in the derivative fair values that are designated as cash flow hedges are deferred to the extent that they are effective and are recorded as a component of accumulated other comprehensive income until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge's change in value is recognized immediately in earnings.

We formally document all relationships between hedging instruments (oil and gas costless collars, interest rate swaps and foreign currency forward exchange contracts) and hedged items, as well as our risk management objectives, strategies for undertaking various hedge transactions and our methods for assessing and testing correlation and hedge ineffectiveness. All hedging instruments are linked to the hedged asset, liability, firm commitment or forecasted transaction. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows of the hedged items. Changes in the assumptions used could impact whether the fair value change in the hedged instrument is charged to earnings or accumulated other comprehensive income.

The fair value of our oil and gas costless collars reflects our best estimate and is based upon exchange or over-the-counter quotations whenever they are available. Quoted valuations may not be available due to location differences or terms that extend beyond the period for which quotations are available. Where quotes are not available, we utilize other valuation techniques or models to estimate market values. The fair value of our interest rate swaps is calculated as the discounted cash flows of the difference between the rate fixed by the hedge instrument and the LIBOR forward curve over the remaining term of the hedge instrument. The fair value of our foreign currency forward exchange contract is calculated as the discounted cash flows of the difference between the fixed payment as specified by the hedge instrument and the expected cash inflow of the forecasted transaction using a foreign currency forward curve.

These modeling techniques require us to make estimates of future prices, price correlation and market volatility and liquidity. Our actual results may differ from our estimates, and these differences can be positive or negative.

Property and Equipment

Property and equipment (excluding oil and gas properties and equipment), both owned and under capital leases, are recorded at cost. Depreciation is provided primarily on the straight-line method over the estimated useful lives of the assets described in "Note 2 — Summary of Significant Accounting Policies" in Item 8. *Financial Statements and Supplementary Data*.

For long-lived assets to be held and used, excluding goodwill, we base our evaluation of recoverability on impairment indicators such as the nature of the assets, the future economic benefit of the assets, any historical or future profitability measurements and other external market conditions or factors that may be present. If such impairment indicators are present or other factors exist that indicate that the carrying amount of the asset may not be recoverable, we determine whether an impairment has occurred through the use of an undiscounted cash flows analysis of the asset at the lowest level for which identifiable cash flows exist. Our marine vessels are assessed on a vessel by vessel basis, while our ROVs are grouped and assessed by asset class. If an impairment has occurred, we recognize a loss for the difference between the carrying amount and the fair value of the asset. The fair value of the asset is measured using quoted market prices or, in the absence of quoted market prices, is based on management's estimate of discounted cash flows.

Assets are classified as held for sale when we have a plan for disposal of certain assets and those assets meet the held for sale criteria. Assets held for sale are reviewed for potential loss on sale when the company commits to a plan to sell and thereafter while the asset is held for sale. Losses are measured as the difference between the fair value less costs to sell and the asset's carrying value. Estimates of anticipated sales prices are judgmental and subject to revisions in future periods, although initial estimates are typically based on sales prices for similar assets and other valuation data.

Recertification Costs and Deferred Drydock Charges

Our Contracting Services and Shelf Contracting vessels are required by regulation to be recertified after certain periods of time. These recertification costs are incurred while the vessel is in drydock. In addition, routine repairs and maintenance are performed and, at times, major replacements and improvements are performed. We expense routine repairs and maintenance as they are incurred. We defer and amortize drydock and related recertification costs over the length of time for which we expect to receive benefits from the drydock and related recertification, which is generally 30 months. Vessels are typically available to earn revenue for the 30-month period between drydock and related recertification processes. A drydock and related recertification process typically lasts one to two months, a period during which the vessel is not available to earn revenue. Major replacements and improvements, which extend the vessel's economic useful life or functional operating capability, are capitalized and depreciated over the vessel's remaining economic useful life. Inherent in this process are estimates we make regarding the specific cost incurred and the period that the incurred cost will benefit.

As of December 31, 2007 and 2006, capitalized deferred drydock charges (described in "Note 8 — Detail of Certain Accounts" in Item 8. *Financial Statements and Supplementary Data*) totaled $48.0 million and $26.4 million, respectively. During the years ended December 31, 2007, 2006 and 2005, drydock amortization expense was $23.0 million, $12.0 million and $8.9 million, respectively. We expect drydock amortization expense to increase in future periods due to increases in the number of vessels as a result of the acquisition completed from 2005 to 2007.

Equity Investments

We periodically review our investments in Deepwater Gateway, Independence Hub and OTSL for impairment. Under the equity method of accounting, an impairment loss would be recorded whenever a decline in value of an equity investment below its carrying amount is determined to be other than temporary. In judging "other than temporary," we would consider the length of time and extent to which the fair value of the investment has been less than the carrying amount of the equity investment, the near-term and longer-term operating and financial prospects of the equity company and our longer-term intent of retaining the investment in the entity. During 2007, CDI determined that there was an other than temporary impairment in OTSL and the full value of CDI's investment in OTSL was impaired and CDI recognized equity losses of OTSL, inclusive of the impairment charge, of

$10.8 million in 2007. See "— Note 9 — Equity Investments" for a detailed discussion of our impairment analysis. There was no impairment of the other equity investments at December 31, 2007.

Worker's Compensation Claims

Our onshore employees are covered by Worker's Compensation. Offshore employees, including divers, tenders and marine crews, are covered by our Maritime Employers Liability insurance policy which covers Jones Act exposures. We incur worker's compensation claims in the normal course of business, which management believes are substantially covered by insurance. Our insurers and legal counsel analyze each claim for potential exposure and estimate the ultimate liability of each claim. Actual liability can be materially different from our estimates and can have a direct impact on our liquidity and results of operations.

Recently Issued Accounting Principles

In September 2006, the FASB issued Statement No. 157, *Fair Value Measurements* ("SFAS No. 157"). This new standard provides enhanced guidance for using fair value to measure assets and liabilities. The statement provides a common definition of fair value and establishes a framework to make the measurement of fair value in generally accepted accounting principles more consistent and comparable. SFAS No. 157 also requires expanded disclosures to provide information about the extent to which fair value is used to measure assets and liabilities, the methods and assumptions used to measure fair value, and the effect of fair value measures on earnings.

SFAS No. 157 was originally effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. The FASB agreed to defer the effective date of SFAS No. 157 for all nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis. We adopted the provisions of SFAS No. 157 on January 1, 2008 for assets and liabilities not subject to the deferral and expect to adopt this standard for all other assets and liabilities by January 1, 2009. The impact of adopting this standard was immaterial on our financial condition and results of operations.

In February 2007, the FASB issued Statement of Financial Accounting Standard No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities* ("SFAS No. 159"). SFAS No. 159 allows entities to voluntarily choose, at specified election dates, to measure many financial assets and financial liabilities at fair value. The election is made on an instrument-by-instrument basis and is irrevocable. If the fair value option is elected for an instrument, SFAS No. 159 specifies that all subsequent changes in fair value for that instrument shall be reported in earnings. The provisions of SFAS No. 159 are effective for fiscal years beginning after November 15, 2007. We adopted the provisions of SFAS No. 159 on January 1, 2008 and it had no impact on our results of operation and financial condition.

In December 2007, the FASB issued Statement No. 141 (Revised), *Business Combinations* ("SFAS No. 141 (R)"). SFAS 141 (R) requires the acquiring entity in a business combination to recognize all the assets acquired and liabilities assumed in the transaction; establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. The provisions of SFAS No. 141 (R) are effective for fiscal years beginning after December 15, 2008. We are currently evaluating the impact, if any, of this statement.

In December 2007, the FASB issued Statement No. 160, *Noncontrolling Interests in Consolidated Financial Statements — an amendment of ARB 51* ("SFAS No. 160"). SFAS No. 160 improves the relevance, comparability, and transparency of financial information provided to investors by requiring all entities to report noncontrolling (minority) interests in subsidiaries as equity in the consolidated financial statements. The provisions of SFAS No. 160 are effective for fiscal years beginning after December 15, 2008. We are currently evaluating the impact, if any, of this statement.

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

We are currently exposed to market risk in three major areas: interest rates, commodity prices and foreign currency exchange rates.

Interest Rate Risk. As of December 31, 2007, including the effects of interest rate swaps, approximately 35% of our outstanding debt was based on floating rates. As a result, we are subject to interest rate risk. In September 2006, we entered into various cash flow hedging interest rate swaps to stabilize cash flows relating to interest payments on $200 million of our Term Loan. Excluding the portion of our debt for which we have interest rate swaps in place, the interest rate applicable to our remaining variable rate debt may rise, increasing our interest expense. The impact of market risk is estimated using a hypothetical increase in interest rates by 100 basis points for our variable rate long-term debt that is not hedged. Based on this hypothetical assumption, we would have incurred an additional $10.4 million in interest expense for the year ended December 31, 2007.

Commodity Price Risk. We have utilized derivative financial instruments with respect to a portion of 2007 and 2006 oil and gas production to achieve a more predictable cash flow by reducing our exposure to price fluctuations. We do not enter into derivative or other financial instruments for trading purposes.

As of December 31, 2007, we have the following volumes under derivative contracts related to our oil and gas producing activities totaling 540 MBbl of oil and 7,650 MMbtu of natural gas:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:			
January 2008 — December 2008	Collar	45 MBbl	$56.67 — 76.51
Natural Gas:			
January 2008 — December 2008	Collar	637,500 MMBtu	$ 7.32 — $10.87

Changes in NYMEX oil and gas strip prices would, assuming all other things being equal, cause the fair value of these instruments to increase or decrease inversely to the change in NYMEX prices.

As of December 31, 2007, we had oil forward sales contracts for the period from January 2008 through December 2009. The contracts cover an average of 97 MBbl per month at a weighted average price of $71.88. In addition, we had natural gas forward sales contracts for the period from January 2008 through December 2009. The contracts cover an average of 1,321,108 MMbtu per month at a weighted average price of $8.28. Hedge accounting does not apply to these contracts.

Foreign Currency Exchange Risk. Because we operate in various regions in the world, we conduct a portion of our business in currencies other than the U.S. dollar (primarily with respect to Well Ops (U.K.) Limited and Helix RDS and Seatrac). The functional currency for Well Ops (U.K.) Limited and Helix RDS is the applicable local currency (British Pound). The functional currency for Seatrac is the applicable currency (Australian Dollar). Although the revenues are denominated in the local currency, the effects of foreign currency fluctuations are partly mitigated because local expenses of such foreign operations also generally are denominated in the same currency. The impact of exchange rate fluctuations during each of the years ended December 31, 2007, 2006 and 2005, respectively, were not material to our results of operations or cash flows.

Assets and liabilities of Wells Ops (U.K.) Limited and Helix RDS are translated using the exchange rates in effect at the balance sheet date, resulting in translation adjustments that are reflected in accumulated other comprehensive income in the shareholders' equity section of our balance sheet. Approximately 7% of our assets are impacted by changes in foreign currencies in relation to the U.S. dollar at December 31, 2007. We recorded unrealized gains (losses) of $3.7 million, $17.6 million and $(11.4) million to our equity account for the year ended December 31, 2007, 2006 and 2005, respectively. Deferred taxes have not been provided on foreign currency translation adjustments since we consider our undistributed earnings (when applicable) of our non-U.S. subsidiaries to be permanently reinvested.

Canyon Offshore, our ROV subsidiary, has operations in the United Kingdom and Asia Pacific. Further, CDI has subsidiaries with operations in the Middle East, Southeast Asia, the Mediterranean, Australia and Latin America. Canyon's and CDI's international subsidiaries conduct the majority of their operations in these regions in

U.S. dollars which they consider the functional currency. When currencies other than the U.S. dollar are to be paid or received, the resulting transaction gain or loss is recognized in the statements of operations. These amounts for the year ended December 31, 2007, 2006 and 2005, respectively, were not material to our results of operations or cash flows.

In December 2006, we entered into various foreign currency forward purchase contracts to stabilize expected cash outflows relating to a shipyard contract where the contractual payments are denominated in euros. These forward contracts qualify for hedge accounting. Under the forward contracts, we hedged €11.0 million at an exchange rate of 1.3326 that was settled in December 2007. In August 2007, we entered into a €14.0 million foreign currency forward contract at an exchange rate of 1.3595 to be settled in May 2008. The aggregate fair value of the hedge instruments that were outstanding as of December 31, 2007 and 2006 was a net asset (liability) of $1.4 million and $(184,000), respectively. For the year ended December 31, 2007, we recorded unrealized gains of approximately $1.1 million, net of tax expense of $498,000, in accumulated other comprehensive income, a component of shareholders' equity.

Subsequent to December 31, 2007, we entered into various foreign currency forward purchase contracts to stabilize expected cash outflows relating to Canyon's vessel charter. The following table provides details related to the forward contracts (amount in thousands):

Forecasted Settlement Date	Amount	Exchange Rate
March 31, 2008	£581	1.9422
April 30, 2008	£563	1.9382
May 30, 2008	£581	1.9343
June 30, 2008	£563	1.9302
July 31, 2008	£581	1.9263
August 29, 2008	£581	1.9225

These forward contracts qualify for hedge accounting.

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

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Management's Report on Internal Control Over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. The Company's internal control system was designed to provide reasonable assurance to the Company's management and Board of Directors regarding the reliability of financial reporting and the preparation and fair presentation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

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

As permitted by guidance provided by the staff of the Securities and Exchange Commission, the scope of management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2007, has excluded the acquired business of Horizon Offshore, Inc. and its subsidiaries. We acquired Horizon Offshore, Inc. on December 11, 2007 and its business represents approximately 15.3% and 6.0% of the Company's total assets and liabilities, respectively, as of December 31, 2007, and approximately 0.9% and 0.8% of the Company's total revenues and net income, respectively, for the year then ended. The Company will include the Horizon business in the scope of management's assessment of internal control over financial reporting beginning in 2008. In making its assessment, management has utilized the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework*. Based on this assessment, management has concluded that, as of December 31, 2007, the Company's internal control over financial reporting is effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

The Company implemented an enterprise resource planning system on January 1, 2008 for its Deepwater division (excluding the Company's ROV and trencher business) and its U.S. Well Operations division, which was subsequent to the date of management's assessment of the effectiveness of internal control over financial reporting.

Ernst & Young LLP has issued an audit report on the Company's internal control over financial reporting as of December 31, 2007.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Helix Energy Solutions Group, Inc.

We have audited the accompanying consolidated balance sheets of Helix Energy Solutions Group, Inc. and subsidiaries as of December 31, 2007 and 2006, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Helix Energy Solutions Group, Inc. and subsidiaries at December 31, 2007 and 2006, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 12 to the consolidated financial statements, in 2007 the Company adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109*, and as discussed in Note 14 to the consolidated financial statements, in 2006 the Company adopted Statement of Financial Accounting Standards No. 123 (revised 2004), *Share-Based Payment.*

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Helix Energy Solutions Group, Inc.'s internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2008 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 28, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Helix Energy Solutions Group, Inc.

We have audited Helix Energy Solutions Group, Inc.'s internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Helix Energy Solutions Group, Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

As indicated in the accompanying Management's Report on Internal Control Over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Horizon Offshore, Inc., which is included in the 2007 consolidated financial statements of Helix Energy Solutions Group, Inc. and constituted 15.3% and 6.0% of total assets and liabilities, respectively, as of December 31, 2007 and 0.9% and 0.8% of revenues and net income, respectively, for the year then ended. Our audit of internal control over financial reporting of Helix Energy Solutions Group, Inc. also did not include an evaluation of the internal control over financial reporting of Horizon Offshore, Inc.

As indicated in the accompanying Management's Report on Internal Control Over Financial Reporting, the Company implemented an enterprise resource planning system on January 1, 2008 for its Deepwater division (excluding the Company's ROV and trencher business) and its U.S. Well Operations division, which was subsequent to the date of management's assessment of the effectiveness of internal control over financial reporting.

In our opinion, Helix Energy Solutions Group, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Helix Energy Solutions Group, Inc. and subsidiaries as of December 31, 2007 and 2006, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2007 and our report dated February 28, 2008 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 28, 2008

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2007	December 31, 2006
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 89,555	$ 206,264
Short-term investments	—	285,395
Accounts receivable —		
Trade, net of allowance for uncollectible accounts of $2,874 and $982	447,502	287,875
Unbilled revenue	64,630	82,834
Other current assets	125,582	61,532
Total current assets	727,269	923,900
Property and equipment	4,088,561	2,721,362
Less — Accumulated depreciation	(843,873)	(508,904)
	3,244,688	2,212,458
Other assets:		
Equity investments	213,429	213,362
Goodwill, net	1,089,758	822,556
Other assets, net	177,209	117,911
	$5,452,353	$4,290,187
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 382,767	$ 240,067
Accrued liabilities	221,366	199,650
Income taxes payable	—	147,772
Current maturities of long-term debt	74,846	25,887
Total current liabilities	678,979	613,376
Long-term debt	1,725,541	1,454,469
Deferred income taxes	625,508	436,544
Decommissioning liabilities	193,650	138,905
Other long-term liabilities	63,183	6,143
Total liabilities	3,286,861	2,649,437
Minority interests	263,926	59,802
Convertible preferred stock	55,000	55,000
Commitments and contingencies		
Shareholders' equity:		
Common stock, no par, 240,000 shares authorized, 91,385 and 90,628 shares issued	755,758	745,928
Retained earnings	1,069,546	752,784
Accumulated other comprehensive income	21,262	27,236
Total shareholders' equity	1,846,566	1,525,948
	$5,452,353	$4,290,187

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

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2007	2006	2005
	(In thousands, except per share amounts)		
Net revenues:			
Contracting services	$1,182,882	$ 937,317	$523,659
Oil and gas	584,563	429,607	275,813
	1,767,445	1,366,924	799,472
Cost of sales:			
Contracting services	789,988	584,295	383,063
Oil and gas	463,701	267,221	133,337
	1,253,689	851,516	516,400
Gross profit	513,756	515,408	283,072
Gain on sale of assets	50,368	2,817	1,405
Selling and administrative expenses	151,380	119,580	62,790
Income from operations	412,744	398,645	221,687
Equity in earnings of investments	19,698	18,130	13,459
Gain on subsidiary equity transaction	151,696	223,134	—
Net interest expense and other	59,444	34,634	7,559
Income before income taxes	524,694	605,275	227,587
Provision for income taxes	174,928	257,156	75,019
Minority interest	29,288	725	—
Net income	320,478	347,394	152,568
Preferred stock dividends	3,716	3,358	2,454
Net income applicable to common shareholders	$ 316,762	$ 344,036	$150,114
Earnings per common share:			
Basic	$ 3.52	$ 4.07	$ 1.94
Diluted	$ 3.34	$ 3.87	$ 1.86
Weighted average common shares outstanding:			
Basic	90,086	84,613	77,444
Diluted	95,938	89,874	82,205

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

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common Stock		Retained Earnings	Unearned Compensation	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
	Shares	Amount		(In thousands)		
Balance, December 31, 2004	76,836	$208,867	$ 258,634	$ —	$ 17,791	$ 485,292
Comprehensive income:						
Net income	—	—	152,568	—	—	152,568
Foreign currency translations adjustments	—	—	—	—	(11,393)	(11,393)
Unrealized loss on hedges, net	—	—	—	—	(8,127)	(8,127)
Comprehensive income						133,048
Convertible preferred stock dividends	—	—	(2,454)	—	—	(2,454)
Activity in company stock plans, net	858	16,527	—	(7,515)	—	9,012
Excess tax benefit from stock-based compensation	—	4,402	—	—	—	4,402
Balance, December 31, 2005	77,694	229,796	408,748	(7,515)	(1,729)	629,300
Comprehensive income:						
Net income	—	—	347,394	—	—	347,394
Foreign currency translations adjustments	—	—	—	—	17,601	17,601
Unrealized gain on hedges, net	—	—	—	—	11,364	11,364
Comprehensive income						376,359
Convertible preferred stock dividends	—	—	(3,358)	—	—	(3,358)
Stock compensation expense	—	9,364	—	—	—	9,364
Adoption of SFAS 123R	—	(7,515)	—	7,515	—	—
Stock issuance	13,033	553,570	—	—	—	553,570
Stock repurchase	(1,682)	(50,266)	—	—	—	(50,266)
Activity in company stock plans, net	1,583	8,319	—	—	—	8,319
Excess tax benefit from stock- based compensation	—	2,660	—	—	—	2,660
Balance, December 31, 2006	90,628	745,928	752,784	—	27,236	1,525,948
Comprehensive income:						
Net income	—	—	320,478	—	—	320,478
Foreign currency translations adjustments	—	—	—	—	3,680	3,680
Unrealized loss on hedges, net	—	—	—	—	(9,654)	(9,654)
Comprehensive income						314,504
Convertible preferred stock dividends	—	—	(3,716)	—	—	(3,716)
Stock compensation expense	—	14,607	—	—	—	14,607
Stock repurchase	(282)	(9,904)	—	—	—	(9,904)
Activity in company stock plans, net	1,039	4,547	—	—	—	4,547
Excess tax benefit from stock- based compensation	—	580	—	—	—	580
Balance, December 31, 2007	91,385	$755,758	$ 1,069,546	$ —	$ 21,262	$ 1,846,566

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

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2007	2006	2005
		(In thousands)	
Cash flows from operating activities:			
Net income	$ 320,478	$ 347,394	$ 152,568
Adjustments to reconcile net income to net cash provided by operating activities —			
Depreciation and amortization	331,919	193,647	110,683
Asset impairment charge	73,950	—	790
Dry hole expense	10,309	38,335	—
Equity in earnings of investments, net of distributions	582	(2,366)	(34)
Equity in (earnings) losses of OTSL, inclusive of impairment charge	10,841	487	(2,817)
Amortization of deferred financing costs	6,505	2,277	1,126
Stock compensation expense	17,302	9,364	1,406
Deferred income taxes	126,959	57,235	42,728
Excess tax benefit from stock-based compensation	(580)	(2,660)	4,402
Gain on subsidiary equity transaction	(151,696)	(223,134)	—
(Gain) loss on sale of assets	(50,368)	(2,817)	(1,405)
Minority interest	29,288	725	—
Changes in operating assets and liabilities:			
Accounts receivable, net	(5,918)	(67,211)	(107,163)
Other current assets	(22,820)	9,969	(6,997)
Income tax payable	(155,903)	142,949	5,384
Accounts payable and accrued liabilities	(51,635)	39,551	59,241
Other noncurrent, net	(72,887)	(29,709)	(17,480)
Net cash provided by operating activities	416,326	514,036	242,432
Cash flows from investing activities:			
Capital expenditures	(943,596)	(469,091)	(361,487)
Acquisition of businesses, net of cash acquired	(147,498)	(887,943)	(66,586)
(Purchases) sale of short-term investments	285,395	(285,395)	30,000
Investments in equity investments	(17,459)	(27,578)	(112,756)
Distributions from equity investments, net	6,679	—	10,492
Increase in restricted cash	(1,112)	(6,666)	(4,431)
Proceeds from sale of subsidiary stock	—	264,401	—
Proceeds from sales of property	78,073	32,342	5,617
Other, net	(136)	—	(774)
Net cash used in investing activities	(739,654)	(1,379,930)	(499,925)
Cash flows from financing activities:			
Borrowings under Helix Term Notes	—	835,000	—
Repayment of Helix Term Notes	(405,408)	(2,100)	—
Borrowings on Helix Revolver	472,800	209,800	—
Repayments on Helix Revolver	(454,800)	(209,800)	—
Borrowings on unsecured senior debt	550,000	—	—
Borrowings on Convertible Senior Notes	—	—	300,000
Borrowings under MARAD loan facility	—	—	2,836
Repayment of MARAD borrowings	(3,823)	(3,641)	(4,321)
Borrowings on CDI Revolver	31,500	201,000	—
Repayments on CDI Revolver	(332,668)	—	—
Borrowings on CDI Term Note	375,000	—	—
Borrowing under loan notes	5,000	5,000	—
Deferred financing costs	(17,165)	(11,839)	(11,678)
Capital lease payments	(2,519)	(2,827)	(2,859)
Preferred stock dividends paid	(3,716)	(3,613)	(2,200)
Redemption of stock in subsidiary	—	—	(2,438)
Repurchase of common stock	(9,904)	(50,266)	—
Excess tax benefit from stock-based compensation	580	2,660	—
Exercise of stock options, net	1,568	8,886	8,726
Net cash provided by (used in) financing activities	206,445	978,260	288,066
Effect of exchange rate changes on cash and cash equivalents	174	2,818	(635)
Net (decrease) increase in cash and cash equivalents	(116,709)	115,184	29,938
Cash and cash equivalents:			
Balance, beginning of year	206,264	91,080	61,142
Balance, end of year	$ 89,555	$ 206,264	$ 91,080

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

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 — Organization

Effective March 6, 2006, we changed our name from Cal Dive International, Inc. to Helix Energy Solutions Group, Inc. ("Helix" or the "Company"). Unless the context indicates otherwise, the terms "we," "us" and "our" in this report refer collectively to Helix and its subsidiaries, including Cal Dive International, Inc. (collectively with its subsidiaries referred to as "Cal Dive" or "CDI"). We are an international offshore energy company that provides reservoir development solutions and other contracting services to the energy market as well as to our own oil and gas properties. Our Contracting Services segment utilizes our vessels, offshore equipment and proprietary technologies to deliver services that reduce finding and development costs and cover the complete lifecycle of an offshore oil and gas field. Our Oil and Gas segment engages in prospect generation, exploration, development and production activities. We operate primarily in the Gulf of Mexico, North Sea, Asia Pacific and Middle East regions.

Contracting Services Operations

We seek to provide services and methodologies which we believe are critical to finding and developing offshore reservoirs and maximizing production economics, particularly from marginal fields. By "marginal", we mean reservoirs that are no longer wanted by major operators or are too small to be material to them. Our "life of field" services are organized in five disciplines: construction, well operations, drilling, production facilities, and reservoir and well technology services. We have disaggregated our contracting services operations into three reportable segments in accordance with Financial Accounting Standards Board ("FASB") Statement No. 131 *Disclosures about Segments of an Enterprise and Related Information* ("SFAS No. 131"): Contracting Services (which currently includes deepwater construction, well operations and reservoir and well technology services and in the future, drilling); Shelf Contracting; and Production Facilities. Within our contracting services operations, we operate primarily in the Gulf of Mexico, the North Sea and Asia/Pacific regions, with services that cover the lifecycle of an offshore oil or gas field. The assets of our Shelf Contracting segment are the assets of Cal Dive. Our ownership in CDI was 58.5% as of December 31, 2007.

Oil and Gas Operations

In 1992 we began our oil and gas operations to provide a more efficient solution to offshore abandonment, to expand our off-season asset utilization of our contracting services business and to achieve incremental returns to our contracting services. Over the last 15 years we have evolved this business model to include not only mature oil and gas properties but also proved and unproved reserves yet to be developed and explored. This has led to the assembly of services that allows us to create value at key points in the life of a reservoir from exploration through development, life of field management and operating through abandonment.

Note 2 — Summary of Significant Accounting Policies

Principles of Consolidation

Our consolidated financial statements include the accounts of majority-owned subsidiaries and variable interest entities in which we are the primary beneficiary. The equity method is used to account for investments in affiliates in which we do not have majority ownership, but have the ability to exert significant influence. We account for our investments in Deepwater Gateway LLC ("Deepwater Gateway"), Independence Hub, LLC ("Independence Hub") and Offshore Technology Solutions Limited ("OTSL") under the equity method of accounting. Minority interests represent minority shareholders' proportionate share of the equity in CDI and Kommandor LLC. All material intercompany accounts and transactions have been eliminated. Certain reclassifications were made to previously reported amounts in the consolidated financial statements and notes thereto to make them consistent with the current presentation format.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash and Cash Equivalents

Cash and cash equivalents are highly liquid financial instruments with original maturities of three months or less. They are carried at cost plus accrued interest, which approximates fair value.

Statement of Cash Flow Information

As of December 31, 2007 and 2006, we had $34.8 million and $33.7 million, respectively, of restricted cash included in other assets (see "— Note 8 — Detail of Certain Accounts"), net, all of which was related to funds required to be escrowed to cover decommissioning liabilities associated with the SMI 130 acquisition in 2002 by our Oil and Gas segment. Under the purchase agreement for those acquisitions, we are obligated to escrow 50% of production up to the first $20 million of escrow and 37.5% of production on the remaining balance up to $33 million in total escrow. We had fully escrowed the requirement as of December 31, 2007. We may use the restricted cash for decommissioning the related field.

The following table provides supplemental cash flow information for the periods stated (in thousands):

	Years Ended December 31,		
	2007	2006	2005
Interest paid (net of capitalized interest)	$ 59,844	$26,105	$ 9,990
Income taxes paid	$ 203,873	$56,972	$22,495

Non-cash investing activities for the years ended December 31, 2007, 2006 and 2005 included $90.7 million, $39.0 million and $28.5 million, respectively, related to accruals of capital expenditures. The accruals have been reflected in the consolidated balance sheet as an increase in property and equipment and accounts payable.

Short-term Investments

Short-term investments are available-for-sale instruments that we expect to realize in cash within one year. These investments are stated at cost, which approximates market value. Any unrealized holding gains or losses are reported in comprehensive income until realized. We did not hold these types of securities at December 31, 2007. All of our short-term investments at December 31, 2006 were municipal auction rate securities. These instruments are long-term variable rate bonds tied to short-term interest rates that are reset through a "Dutch Auction" process which occurs every 7 to 35 days and were classified as available-for-sale securities. The stated maturities of these securities range from November 2015 to November 2045.

Accounts Receivable and Allowance for Uncollectible Accounts

Accounts receivable are stated at the historical carrying amount net of write-offs and allowance for uncollectible accounts. We establish an allowance for uncollectible accounts receivable based on historical experience and any specific customer collection issues that we have identified. Uncollectible accounts receivable are written off when a settlement is reached for an amount that is less than the outstanding historical balance or when we have determined that the balance will not be collected.

Property and Equipment

Overview. Property and equipment, both owned and under capital leases, are recorded at cost. The following is a summary of the components of property and equipment (dollars in thousands):

	Estimated Useful Life	2007	2006
Vessels	10 to 30 years	$ 1,566,720	$ 883,635
Oil and gas leases and related equipment	Units-of-Production	2,354,392	1,746,896
Machinery, equipment, buildings and leasehold improvements	5 to 30 years	167,449	90,831
Total property and equipment		$ 4,088,561	$ 2,721,362

The cost of repairs and maintenance is charged to operations as incurred, while the cost of improvements is capitalized. Total repair and maintenance charges were $44.1 million, $51.0 million and $24.0 million for the years ended December 31, 2007, 2006 and 2005, respectively.

For long-lived assets to be held and used, excluding goodwill, we base our evaluation of recoverability on impairment indicators such as the nature of the assets, the future economic benefit of the assets, any historical or future profitability measurements and other external market conditions or factors that may be present. If such impairment indicators are present or other factors exist that indicate the carrying amount of the asset may not be recoverable, we determine whether an impairment has occurred through the use of an undiscounted cash flows analysis of the asset at the lowest level for which identifiable cash flows exist. Our marine vessels are assessed on a vessel by vessel basis, while our ROVs are grouped and assessed by asset class. If an impairment has occurred, we recognize a loss for the difference between the carrying amount and the fair value of the asset. Impairment expenses are included as a component of cost of sales. The fair value of the asset is measured using quoted market prices or, in the absence of quoted market prices, is based on an estimate of discounted cash flows. During 2005, we recorded impairment charges of $790,000 on certain vessels that met the impairment criteria. Such charges are included in cost of sales in the accompanying Consolidated Statements of Operations. These assets were subsequently disposed of for an immaterial gain. There were no such impairments related to our vessels during 2007 and 2006.

Assets are classified as held for sale when we have a plan for disposal of certain assets and those assets meet the held for sale criteria. At December 31, 2006, we had classified certain assets intended to be disposed of within a 12-month period as assets held for sale totaling approximately $700,000. Assets classified as held for sale are included in other current assets. Assets held for sale at December 31, 2006 were disposed of in January 2007.

Depreciation and Depletion. Depletion for our oil and gas properties is calculated on a unit-of-production basis. The calculation is based on the estimated remaining oil and gas reserves. Depreciation for all other property and equipment is provided on a straight-line basis over the estimated useful lives of the assets.

Oil and Gas Properties. The majority of our interests in oil and gas properties are located offshore in United States waters. We follow the successful efforts method of accounting for our interests in oil and gas properties. Under this method, the costs of successful wells and leases containing productive reserves are capitalized. Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized. Costs incurred relating to unsuccessful exploratory wells are expensed in the period when the drilling is determined to be unsuccessful. See "— Exploratory Costs" below.

Proved Properties. We assess proved oil and gas properties for possible impairment at least annually or when events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. We recognize an impairment loss as a result of a triggering event and when the estimated undiscounted future cash flows from a property are less than the carrying value. If an impairment is indicated, the cash flows are discounted at a rate approximate to our cost of capital and compared to the carrying value for determining the amount of the impairment loss to record. Estimated future cash flows are based on management's expectations for the future and include estimates of crude oil and natural gas reserves and future commodity prices and operating costs. Downward revisions in estimates of reserve quantities or expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future cash flows and could indicate a property impairment. We recorded approximately $59.4 million of impairments in 2007 (all recorded in fourth quarter 2007), primarily related to downward reserve revisions and weak end of life well performance in some of our domestic properties. Such impairments were included in cost of sales for our Oil and Gas segment. During 2006 and 2005, no impairment of proved oil and gas properties was recorded.

Unproved Properties. We also periodically assess unproved properties for impairment based on exploration and drilling efforts to date on the individual prospects and lease expiration dates. Management's assessment of the results of exploration activities, availability of funds for future activities and the current and projected political climate in areas in which we operate also impact the amounts and timing of impairment provisions. During 2007, we recorded $9.9 million ($9.0 million in fourth quarter 2007) of impairment related to unproved oil and gas properties. Such impairments were included in cost of sales for our Oil and Gas segment. During 2006 and 2005, no impairment of unproved oil and gas properties was recorded.

Exploratory Costs. The costs of drilling an exploratory well are capitalized as uncompleted or "suspended" wells temporarily pending the determination of whether the well has found proved reserves. If proved reserves are not found, these capitalized costs are charged to expense. A determination that proved reserves have been found results in the continued capitalization of the drilling costs of the well and its reclassification as a well containing proved reserves. At times, it may be determined that an exploratory well may have found hydrocarbons at the time drilling is completed, but it may not be possible to classify the reserves at that time. In this case, we may continue to capitalize the drilling costs as an uncompleted, or "suspended," well beyond one year if we can justify its completion as a producing well and we are making sufficient progress assessing the reserves and the economic and operating viability of the project. If reserves are not ultimately deemed proved or economically viable, the well is considered impaired and its costs, net of any salvage value, are charged to expense.

Occasionally, we may choose to salvage a portion of an unsuccessful exploratory well in order to continue exploratory drilling in an effort to reach the target geological structure/formation. In such cases, we charge only the unusable portion of the well bore to dry hole expense, and we continue to capitalize the costs associated with the salvageable portion of the well bore and add the costs to the new exploratory well. In certain situations, the well bore may be carried for more than one year beyond the date drilling in the original well bore was suspended. This may be due to the need to obtain, and/or analyze the availability of, equipment or crews or other activities necessary to pursue the targeted reserves or evaluate new or reprocessed seismic and geographic data. If, after we analyze the new information and conclude that we will not reuse the well bore or if the new exploratory well is determined to be unsuccessful after we complete drilling, we will charge the capitalized costs to dry hole expense. During the year ended December 31, 2007 and 2006, we incurred $10.3 million and $38.3 million, respectively, of exploratory dry hole expense. Such impairments were included in cost of sales for our Oil and Gas segment. No dry hole expense was incurred in 2005. See "— Note 7 — Oil and Gas Properties" for detailed discussion of our exploratory activities.

Property Acquisition Costs. Acquisitions of producing properties are recorded at the value exchanged at closing together with an estimate of our proportionate share of the discounted decommissioning liability assumed in the purchase based upon the working interest ownership percentage.

Properties Acquired from Business Combinations. Properties acquired through business combinations are recorded at their fair value. In determining the fair value of the proved and unproved properties, we prepare estimates of oil and gas reserves. We estimate future prices to apply to the estimated reserve quantities acquired and the estimated future operating and development costs to arrive at our estimates of future net revenues. For the fair value assigned to proved reserves, the future net revenues are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the acquisition. To compensate for inherent risks of estimating and valuing unproved reserves, probable and possible reserves are reduced by additional risk weighting factors. See "— Note 4" for a detailed discussion of our acquisition of Remington.

Capitalized Interest. Interest from external borrowings is capitalized on major projects. Capitalized interest is added to the cost of the underlying asset and is amortized over the useful lives of the assets in the same manner as the underlying assets.

Equity Investments

We periodically review our investments in Deepwater Gateway, Independence Hub and OTSL for impairment. Under the equity method of accounting, an impairment loss would be recorded whenever a decline in value of an equity investment below its carrying amount is determined to be other than temporary. In judging "other than temporary," we would consider the length of time and extent to which the fair value of the investment has been less than the carrying amount of the equity investment, the near-term and longer-term operating and financial prospects of the equity company and our longer-term intent of retaining the investment in the entity. During 2007, CDI determined that there was an other than temporary impairment in OTSL and the full value of CDI's investment in OTSL was impaired and CDI recognized equity losses of OTSL, inclusive of the impairment charge, of $10.8 million in 2007. See "— Note 9 — Equity Investments" for a detailed discussion of our impairment analysis. There was no impairment of the other equity investments at December 31, 2007.

Goodwill and Other Intangible Assets

We test for the impairment of goodwill annually and when impairment indicators such as the nature of the assets, the future economic benefit of the assets, any historical or future profitability measurements, and other external market conditions are present. Intangible assets with finite useful lives are amortized using the straight-line method over their useful lives. Intangible assets that have indefinite useful lives are not amortized, but are tested for impairment annually and when impairment indicators as described earlier are present. Our goodwill impairment test involves a comparison of the fair value of each of our reporting units with its carrying amount. The fair value is determined using discounted cash flows and other market-related valuation models, such as earnings multiples and comparable asset market values. We completed our annual goodwill impairment test as of November 1, 2007. The changes in the carrying amount of goodwill by the applicable segments are as follows (in thousands):

	Contracting Services	Shelf Contracting	Oil and Gas	Total
Balance at December 31, 2005	$ 73,917	$ 27,814	$ —	$ 101,731
Remington acquisition (Note 4)	—	—	707,596	707,596
Well Ops SEA Pty Ltd. acquisition (Note 6)	7,415	—	—	7,415
Acergy acquisition adjustment (Note 6)	—	(1,148)	—	(1,148)
Helix Energy Ltd. acquisition adjustment (Note 6)	2,634	—	—	2,634
Tax and other adjustments	4,328	—	—	4,328
Balance at December 31, 2006	88,294	26,666	707,596	822,556
Remington acquisition (Note 4)	—	—	4,796	4,796
Well Ops SEA Phy Ltd. acquisition (Note 6)	6,001	—	—	6,001
Horizon acquisition (Note 5)	—	257,340	—	257,340
Tax and other adjustments	(1,071)	136	—	(935)
Balance at December 31, 2007	$ 93,224	$ 284,142	$ 712,392	$ 1,089,758

Of our total goodwill at December 31, 2007 and 2006, approximately $39.4 million and $41.0 million, respectively, was expected to be deducted for tax purposes. None of our goodwill was impaired based on the impairment test performed as of November 1, 2007. We will continue to test our goodwill and other indefinite-lived intangible assets annually on a consistent measurement date unless events occur or circumstances change between annual tests that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

Recertification Costs and Deferred Drydock Charges

Our Contracting Services and Shelf Contracting vessels are required by regulation to be recertified after certain periods of time. These recertification costs are incurred while the vessel is in drydock. In addition, routine repairs and maintenance are performed and, at times, major replacements and improvements are performed. We expense routine repairs and maintenance as they are incurred. We defer and amortize drydock and related recertification costs over the length of time for which we expect to receive benefits from the drydock and related recertification, which is generally 30 months. Vessels are typically available to earn revenue for the 30-month period between drydock and related recertification processes. A drydock and related recertification process typically lasts one to two months, a period during which the vessel is not available to earn revenue. Major replacements and improvements, which extend the vessel's economic useful life or functional operating capability, are capitalized and depreciated over the vessel's remaining economic useful life. Inherent in this process are estimates we make regarding the specific cost incurred and the period that the incurred cost will benefit.

As of December 31, 2007 and 2006, capitalized deferred drydock charges (included in Other Assets, Net, see "— Note 8 — Detail of Certain Accounts") totaled $48.0 million and $26.4 million, respectively. During the years ended December 31, 2007, 2006 and 2005, drydock amortization expense was $23.0 million, $12.0 million and $8.9 million, respectively.

Accounting for Decommissioning Liabilities

We account for our decommissioning liabilities in accordance with Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* ("SFAS No. 143"). This statement requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying cost of the asset. Our asset retirement obligations consist of estimated costs for dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. An asset retirement obligation and the related asset retirement cost are recorded when an asset is first constructed or purchased. The asset retirement cost is determined and discounted to present value using a credit-adjusted risk-free rate. After the initial recording, the liability is increased for the passage of time, with the increase being reflected as accretion expense in the statement of operations. Subsequent adjustments in the cost estimate are reflected in the liability and the amounts continue to be amortized over the useful life of the related long-lived asset.

SFAS No. 143 calls for measurements of asset retirement obligations to include, as a component of expected costs, an estimate of the price that a third party would demand, and could expect to receive, for bearing the uncertainties and unforeseeable circumstances inherent in the obligations, sometimes referred to as a market-risk premium. To date, the oil and gas industry has no examples of credit-worthy third parties who are willing to assume this type of risk, for a determinable price, on major oil and gas production facilities and pipelines. Therefore, because determining such a market-risk premium would be an arbitrary process, we excluded it from our SFAS No. 143 estimates.

The following table describes the changes in our asset retirement obligations for the year ended 2007 and 2006 (in thousands):

	2007	2006
Asset retirement obligation at January 1,	$ 167,671	$ 121,352
Liability incurred during the period	27,822	40,442
Liability settled during the period	(41,892)	(6,669)
Revision in estimated cash flows	52,903	3,929
Accretion expense (included in depreciation and amortization)	10,975	8,617
Asset retirement obligations at December 31,	$ 217,479	$ 167,671

Revenue Recognition

Contracting Services Revenues

Revenues from Contracting Services and Shelf Contracting are derived from contracts that traditionally have been of relatively short duration; however, during 2007 contract durations started to become longer-term. These contracts contain either lump-sum turnkey provisions or provisions for specific time, material and equipment charges, which are billed in accordance with the terms of such contracts. We recognize revenue as it is earned at estimated collectible amounts.

Unbilled revenue represents revenue attributable to work completed prior to period end that has not yet been invoiced. All amounts included in unbilled revenue at December 31, 2007 and 2006 are expected to be billed and collected within one year.

Dayrate Contracts. Revenues generated from specific time, materials and equipment contracts are generally earned on a dayrate basis and recognized as amounts are earned in accordance with contract terms. In connection with these contracts, we may receive revenues for mobilization of equipment and personnel. In connection with new contracts, revenues related to mobilization are deferred and recognized over the period in which contracted services are performed using the straight-line method. Incremental costs incurred directly for mobilization of equipment and personnel to the contracted site, which typically consist of materials, supplies and transit costs, are also deferred and recognized over the period in which contracted services are performed using the straight-line method. Our policy to amortize the revenues and costs related to mobilization on a straight-line basis over the estimated contract service period is consistent with the general pace of activity, level of services being provided and dayrates being earned over the service period of the contract. Mobilization costs to move vessels when a contract does not exist are expensed as incurred.

Turnkey Contracts. Revenue on significant turnkey contracts is recognized on the percentage-of-completion method based on the ratio of costs incurred to total estimated costs at completion. In determining whether a contract should be accounted for using the percentage-of-completion method, we consider whether:

- the customer provides specifications for the construction of facilities or for the provision of related services;
- we can reasonably estimate our progress towards completion and our costs;
- the contract includes provisions as to the enforceable rights regarding the goods or services to be provided, consideration to be received and the manner and terms of payment;
- the customer can be expected to satisfy its obligations under the contract; and
- we can be expected to perform our contractual obligations.

Under the percentage-of-completion method, we recognize estimated contract revenue based on costs incurred to date as a percentage of total estimated costs. Changes in the expected cost of materials and labor, productivity, scheduling and other factors affect the total estimated costs. Additionally, external factors, including weather and other factors outside of our control, may also affect the progress and estimated cost of a project's completion and, therefore, the timing of income and revenue recognition. We routinely review estimates related to our contracts and reflect revisions to profitability in earnings on a current basis. If a current estimate of total contract cost indicates an ultimate loss on a contract, we recognize the projected loss in full when it is first determined. We recognize additional contract revenue related to claims when the claim is probable and legally enforceable.

Oil and Gas Revenues

We record revenues from the sales of crude oil and natural gas when delivery to the customer has occurred and title has transferred. This occurs when production has been delivered to a pipeline or a barge lifting has occurred. We may have an interest with other producers in certain properties. In this case, we use the entitlements method to account for sales of production. Under the entitlements method, we may receive more or less than our entitled share of production. If we receive more than our entitled share of production, the imbalance is treated as a liability. If we receive less than our entitled share, the imbalance is recorded as an asset. As of December 31, 2007, the net imbalance was a $2.0 million asset and was included in Other Current Assets ($6.7 million) and Accrued Liabilities ($4.7 million) in the accompanying consolidated balance sheet.

Income Taxes

Deferred income taxes are based on the differences between financial reporting and tax bases of assets and liabilities. We utilize the liability method of computing deferred income taxes. The liability method is based on the amount of current and future taxes payable using tax rates and laws in effect at the balance sheet date. Income taxes have been provided based upon the tax laws and rates in the countries in which operations are conducted and income is earned. A valuation allowance for deferred tax assets is recorded when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. We consider the undistributed earnings of our principal non-U.S. subsidiaries to be permanently reinvested. The deconsolidation of CDI's net income for tax return filing purposes after its initial public offering did not have a material impact on our consolidated results of operations; however, because of our inability to recover our tax basis in CDI tax free, a long term deferred tax liability is provided for any incremental increases to the book over tax basis.

It is our policy to provide for uncertain tax positions and the related interest and penalties based upon management's assessment of whether a tax benefit is more likely than not to be sustained upon examination by tax authorities. At December 31, 2007, we believe we have appropriately accounted for any unrecognized tax benefits. To the extent we prevail in matters for which a liability for an unrecognized tax benefit is established or are required to pay amounts in excess of the liability, our effective tax rate in a given financial statement period may be affected.

Foreign Currency

The functional currency for our foreign subsidiaries, Well Ops (U.K.) Limited and Helix RDS, is the applicable local currency (British Pound), and the functional currency of Well Ops SEA Pty. Ltd. is its applicable local currency (Australian Dollar). Results of operations for these subsidiaries are translated into U.S. dollars using average exchange rates during the period. Assets and liabilities of these foreign subsidiaries are translated into U.S. dollars using the exchange rate in effect at December 31, 2007 and 2006 and the resulting translation adjustment, which was an unrealized gain of $3.7 million and $17.6 million, respectively, is included in accumulated other comprehensive income, a component of shareholders' equity. Beginning in 2004, deferred taxes were not provided on foreign currency translation adjustments for operations where we consider our undistributed earnings of our principal non-U.S. subsidiaries to be permanently reinvested. As a result, cumulative deferred taxes on translation adjustments totaling approximately $6.5 million were reclassified from noncurrent deferred income taxes and accumulated other comprehensive income. All foreign currency transaction gains and losses are recognized currently in the statements of operations. These amounts for the years ended December 31, 2007 and 2006 were not material to our results of operations or cash flows.

Canyon Offshore, our ROV subsidiary, has operations in the United Kingdom and Asia Pacific. Further, CDI has subsidiaries with operations in the Middle East, Southeast Asia, the Mediterranean, Australia and Latin America. Canyon's and CDI's international subsidiaries conduct the majority of their operations in these regions in U.S. dollars which is considered to be their functional currency. When currencies other than the U.S. dollar are to be paid or received, the resulting transaction gain or loss is recognized in the statements of operations. These amounts for the year ended December 31, 2007, 2006 and 2005, respectively, were not material to our results of operations or cash flows.

Derivative Instruments and Hedging Activities

We are currently exposed to market risk in three major areas: commodity prices, interest rates and foreign currency exchange risks. Our price risk management activities involve the use of derivative financial instruments to hedge the impact of market price risk exposures primarily related to our oil and gas production, variable interest rate exposure and foreign exchange currency risks. All derivatives are reflected in our balance sheet at fair value, unless otherwise noted.

We engage primarily in cash flow hedges. Hedges of cash flow exposure are entered into to hedge a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability. Changes in the derivative fair values that are designated as cash flow hedges are deferred to the extent that they are effective and are recorded as a component of accumulated other comprehensive income, a component of shareholders' equity, until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge's change in fair value is recognized immediately in earnings. In addition, any change in the fair value of a derivative that does not qualify for hedge accounting is recorded in earnings in the period the change occurs.

We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives, strategies for undertaking various hedge transactions and the methods for assessing and testing correlation and hedge ineffectiveness. All hedging instruments are linked to the hedged asset, liability, firm commitment or forecasted transaction. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in the hedging transactions are highly effective in offsetting changes in cash flows of its hedged items. We discontinue hedge accounting if we determine that a derivative is no longer highly effective as a hedge, or it is probable that a hedged transaction will not occur. If hedge accounting is discontinued, deferred gains or losses on the hedging instruments are recognized in earnings immediately if it is probable the forecasted transaction will not occur. If it is probable the forecasted transaction will occur, any deferred gains or losses in accumulated other comprehensive income is amortized to earnings using the effective interest method.

Commodity Price Risks

The fair value of hedging instruments reflects our best estimate and is based upon exchange or over-the-counter quotations whenever they are available. Quoted valuations may not be available due to location differences or terms that extend beyond the period for which quotations are available. Where quotes are not available, we utilize other valuation techniques or models to estimate market values. These modeling techniques require us to make estimations of future prices, price correlation and market volatility and liquidity. Our actual results may differ from our estimates, and these differences can be positive or negative.

During 2007 and 2006, we entered into various cash flow hedging costless collar contracts to stabilize cash flows relating to a portion of our expected oil and gas production. All of these qualified for hedge accounting. The aggregate fair value of the hedge instruments was a net asset (liability) of $(8.1) million and $5.2 million as of December 31, 2007 and 2006, respectively. For the years ended December 31, 2007, 2006 and 2005, we recorded unrealized gains (losses) of approximately $(8.7) million, $12.1 million and $(8.1) million, net of tax expense (benefit) of $(4.7) million, $6.5 million and $(4.4) million, respectively, in accumulated other comprehensive income, a component of shareholders' equity, as these hedges were highly effective. The balance in the cash flow hedge adjustments account is recognized in earnings when the related hedged item is sold. During 2007, 2006 and

2005, we reclassified approximately $462,000, $9.0 million and $(14.1) million, respectively, of gains (losses) from other comprehensive income to Oil and Gas revenues upon the sale of the related oil and gas production.

Hedge ineffectiveness related to cash flow hedges was a loss of $1.8 million, net of taxes of $951,000, in 2005 as reported in that period's earnings as a reduction of oil and gas revenues. Hedge ineffectiveness resulted from our inability to deliver contractual oil and gas production in 2005 due primarily to the effects of Hurricanes *Katrina* and *Rita.* No hedge ineffectiveness related to our commodity hedges were recognized in 2007 and 2006.

As of December 31, 2007, we had the following volumes under derivative contracts related to our oil and gas producing activities totaling 540 MBbl of oil and 7,650 MMbtu of natural gas:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:			
January 2008 — December 2008	Collar	45 MBbl	$ 56.67 — $76.51
Natural Gas:			
January 2008 — December 2008	Collar	637,500 MMBtu	$ 7.32 — $10.87

Changes in NYMEX oil and gas strip prices would, assuming all other things being equal, cause the fair value of these instruments to increase or decrease inversely to the change in NYMEX prices.

As of December 31, 2007, we had oil forward sales contracts for the period from January 2008 through December 2009. The contracts cover an average of 97 MBbl per month at a weighted average price of $71.88. In addition, we had natural gas forward sales contracts for the period from January 2008 through December 2009. The contracts cover an average of 1,321,108 MMbtu per month at a weighted average price of $8.28. Hedge accounting does not apply to these normal purchase and sale contracts.

Variable Interest Rate Risks

As the rates for our Term Loan are subject to market influences and will vary over the term of the credit agreement, we entered into various cash flow hedging interest rate swaps to stabilize cash flows relating to a portion of our interest payments on our Term Loan. The interest rate swaps were effective October 3, 2006. These interest rate swaps qualified for hedge accounting. See "— Note 11 — Long-Term Debt" below for a detailed discussion of our Term Loan. On December 21, 2007, a prepayment made to a hedged portion of our Term Loan brought the balance of that portion below the amount hedged by interest rate swaps. As a result, the hedge instruments became ineffective and no longer qualified for hedge accounting as of that date. For the period from December 21, 2007 to December 31, 2007, we recognized $618,000 as additional interest expense to adjust the net liability for the swaps to fair value. The aggregate fair value of the derivative instruments was a net liability of $4.7 million and $531,000 as of December 31, 2007 and 2006, respectively. For the year ended December 31, 2006, these hedges were highly effective.

Foreign Currency Exchange Risks

Because we operate in various regions in the world, we conduct a portion of our business in currencies other than the U.S. dollar. In December 2006, we entered into various foreign currency forward purchase contracts to stabilize expected cash outflows relating to a shipyard contract where the contractual payments are denominated in euros. These forward contracts qualify for hedge accounting. Under the forward contracts, we hedged €11.0 million at an exchange rate of 1.3326 that was settled in December 2007. In August 2007, we entered into a €14.0 million foreign currency forward contract at an exchange rate of 1.3595 to be settled in May 2008. The aggregate fair value of the hedge instruments that were still outstanding was a net asset (liability) of $1.4 million and $(184,000) as of December 31, 2007 and 2006, respectively. For the year ended December 31, 2007 and 2006, we recorded unrealized gains of approximately $1.1 million and $184,000, respectively, net of tax expense of $498,000 and $99,000, respectively, in accumulated other comprehensive income, a component of shareholders' equity.

Earnings per Share

Basic earnings per share (“EPS”) is computed by dividing the net income available to common shareholders by the weighted-average shares of common stock outstanding. The calculation of diluted EPS is similar to basic EPS, except the denominator includes dilutive common stock equivalents and the income included in the numerator excludes the effects of the impact of dilutive common stock equivalents, if any. The computation of basic and diluted per share amounts for the years ended December 31, 2007, 2006 and 2005 were as follows (in thousands):

	Year Ended December 31,					
	2007		2006		2005	
	Income	Shares	Income	Shares	Income	Shares
Earnings applicable per common share — Basic	$316,762	90,086	$344,036	84,613	$150,114	77,444
Effect of dilutive securities:						
Stock options	—	376	—	449	—	772
Restricted shares	—	291	—	160	—	240
Employee stock purchase plan	—	6	—	12	—	—
Convertible Senior Notes	—	1,548	—	1,009	—	118
Convertible preferred stock	3,716	3,631	3,358	3,631	2,454	3,631
Earnings applicable per common share — Diluted	$320,478	95,938	$347,394	89,874	$152,568	82,205

There were no antidilutive stock options in the years ended December 31, 2007, 2006 and 2005. Net income for the diluted earnings per share calculation for the years ended December 31, 2007, 2006 and 2005 were adjusted to add back the preferred stock dividends and accretion on 3.6 million shares.

Stock Based Compensation Plans

Prior to January 1, 2006, we used the intrinsic value method of accounting for our stock-based compensation. Accordingly, no compensation expense was recognized when the exercise price of an employee stock option was equal to the common share market price on the grant date and all other terms were fixed. In addition, under the intrinsic value method, on the date of grant for restricted shares, we recorded unearned compensation (a component of shareholders’ equity) that equaled the product of the number of shares granted and the closing price of our common stock on the business day prior to the grant date, and expense was recognized over the vesting period of each grant on a straight-line basis.

The following table reflects our pro forma results if the fair value method had been used for the accounting for these plans for the year ended December 31, 2005 (in thousands, except per share amounts):

	Year Ended December 31, 2005
Net income applicable to common shareholders:	
As Reported	$ 150,114
Add back: Stock-based compensation cost included in reported net income, net of taxes	914
Deduct: Total stock-based compensation cost determined under the fair value method, net of tax	(2,566)
Pro Forma	$ 148,462
Earnings per common share:	
Basic:	
As reported	$ 1.94
Pro forma	$ 1.92
Diluted:	
As reported	$ 1.86
Pro forma	$ 1.84

There were no stock option grants in 2007, 2006 and 2005. The fair value of shares issued under the Employee Stock Purchase Plan was based on the 15% discount received by the employees. The estimated fair value of the options is amortized to pro forma expense over the vesting period. See "— Note 14 — Employee Benefit Plans" for discussion of our stock compensation.

Accounting for Sales of Stock by Subsidiary

We recognize a gain or loss upon the direct sale or issuance of equity by our subsidiaries if the sales price differs from our carrying amount, provided that the sale of such equity is not part of a broader corporate reorganization. See "— Note 3" and "— Note 5" for discussion of CDI's initial public offering and common stock issuance as part of the acquisition of Horizon Offshore, Inc. ("Horizon").

Consolidation of Variable Interest Entities

Effective December 31, 2003, we adopted and applied the provisions of FASB Interpretation No. 46(R), *Consolidation of Variable Interest Entities* ("FIN 46") for all variable interest entities. FIN 46 requires the consolidation of variable interest entities in which an enterprise absorbs a majority of the entity's expected losses, receives a majority of the entity's expected residual returns, or both, as a result of ownership, contractual or other financial, interests in the entity. See "— Note 10" related to our consolidated variable interest entities.

Fair Value of Financial Instruments

Our financial instruments consist of cash and cash equivalents, short-term investments, accounts receivable, accounts payable and our long-term debts. The carrying amount of cash and cash equivalents, short-term investments, accounts receivable and accounts payable approximate fair value due to the highly liquid nature of these short-term instruments. The carrying amount and estimated fair value of our debt instruments, including current maturities as of December 31, 2007 and 2006 were as follows (amount in thousands):

	2007		2006	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Term Loan (1)	$ 423,418	$410,715	$832,900	$834,462
Revolving Credit Facility (2)	18,000	18,000	—	—
Cal Dive Revolving Credit Facility (2)	—	—	201,000	201,000
Cal Dive Term Loan (2)	375,000	375,000	—	—
Convertible Senior Notes (1)	300,000	442,485	300,000	378,780
Senior Unsecured Notes (1)	550,000	559,625	—	—
MARAD Debt (3)	127,463	126,061	131,286	126,691
Loan Notes (4)	6,506	6,506	11,146	11,146

(1) The fair values of these instruments were based on quoted market prices as of December 31, 2007 and 2006, if applicable.

(2) The carrying values of these credit facilities approximate fair value.

(3) The fair value of the MARAD debt was determined by a third-party evaluation of the remaining average life and outstanding principal balance of the MARAD indebtedness as compared to other government guaranteed obligations in the market place with similar terms.

(4) The carrying value of the loan notes approximates fair value as the maturity date of the loan notes is less than one year.

Major Customers and Concentration of Credit Risk

The market for our products and services is primarily the offshore oil and gas industry. Oil and gas companies make capital expenditures on exploration, drilling and production operations offshore, the level of which is generally dependent on the prevailing view of the future oil and gas prices, which have been characterized by significant volatility. Our customers consist primarily of major, well-established oil and pipeline companies and independent oil and gas producers and suppliers. We perform ongoing credit evaluations of our customers and provide allowances for probable credit losses when necessary. The percent of consolidated revenue of major customers was as follows: 2007 — Louis Dreyfus Energy Services (13%) and Shell Offshore, Inc. (10%); 2006 — Louis Dreyfus Energy Services (10%) and Shell Offshore, Inc. (10%); and 2005 — Louis Dreyfus Energy Services (10%) and Shell Trading (US) Company (10%). All of these customers were purchasers of our oil and gas production.

Recently Issued Accounting Principles

In September 2006, the FASB issued Statement No. 157, *Fair Value Measurements* (“SFAS No. 157”). This new standard provides enhanced guidance for using fair value to measure assets and liabilities. The statement provides a common definition of fair value and establishes a framework to make the measurement of fair value in generally accepted accounting principles more consistent and comparable. SFAS No. 157 also requires expanded disclosures to provide information about the extent to which fair value is used to measure assets and liabilities, the methods and assumptions used to measure fair value, and the effect of fair value measures on earnings.

SFAS No. 157 was originally effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. The FASB agreed to defer the effective date of SFAS No. 157 for all nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis. We adopted the provisions of SFAS No. 157 on January 1, 2008 for assets and liabilities not subject to the deferral and expect to adopt this standard for all other assets and liabilities by January 1, 2009. The impact of adopting this standard was immaterial on our financial condition and results of operations.

In February 2007, the FASB issued Statement of Financial Accounting Standard No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities* (“SFAS No. 159”). SFAS No. 159 allows entities to voluntarily choose, at specified election dates, to measure many financial assets and financial liabilities at fair value. The election is made on an instrument-by-instrument basis and is irrevocable. If the fair value option is elected for an instrument, SFAS No. 159 specifies that all subsequent changes in fair value for that instrument shall be reported in earnings. The provisions of SFAS No. 159 are effective for fiscal years beginning after November 15, 2007. We adopted the provisions of SFAS No. 159 on January 1, 2008 and it had no impact on our results of operation and financial condition.

In December 2007, the FASB issued Statement No. 141 (Revised), *Business Combinations* (“SFAS No. 141 (R)”). SFAS 141 (R) requires the acquiring entity in a business combination to recognize all the assets acquired and liabilities assumed in the transaction; establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. The provisions of SFAS No. 141 (R) are effective for fiscal years beginning after December 15, 2008. We are currently evaluating the impact, if any, of this statement.

In December 2007, the FASB issued Statement No. 160, *Noncontrolling Interests in Consolidated Financial Statements — an amendment of ARB 51* (“SFAS No. 160”). SFAS No. 160 improves the relevance, comparability, and transparency of financial information provided to investors by requiring all entities to report noncontrolling (minority) interests in subsidiaries as equity in the consolidated financial statements. The provisions of SFAS No. 160 are effective for fiscal years beginning after December 15, 2008. We are currently evaluating the impact, if any, of this statement.

Note 3 — Initial Public Offering of Cal Dive International, Inc.

In December 2006, we contributed the assets of our Shelf Contracting segment into Cal Dive, our then wholly owned subsidiary. Cal Dive subsequently sold 22,173,000 shares of its common stock in an initial public offering and distributed the net proceeds of $264.4 million to us as a dividend. In connection with the offering, CDI also entered into a $250 million revolving credit facility. In December 2006, Cal Dive borrowed $201 million under the facility and distributed $200 million of the proceeds to us as a dividend. For additional information related to the Cal Dive credit facilities, see “— Note 11 — Long-term Debt” below. We recognized an after-tax gain of $96.5 million, net of taxes of $126.6 million as a result of these transactions. We used the proceeds for general corporate purposes. In connection with the offering, together with shares issued to CDI employees immediately after the offering, our ownership of CDI decreased to approximately 73.0% as of December 31, 2006. Our ownership in CDI was further reduced in December 2007 as a result of CDI’s stock issuance related to the Horizon acquisition. As a result, our ownership in CDI as of December 31, 2007 was approximately 58.5%. See “— Note 5 — Acquisition of Horizon Offshore, Inc.” for detailed discussion of the Horizon acquisition.

Further, in conjunction with the offering, the tax basis of certain CDI’s tangible and intangible assets was increased to fair value. The increased tax basis should result in additional tax deductions available to CDI over a period of two to five years. Under the Tax Matters Agreement with CDI, for a period of up to ten years to the extent CDI generates taxable income sufficient to realize the additional tax deductions, it will be required to pay us 90% of the amount of tax savings actually realized from the step-up of the assets. As of December 31, 2007 and 2006, we have a receivable from CDI of approximately $6.2 million and $11.3 million, respectively, related to the Tax Matters Agreement. For additional information related to the Tax Matters Agreement, see “— Note 12 — Income Taxes.”

Note 4 — Acquisition of Remington Oil and Gas Corporation

On July 1, 2006, we acquired 100% of Remington, an independent oil and gas exploration and production company headquartered in Dallas, Texas, with operations concentrated in the onshore and offshore regions of the Gulf Coast, for approximately $1.4 billion in cash, stock and the assumption of $358.4 million of liabilities. The merger consideration was 0.436 of a share of our common stock and $27.00 in cash for each share of Remington common stock. On July 1, 2006, we issued 13,032,528 shares of our common stock to Remington stockholders and funded the cash portion of the Remington acquisition (approximately $806.8 million) and transaction costs (approximately $18.5 million) through a credit agreement (see “— Note 11 — Long-Term Debt” below).

The Remington acquisition was accounted for as a business combination with the acquisition price allocated to the assets acquired and liabilities assumed based upon their estimated fair values, with the excess being recorded in goodwill. The following table summarizes the estimated fair values of the assets acquired and liabilities assumed at the date of acquisition (in thousands):

Current assets	$ 154,293
Property and equipment	863,935
Goodwill	712,392
Other intangible assets (1)	6,800
Total assets acquired	$ 1,737,420
Current liabilities	$ 130,409
Deferred income taxes	204,096
Decommissioning liabilities (including current portion)	22,137
Other non-current liabilities	1,800
Total liabilities assumed	$ 358,442
Net assets acquired	$ 1,378,978

(1) The intangible asset was related to a favorable drilling rig contract and several non-compete agreements between the Company and certain members of senior management. The fair value of the drilling rig contract was $5.0 million at the date of the acquisition, with $5.0 million reclassified into property and equipment for drilling of certain successful exploratory wells in the year ended December 31, 2007. The fair value of the non-compete agreements was $1.8 million, which is being amortized over the term of the agreements (three years) on a straight-line basis.

The results of the Remington acquisition are included in the accompanying statements of operations since the date of purchase in our Oil and Gas segment. See pro forma combined operating results of the Company and the Remington acquisition for the year ended December 31, 2006 in “— Note 6 — Other Acquisitions” below.

Note 5 — Acquisition of Horizon Offshore, Inc.

On December 11, 2007, CDI acquired 100% of Horizon, a marine construction services company headquartered in Houston, Texas. Under the terms of the merger, each share of common stock, par value $0.00001 per share, of Horizon was converted into the right to receive $9.25 in cash and 0.625 shares of CDI’s common stock. All shares of Horizon restricted stock that had been issued but had not vested prior to the effective time of the merger became fully vested at the effective time of the merger and converted into the right to receive the merger consideration. CDI issued approximately 20.3 million shares of common stock and paid approximately $300 million in cash to the former Horizon stockholders upon completion of the acquisition. The cash portion of the merger consideration was paid from cash on hand and from borrowings of $375 million under CDI's new $675 million credit facility, which consists of a $375 million senior secured term loan and a $300 million senior secured revolving credit facility (see "— Note 11 — Long-Term Debt" below).

The aggregate purchase price, including transaction costs of $7.7 million, was approximately $630 million consisting of $308 million of cash and $322 million of stock, CDI also assumed and repaid approximately $104 million in Horizon debt, including accrued interest and prepayment penalties, and acquired $171 million of cash. Through the acquisition, the Company acquired nine construction vessels, including four pipelay/pipebury barges, one dedicated pipebury barge, one DSV, one combination derrick/pipelay barge and two derrick barges. The acquisition was accounted for as a business combination with the acquisition price allocated to the assets acquired and liabilities assumed based upon their estimated fair values. The following table summarizes the estimated preliminary fair values of the assets acquired and liabilities assumed at the date of acquisition (in thousands):

Cash	$170,697
Other current assets	157,507
Property and equipment	351,155
Other long-term assets	15,270
Goodwill	257,340
Intangible assets	9,510
Total assets acquired	961,479
Current liabilities	175,924
Deferred income taxes	67,826
Long-term debt	87,641
Other non-current liabilities	100
Total liabilities assumed	331,491
Net assets acquired	$629,988

The intangible assets relate to the fair value of contract backlog, customer relationships and non-compete agreements between CDI and certain members of Horizon's senior management as follows (dollars in thousands):

	Fair Value	Amortization Period
Customer relationships	$ 2,960	1.5 years
Contract backlog	3,060	5 years
Non-compete agreements	3,000	1 year
Trade name	490	9 years
	$ 9,510	

At December 31, 2007, the net carrying amount for these intangibles was $8.9 million.

The allocation of the purchase price was based upon preliminary valuations. Estimates and assumptions are subject to change upon the receipt and CDI management's review of the final valuations. The primary area of the purchase price allocation that is not yet finalized relates to post-closing purchase price adjustments and the receipt of final valuations. The final valuation of net assets is expected to be completed no later than one year from the acquisition date. The results of Horizon are included in the accompanying consolidated and combined statements of operations since the date of purchase in our Shelf Contracting segment. See pro forma combined operating results of the Company and the Horizon acquisition for the years ended December 31, 2007 and 2006 in "— Note 6 — Other Acquisitions" below.

We recognized a non-cash pre-tax gain of $151.7 million ($98.6 million net of taxes of $53.1 million) in 2007 as our share of CDI's underlying equity increased as a result of CDI's issuance of 20.3 million shares of common stock to former Horizon stockholders, which reduced our ownership to 58.5%. The gain was calculated as the difference in the value of our investment in CDI immediately before and after CDI's stock issuance.

Note 6 — Other Acquisitions

2007

Well Ops SEA Pty Ltd.

In October 2006, we acquired a 58% interest in Seatrac Pty Ltd. ("Seatrac") for total consideration of approximately $12.7 million (including $180,000 of transaction costs), with approximately $9.1 million paid to existing Seatrac shareholders and $3.4 million for subscription of new Seatrac shares. We renamed this entity Well Ops SEA Pty Ltd. ("WOSEA"). WOSEA is a subsea well intervention and engineering services company located in Perth, Australia. Under the terms of the purchase agreement, we had an option to purchase the remaining 42% of the entity for approximately $10.1 million. On July 1, 2007, we exercised this option and now own 100% of the entity. In addition, the agreement with the existing shareholders provides for an earnout period of five years from the closing date for the purchase of the remaining 42% of WOSEA. If during this five-year period WOSEA achieves certain financial performance objectives, the shareholders will be entitled to additional consideration of approximately $4.6 million. This purchase was accounted for as a business combination with the acquisition price allocated to the assets acquired and liabilities assumed based upon their estimated fair value, with the excess being recorded as goodwill. The following table summarizes the preliminary estimated fair values of the assets acquired and liabilities assumed at July 1, 2007 (in thousands):

Cash and cash equivalents	$ 2,631
Other current assets	4,279
Property and equipment	9,571
Goodwill	11,328
Total assets acquired	$27,809
Accounts payable and accrued liabilities	$ 5,059
Net assets acquired	$22,750

The allocation of the purchase price was based upon preliminary valuations. Estimates and assumptions are subject to change upon the receipt and management's review of the final valuations. The primary areas of the purchase price allocation that are not yet finalized relate to the identification and valuation of potential intangible assets and valuation of certain equipment. The final valuation of net assets is expected to be completed no later than one year from the acquisition date. Any future change in the value of net assets will be offset by a corresponding increase or decrease in goodwill. Pro forma combined operating results for the years ended December 31, 2007 and 2006 (adjusted to reflect the results of operations of WOSEA prior to its acquisition) are not provided because the pre-acquisition results related to WOSEA were not material to the historical results of the Company.

2006

Fraser Diving International Ltd.

In July 2006, we acquired the business of Singapore-based Fraser Diving International Ltd. ("Fraser") for an aggregate purchase price of approximately $29.3 million, subject to post-closing adjustments, and the assumption of $2.2 million of liabilities. Fraser owned six portable saturation diving systems and 15 surface diving systems that operate primarily in Southeast Asia, the Middle East, Australia and the Mediterranean. Included in the purchase price is a payment of $2.5 million made in December 2005 to Fraser for the purchase of one of the portable saturation diving systems. The acquisition was accounted for as a business combination with the acquisition price allocated to the assets acquired and liabilities assumed based upon their estimated fair values. The final valuation of net assets was completed in the second quarter of 2007. The following table summarizes the estimated fair values of the assets acquired and liabilities assumed at the date of acquisition (in thousands):

Cash and cash equivalents	$ 2,332
Accounts receivable	1,817
Prepaid expenses and deposits	691
Portable saturation diving systems and surface diving systems	23,685
Diving support equipment, support facilities and other equipment	3,004
Total assets acquired	$31,529
Accounts payable and accrued liabilities	$ 2,243
Net assets acquired	$29,286

The results of Fraser have been included in the accompanying consolidated statements of operations in our Shelf Contracting segment since the date of purchase. Pro forma combined operating results for the year ended December 31, 2006 (adjusted to reflect the results of operations of Fraser prior to its acquisition) are not provided because the pre-acquisition results related to Fraser were not material to the historical results of the Company.

2005

Torch Offshore, Inc.

In a bankruptcy auction held in June 2005, we were the high bidder for seven vessels, including the *Express,* and a portable saturation system for approximately $85.9 million, pursuant to the terms of an amended and restated asset purchase agreement, executed in May 2005, with Torch Offshore, Inc. ("Torch"). This transaction received regulatory approval, including completion of a review pursuant to a Second Request from the U.S. Department of Justice, in August 2005 and subsequently closed. The total purchase price for the Torch vessels was approximately $85.9 million, including certain costs incurred related to the transaction. The acquisition was an asset purchase with the acquisition price allocated to the assets acquired based upon their estimated fair values. All of the assets acquired except for the *Express* (included in our Contracting Services segment) are included in the Shelf Contracting segment. The results of operations of the acquired vessels are included in the accompanying consolidated statements of operations since the date of the purchase, August 31, 2005.

Acergy US Inc.

In April 2005, we agreed to acquire the diving and shallow water pipelay assets of Acergy that operate in the waters of the Gulf of Mexico and Trinidad. The transaction included: seven diving support vessels; two diving and pipelay vessels (the *Kestrel* and the *DLB 801);* a portable saturation diving system; various general diving equipment and Louisiana operating bases at the Port of Iberia and Fourchon. All of the assets are included in the Shelf Contracting segment. The transaction required regulatory approval, including the completion of a review pursuant to a Second Request from the U.S. Department of Justice. On October 18, 2005, we received clearance from the U.S. Department of Justice to close the purchase from Acergy. Under the terms of the clearance, we were required to divest two diving support vessels and a portable saturation diving system from the combined asset package acquired through this transaction and the Torch transaction. We disposed of these assets in 2006 and 2007. These assets were included in assets held for sale totaling approximately $700,000 and $7.8 million as of December 31, 2006 and 2005, respectively. On November 1, 2005, we closed the transaction to purchase the Acergy diving assets operating in the Gulf of Mexico. We acquired the *DLB 801* in January 2006 for approximately $38.0 million and the *Kestrel* for approximately $39.9 million in March 2006.

The Acergy acquisition was accounted for as a business combination with the acquisition price allocated to the assets acquired and liabilities assumed based upon their fair values, with the excess recorded as goodwill. The final valuation of net assets was completed in the second quarter of 2006. The total transaction value for all of the assets was approximately $124.3 million. The allocation of the Acergy purchase prices was as follows (in thousands):

Vessels	$ 94,484
Goodwill	11,693
Portable saturation system and diving equipment	9,494
Facilities, land and leasehold improvements	4,314
Customer relationships intangible asset (1)	3,698
Materials and supplies	631
Total	$124,314

(1) The customer relationship intangible asset is amortized over eight years on a straight-line basis, or approximately $463,000 per year.

The results of operations of the acquired assets are included in the accompanying consolidated statements of operations in our Shelf Contracting segment since the date of the purchase. Pro forma combined operating results adjusted to reflect the results of operations of the DLB 801 and the Kestrel prior to their acquisition from Acergy in January and March 2006, respectively, are not provided because the 2006 pre-acquisition results related to these vessels were immaterial to our historical results. See pro forma combined operating results of the Company and the Acergy acquisition for the year ended December 31, 2006 below.

Subsequent to our purchase of the *DLB 801*, we sold a 50% interest in the vessel in January 2006 for approximately $19.0 million. We received $6.5 million in cash in 2005 and a $12.5 million interest-bearing promissory note in 2006. The promissory note as of December 31, 2006 was $1.5 million. The balance of the promissory note was received in 2007. Subsequent to the sale of the 50% interest, we entered into a 10-year charter lease agreement with the purchaser, in which the lessee has an option to purchase the remaining 50% interest in the vessel. This lease was accounted for as an operating lease. Included in our lease accounting analysis was an assessment of the likelihood of the lessee performing under the full term of the lease. The remaining 50% interest and the related 10-year charter lease agreement were conveyed to CDI in 2006. In December 2007, we entered into a global settlement with the lessee pursuant to which we received full payment of all amounts owed under the charter agreement and we sold our remaining interest in the DLB 801 to the lessee for cash consideration of $18.6 million. As a result, we recognized a gain on sale of $2.2 million in our Shelf Contracting segment.

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Helix Energy Limited

On November 3, 2005, we acquired Helix Energy Limited for approximately $32.7 million (approximately $27.1 million in cash, including transaction costs, and $5.6 million, at time of acquisition, in two year, variable rate notes payable to certain former owners that were repaid in November 2007), offset by $3.4 million of cash acquired. Helix Energy Limited is an Aberdeen, UK based provider of reservoir and well technology services to the upstream oil and gas industry with offices in London, Kuala Lumpur (Malaysia) and Perth (Australia). The acquisition was accounted for as a business combination with the acquisition price allocated to the assets acquired and liabilities assumed as follows (in thousands):

Cash and cash equivalents	$ 3,417
Other current assets	9,786
Property and equipment, net	632
Intangibles with definite useful lives (1)	10,459
Trade name intangible (2)	6,309
Goodwill	9,549
Total assets acquired	$40,152
Accounts payable and accrued liabilities	$ 4,920
Deferred tax liability	2,532
Net assets acquired	$32,700

(1) Intangibles with definite useful lives include the following:

- $1.1 million of patented technology, which is amortized over 20 years on a straight-line basis, or approximately $56,800 per year;
- $6.9 million of customer relationship, which is amortized over 12 years on a straight-line basis, or approximately $578,000 per year; and
- $2.4 million of non-compete intangible asset, which is amortized over 3.5 years on a straight-line basis, or approximately $683,000 per year.

(2) The trade name intangible has an indefinite useful life. It is not amortized, but is tested for impairment at least annually or when impairment indicators are present.

The final valuation of net assets was completed in 2006. The results of Helix Energy Limited are included in the accompanying statements of operations (Contracting Services segment) since the date of the purchase.

Pro forma combined operating results of the Company and the Horizon and Remington acquisitions for the years ended December 31, 2007 and 2006 were presented as if the acquisitions had been completed as of January 1, 2006. The unaudited pro forma combined results were as follows (in thousands, except per share data):

	Year Ended December 31,	
	2007	2006 (1)
Net revenues	$ 2,150,041	$ 2,040,600
Income before income taxes (2)	496,639	673,354
Net income (2)	298,195	369,889
Net income applicable to common shareholders (2)	294,479	366,531
Earnings per common share (2):		
Basic	$ 3.27	$ 4.02
Diluted	$ 3.11	$ 3.84

(1) Includes approximately $11.5 million of severance and incentive compensation expense, and approximately $20.6 million of non-cash stock compensation expense for vesting of stock options and restricted shares incurred by Remington in June 30, 2006.

(2) Includes pre-tax gain of approximately $151.7 million and $223.1 million related to CDI's issuance of stock during the year ended December 31, 2007 and 2006, respectively. The taxes associated with this gain were approximately $53.1 million and $126.6 million, respectively.

Note 7 — Oil and Gas Properties

We follow the successful efforts method of accounting for our interests in oil and gas properties. Under the successful efforts method, the costs of successful wells and leases containing productive reserves are capitalized. Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized. Costs incurred relating to unsuccessful exploratory wells are expensed in the period the drilling is determined to be unsuccessful.

At December 31, 2007, we had capitalized approximately $19.1 million of exploratory drilling costs associated with ongoing exploration and/or appraisal activities. Such capitalized costs may be charged against earnings in future periods if management determines that commercial quantities of hydrocarbons have not been discovered or that future appraisal drilling or development activities are not likely to occur. The following table provides a detail of our capitalized exploratory project costs at December 31, 2007 and 2006 (in thousands):

	2007	2006
Noonan (1)	$ —	$27,824
Huey	11,556	11,378
Castleton (part of Gunnison)	7,071	7,070
Other	469	3,711
Total	$19,096	$49,983

(1) Well was completed in 2007.

As of December 31, 2007, the exploratory well costs for Castleton and Huey had been capitalized for longer than one year. We are not the operator of Castleton.

The following table reflects net changes in suspended exploratory well costs during the year ended December 31, 2007, 2006 and 2005 (in thousands):

	2007	2006	2005
Beginning balance at January 1,	$ 49,983	$ 12,014	$ 1,052
Additions pending the determination of proved reserves	213,699	138,679	10,962
Reclassifications to proved properties	(234,277)	(62,375)	—
Charged to dry hole expense	(10,309)	(38,335)	—
Ending balance at December 31,	$ 19,096	$ 49,983	$12,014

Further, the following table details the components of exploration expense for the years ended December 31, 2007, 2006 and 2005 (in thousands):

	Years Ended December 31,		
	2007	2006	2005
Delay rental and geological and geophysical costs	$ 6,538	$ 4,780	$6,465
Dry hole expense	10,309	38,335	—
Total exploration expense	$16,847	$43,115	$6,465

In March 2005, we acquired a 30% working interest in a proved undeveloped field in Atwater Block 63 (Telemark) of the Deepwater Gulf of Mexico for cash and assumption of certain decommissioning liabilities. In December 2005, we were advised by Norsk Hydro USA Oil and Gas, Inc. (“Norsk Hydro”) that Norsk Hydro would not pursue its development plan for the deepwater discovery. As a result, we acquired a 100% working interest and operatorship in April 2006 following a non-consent to our plan of development by Norsk Hydro. Our interest in this property and surrounding fields was sold in July 2006 for $15 million in cash and we also retained a reservation of an overriding royalty interest in the Telemark development. We recorded a gain of $2.2 million in 2006 related to this sale.

In June 2005, we acquired a mature property package on the Gulf of Mexico shelf from Murphy — Oil Corporation (“Murphy”). The acquisition cost included both cash ($163.5 million) and the assumption of the estimated abandonment liability from Murphy of approximately $32.0 million (a non-cash investing activity). The acquisition represented essentially all of Murphy’s Gulf of Mexico Shelf properties consisting of eight operated and eleven non-operated fields. The results of the acquisition are included in the accompanying statements of operations since the date of purchase.

We agreed to participate in the drilling of an exploratory well (Tulane prospect) that was drilled in the first quarter of 2006. This prospect targeted reserves in deeper sands, within the same trapping fault system, of a currently producing well. In March 2006, mechanical difficulties were experienced in the drilling of this well, and after further review, the well was plugged and abandoned. Approximately $21.7 million related to this well was charged to earnings during the year ended December 31, 2006. Further, in the third quarter of 2006, we expensed approximately $15.9 million of exploratory drilling costs related to two deep shelf properties (acquired in the Remington acquisition which were in process prior to acquisition) in which we determined commercial quantities of hydrocarbons were not discovered.

In August 2006, we acquired a 100% working interest in the Typhoon oil field (Green Canyon Blocks 236/237), the Boris oil field (Green Canyon Block 282) and the Little Burn oil field (Green Canyon Block 238) for assumption of certain decommissioning liabilities. We have received suspension of production (“SOP”) approval from the MMS. We will also have farm-in rights on five near-by blocks where three prospects have been identified in the Typhoon mini-basin. Following the acquisition of the Typhoon field and MMS approval, we renamed the field Phoenix. We expect to deploy a minimal floating production system in mid-2008 in the Phoenix field.

In December 2006, we acquired a 100% working interest in the Camelot gas field in the North Sea in exchange for the assumption of certain decommissioning liabilities estimated at approximately $7.6 million. In June 2007, we sold a 50% working interest in this property for approximately $1.8 million and the assumption by the purchaser of 50% of the decommissioning liability of approximately $4.0 million. We recognized a gain of approximately $1.6 million as a result of this sale.

In 2007, we incurred $25.1 million of plug and abandonment overruns related to hurricanes *Katrina* and *Rita*, partially offset by insurance recoveries of $4.0 million. In addition, we increased our abandonment liability at December 31, 2007 for work yet to be done for certain properties damaged by the hurricanes totaling $9.6 million, partially offset by estimated insurance recoveries of $4.9 million. Further, in 2006, we expensed inspection and repair costs related to damages sustained by Hurricanes *Katrina* and *Rita* for our oil and gas properties totaling approximately $16.8 million, partially offset by $9.7 million of insurance recoveries received. In 2005, we expensed approximately $7.1 million of inspection and repair costs as a result of damages caused by these hurricanes. No insurance recoveries were received in 2005.

On September 30, 2007, we sold a 30% working interest in the Phoenix, Boris oilfield and the Little Burn oilfield (Green Canyon Block 238) to Sojitz GOM Deepwater, Inc. (“Sojitz”), a wholly owned subsidiary of Sojitz Corporation, for a cash payment of $40 million and the proportionate recovery of all past and future capital expenditures related to the re-development of the fields, excluding the conversion of the *Helix Producer I*, which we plan to use as a redeployable floating production unit (“FPU”). Proceeds of $51.2 million from the sale were collected in October 2007. Sojitz will also pay its proportionate share of the operating costs including fees payable for the use of the FPU. A gain of approximately $40.4 million was recorded in 2007.

Also in 2007, we recorded impairment expense of approximately $59.4 million (all recorded in fourth quarter 2007) related to our proved oil and gas properties primarily as a result of downward reserve revisions and weak end of life well performance in some of our domestic properties. In addition, we recorded approximately $9.9 million ($9.0 million in fourth quarter 2007) of impairment expense related to our unproved properties primarily due to management’s assessment that exploration activities will not commence prior to the respective lease expiration dates. Further, we expensed approximately $5.9 million of dry hole exploratory costs in fourth quarter related to our South Marsh Island 123 #1 well drilled in 2007 due to management’s decision not to execute previous development plans prior to the lease expiring. Lastly, fourth quarter 2007 depletion was impacted by certain producing properties that experienced significant proved reserve declines, thus causing a significant increase in the depletion rate for these properties. The impact in fourth quarter 2007 was approximately $12.5 million.

Our oil and gas activities in the United States are regulated by the federal government and require significant third-party involvement, such as refinery processing and pipeline transportation. We record revenue from our offshore properties net of royalties paid to the MMS. Royalty fees paid totaled approximately $57.1 million, $41.0 million and $34.0 million for the years ended December 31, 2007, 2006 and 2005, respectively. In accordance with federal regulations that require operators in the Gulf of Mexico to post an area wide bond of $3 million, the MMS has allowed us to fulfill such bonding requirements through an insurance policy.

Note 8 — Details of Certain Accounts (in thousands)

Other current assets consisted of the following as of December 31, 2007 and 2006:

	2007	2006
Other receivables	$ 6,733	$ 3,882
Prepaid insurance	21,133	17,320
Other prepaids	14,922	9,174
Spare parts inventory	29,925	3,660
Current deferred tax assets	13,810	3,706
Hedging assets	1,424	5,202
Insurance claims to be reimbursed	10,173	3,627
Income tax receivable	8,838	—
Gas imbalance	6,654	4,739
Other	11,970	10,222
	$125,582	$61,532

Other assets, net, consisted of the following as of December 31, 2007 and 2006:

	2007	2006
Restricted cash	$ 34,788	$ 33,676
Deposits	8,417	524
Deferred drydock costs, net	47,964	26,405
Deferred financing costs	39,290	28,257
Intangible assets with definite lives	22,216	20,783
Intangible asset with indefinite life	7,022	6,922
Contracts receivable	14,635	—
Other	2,877	1,344
	$177,209	$117,911

Accrued liabilities consisted of the following as of December 31, 2007 and 2006:

	2007	2006
Accrued payroll and related benefits	$ 50,389	$ 42,381
Royalties payable (1)	21,974	67,822
Current decommissioning liability	23,829	28,766
Unearned revenue	21,543	13,223
Insurance claims to be reimbursed	14,173	3,627
Accrued interest	7,090	15,579
Accrued severance (2)	14,786	—
Deposits	13,600	—
Hedging liability	10,308	184
Other	43,674	28,068
	$221,366	$199,650

(1) In 2007, we reclassified $55.1 million accrued liabilities to Other Long Term Liabilities related to disputed MMS royalties (see "— Note 18 — Commitments and Contingencies").

(2) Related to payments to be made to former Horizon personnel as a result of the acquisition by CDI.

Note 9 — Equity Investments

In June 2002, we formed Deepwater Gateway, L.L.C. with Enterprise, in which we each own a 50% interest, to design, construct, install, own and operate a TLP production hub primarily for Anadarko Petroleum Corporation's Marco Polo field discovery in the Deepwater Gulf of Mexico. Our share of the construction costs was approximately $120 million. Our investment in Deepwater Gateway totaled $112.8 million and $119.3 million as of December 31, 2007 and 2006, respectively, and was included in our Production Facilities segment. The investment balance at December 31, 2007 and 2006 included approximately $1.7 million of capitalized interest and insurance paid by us. In August 2002, Enterprise and we completed a limited recourse project financing for this venture. In accordance with terms of the term loan, Deepwater Gateway had the right to repay the principal amount plus any accrued interest due under its term loan at any time without penalty. Deepwater Gateway repaid the term loan in full in March 2005.

In December 2004, we acquired a 20% interest in Independence Hub, LLC, an affiliate of Enterprise. Independence owns the Independence Hub platform located in Mississippi Canyon block 920 in a water depth of 8,000 feet. The platform reached mechanical completion in May 2007. As a result, our performance guaranty related to Independence terminated in May 2007 with no further obligations. First production began in July 2007. Our investment in Independence was $95.7 million and $82.7 million as of December 31, 2007 and 2006, respectively (including capitalized interest of $6.2 million and $5.5 million at December 31, 2007 and 2006, respectively), and was included in our Production Facilities segment.

In July 2005, we acquired a 40% minority ownership interest in OTSL in exchange for our DP DSV, *Witch Queen*. Our investment in OTSL totaled $10.9 million at December 31, 2006 and is part of our Shelf Contracting segment. OTSL provides marine construction services to the oil and gas industry in and around Trinidad and Tobago, as well as the U.S. Gulf of Mexico. OTSL qualified as a variable interest entity ("VIE") under FIN 46. We determined that we were not the primary beneficiary of OTSL and, thus, have not consolidated the financial results of OTSL. We account for our investment in OTSL under the equity method of accounting.

We periodically review our equity investments for impairment. Recognition of an impairment occurs when the decline in an investment is deemed other than temporary. During the second quarter of 2007, OTSL generated significant operating losses, lost several project bids and ultimately decided to exit the saturation diving market. CDI determined that there was an other than temporary impairment in OTSL at June 30, 2007 and the full value of its investment in OTSL was impaired and recognized equity losses of OTSL, inclusive of the impairment charge, of $11.8 million in the second quarter of 2007. In accordance with the terms of the OTSL agreement, CDI is not required to make additional investments and has no plans to make additional investments in OTSL and therefore will not be subject to future losses or impairments relating to its ownership interest.

We made the following contributions to our equity investments during the years ended December 31, 2007, 2006 and 2005 (in thousands):

	Year Ended December 31,		
	2007	2006	2005
Deepwater Gateway, L.L.C.	$ —	$ —	$ 72,000
Independence Hub, LLC	12,475	27,578	39,060
OTSL	—	—	8,400
Other	4,984	—	—
Total	$17,459	$27,578	$119,460

We received the following distributions from our equity investments during the years ended December 31, 2007, 2006 and 2005 (in thousands):

	Year Ended December 31,		
	2007	2006	2005
Deepwater Gateway, L.L.C.	$27,000	$16,250	$21,100
Independence Hub, LLC	10,800	—	—
Total	$37,800	$16,250	$21,100

Note 10 — Consolidated Variable Interest Entities

In October 2006, we, along with Kommandor RØMØ, a Danish corporation, formed Kommandor LLC, a Delaware limited liability company, to initially convert a ferry vessel into a dynamically-positioned construction services vessel. Upon completion of the initial conversion, this vessel will be leased under a bareboat charter to us for further conversion and subsequent use as a floating production system in the Deepwater Gulf of Mexico, initially for the Phoenix field. Our initial investment for our 50% interest in Kommandor LLC was $15 million. Further, we provided a loan facility of up to $40 million and Kommandor RØMØ has loaned $5 million to the entity for purposes of completing the initial conversion. Kommandor LLC has an executed loan agreement with a financial institution for term financing for $45 million of the initial conversion upon delivery of the vessel under the bareboat charter. Funding is subject to customary conditions. Proceeds from this financing will be used to repay amounts loaned to Kommandor LLC by us and Kommandor RØMØ. Conversion of the vessel is expected to be completed in two phases. The first phase is expected to be completed in second quarter 2008 for approximately $87 million. The secondphase of the conversion is expected to be completed by third quarter 2008. Estimated cost of conversion for the second phase is approximately $117 million, in which we expect to participate 100%.

In addition, per the operating agreement with Kommandor RØMØ, for a period of two months immediately following the fifth anniversary of the completion of the initial conversion, we may purchase Kommandor RØMØ's membership interest at a value specified in the agreement ("Helix Option Period"). In addition, for a period of two months starting from 30 days after the Helix Option Period, Kommandor RØMØ can require us to purchase its share of the company at a value specified in the operating agreement. We estimate the cash outlay to Kommandor RØMØ for its interest in Kommandor LLC at the time the put or call is exercised to be approximately $27 million.

Kommandor LLC qualified as a VIE under FIN 46. We determined that we were the primary beneficiary of Kommandor LLC and, thus, have consolidated the financial results of Kommandor LLC as of December 31, 2007 and 2006. The results of Kommandor LLC are included in our Production Facilities segment. Kommandor LLC has been a development stage enterprise since its formation in October 2006.

Note 11 — Long-Term Debt

Senior Unsecured Notes

On December 21, 2007, we issued $550 million of 9.5% Senior Unsecured Notes due 2016 ("Senior Unsecured Notes"). The Senior Unsecured Notes are fully and unconditionally guaranteed by substantially all of our existing restricted domestic subsidiaries, except for CDI and Cal Dive I-Title XI, Inc. In addition, any future restricted domestic subsidiaries that guarantee any of our and/or our restricted subsidiaries' indebtedness are required to guarantee the Senior Unsecured Notes. CDI, the subsidiaries of CDI, and our foreign subsidiaries will not be guarantors. We used the proceeds from the Senior Unsecured Notes to repay outstanding indebtedness under our senior secured credit facilities (see below).

The Senior Unsecured Notes are junior in right of payment to all our existing and future secured indebtedness and obligations and rank equally in right of payment with all existing and future senior unsecured indebtedness of the Company. The Senior Unsecured Notes rank senior in right of payment to any of our future subordinated indebtedness and are fully and unconditionally guaranteed by the guarantors listed above on a senior basis.

The Senior Unsecured Notes mature on January 15, 2016. Interest on the Senior Unsecured Notes accrues at the rate of 9.5% per annum and is payable semiannually in arrears on each January 15 and July 15, commencing July 15, 2008. Interest is computed on the basis of a 360-day year comprising twelve 30-day months.

Included in the Senior Unsecured Notes indenture are terms, conditions and covenants that are customary for this type of offering. The covenants include limitations on our and our subsidiaries' ability to incur additional indebtedness, pay dividends, repurchase our common stock, and sell or transfer assets. As of December 31, 2007, we were in compliance with these covenants.

The Senior Unsecured Notes may be redeemed prior to the stated maturity under the following circumstances:

- After January 15, 2012, we may redeem all or a portion of the Senior Unsecured Notes, on not less than 30 nor more than 60 days' prior notice, at the redemption prices (expressed as percentages of the principal amount) set forth below, plus accrued and unpaid interest, if any, thereon, to the applicable redemption date.

Year	Redemption Price
2012	104.750%
2013	102.375%
2014 and thereafter	100.000%

- In addition, at any time and from time to time prior to January 15, 2011, we may use the net proceeds of one or more equity offerings to redeem up to an aggregate of 35% of the aggregate principal amount of Senior Unsecured Notes at a redemption price equal to 109.5% of the aggregate principal amount of the Senior Unsecured Notes redeemed, plus accrued and unpaid interest, if any, to the redemption date; provided that this redemption provision shall not be applicable with respect to any transaction that results in a change of control. At least 65% of the aggregate principal amount of Senior Unsecured Notes must remain outstanding immediately after the occurrence of such redemption.

In the event a change of control occurs, each holder of the Senior Unsecured Notes will have the right to require us to purchase all or any part of such holder's Senior Unsecured Notes. In such event, we will offer to purchase all of the Senior Unsecured Notes at a purchase price in cash in an amount equal to 101% of the principal amount, plus accrued and unpaid interest, if any, to the date of purchase.

Senior Credit Facilities

On July 3, 2006, we entered into a Credit Agreement (the "Credit Agreement") with Bank of America, N.A., as administrative agent and as lender, together with the other lenders (collectively, the "Lenders"). Under the Credit Agreement, we borrowed $835 million in a term loan (the "Term Loan") and may borrow revolving loans (the "Revolving Loans") under a revolving credit facility up to an outstanding amount of $300 million (the "Revolving Credit Facility"). In addition, the Revolving Credit Facility may be used for issuances of letters of credit up to an outstanding amount of $50 million. The proceeds from the Term Loan were used to fund the cash portion of the Remington acquisition.

The Term Loan and the Revolving Loans (together, the "Loans"), at our election, bear interest either in relation to Bank of America's base rate or to LIBOR. The Term Loan or portions thereof bear interest at one, three or six month LIBOR at our election plus a margin of 2.00%. Our current election is to bear interest based on LIBOR. Our interest rate for year ended December 31, 2007 and 2006 was approximately 7.1% and 7.4%, respectively, (including the effects of our interest rate swaps). The Revolving Loans or portions thereof bearing interest at LIBOR will bear interest based on one, three or six month LIBOR at our election plus a margin ranging from 1.00% to 2.25%. Margins on the Revolving Loans will fluctuate in relation to our consolidated leverage ratio as provided in the Credit Agreement.

The Term Loan matures on July 1, 2013 and is subject to quarterly scheduled principal payments. As a result of a $400 million prepayment made in December 2007, the scheduled principal payment was reduced from $2.1 million quarterly to $1.1 million quarterly. The Revolving Loans mature on July 1, 2011. We may elect to prepay amounts outstanding under the Term Loan without prepayment penalty, but may not reborrow any amounts prepaid. We may prepay amounts outstanding under the Revolving Loans without prepayment penalty, and may reborrow amounts prepaid prior to maturity. We had $240.8 million available under the Revolving Loans (including unsecured letters of credit of $41.2 million) at December 31, 2007. We did not have any amount outstanding under the Revolving Loans at December 31, 2006. In addition, upon the occurrence of certain dispositions or the issuance or incurrence of certain types of indebtedness, we may be required to prepay a portion of the Term Loan equal to the amount of proceeds received from such occurrences. Such prepayments will be applied first to the Term Loan, and any excess will be applied to the Revolving Loans, if any.

The Credit Agreement and the other documents entered into in connection with the Credit Agreement (together, the "Loan Documents") include terms, conditions and covenants that we consider customary for this type of transaction. The covenants include restrictions on the Company's and our subsidiaries' ability to grant liens, incur indebtedness, make investments, merge or consolidate, sell or transfer assets and pay dividends. The credit facility also places certain annual and aggregate limits on expenditures for acquisitions, investments in joint ventures and capital expenditures. The Credit Agreement requires us to meet minimum financial ratios for interest coverage, consolidated leverage and, until we achieve investment grade ratings from S&P and Moody's, collateral coverage.

If we or any of our subsidiaries do not pay any amounts owed to the Lenders under the Loan Documents when due, breach any other covenant to the Lenders or fail to pay other debt above a stated threshold, in each case, subject to applicable cure periods, then the Lenders have the right to stop making advances to us and to declare the Loans immediately due. The Credit Agreement includes other events of default that are customary for this type of transaction. As of December 31, 2007, we were in compliance with these covenants.

The Loans and our other obligations to the Lenders under the Loan Documents are guaranteed by all of our U.S. subsidiaries other than CDI and Cal Dive — Title XI, Inc., and are secured by a lien on substantially all of our assets and properties and all of the assets and properties of our U.S. subsidiaries, other than those of CDI and Cal Dive — Title XI, Inc.. In addition, we have pledged a portion of the shares of our significant foreign subsidiaries to the lenders as additional security. The Senior Credit Facilities also contain provisions that limit our ability to incur certain types of additional indebtedness. These provisions effectively prohibit us from incurring any additional secured indebtedness or indebtedness guaranteed by the Company. The Senior Credit Facilities do however permit us to incur unsecured indebtedness, and also provide for our subsidiaries to incur project financing indebtedness (such as our MARAD loans) secured by the underlying asset, provided that the indebtedness is not guaranteed by us.

As the rates for our Term Loan are subject to market influences and will vary over the term of the credit agreement, we entered into various cash flow hedging interest rate swaps to stabilize cash flows relating to a portion of our interest payments for our Term Loan. The interest rate swaps were effective October 3, 2006. These interest rate swaps qualified for hedge accounting. On December 21, 2007, a prepayment made to a hedged portion of our Term Loan brought the balance of that portion below the amount hedged by interest rate swaps. As a result, the hedge instruments became ineffective and no longer qualify for hedge accounting as of that date. For the period from December 21, 2007 to December 31, 2007, we recognized $402,000 as additional interest expense, net of taxes of $216,000 to adjust the net liability for the swaps to fair value ($4.0 million). The aggregate fair value of the hedge instruments was a net liability of $531,000 as of December 31, 2006. For the year ended December 31, 2006, these hedges were highly effective.

Cal Dive International, Inc. Credit Facility

In December 2007, CDI replaced its five-year $250 million revolving credit facility by entering into a secured credit facility with a bank group led by Bank of America, N.A., which also serves as administrative agent, consisting of a $375 million term loan and a $300 million revolving credit facility. Both the term loan and the revolving loans mature on December 11, 2012. Loans under this facility are non-recourse to Helix. The term loan and the revolving loans may consist of loans bearing interest in relation to the Federal Funds Rate or to Bank of America's base rate, known as Base Rate Loans, and loans bearing interest in relation to a LIBOR rate, known as Eurodollar Rate Loans, in each case plus an applicable margin. The margins on the revolving loans range from 0.75% to 1.50% on Base Rate Loans and 1.75% to 2.50% on Eurodollar Rate Loans. The margins on the term loan are 1.25% on Base Rate Loans and 2.25% on Eurodollar Rate Loans. If a default exists, the interest rates may be increased.

The credit agreement and the other documents entered into in connection with the credit agreement include terms and conditions, including covenants, which we consider customary for this type of transaction. The covenants include restrictions on CDI and CDI's subsidiaries' ability to grant liens, incur indebtedness, make investments, merge or consolidate, sell or transfer assets and pay dividends. In addition, the credit agreement obligates CDI to meet minimum financial requirements specified in the agreement. The credit facility is secured by vessel mortgages on all of CDI's vessels (except for the Sea Horizon), a pledge of all of the stock of all of CDI's domestic subsidiaries and 66% of the stock of two of CDI's foreign subsidiaries, and a security interest in, among other things, all of CDI's equipment, inventory, accounts and general intangible assets. At December 31, 2007, CDI was in compliance with all debt covenants.

On December 11, 2007, CDI borrowed $375 million under their term loan and used those proceeds to fund the cash portion of their merger consideration in connection with CDI's acquisition of Horizon and to retire Horizon's existing debt. The term loan requires quarterly principal payments of $20 million beginning June 20, 2008. At December 31, 2007 there was $273.3 million available under the revolving credit facility (including $26.7 million of unsecured letters of credit). CDI expects to use the remaining availability under the revolving credit facility for its working capital and other general corporate purposes.

Convertible Senior Notes

On March 30, 2005, we issued $300 million of 3.25% Convertible Senior Notes due 2025 ("Convertible Senior Notes") at 100% of the principal amount to certain qualified institutional buyers. The Convertible Senior Notes are convertible into cash and, if applicable, shares of our common stock based on the specified conversion rate, subject to adjustment. As a result of our two for one stock split paid on December 8, 2005, effective as of December 2, 2005, the initial conversion rate of the Convertible Senior Notes of 15.56, which was equivalent to a conversion price of approximately $64.27 per share of common stock, was changed to 31.12 shares of common stock per $1,000 principal amount of the Convertible Senior Notes, which is equivalent to a conversion price of approximately $32.14 per share of common stock. We may redeem the Convertible Senior Notes on or after December 20, 2012. Beginning with the period commencing on December 20, 2012 to June 14, 2013 and for each six-month period thereafter, in addition to the stated interest rate of 3.25% per annum, we will pay contingent interest of 0.25% of the market value of the Convertible Senior Notes if, during specified testing periods, the average trading price of the Convertible Senior Notes exceeds 120% or more of the principal value. In addition, holders of the Convertible Senior Notes may require us to repurchase the notes at 100% of the principal amount on each of December 15, 2012, 2015, and 2020, and upon certain events.

The Convertible Senior Notes can be converted prior to the stated maturity under the following circumstances:

- during any fiscal quarter (beginning with the quarter ended March 31, 2005) if the closing sale price of our common stock for at least 20 trading days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter exceeds 120% of the conversion price on that 30th trading day (i.e., $38.56 per share);
- upon the occurrence of specified corporate transactions; or
- if we have called the Convertible Senior Notes for redemption and the redemption has not yet occurred.

To the extent we do not have alternative long-term financing secured to cover such conversion notice, the Convertible Senior Notes would be classified as a current liability in the accompanying balance sheet.

In connection with any conversion, we will satisfy our obligation to convert the Convertible Senior Notes by delivering to holders in respect of each $1,000 aggregate principal amount of notes being converted a "settlement amount" consisting of:

- cash equal to the lesser of $1,000 and the conversion value, and
- to the extent the conversion value exceeds $1,000, a number of shares equal to the quotient of (A) the conversion value less $1,000, divided by (B) the last reported sale price of our common stock for such day.

The conversion value means the product of (1) the conversion rate in effect (plus any applicable additional shares resulting from an adjustment to the conversion rate) or, if the Convertible Senior Notes are converted during a registration default, 103% of such conversion rate (and any such additional shares), and (2) the average of the last reported sale prices of our common stock for the trading days during the cash settlement period. In the fourth quarter of 2007, the closing sale price of our common stock for at least 20 trading days in the period of 30 consecutive trading days ending on December 31, 2007 exceeded 120% of the conversion price (i.e. $38.56 per share). As a result, pursuant to the terms of the indenture, the Convertible Senior Notes can be converted during first quarter 2008. As we have sufficient financing available under our Revolving Credit Facility and a commitment from a financial institution to fully fund the cash portion of the potential conversion, the Convertible Senior Notes continue to be classified as a long-term liability in the accompanying balance sheet. During 2006, no conversion triggers were met.

Approximately 1.5 million and 1.0 million shares underlying the Convertible Senior Notes were included in the calculation of diluted earnings per share for the year ended December 31, 2007 and 2006, respectively, because our weighted average share price for each period was above the conversion price of approximately $32.14 per share. As a result, there would be a premium over the principal amount, which is paid in cash, and the shares would be issued on conversion. The maximum number of shares of common stock which may be issued upon conversion of the Convertible Senior Notes is 13,303,770. In addition to the 13,303,770 shares of common stock registered, we registered an indeterminate number of shares of common stock issuable upon conversion of the Convertible Senior Notes by means of an antidilution adjustment of the conversion price pursuant to the terms of the Convertible Senior Notes. Proceeds from the offering were used for general corporate purposes including a capital contribution of $72 million, made in March 2005, to Deepwater Gateway to enable it to repay its term loan, and strategic acquisitions in 2005 (Torch and Acergy vessels and Murphy oil and gas properties).

MARAD Debt

At December 31, 2007 and 2006, $127.5 million and $131.3 million, respectively, was outstanding on our long-term financing for construction of the *Q4000.* This U.S. Government guaranteed financing is pursuant to Title XI of the Merchant Marine Act of 1936 which is administered by the Maritime Administration (“MARAD Debt”). The MARAD Debt is payable in equal semi-annual installments which began in August 2002 and matures 25 years from such date. The MARAD Debt is collateralized by the *Q4000,* with us guaranteeing 50% of the debt, and initially bore interest at a floating rate which approximated AAA Commercial Paper yields plus 20 basis points. As provided for in the existing MARAD Debt agreements, in September 2005, we fixed the interest rate on the debt through the issuance of a 4.93% fixed-rate note with the same maturity date (February 2027). In accordance with the MARAD Debt agreements, we are required to comply with certain covenants and restrictions, including the maintenance of minimum net worth, working capital and debt-to-equity requirements. As of December 31, 2007 and 2006, we were in compliance with these covenants.

In September 2005, we entered into an interest rate swap agreement with a bank. The swap was designated as a cash flow hedge of a forecasted transaction in anticipation of the refinancing of the MARAD Debt from floating rate debt to fixed-rate debt that closed on September 30, 2005. The interest rate swap agreement totaled an aggregate notional amount of $134.9 million with a fixed interest rate of 4.695%. On September 30, 2005, we terminated the interest rate swap and received cash proceeds of approximately $1.5 million representing a gain on the interest rate differential. This gain was deferred and is being amortized over the remaining life of the MARAD Debt as an adjustment to interest expense.

Other

In connection with the acquisition of Helix Energy Limited, we entered into a two-year note payable to the former owners totaling approximately 3.1 million British Pounds, or approximately $5.6 million, on November 3, 2005 (approximately $6.2 million at December 31, 2006). The notes bore interest at a LIBOR based floating rate with interest payments due quarterly beginning January 1, 2006. The loan notes were repaid in November 2007.

In connection with borrowings under our long-term debt financings described above, we paid deferred financing cost of $17.2 million and $11.8 million during the years ended December 31, 2007 and 2006, respectively. Deferred financing costs of $39.3 million and $28.3 million are included in Other Assets, Net (see “— Note 8 — Detail of Certain Accounts”) as of December 31, 2007 and 2006, respectively, and are being amortized over the life of the respective agreement. In December 2007, as a result of prepaying $400 million of the Term Loan, we expensed $3.5 million, the proportionate share of the deferred financing cost related to the Term Loan. The amount was recorded as additional interest expense.

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Scheduled maturities of long-term debt and capital lease obligations outstanding as of December 31, 2007 were as follows (in thousands):

	Helix Term Loan	Helix Revolving Loans	CDI Term Loan	Senior Unsecured Notes	Convertible Senior Notes	MARAD Debt	Loan Note (1)	Capital Leases	Total
Less than one year	$ 4,326	$ —	$ 60,000	$ —	$ —	$ 4,014	$ 5,002	$ 1,504	$ 74,846
One to two years	4,326	—	80,000	—	—	4,214	—	—	88,540
Two to three years	4,326	—	80,000	—	—	4,424	—	—	88,750
Three to four years	4,326	18,000	80,000	—	—	4,645	—	—	106,971
Four to five years	4,326	—	75,000	—	—	4,877	—	—	84,203
Over five years	401,788	—	—	550,000	300,000	105,289	—	—	1,357,077
Long-term debt	423,418	18,000	375,000	550,000	300,000	127,463	5,002	1,504	1,800,387
Current maturities	(4,326)	—	(60,000)	—	—	(4,014)	(5,002)	(1,504)	(74,846)
Long-term debt, less current maturities	$ 419,092	$ 18,000	$ 315,000	$ 550,000	$ 300,000	$ 123,449	$ —	$ —	$ 1,725,541

(1) Represents the $5 million loan provided by Kommandor RØMØ to Kommandor LLC as of December 31, 2007.

We had unsecured letters of credit outstanding at December 31, 2007 totaling approximately $67.9 million. These letters of credit primarily guarantee various contract bidding and insurance activities. The following table details our interest expense and capitalized interest for the years ended December 31, 2007, 2006 and 2005 (in thousands):

	Year Ended December 31,		
	2007	2006	2005
Interest expense	$ 100,397	$ 51,913	$ 14,970
Interest income	(9,539)	(6,259)	(5,917)
Capitalized interest	(31,790)	(10,609)	(2,025)
Interest expense, net	$ 59,068	$ 35,045	$ 7,028

Note 12 — Income Taxes

We and our subsidiaries, including acquired companies from their respective dates of acquisition, file a consolidated U.S. federal income tax return. At December 13, 2006, CDI was separated from our tax consolidated group as a result of its initial public offering. As a result, we are required to accrue income tax expense on our share of CDI's net income after the initial public offering in all periods where we consolidate their operations. The deconsolidation of CDI's net income after its initial public offering did not have a material impact on our consolidated results of operations; however, because of our inability to recover our tax basis in CDI tax free, a long term deferred tax liability is provided for any incremental tax increases to the book over tax basis.

We conduct our international operations in a number of locations that have varying laws and regulations with regard to taxes. Management believes that adequate provisions have been made for all taxes that will ultimately be payable. Income taxes have been provided based on the US statutory rate of 35% adjusted for items which are allowed as deductions for federal income tax reporting purposes, but not for book purposes. The primary differences between the statutory rate and our effective rate were as follows:

	Year Ended December 31,		
	2007	2006	2005
Statutory rate	35.0%	35.0%	35.0%
Gain on subsidiary equity transaction	—	8.0	—
Foreign provision	(1.4)	(0.2)	—
Percentage depletion in excess of basis	—	(0.1)	(0.7)
IRC Section 199 deduction	(0.2)	(0.2)	(0.5)
Other	(0.1)	—	(0.8)
Effective rate	33.3%	42.5%	33.0%

Components of the provision for income taxes reflected in the statements of operations consisted of the following (in thousands):

	Year Ended December 31,		
	2007	2006	2005
Current	$ 47,970	$199,921	$32,291
Deferred	126,958	57,235	42,728
	$174,928	$257,156	$75,019

	Year Ended December 31,		
	2007	2006	2005
Domestic	$149,793	$247,588	$68,957
Foreign	25,135	9,568	6,062
	$174,928	$257,156	$75,019

In 2007, 2006 and 2005, our oil and gas activities and certain construction activities qualified for a tax deduction under Internal Revenue Code ("IRC") Section 199. In addition, due to our taxable income position at December 31, 2007, 2006 and 2005, the IRC allowed a deduction for percentage depletion in excess of basis on our oil and gas activities.

As a result of the Remington acquisition on July 1, 2006, a deferred tax asset was recorded as a part of the purchase price allocation to reflect the availability of approximately $65.2 million of net operating loss carryforward as of the acquisition date. As a result of our taxable income position during 2007 and 2006, we were able to utilize all of the $65.2 million of the net operating loss carryforward at December 31, 2007.

Deferred income taxes result from the effect of transactions that are recognized in different periods for financial and tax reporting purposes. The nature of these differences and the income tax effect of each as of December 31, 2007 and 2006 are as follows (in thousands):

	2007	2006
Deferred tax liabilities:		
Depreciation and Depletion	$ 581,178	$416,762
Subsidiary book basis in excess of tax	50,339	—
Equity investments in production facilities	35,288	30,723
Prepaid and other	59,237	31,383
Total deferred tax liabilities	$ 726,042	$478,868
Deferred tax assets:		
Net operating loss carryforward	$ (19,933)	$ (3,888)
Decommissioning liabilities	(65,685)	(33,367)
Reserves, accrued liabilities and other	(31,693)	(8,775)
Valuation allowance	2,967	—
Total deferred tax assets	$ (114,344)	$ (46,030)
Net deferred tax liability	$ 611,698	$432,838

At December 31, 2007 and 2006, we had $7.6 million and $4.9 million of net operating losses, respectively, that were incurred in the United Kingdom. The utilization of these net operating losses is restricted to the entity generating the loss. The U.K. losses have an indefinite carryforward period.

The utilization of Horizon’s net operating loss carryforward is limited due to changes in control for tax purposes occurring both prior to, and in connection with, CDI’s acquisition of Horizon on December 11, 2007. As a result, net operating losses of approximately $11.0 million have an annual limit of approximately $611,000. The remaining tax benefits have an annual limit of approximately $26.2 million. We estimate that the limitation of the tax benefits for periods prior to December 11, 2007 that can be utilized during the loss carryforward period will not adversely affect our cash flows.

As of December 31, 2007, CDI had $46.1 million in net operating loss carry forward, which begin to expire in 2016, $7.4 million in U.S. foreign tax credit carry forward, which begin to expire in 2016, and $888,000 in non-expiring U.S. alternative minimum tax carry forward.

For the year ended December 31, 2007, CDI established a $3.0 million valuation allowance related to a book capital loss, as management believes it is more likely than not that we will not be able to utilize the tax benefit.

Additional valuation allowances may be made in the future if in management’s opinion it is more likely than not that the tax benefit will not be utilized. Any limitations on our ability to utilize our tax benefit carry forward could result in an increase in our federal income tax liability in future taxable periods, which could affect our cash flow.

We consider the undistributed earnings of our principal non-U.S. subsidiaries to be permanently reinvested. At December 31, 2007 and 2006, our principal non-U.S. subsidiaries had accumulated earnings and profits of approximately $87.6 million and a $20.3 million, respectively. We have not provided deferred U.S. income tax on the accumulated earnings and profits. Alternatively, as a result of our inability to recover our tax basis in CDI tax free, we have provided a deferred tax liability on the incremental increases to the book over tax basis.

We adopted the provisions of FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (“FIN 48”) on January 1, 2007. The impact of the adoption of FIN 48 was immaterial to our financial position, results of operations and cash flows. We account for tax related interest in interest expense and tax penalties in operating expenses as allowed under FIN 48. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows (in thousands):

	Liability for Unrecognized Tax Benefits
Gross unrecognized tax benefits at January 1, 2007	$ —
Increases in tax positions for prior years	640
Gross unrecognized tax benefits at December 31, 2007	$ 640

The total amount of tax benefits that, if recognized, would affect the effective tax rate was $640,000 at December 31, 2007. At December 31, 2007, we did not accrue for any interest and penalties related to unrecognized tax benefits.

During the fourth quarter of 2006, Horizon received a tax assessment from the Servicio de Administracion Tributaria (“SAT”), the Mexican taxing authority, for approximately $23 million related to fiscal 2001, including penalties, interest and monetary correction. The SAT’s assessment claims unpaid taxes related to services performed among the Horizon subsidiaries that CDI acquired at the time it acquired Horizon. CDI believes under the Mexico and United States double taxation treaty that these services are not taxable and that the tax assessment itself is invalid. On February 14, 2008, CDI received notice from the SAT upholding the original assessment. We believe that CDI’s position is supported by law and CDI intends to vigorously defend its position. However, the ultimate outcome of this litigation and CDI’s potential liability from this assessment, if any, cannot be determined at this time. Nonetheless, an unfavorable outcome with respect to the Mexico tax assessment could have a material adverse effect on our financial position and results of operations. Horizon’s 2002 through 2007 tax years remain subject to examination by the appropriate governmental agencies for Mexico tax purposes, with 2002 and 2003 currently under audit.

We file tax returns in the U.S. and in various state, local and non-U.S. jurisdictions. We anticipate that any potential adjustments to our state, local and non-U.S. jurisdiction tax returns by tax authorities would not have a material impact on our financial position. The tax periods ending December 31, 2002, 2003, 2004, 2005, 2006 and 2007 remain subject to examination by the U.S. Internal Revenue Service (“IRS”). In addition, as we acquired Remington on July 1, 2006 we are exposed to any tax uncertainties related to Remington. For Remington, the tax period ending June 30, 2006 remains subject to examination by the IRS. The 2004 and 2005 tax returns for Remington were examined by the IRS and the examination was concluded with no adjustment.

In December 2006, we entered into the Tax Matters Agreement with CDI in connection with the CDI initial public offering. The following is a summary of the material terms of the Tax Matters Agreement:

- *Liability for Taxes.* Each party has agreed to indemnify the other in respect of all taxes for which it is responsible under the Tax Matters Agreement. We are generally responsible for all federal, state, local and foreign income taxes that are imposed on or are attributable to CDI or any of its subsidiaries for all tax periods (or portions thereof) ending on or before CDI’s initial public offering. CDI is generally responsible for all federal, state, local and foreign income taxes that are imposed on or are attributable to CDI or any of its subsidiaries for all tax periods (or portions thereof) beginning after its initial public offering. CDI is also responsible for all taxes other than income taxes imposed on or attributable to CDI or any of its subsidiaries for all tax periods.
- *Tax Benefit Payments.* As a result of certain taxable income recognition by us in conjunction with the CDI initial public offering, CDI will become entitled to certain tax benefits that are expected to be realized by CDI in the ordinary course of its business and otherwise would not have been available to CDI. These benefits are generally attributable to increased tax deductions for amortization of tangible and intangible assets and to increased tax basis in nonamortizable assets. Under the Tax Matters Agreement, for a period of

up to ten years, CDI will be required to make annual payments to us equal to 90% of the amount of taxes which CDI saves for each tax period as a result of these increased tax benefits. The timing of CDI's payments to us under the Tax Matters Agreement will be determined with reference to when CDI actually realizes the projected tax savings. This timing will depend upon, among other things, the amount of their taxable income and the timing at which certain assets are sold or disposed.

- *Preparation and Filing of Tax Returns.* We will prepare and file all income tax returns that include CDI or any of its subsidiaries if we are responsible for any portion of the taxes reported on such tax returns. The Tax Matters Agreement also provides that we will have the sole authority to respond to and conduct all tax proceedings (including tax audits) relating to such income tax returns.

For the year ended December 31, 2007, this agreement did not have a material impact on our consolidated results of operations.

Note 13 — Convertible Preferred Stock

On January 8, 2003, we completed the private placement of $25 million of a newly designated class of cumulative convertible preferred stock (Series A-1 Cumulative Convertible Preferred Stock, par value $0.01 per share) that is convertible into 1,666,668 shares of our common stock at $15 per share. The preferred stock was issued to a private investment firm. Subsequently in June 2004, the preferred stockholder exercised its existing right and purchased $30 million in additional cumulative convertible preferred stock (Series A-2 Cumulative Convertible Preferred Stock, par value $0.01 per share). In accordance with the January 8, 2003 agreement, the $30 million in additional preferred stock is convertible into 1,964,058 shares of our common stock at $15.27 per share. In the event the holder of the convertible preferred stock elects to redeem into our common stock and our common stock price is below the conversion prices, unless we have elected to settle in cash, the holder would receive additional shares above the 1,666,668 common shares (Series A-1 tranche) and 1,964,058 common shares (Series A-2 tranche). The incremental shares would be treated as a dividend and reduce net income applicable to common shareholders.

The preferred stock has a minimum annual dividend rate of 4%, subject to adjustment, payable quarterly in cash or common shares at our option. The dividend rate for the years ended December 31, 2007, 2006 and 2005 was 6.4%, 6.9% and 5.9%, respectively. We paid these dividends in 2007, 2006 and 2005 in cash. The holder may redeem the value of its original and additional investment in the preferred shares to be settled in common stock at the then prevailing market price or cash at our discretion. In the event we are unable to deliver registered common shares, we could be required to redeem in cash.

The proceeds received from the sales of this stock, net of transaction costs, have been classified outside of shareholders' equity on the balance sheet below total liabilities. Prior to the conversion, common shares issuable will be assessed for inclusion in the weighted average shares outstanding for our diluted earnings per share using the if converted method based on the lower of our share price at the beginning of the applicable period or the applicable conversion price ($15.00 and $15.27).

Note 14 — Employee Benefit Plans

Defined Contribution Plan

We sponsor a defined contribution 401(k) retirement plan covering substantially all of our employees. Our contributions are in the form of cash and are determined annually as 50 percent of each employee's contribution up to 5 percent of the employee's salary. Our costs related to this plan totaled $2.8 million, $2.3 million and $963,000 for the years ended December 31, 2007, 2006 and 2005, respectively.

Stock-Based Compensation Plans

We have three stock-based compensation plans: the 1995 Long-Term Incentive Plan, as amended (the "1995 Incentive Plan"), the 2005 Long-Term Incentive Plan (the "2005 Incentive Plan") and the 1998 Employee Stock

Purchase Plan (the "ESPP"). In addition, CDI has a stock-based compensation plan, the 2006 Long-Term Incentive Plan (the "CDI Incentive Plan") and an Employee Stock Purchase Plan (the "CDI ESPP") available only to the employees of CDI and its subsidiaries.

Under the 1995 Incentive Plan, a maximum of 10% of the total shares of common stock issued and outstanding may be granted to key executives and selected employees and non-employee members of the Board of Directors. Following the approval by shareholders of the 2005 Incentive Plan on May 10, 2005, no further grants have been or will be made under the 1995 Plan. The aggregate number of shares that may be granted under the 2005 Incentive Plan is 6,000,000 shares (after adjustment for the December 8, 2005 two-for-one stock split) of which 4,000,000 shares may be granted in the form of restricted stock or restricted stock units and 2,000,000 shares may be granted in the form of stock options. The 1995 and 2005 Incentive Plans and the ESPP are administered by the Compensation Committee of the Board of Directors, which in the case of the 1995 and 2005 Incentive Plans, determines the type of award to be made to each participant, and as set forth in the related award agreement, the terms, conditions and limitations applicable to each award. The committee may grant stock options, stock, stock units, and cash awards. Awards granted to employees under the 1995 and 2005 Incentive Plan typically vest 20% per year for a five-year period (or in the case of certain stock option awards under the 1995 Incentive Plan, 33% per year for a three-year period); if in the form of stock options, have a maximum exercise life of ten years; and, subject to certain exceptions, are not transferable.

Prior to January 1, 2006, we used the intrinsic value method of accounting for our stock-based compensation. Accordingly, no compensation expense was recognized when the exercise price of an employee stock option was equal to the common share market price on the grant date and all other terms were fixed. In addition, under the intrinsic value method, on the date of grant for restricted shares, we recorded unearned compensation (a component of shareholders' equity) that equaled the product of the number of shares granted and the closing price of our common stock on the business day prior to the grant date, and expense was recognized over the vesting period of each grant on a straight-line basis.

On January 1, 2006, we adopted Statement of Financial Accounting Standards No. 123 (Revised 2004) *Share-Based Payments* ("SFAS 123R") and began accounting for our stock-based compensation plans under the fair value method. We continue to use the Black-Scholes option pricing model for valuing share-based payments relating to stock options and recognize compensation cost on a straight-line basis over the respective vesting period. No forfeitures were estimated for outstanding unvested options and restricted shares as historical forfeitures have been immaterial. We have selected the modified-prospective method of adoption. Under that transition method, compensation cost recognized in 2006 included: a) compensation cost for all share-based payments granted prior to, but not yet vested as of January 1, 2006, based on the grant-date fair value, and (b) compensation cost for all share-based payments granted subsequent to January 1, 2006, based on the grant-date fair value. In addition to the compensation cost recognition requirements, tax deduction benefits for an award in excess of recognized compensation cost is reported as a financing cash flow rather than as an operating cash flow. The adoption did not have a material impact on our consolidated results of operations, earnings per share and cash flows. There were no stock option grants in 2007, 2006 or 2005.

Stock Options

The options outstanding at December 31, 2007, have exercise prices as follows: 163,000 shares at $8.57; 67,510 shares at $9.32; 84,510 shares at $10.92; 50,450 shares at $10.94; 40,000 shares at $11.00; 181,280 shares at $12.18; 52,800 shares at $13.91; and 97,000 shares ranging from $8.14 to $12.00, and a weighted average remaining contractual life of 4.9 years.

Options outstanding are as follows:

	2007		2006		2005	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Options outstanding at beginning of year	883,070	$ 10.86	1,717,904	$ 10.91	2,599,894	$ 10.65
Exercised	(141,186)	$ 11.10	(792,394)	$ 11.21	(858,070)	$ 10.17
Terminated	(5,334)	$ 10.92	(42,440)	$ 10.96	(23,920)	$ 10.82
Options outstanding at end of year	736,550	$ 10.55	883,070	$ 10.86	1,717,904	$ 10.91
Options exercisable end of year	537,514	$ 10.28	515,318	$ 10.34	1,066,316	$ 10.94

For the years ended December 31, 2007 and 2006, $1.0 million and $1.4 million, respectively, was recognized as compensation expense related to stock options. No expense related to stock options was recognized in 2005 under the intrinsic value method. The aggregate intrinsic value of the stock options exercised in 2007, 2006 and 2005 was approximately $4.1 million, $21.3 million and $12.6 million, respectively. Future compensation cost associated with unvested options at December 31, 2007 and 2006 totaled approximately $800,000 and $1.8 million, respectively. The aggregate intrinsic value of options exercisable at December 31, 2007 and 2006 was approximately $16.8 million and $10.8 million, respectively. The weighted average vesting period related to nonvested stock options at December 31, 2007 was approximately 0.8 years.

Restricted Shares

We grant restricted shares to members of our board of directors, key executives and selected management employees. Compensation cost for each award is the product of market value of each share and the number of shares granted. The following table summarizes information about our restricted shares during the years ended December 31, 2007, 2006 and 2005:

	2007		2006		2005	
	Shares	Grant Date Fair Value (1)	Shares	Grant Date Fair Value (1)	Shares	Grant Date Fair Value (1)
Restricted shares outstanding at beginning of year	729,212	$ 32.29	384,902	$ 25.59	—	$ —
Granted	702,297	$ 31.77	497,450	$ 37.07	388,350	$ 25.56
Vested	(236,667)	$ 31.32	(66,865)	$ 24.51	—	$ —
Forfeited	(28,765)	$ 31.59	(86,275)	$ 36.04	(3,448)	$ 21.86
Restricted shares outstanding at end of year	1,166,077	$ 32.19	729,212	$ 32.29	384,902	$ 25.59

(1) Represents the average grant date market value, which is based on the quoted market price of the common stock on the business day prior to the date of grant.

For the year ended December 31, 2005, the amounts granted were recorded as unearned compensation, a component of shareholders' equity and charged to expense over the respective vesting periods on a straight-line basis. Amortization of unearned compensation totaled $1.4 million for the year ended December 31, 2005. The balance in unearned compensation at December 31, 2005 was $7.5 million and was reversed in January 2006 upon adoption of the fair value method. For the years ended December 31, 2007 and 2006, $11.7 million and $6.3 million, respectively, was recognized as compensation expense related to restricted shares. In 2007, compensation expense of $2.1 million was related to the CDI Incentive Plan. Future compensation cost associated with unvested restricted stock awards at December 31, 2007 and 2006 totaled approximately $41.8 million and $17.5 million, respectively, of which $13.4 million and $8.0 million is related to the CDI Incentive Plan. The weighted average vesting period related to nonvested restricted stock awards at December 31, 2007 was approximately 3.5 years.

In January 2008, we granted certain key executives and select management employees 418,434 and 45,784 restricted shares and restricted stock units, respectively, under the 2005 Long-Term Incentive Plan. The shares and units vest 20% per year for a five-year period. The market value of the restricted stock is based on the quoted market price of the common stock on the business day prior to the grant date. The market value of the restricted shares was $41.50 per share or $17.4 million. We also granted our outside directors 1,107 restricted shares. The shares vest on January 1, 2009. The market value of the restricted shares was $41.50 per share or $45,941.

Employee Stock Purchase Plan

Effective May 12, 1998, we adopted a qualified, non-compensatory ESPP, which allows employees to acquire shares of common stock through payroll deductions over a six-month period. The purchase price is equal to 85% of the fair market value of the common stock on either the first or last day of the subscription period, whichever is lower. Purchases under the plan are limited to the lesser of 10% of an employee's base salary or $25,000 of our stock value. In 2007, we issued 222,984 shares of our common stock to our employees under the ESPP, which increased the number of shares of our outstanding common stock. We subsequently repurchased approximately the same number of shares of our common stock in the open market at a weighted average price of $35.04 per share in 2007 and reduced the number of shares of our outstanding common stock. Under this plan 97,598 and 79,878 shares of common stock were purchased in the open market for our employees at a weighted-average share price of $33.12 and $23.11 during 2006 and 2005, respectively. For the years ended December 31, 2007 and 2006, we recognized $2.1 and $1.6 million, respectively, of compensation expense related to stock purchased under the ESPP and the CDI ESPP (of which $600,000 of expense was related to the CDI ESPP that became effective third quarter 2007). No expenses related to the ESPP were recognized in 2005 under the intrinsic value method.

In January 2008, we issued 46,152 shares of our common stock to our employees under this plan to satisfy the employee purchase period from July 1, 2007 to December 31, 2007, which increased our common stock outstanding.

Stock Compensation Modifications

Under our 1995 Incentive Plan and our 2005 Long-Term Incentive Plan, upon a stock recipient's termination of employment, which is defined as employment with us and any of our majority-owned subsidiaries, any unvested restricted stock and stock options are forfeited immediately and all unexercised vested options are forfeited, as specified under the applicable plan or agreement. Ordinarily, once our beneficial ownership of CDI falls to 50% or below (the "Trigger Date"), the options and unvested shares granted to CDI employees would be forfeited at such date under our current plans. As part of the Employee Matters Agreement between us and CDI, which was executed in December 2006, with respect to any employee who is a Cal Dive employee as of the date of the IPO, we have agreed to extend the life of any vested and unexercised stock options to the earlier of (1) the expiration of the general term of the option or (2) the later of (i) December 31 of the calendar year in which the Trigger Date occurs, or (ii) the 15th day of the third month after the expiration of the 60-day period commencing on the Trigger Date (135 days). To the extent that any such employee would forfeit options because they have not vested as of such date, such options will be accelerated and will vest at the Trigger Date. In addition, under the Employee Matters Agreement, restricted stock awards granted to employees of CDI as of the IPO closing date will continue under their present terms and the terms of the plans under which they were granted. The modification date for these restricted stock and options occurred at the date the Employee Matters Agreement was adopted. However, no accounting charge will occur until the Trigger Date occurs and the impact of the modification, if any, can be measured.

Note 15 — Shareholders' Equity

Our amended and restated Articles of Incorporation provide for authorized Common Stock of 240,000,000 shares with no par value per share and 5,000,000 shares of preferred stock, $0.01 par value per share, in one or more series.

In November 2005, our Board of Directors declared a two-for-one split of our common stock in the form of a 100% stock distribution on December 8, 2005 to all holders of record at the close of business on December 1, 2005. All share and per share data in these financial statements have been restated to reflect the stock split.

The components of accumulated other comprehensive income as of December 31, 2007 and 2006 were as follows (in thousands):

	2007	2006
Cumulative foreign currency translation adjustment	$28,260	$24,580
Unrealized gain (loss) on hedges, net	(6,998)	2,656
Accumulated other comprehensive income	$21,262	$27,236

Note 16 — Stock Buyback Program

On June 28, 2006, our Board of Directors authorized us to discretionarily purchase up to $50 million of our common stock in the open market. In October and November 2006, we purchased approximately 1.7 million shares under this program for a weighted average price of $29.86 per share, or $50.0 million.

Note 17 — Related Party Transactions

Cal Dive International, Inc.

Before the IPO of Cal Dive, we provided to Cal Dive certain management and administrative services including: (i) accounting, treasury, payroll and other financial services; (ii) legal, insurance and claims services; (iii) information systems, network and communication services; (iv) employee benefit services (including direct third-party group insurance costs and 401(k) contribution matching costs discussed below); and (v) corporate facilities management services. Total allocated costs to Cal Dive for such services were approximately $12.8 million, $16.5 million and $8.5 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Included in these costs are costs related to the participation by CDI's employees in our employee benefit plans through December 31, 2007, including employee medical insurance and a defined contribution 401(k) retirement plan. These costs were recorded as a component of operating expenses and were approximately $9.2 million, $5.8 million and $3.3 million for the years ended December 31, 2007, 2006 and 2005, respectively. Our defined contribution 401(k) retirement plan is further disclosed in "— Note 14."

In addition, Cal Dive provided to us operational and field support services including: (i) training and quality control services; (ii) marine administration services; (iii) supply chain and base operation services; (iv) environmental, health and safety services; (v) operational facilities management services; and (vi) human resources. Total allocated costs to us for such services were approximately $3.4 million, $5.6 million and $4.1 million for the years ended December 31, 2007, 2006 and 2005, respectively. These amounts are eliminated in the accompanying consolidated financial statements.

In contemplation of the IPO of CDI, we entered into intercompany agreements with CDI that address the rights and obligations of each respective company, including a Master Agreement, a Corporate Services Agreement, an Employee Matters Agreement and a Tax Matters Agreement. The Master Agreement describes and provides a framework for the separation of our business from CDI's business, allocates liabilities (including those potential liabilities related to litigation) between the parties, allocates responsibilities and provides standards for each of the parties' conduct going forward (e.g., coordination regarding financial reporting), and sets forth the indemnification obligations of each party. In addition, the Master Agreement provides us with a preferential right to use a specified number of CDI's vessels in accordance with the terms of such agreement.

Pursuant to the Corporate Services Agreement, each party agrees to provide specified services to the other party, including administrative and support services for the time period specified therein. Generally after we cease to own 50% or more of the total voting power of CDI common stock, all services may be terminated by either party upon 60 days notice, but a longer notice period is applicable for selected services. Each of the services shall be provided in exchange for a monthly charge as calculated for each service (based on relative revenues, number of users for a particular service, or other specified measure). In general, under the Corporate Services Agreement we provide CDI with services related to the tax, treasury, audit, insurance (including claims) and information technology functions; CDI provides us with services related to the human resources, training and orientation functions, and certain supply chain and environmental, health and safety services. However, the Corporate Services Agreement was amended effective January 1, 2008 to reflect that CDI no longer provides us with these functions.

Pursuant to the Employee Matters Agreement, except as otherwise provided, CDI generally accepts and assumes all employment related obligations with respect to all individuals who are employees of CDI as of the IPO closing date, including expenses related to existing options and restricted stock. Those employees are entitled to retain their Helix stock options and restricted stock grants under their original terms except as mandated by applicable law. The Employee Matters Agreement also permits CDI employees to participate in our Employee Stock Purchase Plan for the offering period that ended June 30, 2007, and CDI paid us $1.6 million in July 2007, which was the fair market value of the shares of our stock purchased by such employees.

Pursuant to the Tax Matters Agreement, we are generally responsible for all federal, state, local and foreign income taxes that are attributable to CDI for all tax periods ending on the IPO; CDI is generally responsible for all such taxes beginning after the IPO. In addition, the agreement provides that for a period of up to ten years, CDI is required to make annual payments to us equal to 90% of tax benefits derived by CDI from tax basis adjustments resulting from the "Boot" gain recognized by us as a result of the distributions made to us as part of the IPO transaction. See "— Note 12 — Income Taxes" for more detailed disclosure of the Tax Matters Agreement.

Other

In April 2000, we acquired a 20% working interest in Gunnison, a Deepwater Gulf of Mexico prospect of Kerr-McGee. Financing for the exploratory costs of approximately $20 million was provided by an investment partnership (OKCD Investments, Ltd. or "OKCD"), the investors of which include current and former Helix senior management, in exchange for a revenue interest that is an overriding royalty interest of 25% of Helix's 20% working interest. Production began in December 2003. Payments to OKCD from us totaled $22.1 million, $34.6 million and $28.1 million in the years ended December 31, 2007, 2006 and 2005, respectively. Our Chief Executive Officer, Owen Kratz, through Class A limited partnership interests in OKCD, personally owns approximately 73% of the partnership. Another executive officer of the Company, A. Wade Pursell, our Executive Vice President and Chief Financial Officer, owns approximately 1.33% of the partnership. In 2000, OKCD also awarded Class B limited partnership interests to key Helix employees.

During 2007, 2006 and 2005, we paid $12.3 million, $6.1 million and $1.8 million, respectively, to Weatherford International, Ltd. ("Weatherford"), an oil and gas industry company, for services provided to us. A member of our board of directors is part of the senior management team of Weatherford.

In connection with the acquisition of Helix Energy Limited, we entered into two-year notes payable to former owners totaling approximately 3.1 million British Pounds, or approximately $5.6 million, on November 3, 2005 (approximately $6.2 million at December 31, 2006). The notes bore interest at a LIBOR based floating rate with payments due quarterly beginning January 31, 2006. The loan notes were repaid in November 2007.

Note 18 — Commitments and Contingencies

Lease Commitments

We lease several facilities, ROVs and vessels under noncancelable operating leases. Future minimum rentals under these leases are approximately $140.5 million at December 31, 2007 with $59.0 million due in 2008, $41.5 million in 2009, $16.6 million in 2010, $6.9 million in 2011, $4.4 million in 2012 and $12.1 million thereafter. Total rental expense under these operating leases was approximately $76.0 million, $25.3 million and $23.4 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Insurance

We carry Hull and Increased Value insurance which provides coverage for physical damage to an agreed amount for each vessel. The deductibles are based on the value of the vessel with a maximum deductible of $1.0 million on the *Q4000* and $500,000 on the *Intrepid, Seawell, Express* and *Kestrel.* Other vessels carry deductibles between $25,000 and $350,000. We also carry Protection and Indemnity ("P&I") insurance which covers liabilities arising from the operation of the vessels and General Liability insurance which covers liabilities arising from construction operations. The deductible on both the P&I and General Liability is $100,000 per occurrence. Onshore employees are covered by Workers' Compensation. Offshore employees, including divers and tenders and marine crews, are covered by Maritime Employers Liability insurance policy which covers Jones Act exposures and includes a deductible of $100,000 per occurrence plus a $2.0 million annual aggregate deductible. In addition to the liability policies named above, we carry various layers of Umbrella Liability for total limits of $300,000,000 excess of primary limits. Our self-insured retention on our medical and health benefits program for employees is $200,000 per participant.

We incur workers' compensation and other insurance claims in the normal course of business, which management believes are covered by insurance. The Company analyzes each claim for potential exposure and estimate the ultimate liability of each claim. Our liability at December 31, 2007 and 2006 , above the applicable deductible limits, were $14.2 million and $3.6 million, respectively. The related receivable from insurance companies at December 31, 2007 and 2006 were $10.2 million and $3.6 million respectively. These amounts are reflected in Accrued Liabilities and Other Current Assets in the consolidated balance sheet. See "— Note 8 — Details of Certain Accounts." We have not incurred any significant losses as a result of claims denied by our insurance carriers. Our services are provided in hazardous environments where accidents involving catastrophic damage or loss of life could occur, and litigation arising from such an event may result in our being named a defendant in lawsuits asserting large claims. Although there can be no assurance the amount of insurance we carry is sufficient to protect us fully in all events, or that such insurance will continue to be available at current levels of cost or coverage, we believe that our insurance protection is adequate for our business operations. A successful liability claim for which we are underinsured or uninsured could have a material adverse effect on our business.

Litigation and Claims

On December 2, 2005, we received an order from the U.S. Department of the Interior Minerals Management Service ("MMS") that the price threshold for both oil and gas was exceeded for 2004 production and that royalties are due on such production notwithstanding the provisions of the Outer Continental Shelf Deep Water Royalty Relief Act of 2005 ("DWRRA"), which was intended to stimulate exploration and production of oil and natural gas in the deepwater Gulf of Mexico by providing relief from the obligation to pay royalty on certain federal leases. Our only oil and gas leases affected by this dispute are Garden Banks Blocks 667, 668 and 669 ("Gunnison"). On May 2, 2006, the MMS issued another order that superseded the December 2005 order, and claimed that royalties on gas production are due for 2003 in addition to oil and gas production in 2004. The May 2006 Order also seeks interest on all royalties allegedly due. We filed a timely notice of appeal with respect to both the December 2005 Order and the May 2006 Order. Other operators in the Deep Water Gulf of Mexico who have received notices similar to ours are seeking royalty relief under the DWRRA, including Kerr-McGee, the operator of Gunnison. In March of 2006, Kerr-McGee filed a lawsuit in federal district court challenging the enforceability of price thresholds in certain deepwater Gulf of Mexico Leases, including ours. On October 30, 2007, the federal district court in the Kerr-McGee case entered judgment in favor of Kerr-McGee and held that the Department of the Interior exceeded its authority by including the price thresholds in the subject leases. The government filed a notice of appeal of that decision on December 21, 2007. We do not anticipate that the MMS director will issue decisions in our or the other companies' administrative appeals until the Kerr-McGee litigation has been resolved in a final decision. As a result of this dispute, we have recorded reserves for the disputed royalties (and any other royalties that may be claimed for production during 2005, 2006 and 2007) plus interest at 5% for our portion of the Gunnison related MMS claim. The total reserved amount at December 31, 2007 was approximately $55.1 million and is included in Other Long-Term Liabilities in the accompanying consolidated balance sheet. At this time, it is not anticipated that any penalties would be assessed even if we are unsuccessful in our appeal.

Although the above discussed matters may have the potential for additional liability and may have an impact on our consolidated financial results for a particular reporting period, we believe that the outcome of all such matters and proceedings will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Contingencies

During the fourth quarter of 2006, Horizon received a tax assessment from the SAT, the Mexican taxing authority, for approximately $23 million related to fiscal 2001, including penalties, interest and monetary correction. The SAT's assessment claims unpaid taxes related to services performed among the Horizon subsidiaries that CDI acquired at the time it acquired Horizon. CDI believes under the Mexico and United States double taxation treaty that these services are not taxable and that the tax assessment itself is invalid. On February 14, 2008, CDI received notice from the SAT upholding the original assessment. We believe that CDI's position is supported by law and CDI intends to vigorously defend its position. However, the ultimate outcome of this litigation and CDI's potential liability from this assessment, if any, cannot be determined at this time. Nonetheless, an unfavorable outcome with respect to the Mexico tax assessment could have a material adverse effect on our financial position and results of operations. Horizon's 2002 through 2007 tax years remain subject to examination by the appropriate governmental agencies for Mexico tax purposes, with 2002 and 2003 currently under audit.

Commitments

We are converting the *Caesar* (acquired in January 2006 for $27.5 million in cash) into a deepwater pipelay vessel. Total conversion costs are estimated to be approximately $145 million, of which approximately $87.8 million had been incurred, with an additional $35.8 million committed, at December 31, 2007. In addition, we are upgrading the *Q4000* to include drilling capability by adding a modular-based drilling system, and will also perform thruster modifications and other significant upgrades on the vessel. The total cost for all of these activities is estimated to be approximately $134 million, of which approximately $79.8 million had been incurred, with an additional $18.6 million committed, at December 31, 2007.

We are also constructing the *Well Enhancer,* a $198 million multi-service dynamically positioned dive support/well intervention vessel that will be capable of working in the North Sea and West of Shetlands to support our expected growth in that region. We expect the *Well Enhancer* to join our fleet in 2008. At December 31, 2007, we had incurred approximately $94.1 million, with an additional $58.9 million committed to this project.

Further, we, along with Kommandor RØMØ have begun the conversion of a ferry vessel into a dynamically-positioned construction services vessel. Conversion of the vessel is expected to be completed in two phases. The first phase of the conversion is estimated to be approximately $87 million and is expected to be completed by second quarter 2008. As of December 31, 2007, $58.5 million had been incurred related to the conversion (our portion was $29.3 million), with an additional $10.1 million committed. The second phase of the conversion into a minimal floating production system, *Helix Producer* I, is expected to be competed in third quarter 2008. Estimated cost of conversion for the second phase is approximately $117 million, in which we expect to fund 100%. See "— Note 10 — Consolidated Variable Interest Entities" for detailed discussion of Kommandor LLC.

As of December 31, 2007, we have also committed approximately $113.1 million in additional capital expenditures for exploration, development and drilling costs related to our oil and gas properties.

Note 19 — Business Segment Information

Our operations are conducted through the following lines of business: contracting services operations and oil and gas operations. We have disaggregated our contracting services operations into three reportable segments in accordance with SFAS No. 131: Contracting Services, Shelf Contracting and Production Facilities. As a result, our reportable segments consist of the following: Contracting Services, Shelf Contracting, Oil and Gas and Production Facilities. Contracting Services operations include deepwater pipelay, well operations, robotics and reservoir and well tech services. Shelf Contracting operations consist of CDI, which include all assets deployed primarily for diving-related activities and shallow water construction. See "— Note 3" for discussion of initial public offering of CDI common stock. All material Intercompany transactions between the segments have been eliminated.

We evaluate our performance based on income before income taxes of each segment. Segment assets are comprised of all assets attributable to the reportable segment. The majority of our Production Facilities segment (Deepwater Gateway and Independence Hub) are accounted for under the equity method of accounting. Our investment in Kommandor LLC was consolidated in accordance with FIN 46 and is included in our Production Facilities segment.

The following summarizes certain financial data by business segment:

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Revenues —			
Contracting Services	$ 708,833	$ 485,246	$ 328,315
Shelf Contracting	623,615	509,917	223,211
Oil and Gas	584,563	429,607	275,813
Intercompany elimination	(149,566)	(57,846)	(27,867)
Total	$ 1,767,445	$ 1,366,924	$ 799,472
Income from operations —			
Contracting Services	$ 130,116	$ 90,250	$ 42,299
Shelf Contracting (1) (2)	183,130	185,366	57,261
Oil and Gas	123,353	132,104	123,104
Production Facilities (3)	(847)	(1,051)	(977)
Intercompany elimination	(23,008)	(8,024)	—
Total	$ 412,744	$ 398,645	$ 221,687

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Net interest expense and other —			
Contracting Services (5)	$ 49,824	$ 36,076	$ 8,571
Shelf Contracting	9,259	(163)	(45)
Oil and Gas	(1,407)	(1,339)	(1,117)
Production Facilities	1,768	60	150
Total	$ 59,444	$ 34,634	$ 7,559
Equity in losses of OTSL, inclusive of impairment	$ (10,841)	$ (487)	$ 2,817
Equity in earnings of equity investments excluding OTSL	$ 30,539	$ 18,617	$ 10,642
Income before income taxes —			
Contracting Services (4)	$ 232,112	$ 277,512	$ 33,762
Shelf Contracting (1) (2)	163,031	185,042	60,123
Oil and Gas	124,760	133,443	124,221
Production Facilities (3)	27,799	17,302	9,481
Intercompany elimination	(23,008)	(8,024)	—
Total	$ 524,694	$ 605,275	$ 227,587
Provision for income taxes —			
Contracting Services	$ 82,398	$ 140,306	$ 9,949
Shelf Contracting	57,430	65,710	21,009
Oil and Gas	24,896	45,084	40,734
Production Facilities	10,204	6,056	3,327
Total	$ 174,928	$ 257,156	$ 75,019
Identifiable assets —			
Contracting Services	$ 1,177,431	$ 1,313,206	$ 736,852
Shelf Contracting	1,274,050	452,153	277,446
Oil and Gas	2,634,238	2,282,715	478,522
Production Facilities	366,634	242,113	168,044
Total	$ 5,452,353	$ 4,290,187	$ 1,660,864
Capital expenditures —			
Contracting Services	$ 287,577	$ 130,938	$ 90,037
Shelf Contracting	30,301	38,086	32,383
Oil and Gas	519,632	282,318	238,698
Production Facilities	123,545	45,327	111,429
Total	$ 961,055	$ 496,669	$ 472,547

	Year Ended December 31,		
	2007	2006 (in thousands)	2005
Depreciation and amortization —			
Contracting Services	$ 40,850	$ 34,165	$ 25,102
Shelf Contracting (1)	40,698	24,515	15,734
Oil and Gas	324,321	134,967	70,637
Total	$ 405,869	$ 193,647	$ 111,473

(1) Included pre-tax $790,000 of asset impairment charges in 2005.

(2) Included $ (10.8) million, $(487,000) and $2.8 million equity in (losses) earnings from investment in OTSL in 2007, 2006 and 2005, respectively.

(3) Represents selling and administrative expense of Production Facilities incurred by us. See Equity in Earnings of Production Facilities investments for earnings contribution.

(4) Includes pre-tax gain of $151.7 million related to the Horizon acquisition in 2007 and pre-tax gain of $223.1 million related to the initial public offering of CDI common stock and transfer of debt through dividend distributions from CDI in 2006.

(5) Includes interest expense related to the Term Loan. The proceeds from the Tem Loan were used to fund the cash portion of the Remington acquisition.

Intercompany segment revenues during the years ended December 31, 2007, 2006 and 2005 were as follows (in thousands):

	Year Ended December 31,		
	2007	2006	2005
Contracting Services	$ 115,864	$42,585	$26,431
Shelf Contracting	33,702	15,261	1,436
Total	$ 149,566	$57,846	$27,867

Intercompany segment profit (which only relates to intercompany capital projects) during the years ended December 31, 2007, 2006 and 2005 were as follows (in thousands):

	Year Ended December 31,		
	2007	2006	2005
Contracting Services	$10,026	$2,460	$ —
Shelf Contracting	12,982	5,564	—
Total	$23,008	$8,024	$ —

Revenue by geographic region during the years ended December 31, 2007, 2006 and 2005 were as follows (in thousands):

	Year Ended December 31,		
	2007	2006	2005
United States	$ 1,261,844	$ 1,063,821	$630,227
United Kingdom	230,189	190,064	83,239
Other	275,412	113,039	86,006
Total	$ 1,767,445	$ 1,366,924	$799,472

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Property and equipment, net of depreciation, by geographic region during the years ended December 31, 2007, 2006 and 2005 were as follows (in thousands):

	Year Ended December 31,		
	2007	2006	2005
United States	$ 2,915,655	$ 2,046,043	$843,304
United Kingdom	189,117	110,451	72,932
Other	139,916	55,964	126
Total	$ 3,244,688	$ 2,212,458	$916,362

Note 20 — Allowance Accounts

The following table sets forth the activity in our valuation accounts for each of the three years in the period ended December 31, 2007 (in thousands):

	Allowance for Uncollectible Accounts	Deferred Tax Asset Valuation Allowance
Balance, December 31, 2004	$ 7,768	$ —
Additions	2,577	—
Deductions	(9,760)	—
Balance, December 31, 2005	585	—
Additions	3,598	—
Deductions	(3,201)	—
Balance, December 31, 2006	982	—
Additions	5,122	2,967
Deductions	(3,230)	—
Balance, December 31, 2007	$ 2,874	$ 2,967

See "— Note 2 — Summary of Significant Accounting Policies" for a detailed discussion regarding our accounting policy on Accounts Receivable and Allowance for Uncollectible Accounts and "— Note 12 — Income Taxes" for a detailed discussion of the valuation allowance related to our deferred tax assets.

Note 21 — Supplemental Oil and Gas Disclosures (Unaudited)

The following information regarding our oil and gas producing activities is presented pursuant to SFAS No. 69, *Disclosures About Oil and Gas Producing Activities* (in thousands).

Capitalized Costs

Aggregate amounts of capitalized costs relating to our oil and gas activities and the aggregate amount of related accumulated depletion, depreciation and amortization as of the dates indicated are presented below:

	2007	2006
Unproved oil and gas properties	$ 101,453	$ 101,845
Proved oil and gas properties	2,228,924	1,576,742
Total oil and gas properties	2,330,377	1,678,587
Accumulated depletion, depreciation and amortization	(617,922)	(335,112)
Net capitalized costs	$ 1,712,455	$ 1,343,475

Included in capitalized costs of proved oil and gas properties being amortized is an estimate of our proportionate share of decommissioning liabilities assumed relating to these properties which are also reflected as decommissioning liabilities in the accompanying consolidated balance sheets at fair value on a discounted basis. At December 31, 2007 and 2006, our oil and gas operations' decommissioning liabilities were $217.5 million and $167.7 million, respectively.

Costs Incurred in Oil and Gas Producing Activities

The following table reflects the costs incurred in oil and gas property acquisition and development activities, including estimated decommissioning liabilities assumed, during the years indicated:

	United States	United Kingdom	Total
Year Ended December 31, 2007 —			
Property acquisition costs:			
Proved properties	$ 12,703	$ —	$ 12,703
Unproved properties	16,347	—	16,347
Total property acquisition costs	29,050	—	29,050
Exploration costs	220,237	—	220,237
Development costs (1)	351,964	—	351,964
Asset retirement cost	58,082	—	58,082
Total costs incurred	**$ 659,333**	**$ —**	**$ 659,333**
Year Ended December 31, 2006 —			
Property acquisition costs:			
Proved properties	$ 770,307	$ 365	$ 770,672
Unproved properties	105,519	—	105,519
Total property acquisition costs	875,826	365	876,191
Exploration costs	143,459	—	143,459
Development costs (1)	159,688	—	159,688
Asset retirement cost	32,863	7,579	40,442
Total costs incurred	**$ 1,211,836**	**$ 7,944**	**$ 1,219,780**
Year Ended December 31, 2005 —			
Property acquisition costs:			
Proved properties	$ 183,837	$ —	$ 183,837
Unproved properties	—	—	—
Total property acquisition costs	183,837	—	183,837
Exploration costs	5,728	—	5,728
Development costs (1)	67,193	—	67,193
Asset retirement cost	36,119	—	36,119
Total costs incurred	**$ 292,877**	**$ —**	**$ 292,877**

(1) Development costs include costs incurred to obtain access to proved reserves to drill and equip development wells. Development costs also include costs of developmental dry holes.

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Results of Operations for Oil and Gas Producing Activities

	United States	United Kingdom	Total
Year Ended December 31, 2007 —			
Revenues	$ 581,904	$ 2,659	$584,563
Production (lifting) costs	118,032	5,102	123,134
Exploration expenses (2)	16,847	—	16,847
Depreciation, depletion, amortization and accretion	228,083	615	228,698
Abandonment and impairment	95,023	—	95,023
Gain on sale of oil and gas properties	42,566	1,717	44,283
Selling and administrative	40,176	1,615	41,791
Pretax income (loss) from producing activities	126,309	(2,956)	123,353
Income tax expense (benefit)	26,240	(1,344)	24,896
Results of oil and gas producing activities (1)	**$ 100,069**	**$ (1,612)**	**$ 98,457**
Year Ended December 31, 2006 —			
Revenues	$ 429,607	$ —	$429,607
Production (lifting) costs	89,139	—	89,139
Exploration expenses (2)	43,115	—	43,115
Depreciation, depletion, amortization and accretion	134,967	—	134,967
Gain on sale of oil and gas properties	2,248	—	2,248
Selling and administrative	27,645	4,885	32,530
Pretax income (loss) from producing activities	136,989	(4,885)	132,104
Income tax expense (benefit)	47,527	(2,443)	45,084
Results of oil and gas producing activities (1)	**$ 89,462**	**$ (2,442)**	**$ 87,020**
Year Ended December 31, 2005 —			
Revenues	$ 275,813	$ —	$275,813
Production (lifting) costs	56,235	—	56,235
Exploration expenses (2)	6,465	—	6,465
Depreciation, depletion, amortization and accretion	70,637	—	70,637
Selling and administrative	19,372	—	19,372
Pretax income from producing activities	123,104	—	123,104
Income tax expense	40,734	—	40,734
Results of oil and gas producing activities (1)	**$ 82,370**	**$ —**	**$ 82,370**

(1) Excludes net interest expense and other.

(2) See "— Note 7" for additional information related to the components of our exploration costs.

Estimated Quantities of Proved Oil and Gas Reserves

We employ full-time experienced reserve engineers and geologists who are responsible for determining proved reserves in conformance with SEC guidelines. Engineering reserve estimates were prepared by us based upon our interpretation of production performance data and sub-surface information derived from the drilling of existing wells. Our internal reservoir engineers and independent petroleum engineers analyzed 100% of our United States oil and gas fields on an annual basis (143 fields as of December 31, 2007). We consider any field with discounted future net revenues of 1% or greater of the total discounted future net revenues of all our fields to be significant. An “engineering audit,” as we use the term, is a process involving an independent petroleum engineering firm’s (Huddleston) extensive visits, collection and examination of all geologic, geophysical, engineering and economic data requested by the independent petroleum engineering firm. Our use of the term “engineering audit” is intended only to refer to the collective application of the procedures which Huddleston was engaged to perform and may be defined and used differently by other companies.

The engineering audit of our reserves by the independent petroleum engineers involves their rigorous examination of our technical evaluation, interpretation and extrapolations of well information such as flow rates and reservoir pressure declines as well as other technical information and measurements. Our internal reservoir engineers interpret this data to determine the nature of the reservoir and ultimately the quantity of proved oil and gas reserves attributable to a specific property. Our proved reserves in this Annual Report include only quantities that we expect to recover commercially using current prices, costs, existing regulatory practices and technology. While we are reasonably certain that the proved reserves will be produced, the timing and ultimate recovery can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and changes in projections of long-term oil and gas prices. Revisions can include upward or downward changes in the previously estimated volumes of proved reserves for existing fields due to evaluation of (1) already available geologic, reservoir or production data or (2) new geologic or reservoir data obtained from wells. Revisions can also include changes associated with significant changes in development strategy, oil and gas prices, or the related production equipment/facility capacity. Huddleston also examined our estimates with respect to reserve categorization, using the definitions for proved reserves set forth in Regulation S-X Rule 4-10(a) and subsequent SEC staff interpretations and guidance.

In the conduct of the engineering audit, Huddleston did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties or sales of production. However, if in the course of the examination something came to the attention of Huddleston which brought into question the validity or sufficiency of any such information or data, Huddleston did not rely on such information or data until they had satisfactorily resolved their questions relating thereto or had independently verified such information or data. Furthermore, in instances where decline curve analysis was not adequate in determining proved producing reserves, Huddleston evaluated our volumetric analysis, which included the analysis of production and pressure data. Each of the PUDs analyzed by Huddleston included volumetric analysis, which took into consideration recovery factors relative to the geology of the location and similar reservoirs. Where applicable, Huddleston examined data related to well spacing, including potential drainage from offsetting producing wells in evaluating proved reserves for un-drilled well locations.

The engineering audit by Huddleston included 100% of the producing properties together with a percentage of the non-producing and undeveloped properties. Properties for analysis were selected by us and Huddleston based on discounted future net revenues. All of our significant properties were included in the engineering audit and such audited properties constituted 97% of the total discounted future net revenues. Huddleston audited approximately 96% of our total reserve base in the United States, including what was deemed to be the most valuable properties. Huddleston audited 92% of proved developed reserves and 98% of the proved undeveloped reserves totaling 96% of both categories combined. Huddleston also analyzed the methods utilized by us in the preparation of all of the estimated reserves and revenues. Huddleston’s audit report represents they believe our methodologies are consistent with the methodologies required by the SEC, SPE and FASB. There were no limitations imposed, nor limitations encountered by us or Huddleston.

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table presents our net ownership interest in proved oil reserves (MBbls):

	United States	United (2) Kingdom	Total
Total proved reserves at December 31, 2004	**10,517**	**—**	**10,517**
Revision of previous estimates	(403)	—	(403)
Production	(2,473)	—	(2,473)
Purchases of reserves in place	6,653	—	6,653
Sales of reserves in place	—	—	—
Extensions and discoveries	579	—	579
Total proved reserves at December 31, 2005	**14,873**	**—**	**14,873**
Revision of previous estimates	(607)	—	(607)
Production	(3,400)	—	(3,400)
Purchases of reserves in place	24,820	—	24,820
Sales of reserves in place	—	—	—
Extensions and discoveries	651	—	651
Total proved reserves at December 31, 2006 (1)	**36,337**	**—**	**36,337**
Revision of previous estimates	(473)	97	(376)
Production	(3,723)	—	(3,723)
Purchases of reserves in place	—	—	
Sales of reserves in place	(1,858)	(49)	(1,907)
Extensions and discoveries	9,346	—	9,346
Total proved reserves at December 31, 2007	**39,629**	**48**	**39,677**
Total proved developed reserves as of :			
December 31, 2004	6,429	—	6,429
December 31, 2005	7,759	—	7,759
December 31, 2006	13,328	—	13,328
December 31, 2007	14,703	10	14,713

(1) Proved reserves at December 31, 2006 included approximately 17,573 MBbls acquired from the Remington acquisition.

(2) Reflects current 50% ownership in United Kingdom reserves in 2007; 100% ownership in 2006.

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table presents our net ownership interest in proved gas reserves, including natural gas liquids (MMcf):

	United States	United Kingdom (2)	Total
Total proved reserves at December 31, 2004	**53,204**	**—**	**53,204**
Revision of previous estimates	(1,124)	—	(1,124)
Production	(18,137)	—	(18,137)
Purchases of reserves in place	91,089	—	91,089
Sales of reserves in place	—	—	—
Extensions and discoveries	11,041	—	11,041
Total proved reserves at December 31, 2005	**136,073**	**—**	**136,073**
Revision of previous estimates	4,678	—	4,678
Production	(27,949)	—	(27,949)
Purchases of reserves in place	169,375	23,634	193,009
Sales of reserves in place	—	—	—
Extensions and discoveries	12,212	—	12,212
Total proved reserves at December 31, 2006 (1)	**294,389**	**23,634**	**318,023**
Revision of previous estimates	(12,209)	5,666	(6,543)
Production	(42,163)	(300)	(42,463)
Purchases of reserves in place	160	—	160
Sales of reserves in place	(2,932)	(14,700)	(17,632)
Extensions and discoveries	187,439	—	187,439
Total proved reserves at December 31, 2007	**424,684**	**14,300**	**438,984**
Total proved developed reserves as of :			
December 31, 2004	36,362	—	36,362
December 31, 2005	55,321	—	55,321
December 31, 2006	156,251	—	156,251
December 31, 2007	134,047	1,500	135,547

(1) Proved reserves at December 31, 2006 included approximately 159,338 MMcf acquired from the Remington acquisition.

(2) Reflects current 50% ownership in United Kingdom reserves in 2007; 100% ownership in 2006.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following table reflects the standardized measure of discounted future net cash flows relating to our interest in proved oil and gas reserves:

	United States	United Kingdom (1)	Total
As of December 31, 2007 —			
Future cash inflows	$ 6,769,106	$126,700	$ 6,895,806
Future costs:			
Production	(622,842)	(42,350)	(665,192)
Development and abandonment	(883,923)	(46,600)	(930,523)
Future net cash flows before income taxes	5,262,341	37,750	5,300,091
Future income tax expense	(1,617,709)	(18,850)	(1,636,559)
Future net cash flows	3,644,632	18,900	3,663,532
Discount at 10% annual rate	(831,705)	(4,313)	(836,018)
Standardized measure of discounted future net cash flows	**$ 2,812,927**	**$ 14,587**	**$ 2,827,514**
As of December 31, 2006 —			
Future cash inflows	$ 3,814,201	$173,520	$ 3,987,721
Future costs:			
Production	(588,000)	(8,521)	(596,521)
Development and abandonment	(707,398)	(66,300)	(773,698)
Future net cash flows before income taxes	2,518,803	98,699	2,617,502
Future income tax expense	(776,120)	(53,791)	(829,911)
Future net cash flows	1,742,683	44,908	1,787,591
Discount at 10% annual rate	(416,738)	(9,910)	(426,648)
Standardized measure of discounted future net cash flows	**$ 1,325,945**	**$ 34,998**	**$ 1,360,943**
As of December 31, 2005 —			
Future cash inflows	$ 2,131,985	$ —	$ 2,131,985
Future costs:			
Production	(311,163)	—	(311,163)
Development and abandonment	(450,558)	—	(450,558)
Future net cash flows before income taxes	1,370,264	—	1,370,264
Future income tax expense	(433,335)	—	(433,335)
Future net cash flows	936,929	—	936,929
Discount at 10% annual rate	(209,867)	—	(209,867)
Standardized measure of discounted future net cash flows	**$ 727,062**	**$ —**	**$ 727,062**

(1) Reflects current 50% ownership in United Kingdom reserves in 2007; 100% ownership in 2006.

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Future cash inflows are computed by applying year-end prices, adjusted for location and quality differentials on a property-by-property basis, to year-end quantities of proved reserves, except in those instances where fixed and determinable price changes are provided by contractual arrangements at year-end. The discounted future cash flow estimates do not include the effects of our derivative instruments or forward sales agreements. See the following table for base prices used in determining the standardized measure:

	United States	United Kingdom	Total
Year Ended December 31, 2007 —			
Average oil price per Bbl	$93.98	$ 49.69	$93.92
Average gas prices per Mcf	$ 7.17	$ 8.69	$ 7.22
Year Ended December 31, 2006 —			
Average oil price per Bbl	$59.75	$ —	$59.75
Average gas prices per Mcf	$ 5.58	$ 7.23	$ 5.70
Year Ended December 31, 2005 —			
Average oil price per Bbl	$59.82	$ —	$59.82
Average gas prices per Mcf	$ 9.13	$ —	$ 9.13

The future income tax expense was computed by applying the appropriate year-end statutory rates, with consideration of future tax rates already legislated, to the future pretax net cash flows less the tax basis of the associated properties. Future net cash flows are discounted at the prescribed rate of 10%. We caution that actual future net cash flows may vary considerably from these estimates. Although our estimates of total proved reserves, development costs and production rates were based on the best information available, the development and production of oil and gas reserves may not occur in the periods assumed. Actual prices realized, costs incurred and production quantities may vary significantly from those used. Therefore, such estimated future net cash flow computations should not be considered to represent our estimate of the expected revenues or the current value of existing proved reserves.

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Changes in Standardized Measure of Discounted Future Net Cash Flows

Principal changes in the standardized measure of discounted future net cash flows attributable to our proved oil and gas reserves are as follows:

	Year Ended December 31,		
	2007	2006	2005
Standardized measure, beginning of year	$ 1,360,943	$ 727,062	$ 286,739
Changes during the year:			
Sales, net of production costs	(461,430)	(340,468)	(213,113)
Net change in prices and production costs	1,208,823	(328,149)	194,965
Changes in future development costs	(17,689)	(49,357)	(63,621)
Development costs incurred	351,964	159,616	67,193
Accretion of discount	261,931	106,333	40,808
Net change in income taxes	(665,750)	(254,770)	(214,936)
Purchases of reserves in place	(951)	1,245,847	575,320
Extensions and discoveries	1,285,499	82,730	80,720
Sales of reserves in place	(247,344)	—	—
Net change due to revision in quantity estimates	(80,865)	(6,067)	(12,442)
Changes in production rates (timing) and other	(167,617)	18,166	(14,571)
Total	1,466,571	633,881	440,323
Standardized measure, end of year	$ 2,827,514	$ 1,360,943	$ 727,062

Note 22 — Subsequent Event

Martin Ferron resigned as our President and Chief Executive Officer effective February 4, 2008. Concurrently, Mr. Ferron resigned from our Board of Directors. Mr. Ferron remained employed by us through February 18, 2008, after which his employment was terminated. At the time of Mr. Ferron's resignation, Owen Kratz, who served as Executive Chairman of Helix, resumed the role and assumed the duties of the President and Chief Executive Officer, and was subsequently elected as President and Chief Executive Officer of Helix.

Note 23 — Quarterly Financial Information (Unaudited)

The offshore marine construction industry in the Gulf of Mexico is highly seasonal as a result of weather conditions and the timing of capital expenditures by the oil and gas companies. Historically, a substantial portion of our services has been performed during the summer and fall months. As a result, historically a disproportionate portion of our revenues and net income is earned during such period. The following is a summary of consolidated quarterly financial information for 2007 and 2006 (in thousands, except per share data):

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
2007				
Net revenues	$ 396,055	$410,574	$ 460,573	$ 500,243
Gross profit	135,615	141,765	166,318	70,058
Net income	56,765	58,647	83,773	121,293
Net income applicable to common shareholders	55,820	57,702	82,828	120,412
Basic earnings per common share	0.62	0.64	0.92	1.34
Diluted earnings per common share	0.60	0.61	0.88	1.25
2006				
Net revenues	$ 291,648	$305,013	$ 374,424	$ 395,839
Gross profit	102,266	131,692	130,470	150,980
Net income	56,193	69,944	57,833	163,424
Net income applicable to common shareholders	55,389	69,139	57,029	162,479
Basic earnings per common share	0.71	0.88	0.62	1.80
Diluted earnings per common share	0.67	0.83	0.60	1.73

Note 24 — Condensed Consolidated Guarantor and Non-Guarantor Financial Information

The payment of obligations under the Senior Unsecured Notes is guaranteed by all of our restricted domestic subsidiaries ("Subsidiary Guarantors") except for Cal Dive and Cal Dive I-Title XI, Inc. Each of these Subsidiary Guarantors is included in our consolidated financial statements and has fully and unconditionally guaranteed the Senior Unsecured Notes on a joint and several basis. As a result of these guarantee arrangements, we are required to present the following condensed consolidating financial information. The accompanying guarantor financial information is presented on the equity method of accounting for all periods presented. Under this method, investments in subsidiaries are recorded at cost and adjusted for our share in the subsidiaries' cumulative results of operations, capital contributions and distributions and other changes in equity. Elimination entries relate primarily to the elimination of investments in subsidiaries and associated intercompany balances and transactions.

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HELIX ENERGY SOLUTIONS GROUP, INC.

CONDENSED CONSOLIDATING BALANCE SHEETS

	As of December 31, 2007				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
			(In thousands)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ 3,507	$ 2,609	$ 83,439	$ —	$ 89,555
Accounts receivable, net	85,122	104,619	257,761	—	447,502
Unbilled revenue	14,232	(280)	50,678	—	64,630
Other current assets	74,665	45,752	55,529	(50,364)	125,582
Total current assets	177,526	152,700	447,407	(50,364)	727,269
Intercompany	38,989	48,047	(80,592)	(6,444)	—
Property and equipment, net	92,864	2,093,194	1,060,298	(1,668)	3,244,688
Other assets:					
Equity investments in unconsolidated affiliates	—	—	213,429	—	213,429
Equity investments in affiliates	3,015,250	33,000	—	(3,048,250)	—
Goodwill, net	—	757,752	332,281	(275)	1,089,758
Other assets, net	86,235	40,686	111,259	(60,971)	177,209
	$3,410,864	$3,125,379	$ 2,084,082	$(3,167,972)	$5,452,353
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 43,774	$ 207,222	$ 131,730	$ 41	$ 382,767
Accrued liabilities	40,415	71,945	110,443	(1,437)	221,366
Income taxes payable	(3,043)	159	4,467	(1,583)	—
Current maturities of long-term debt	4,327	2	113,975	(43,458)	74,846
Total current liabilities	85,473	279,328	360,615	(46,437)	678,979
Long-term debt	1,287,092	—	490,615	(52,166)	1,725,541
Deferred income taxes	137,967	318,492	178,275	(9,226)	625,508
Decommissioning liabilities	—	189,639	4,011	—	193,650
Other long-term liabilities	3,294	56,325	9,244	(5,680)	63,183
Due to parent	(9,000)	98,504	10,347	(99,851)	—
Total liabilities	1,504,826	942,288	1,053,107	(213,360)	3,286,861
Minority interests	—	—	—	263,926	263,926
Convertible preferred stock	55,000	—	—	—	55,000
Shareholders' equity	1,851,038	2,183,091	1,030,975	(3,218,538)	1,846,566
	$3,410,864	$3,125,379	$ 2,084,082	$(3,167,972)	$5,452,353

HELIX ENERGY SOLUTIONS GROUP, INC.

CONDENSED CONSOLIDATING BALANCE SHEETS

	As of December 31, 2006				
	Helix	Guarantors	Non-Guarantors (in thousands)	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 142,489	$ 7,690	$ 56,085	$ —	$ 206,264
Short-term investments	285,395	—	—	—	285,395
Accounts receivable, net	53,183	112,676	122,016	—	287,875
Unbilled revenue	37,543	(370)	45,661	—	82,834
Other current assets	24,377	15,723	21,400	32	61,532
Total current assets	542,987	135,719	245,162	32	923,900
Intercompany	(21,106)	(6,452)	6,730	20,828	—
Property and equipment, net	12,782	1,661,658	538,018	—	2,212,458
Other assets:					
Equity investments in unconsolidated affiliates	—	—	213,362	—	213,362
Equity investments in affiliates	2,402,442	17,860	—	(2,420,302)	—
Goodwill, net	—	752,956	69,582	18	822,556
Other assets, net	45,588	40,886	56,922	(25,485)	117,911
	$2,982,693	$2,602,627	$ 1,129,776	$(2,424,909)	$4,290,187
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 43,480	$ 143,783	$ 52,804	$ —	$ 240,067
Accrued liabilities	42,355	118,658	38,683	(46)	199,650
Income taxes payable	143,813	1,199	5,655	(2,895)	147,772
Current maturities of long-term debt	8,400	7	17,480	—	25,887
Total current liabilities	238,048	263,647	114,622	(2,941)	613,376
Long-term debt	1,124,500	2	355,452	(25,485)	1,454,469
Deferred income taxes	71,527	281,516	83,501	—	436,544
Decommissioning liabilities	—	131,326	7,579	—	138,905
Other long-term liabilities	531	1,515	4,021	76	6,143
Due to parent	(9,000)	(79,638)	9,000	79,638	—
Total liabilities	1,425,606	598,368	574,175	51,288	2,649,437
Minority interests	—	—	2,989	56,813	59,802
Convertible preferred stock	55,000	—	—	—	55,000
Shareholders' equity	1,502,087	2,004,259	552,612	(2,533,010)	1,525,948
	$2,982,693	$2,602,627	$ 1,129,776	$(2,424,909)	$4,290,187

HELIX ENERGY SOLUTIONS GROUP, INC.

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

	For The Year Ended December 31, 2007				
	Helix	Guarantors	Non-Guarantors (in thousands)	Consolidating Entries	Consolidated
Net revenues	$255,297	$ 766,453	$ 908,625	$ (162,930)	$ 1,767,445
Cost of sales	194,291	601,792	594,413	(136,807)	1,253,689
Gross profit	61,006	164,661	314,212	(26,123)	513,756
Gain on sale of assets	1,960	42,566	5,842	—	50,368
Selling and administrative expenses	38,063	44,940	71,510	(3,133)	151,380
Income from operations	24,903	162,287	248,544	(22,990)	412,744
Equity in earnings of unconsolidated affiliates	—	—	19,698	—	19,698
Equity in earnings of affiliates	219,955	15,140	—	(235,095)	—
Gain on subsidiary equity transaction	151,696	—	—	—	151,696
Net interest expense and other	(14,893)	49,064	20,929	4,344	59,444
Income before income taxes	411,447	128,363	247,313	(262,429)	524,694
Provision for income taxes	65,429	40,033	71,260	(1,794)	174,928
Minority interest	—	—	113	29,175	29,288
Net income	346,018	88,330	175,940	(289,810)	320,478
Preferred stock dividends	3,716	—	—	—	3,716
Net income applicable to common shareholders	$342,302	$ 88,330	$ 175,940	$ (289,810)	$ 316,762

	For The Year Ended December 31, 2006				
	Helix	Guarantors	Non-Guarantors (in thousands)	Consolidating Entries	Consolidated
Net revenues	$166,016	$ 567,090	$ 703,129	$ (69,311)	$ 1,366,924
Cost of sales	112,606	375,969	423,154	(60,213)	851,516
Gross profit	53,410	191,121	279,975	(9,098)	515,408
Gain on sale of assets	220	2,248	349	—	2,817
Selling and administrative expenses	33,838	33,135	53,823	(1,216)	119,580
Income from operations	19,792	160,234	226,501	(7,882)	398,645
Equity in earnings of unconsolidated affiliates	—	—	18,130	—	18,130
Equity in earnings of affiliates	249,593	9,996	—	(259,589)	—
Gain on subsidiary equity transaction	223,134	—	—	—	223,134
Net interest expense and other	13,578	14,301	6,755	—	34,634
Income before income taxes	478,941	155,929	237,876	(267,471)	605,275
Provision for income taxes	126,012	60,274	73,763	(2,893)	257,156
Minority interest	—	—	179	546	725
Net income	352,929	95,655	163,934	(265,124)	347,394
Preferred stock dividends	3,358	—	—	—	3,358
Net income applicable to common shareholders	$349,571	$ 95,655	$ 163,934	$ (265,124)	$ 344,036

HELIX ENERGY SOLUTIONS GROUP, INC.

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

	For The Year Ended December 31, 2005				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
			(in thousands)		
Net revenues	$ 71,712	$ 401,909	$ 362,599	$ (36,748)	$ 799,472
Cost of sales	53,569	229,551	270,028	(36,748)	516,400
Gross profit	18,143	172,358	92,571	—	283,072
Gain on sale of assets	210	—	1,195	—	1,405
Selling and administrative expenses	17,292	24,038	21,460	—	62,790
Income from operations	1,061	148,320	72,306	—	221,687
Equity in earnings of unconsolidated affiliates	—	—	13,459	—	13,459
Equity in earnings of affiliates	162,029	8,281	—	(170,310)	—
Gain on subsidiary equity transaction	—	—	—	—	—
Net interest expense and other	8,313	(6,948)	6,194	—	7,559
Income before income taxes	154,777	163,549	79,571	(170,310)	227,587
Provision for income taxes	2,209	50,824	21,986	—	75,019
Minority interest	—	—	—	—	—
Net income	152,568	112,725	57,585	(170,310)	152,568
Preferred stock dividends	2,454	—	—	—	2,454
Net income applicable to common shareholders	$150,114	$ 112,725	$ 57,585	$ (170,310)	$ 150,114

HELIX ENERGY SOLUTIONS GROUP, INC.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

	For The Year Ended December 31, 2007				
	Helix	Guarantors	Non-Guarantors (In thousands)	Consolidating Entries	Consolidated
Cash flow from operating activities:					
Net income	$ 346,018	$ 88,330	$ 175,940	$ (289,810)	$ 320,478
Adjustments to reconcile net income to net cash provided by (used in) operating activities:					
Equity in earnings of unconsolidated affiliates	—	—	11,423	—	11,423
Equity in earnings of affiliates	(219,955)	(15,139)	—	235,094	—
Other adjustments	(307,354)	300,166	(115,393)	207,006	84,425
Net cash provided by (used in) operating activities	(181,291)	373,357	71,970	152,290	416,326
Cash flows from investing activities:					
Capital expenditures	(81,577)	(642,364)	(219,655)	—	(943,596)
Acquisition of businesses, net of cash acquired	—	—	(147,498)	—	(147,498)
Short-term investments	285,395	—	—	—	285,395
Investments in equity investments	—	—	(17,459)	—	(17,459)
Distributions from equity investments, net	—	—	6,679	—	6,679
Increases in restricted cash	—	(1,112)	—	—	(1,112)
Proceeds from sales of property	—	53,547	24,526	—	78,073
Other, net	—	(136)	—	—	(136)
Net cash provided by (used in) investing activities	203,818	(590,065)	(353,407)	—	(739,654)
Cash flows from financing activities:					
Borrowings on revolver	472,800	—	31,500	—	504,300
Repayments on revolver	(454,800)	—	(332,668)	—	(787,468)
Borrowings under debt	550,000	—	380,000	—	930,000
Repayments of debt	(405,408)	—	(3,823)	—	(409,231)
Deferred financing costs	(11,377)	—	(5,788)	—	(17,165)
Capital lease payments	—	(2,519)	—	—	(2,519)
Preferred stock dividends paid	(3,716)	—	—	—	(3,716)
Repurchase of common stock	(9,904)	—	—	—	(9,904)
Excess tax benefit from stock-based compensation	580	—	—	—	580
Exercise of stock options, net	1,568	—	—	—	1,568
Intercompany financing	(301,252)	214,146	239,396	(152,290)	—
Net cash provided by (used in) financing activities	(161,509)	211,627	308,617	(152,290)	206,445

	For The Year Ended December 31, 2007				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
	(In thousands)				
Effect of exchange rate changes on cash and cash equivalents	—	—	174	—	174
Net increase (decrease) in cash and cash equivalents	(138,982)	(5,081)	27,354	—	(116,709)
Cash and cash equivalents:					
Balance, beginning of year	142,489	7,690	56,085	—	206,264
Balance, end of year	$ 3,507	$ 2,609	$ 83,439	$ —	$ 89,555

HELIX ENERGY SOLUTIONS GROUP, INC.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

	For The Year Ended December 31, 2006				
	Helix	Guarantors	Non-Guarantors (In thousands)	Consolidating Entries	Consolidated
Cash flow from operating activities:					
Net income	$ 352,929	$ 95,655	$ 163,934	$ (265,124)	$ 347,394
Adjustments to reconcile net income to net cash provided by (used in) operating activities:					
Equity in earnings of unconsolidated affiliates	—	—	(1,879)	—	(1,879)
Equity in earnings of affiliates	(249,593)	(9,996)	—	259,589	—
Other adjustments	10,788	137,121	(20,145)	40,757	168,521
Net cash provided by (used in) operating activities	114,124	222,780	141,910	35,222	514,036
Cash flows from investing activities:					
Capital expenditures	(9,170)	(362,343)	(97,578)	—	(469,091)
Acquisition of businesses, net of cash acquired	—	(772,244)	(115,699)	—	(887,943)
(Purchases) sale of short-term investments	(285,395)	—	—	—	(285,395)
Investments in equity investments	—	—	(27,578)	—	(27,578)
Increases in restricted cash	—	(6,666)	—	—	(6,666)
Proceeds from sale of subsidiary stock	264,401	—	—	—	264,401
Proceeds from sales of property	514	15,000	16,828	—	32,342
Net cash used in investing activities	(29,650)	(1,126,253)	(224,027)	—	(1,379,930)

	For The Year Ended December 31, 2006				
	Helix	Guarantors	Non-Guarantors (In thousands)	Consolidating Entries	Consolidated
Cash flows from financing activities:					
Borrowings on revolver	209,800	—	201,000	—	410,800
Repayments on revolver	(209,800)	—	—	—	(209,800)
Borrowings under debt	835,000	—	5,000	—	840,000
Repayments of debt	(2,100)	—	(3,641)	—	(5,741)
Deferred financing costs	(11,462)	—	(377)	—	(11,839)
Capital lease payments	—	(2,827)	—	—	(2,827)
Preferred stock dividends paid	(3,613)	—	—	—	(3,613)
Repurchase of common stock	(50,266)	—	—	—	(50,266)
Subsidiary stock issuance	—	—	264,401	(264,401)	—
Excess tax benefit from stock-based compensation	2,660	—	—	—	2,660
Exercise of stock options, net	8,886	—	—	—	8,886
Intercompany financing	(797,361)	910,649	(342,467)	229,179	—
Net cash provided by (used in) financing activities	(18,256)	907,822	123,916	(35,222)	978,260
Effect of exchange rate changes on cash and cash equivalents	—	—	2,818	—	2,818
Net increase in cash and cash equivalents	66,218	4,349	44,617	—	115,184
Cash and cash equivalents:					
Balance, beginning of year	76,271	3,341	11,468	—	91,080
Balance, end of year	$ 142,489	$ 7,690	$ 56,085	$ —	$ 206,264

HELIX ENERGY SOLUTIONS GROUP, INC.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

	For The Year Ended December 31, 2005				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
			(In thousands)		
Cash flow from operating activities:					
Net income	$ 152,568	$ 112,725	$ 57,585	$ (170,310)	$ 152,568
Adjustments to reconcile net income to net cash provided by (used in) operating activities:					
Equity in earnings of unconsolidated affiliates	—	—	(2,851)	—	(2,851)
Equity in earnings of affiliates	(162,029)	(8,281)	—	170,310	—
Other adjustments	(61,950)	126,349	(37,660)	65,976	92,715
Net cash provided by (used in) operating activities	(71,411)	230,793	17,074	65,976	242,432
Cash flows from investing activities:					
Capital expenditures	(69,382)	(253,256)	(38,849)	—	(361,487)
Acquisition of businesses, net of cash acquired	—	—	(66,586)	—	(66,586)
(Purchases) sale of short-term investments	30,000	—	—	—	30,000
Investments in equity investments	—	—	(112,756)	—	(112,756)
Distributions from equity investments, net	—	—	10,492	—	10,492
Increases in restricted cash	—	(11,931)	7,500	—	(4,431)
Proceeds from sales of property	210	—	5,407	—	5,617
Other, net	—	726	(1,500)	—	(774)
Net cash used in investing activities	(39,172)	(264,461)	(196,292)	—	(499,925)
Cash flows from financing activities:					
Borrowings under debt	300,000	—	2,836	—	302,836
Repayments of debt	—	—	(4,321)	—	(4,321)
Deferred financing costs	(11,678)	—	—	—	(11,678)
Capital lease payments	—	(2,859)	—	—	(2,859)
Preferred stock dividends paid	(2,200)	—	—	—	(2,200)
Repurchase of common stock	(2,438)	—	—	—	(2,438)
Exercise of stock options, net	8,726	—	—	—	8,726
Intercompany financing	(153,926)	37,158	182,744	(65,976)	—
Net cash provided by (used in) financing activities	138,484	34,299	181,259	(65,976)	288,066

	For The Year Ended December 31, 2005				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
			(In thousands)		
Effect of exchange rate changes on cash and cash equivalents	—	—	(635)	—	(635)
Net increase in cash and cash equivalents	27,901	631	1,406	—	29,938
Cash and cash equivalents:					
Balance, beginning of year	48,370	2,710	10,062	—	61,142
Balance, end of year	$ 76,271	$ 3,341	$ 11,468	$ —	$ 91,080

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

None.

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

(a) *Evaluation of disclosure controls and procedures.* Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") as of the end of the fiscal year ended December 31, 2007. In its evaluation, management used the criterion set forth in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on this evaluation, the principal executive officer and the principal financial officer believes that our disclosure controls and procedures were effective as of the end of the fiscal year ended December 31, 2007 to ensure that information that is required to be disclosed by us in the reports we file or submit under the Exchange Act is (i) identified, recorded, processed, summarized and reported, on a timely basis and (ii) accumulated and communicated to our management, as appropriate, to allow timely decisions regarding required disclosure.

(b) Changes in internal control over financial reporting. There have been no changes, with exception of the items detailed below in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Securities Exchange Act, in the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We implemented an enterprise resource planning system on January 1, 2008 for our Deepwater division (excluding our ROV and trencher business) and our U.S. Well Operations division, which was subsequent to the date of our management's assessment of the effectiveness of internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting and the Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting thereon are set forth in Part II, Item 8 of this report on Form 10-K on page 71 and page 73, respectively.

Item 9B. ***Other Information.***

None.

PART III

Item 10. *Directors, and Executive Officers and Corporate Governance.*

Except as set forth below, the information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with our 2008 Annual Meeting of Shareholders. See also “Executive Officers of the Registrant” appearing in Part I of this Report.

Code of Ethics

We have adopted a *Code of Business Conduct and Ethics* for all directors, officers and employees as well as a *Code of Ethics for Chief Executive Officer and Senior Financial Officers* specific to those officers. Copies of these documents are available at our Website www.helixesg.com under *Corporate Governance*. Interested parties may also request a free copy of these documents from:

Helix Energy Solutions Group, Inc.
ATTN: Corporate Secretary
400 N. Sam Houston Parkway E., Suite 400
Houston, Texas 77060

Item 11. *Executive Compensation.*

The information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with our 2008 Annual Meeting of Shareholders.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.*

The information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with our 2008 Annual Meeting of Shareholders.

Item 13. *Certain Relationships and Related Transactions.*

The information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with our 2008 Annual Meeting of Shareholders.

Item 14. *Principal Accounting Fees and Services.*

The information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection our 2008 Annual Meeting of Shareholders.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules.***

(1) ***Financial Statements.***

The following financial statements included on pages 70 through 143 in this Annual Report are for the fiscal year ended December 31, 2007.

- Management's Report on Internal Control Over Financial Reporting
- Report of Independent Registered Public Accounting Firm
- Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting
- Consolidated Balance Sheets as of December 31, 2007 and 2006
- Consolidated Statements of Operations for the Years Ended December 31, 2007, 2006 and 2005
- Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2007, 2006 and 2005
- Consolidated Statements of Cash Flows for the Years Ended December 31, 2007, 2006 and 2005
- Notes to Consolidated Financial Statements.

All financial statement schedules are omitted because the information is not required or because the information required is in the financial statements or notes thereto.

(2) ***Exhibits.***

Pursuant to Item 601(b)(4)(iii), the Registrant agrees to forward to the commission, upon request, a copy of any instrument with respect to long-term debt not exceeding 10% of the total assets of the Registrant and its consolidated subsidiaries.

The following exhibits are filed as part of this Annual Report:

Exhibits	
2.1	Agreement and Plan of Merger dated January 22, 2006, among Cal Dive International, Inc. and Remington Oil and Gas Corporation, incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K/A, filed by the registrant with the Securities and Exchange Commission on January 25, 2006 (the "Form 8-K/A").
2.2	Amendment No. 1 to Agreement and Plan of Merger dated January 24, 2006, by and among, Cal Dive International, Inc., Cal Dive Merger — Delaware, Inc. and Remington Oil and Gas Corporation, incorporated by reference to Exhibit 2.2 to the Form 8-K/A.
3.1	2005 Amended and Restated Articles of Incorporation, as amended, of registrant, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by registrant with the Securities and Exchange Commission on March 1, 2006.
3.2	Second Amended and Restated By-Laws of Helix, as amended, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on September 28, 2006.
3.3	Certificate of Rights and Preferences for Series A-1 Cumulative Convertible Preferred Stock, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by registrant with the Securities and Exchange Commission on January 22, 2003 (the "2003 Form 8-K").
3.4	Certificate of Rights and Preferences for Series A-2 Cumulative Convertible Preferred Stock, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by registrant with the Securities and Exchange Commission on June 28, 2004 (the "2004 Form 8-K").
4.1	Credit Agreement dated July 3, 2006 by and among Helix Energy Solutions Group, Inc., and Bank of America, N.A., as administrative agent and as lender, together with the other lender parties thereto, incorporated by reference to Exhibit 4.1 to the registrant's Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on July 5, 2006.
4.2	Participation Agreement among ERT, Helix Energy Solutions Group, Inc., Cal Dive/Gunnison Business Trust No. 2001-1 and Bank One, N.A., et. al., dated as of November 8, 2001, incorporated by reference to Exhibit 4.2 to Form 10-K for the fiscal year ended December 31, 2001, filed by the registrant with the Securities and Exchange Commission on March 28, 2002 (the "2001 Form 10-K").

Exhibits

4.3 Form of Common Stock certificate, incorporated by reference to Exhibit 4.7 to the Form 8-A filed by the Registrant with the Securities and Exchange Commission on June 30, 2006.

4.4 Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of August 16, 2000, incorporated by reference to Exhibit 4.4 to the 2001 Form 10-K.

4.5 Amendment No. 1 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of January 25, 2002, incorporated by reference to Exhibit 4.9 to the Form 10-K/A filed with the Securities and Exchange Commission on April 8, 2003.

4.6 Amendment No. 2 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of November 15, 2002, incorporated by reference to Exhibit 4.4 to the Form S-3 filed with the Securities and Exchange Commission on February 26, 2003.

4.7 First Amended and Restated Agreement dated January 17, 2003, but effective as of December 31, 2002, by and between Helix Energy Solutions Group, Inc. and Fletcher International, Ltd., incorporated by reference to Exhibit 10.1 to the 2003 Form 8-K.

4.8 Amended and Restated Credit Agreement among Cal Dive/Gunnison Business Trust No. 2001-1, Energy Resource Technology, Inc., Helix Energy Solutions Group, Inc., Wilmington Trust Company, a Delaware banking corporation, the Lenders party thereto, and Bank One, NA, as Agent, dated July 26, 2002, incorporated by reference to Exhibit 4.12 to the Form 10-K/A filed with the Securities and Exchange Commission on April 8, 2003.

4.9 First Amendment to Amended and Restated Credit Agreement among Cal Dive/Gunnison Business Trust No. 2001-1, Energy Resource Technology, Inc., Helix Energy Solutions Group, Inc., Wilmington Trust Company, a Delaware banking corporation, the Lenders party thereto, and Bank One, NA, as Agent, dated January 7, 2003, incorporated by reference to Exhibit 4.13 to the Form 10-K/A filed with the Securities and Exchange Commission on April 8, 2003.

4.10 Second Amendment to Amended and Restated Credit Agreement among Cal Dive/Gunnison Business Trust No. 2001-1, Energy Resource Technology, Inc., Helix Energy Solutions Group, Inc., Wilmington Trust Company, a Delaware banking corporation, the Lenders party thereto, and Bank One, NA, as Agent, dated February 14, 2003, incorporated by reference to Exhibit 4.14 to the 2002 Form 10-K/A.

4.11 Lease with Purchase Option Agreement between Banc of America Leasing & Capital, LLC and Canyon Offshore Ltd. dated July 31, 2003 incorporated by reference to Exhibit 10.1 to the Form 10-Q for the fiscal quarter ended September 30, 2003, filed by the registrant with the Securities and Exchange Commission on November 13, 2003.

4.12 Amendment No. 3 Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of July 31, 2003, incorporated by reference to Exhibit 4.12 to Annual Report on Form 10-K for the year ended December 31, 2004, filed by the registrant with the Securities Exchange Commission on March 16, 2005 (the "2004 10-K").

4.13 Amendment No. 4 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of December 15, 2004 , incorporated by reference to Exhibit 4.13 to the 2004 10-K.

4.14 Indenture relating to the 3.25% Convertible Senior Notes due 2025 dated as of March 30, 2005, between Cal Dive International, Inc. and JPMorgan Chase Bank, National Association, as Trustee., incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on April 4, 2005 (the "April 2005 8-K").

4.15 Form of 3.25% Convertible Senior Note due 2025 (filed as Exhibit A to Exhibit 4.15).

4.16 Registration Rights Agreement dated as of March 30, 2005, between Cal Dive International, Inc. and Banc of America Securities LLC, as representative of the initial purchasers, incorporated by reference to Exhibit 4.3 to the April 2005 8-K.

Exhibits

4.17	Trust Indenture, dated as of August 16, 2000, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee, incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on October 6, 2005 (the "October 2005 8-K").
4.18	Supplement No. 1 to Trust Indenture, dated as of January 25, 2002, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee, incorporated by reference to Exhibit 4.2 to the October 2005 8-K.
4.19	Supplement No. 2 to Trust Indenture, dated as of November 15, 2002, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee, incorporated by reference to Exhibit 4.3 to the October 2005 8-K.
4.20	Supplement No. 3 to Trust Indenture, dated as of December 14, 2004, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee, incorporated by reference to Exhibit 4.4 to the October 2005 8-K.
4.21	Supplement No. 4 to Trust Indenture, dated September 30, 2005, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee, incorporated by reference to Exhibit 4.5 to the October 2005 8-K.
4.22	Form of United States Government Guaranteed Ship Financing Bonds, *Q4000* Series 4.93% Sinking Fund Bonds Due February 1, 2027 (filed as Exhibit A to Exhibit 4.21).
4.23	Form of Third Amended and Restated Promissory Note to United States of America, incorporated by reference to Exhibit 4.6 to the October 2005 8-K.
4.24	Term Loan Agreement by and among Kommandor LLC, Nordea Bank Norge ASA, as arranger and agent, Nordea Bank Finland Plc, as swap bank, together with the other lender parties thereto, effective as of June 13, 2007 incorporated by reference to Exhibit 4.7 to the registrants Quarterly Report on Form 10-Q for the fiscal quarter ended June 30, 2007, file by the registrant with the Securities and Exchange Commission on August 3, 2007.
4.25	Indenture, dated as of December 21, 2007, by and among Helix Energy Solutions Group, Inc., the Guarantors and Wells Fargo Bank, N.A. incorporated by reference to Exhibit 4.1 to the registrants Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on December 21, 2007 (the "December 2007 8-K").
10.1	1995 Long Term Incentive Plan, as amended, incorporated by reference to Exhibit 10.3 to the Form S-1.
10.2	Employment Agreement between Owen Kratz and Company dated February 28, 1999, incorporated by reference to Exhibit 10.5 to the registrant's Annual Report on Form 10-K for the fiscal year ended December 31, 1998, filed by the registrant with the Securities and Exchange Commission on March 31, 1999 (the "1998 Form 10-K").
10.3	Employment Agreement between Martin R. Ferron and Company dated February 28, 1999, incorporated by reference to Exhibit 10.6 of the 1998 Form 10-K.
10.4	Employment Agreement between A. Wade Pursell and Company dated January 1, 2002, incorporated by reference to Exhibit 10.7 of the 2001 Form 10-K.
10.5	Helix 2005 Long Term Incentive Plan, including the Form of Restricted Stock Award Agreement, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on May 12, 2005.
10.6	Employment Agreement by and between Helix and Bart H. Heijermans, effective as of September 1, 2005, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on September 1, 2005.
10.7	Termination Agreement between James Lewis Connor, III and Company dated August 31, 2006 incorporated by reference to Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2006, filed by the registrant with the Securities and Exchange Commission on November 7, 2006 (the "2006 Form 10-Q").
10.8	Employment Agreement between Alisa B. Johnson and Company dated September 18, 2006, incorporated by reference to Exhibit 10.2 to the 2006 Form 10-Q.

Exhibits	
10.9	Employment Letter from the Company to Robert P. Murphy dated December 21, 2006, incorporated by reference to Exhibit 10.9 to the 2006 Annual Report on Form 10-K (“2006 Form 10-K”).
10.10	Master Agreement between the Company and Cal Dive International, Inc. dated December 8, 2006, incorporated by reference to Exhibit 10.10 to the 2006 Form 10-K.
10.11	Tax agreement between the Company and Cal Dive International, Inc. dated December 14, 2006, incorporated by reference to Exhibit 10.11 to the 2006 Form 10-K.
10.12	Registration Rights Agreement dated as of December 21, 2007 by and among Helix Energy Solutions Group, Inc., the Guarantors named therein and Banc of America Securities LLC, as representative of the Initial Purchasers, incorporated by reference to Exhibit 10.1 to December 2007 8-K.
10.13	Purchase Agreement dated as of December 18, 2007 by and among Helix Energy Solutions Group, Inc., the Guarantors named therein and Banc of America Securities LLC, and the other Initial Purchasers named therein incorporated by reference to Exhibit 10.2 to the December 2007 8-K.
10.14	Amendment No. 1 to Credit Agreement, dated as of November 29, 2007, by and among Helix, as borrower, Bank of America, N.A., as administrative agent, and the lenders named thereto incorporated by reference to Exhibit 10.3 to the December 2007 8-K.
10.15	Letter Agreement by and between Helix Energy Solutions Group, Inc. and Martin R. Ferron dated February 8, 2008 incorporated by reference to Exhibit 10.1 to the registrants Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on February 8, 2008 (the “February 2008 8-K”).
21.1*	List of Subsidiaries of the Company.
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of Huddleston & Co., Inc..
31.1*	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Owen Kratz, Chief Executive Officer.
31.2*	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by A. Wade Pursell, Chief Financial Officer
32.1**	Certification of Helix’s Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes — Oxley Act of 2002

* Filed herewith.

** Furnished herewith.

SIGNATURES

Pursuant to the requirements of section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

HELIX ENERGY SOLUTIONS GROUP, INC.

By: /s/ A. WADE PURSELL
A. Wade Pursell
Executive Vice President and
Chief Financial Officer

February 29, 2008

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ OWEN KRATZ Owen Kratz	President, Chief Executive Officer and Director (principal executive officer)	February 29, 2008
/s/ A. WADE PURSELL A. Wade Pursell	Executive Vice President and Chief Financial Officer (principal financial officer)	February 29, 2008
/s/ LLOYD A. HAJDIK Lloyd A. Hajdik	Vice President — Corporate Controller and Chief Accounting Officer (principal accounting officer)	February 29, 2008
/s/ GORDON F. AHALT Gordon F. Ahalt	Director	February 29, 2008
/s/ BERNARD J. DUROC-DANNER Bernard J. Duroc-Danner	Director	February 29, 2008
/s/ JOHN V. LOVOI John V. Lovoi	Director	February 29, 2008
/s/ T. WILLIAM PORTER T. William Porter	Director	February 29, 2008
/s/ WILLIAM L. TRANSIER William L. Transier	Director	February 29, 2008
/s/ ANTHONY TRIPODO Anthony Tripodo	Director	February 29, 2008
/s/ JAMES A. WATT James A. Watt	Director	February 29, 2008

INDEX TO EXHIBITS

Exhibits

2.1	Agreement and Plan of Merger dated January 22, 2006, among Cal Dive International, Inc. and Remington Oil and Gas Corporation, incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K/A, filed by the registrant with the Securities and Exchange Commission on January 25, 2006 (the "Form 8-K/A").
2.2	Amendment No. 1 to Agreement and Plan of Merger dated January 24, 2006, by and among, Cal Dive International, Inc., Cal Dive Merger — Delaware, Inc. and Remington Oil and Gas Corporation, incorporated by reference to Exhibit 2.2 to the Form 8-K/A.
3.1	2005 Amended and Restated Articles of Incorporation, as amended, of registrant, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by registrant with the Securities and Exchange Commission on March 1, 2006.
3.2	Second Amended and Restated By-Laws of Helix, as amended, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on September 28, 2006.
3.3	Certificate of Rights and Preferences for Series A-1 Cumulative Convertible Preferred Stock, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by registrant with the Securities and Exchange Commission on January 22, 2003 (the "2003 Form 8-K").
3.4	Certificate of Rights and Preferences for Series A-2 Cumulative Convertible Preferred Stock, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by registrant with the Securities and Exchange Commission on June 28, 2004 (the "2004 Form 8-K").
4.1	Credit Agreement dated July 3, 2006 by and among Helix Energy Solutions Group, Inc., and Bank of America, N.A., as administrative agent and as lender, together with the other lender parties thereto, incorporated by reference to Exhibit 4.1 to the registrant's Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on July 5, 2006.
4.2	Participation Agreement among ERT, Helix Energy Solutions Group, Inc., Cal Dive/Gunnison Business Trust No. 2001-1 and Bank One, N.A., et. al., dated as of November 8, 2001, incorporated by reference to Exhibit 4.2 to Form 10-K for the fiscal year ended December 31, 2001, filed by the registrant with the Securities and Exchange Commission on March 28, 2002 (the "2001 Form 10-K").
4.3	Form of Common Stock certificate, incorporated by reference to Exhibit 4.7 to the Form 8-A filed by the Registrant with the Securities and Exchange Commission on June 30, 2006.
4.4	Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of August 16, 2000, incorporated by reference to Exhibit 4.4 to the 2001 Form 10-K.
4.5	Amendment No. 1 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of January 25, 2002, incorporated by reference to Exhibit 4.9 to the Form 10-K/A filed with the Securities and Exchange Commission on April 8, 2003.
4.6	Amendment No. 2 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of November 15, 2002, incorporated by reference to Exhibit 4.4 to the Form S-3 filed with the Securities and Exchange Commission on February 26, 2003.
4.7	First Amended and Restated Agreement dated January 17, 2003, but effective as of December 31, 2002, by and between Helix Energy Solutions Group, Inc. and Fletcher International, Ltd., incorporated by reference to Exhibit 10.1 to the 2003 Form 8-K.
4.8	Amended and Restated Credit Agreement among Cal Dive/Gunnison Business Trust No. 2001-1, Energy Resource Technology, Inc., Helix Energy Solutions Group, Inc., Wilmington Trust Company, a Delaware banking corporation, the Lenders party thereto, and Bank One, NA, as Agent, dated July 26, 2002, incorporated by reference to Exhibit 4.12 to the Form 10-K/A filed with the Securities and Exchange Commission on April 8, 2003.
4.9	First Amendment to Amended and Restated Credit Agreement among Cal Dive/Gunnison Business Trust No. 2001-1, Energy Resource Technology, Inc., Helix Energy Solutions Group, Inc., Wilmington Trust Company, a Delaware banking corporation, the Lenders party thereto, and Bank One, NA, as Agent, dated January 7, 2003, incorporated by reference to Exhibit 4.13 to the Form 10-K/A filed with the Securities and Exchange Commission on April 8, 2003.

Exhibits

4.10 Second Amendment to Amended and Restated Credit Agreement among Cal Dive/Gunnison Business Trust No. 2001-1, Energy Resource Technology, Inc., Helix Energy Solutions Group, Inc., Wilmington Trust Company, a Delaware banking corporation, the Lenders party thereto, and Bank One, NA, as Agent, dated February 14, 2003, incorporated by reference to Exhibit 4.14 to the 2002 Form 10-K/A.

4.11 Lease with Purchase Option Agreement between Banc of America Leasing & Capital, LLC and Canyon Offshore Ltd. dated July 31, 2003 incorporated by reference to Exhibit 10.1 to the Form 10-Q for the fiscal quarter ended September 30, 2003, filed by the registrant with the Securities and Exchange Commission on November 13, 2003.

4.12 Amendment No. 3 Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of July 31, 2003, incorporated by reference to Exhibit 4.12 to Annual Report on Form 10-K for the year ended December 31, 2004, filed by the registrant with the Securities Exchange Commission on March 16, 2005 (the "2004 10-K").

4.13 Amendment No. 4 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of December 15, 2004 , incorporated by reference to Exhibit 4.13 to the 2004 10-K.

4.14 Indenture relating to the 3.25% Convertible Senior Notes due 2025 dated as of March 30, 2005, between Cal Dive International, Inc. and JPMorgan Chase Bank, National Association, as Trustee., incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on April 4, 2005 (the "April 2005 8-K").

4.15 Form of 3.25% Convertible Senior Note due 2025 (filed as Exhibit A to Exhibit 4.15).

4.16 Registration Rights Agreement dated as of March 30, 2005, between Cal Dive International, Inc. and Banc of America Securities LLC, as representative of the initial purchasers, incorporated by reference to Exhibit 4.3 to the April 2005 8-K.

4.17 Trust Indenture, dated as of August 16, 2000, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee, incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on October 6, 2005 (the "October 2005 8-K").

4.18 Supplement No. 1 to Trust Indenture, dated as of January 25, 2002, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee, incorporated by reference to Exhibit 4.2 to the October 2005 8-K.

4.19 Supplement No. 2 to Trust Indenture, dated as of November 15, 2002, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee, incorporated by reference to Exhibit 4.3 to the October 2005 8-K.

4.20 Supplement No. 3 to Trust Indenture, dated as of December 14, 2004, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee, incorporated by reference to Exhibit 4.4 to the October 2005 8-K.

4.21 Supplement No. 4 to Trust Indenture, dated September 30, 2005, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee, incorporated by reference to Exhibit 4.5 to the October 2005 8-K.

4.22 Form of United States Government Guaranteed Ship Financing Bonds, *Q4000* Series 4.93% Sinking Fund Bonds Due February 1, 2027 (filed as Exhibit A to Exhibit 4.21).

4.23 Form of Third Amended and Restated Promissory Note to United States of America, incorporated by reference to Exhibit 4.6 to the October 2005 8-K.

4.24 Term Loan Agreement by and among Kommandor LLC, Nordea Bank Norge ASA, as arranger and agent, Nordea Bank Finland Plc, as swap bank, together with the other lender parties thereto, effective as of June 13, 2007 incorporated by reference to Exhibit 4.7 to the registrants Quarterly Report on Form 10-Q for the fiscal quarter ended June 30, 2007, file by the registrant with the Securities and Exchange Commission on August 3, 2007.

4.25 Indenture, dated as of December 21, 2007, by and among Helix Energy Solutions Group, Inc., the Guarantors and Wells Fargo Bank, N.A. incorporated by reference to Exhibit 4.1 to the registrants Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on December 21, 2007 (the "December 2007 8-K").

Exhibits

10.1	1995 Long Term Incentive Plan, as amended, incorporated by reference to Exhibit 10.3 to the Form S-1.
10.2	Employment Agreement between Owen Kratz and Company dated February 28, 1999, incorporated by reference to Exhibit 10.5 to the registrant's Annual Report on Form 10-K for the fiscal year ended December 31, 1998, filed by the registrant with the Securities and Exchange Commission on March 31, 1999 (the "1998 Form 10-K").
10.3	Employment Agreement between Martin R. Ferron and Company dated February 28, 1999, incorporated by reference to Exhibit 10.6 of the 1998 Form 10-K.
10.4	Employment Agreement between A. Wade Pursell and Company dated January 1, 2002, incorporated by reference to Exhibit 10.7 of the 2001 Form 10-K.
10.5	Helix 2005 Long Term Incentive Plan, including the Form of Restricted Stock Award Agreement, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on May 12, 2005.
10.6	Employment Agreement by and between Helix and Bart H. Heijermans, effective as of September 1, 2005, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on September 1, 2005.
10.7	Termination Agreement between James Lewis Connor, III and Company dated August 31, 2006 incorporated by reference to Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2006, filed by the registrant with the Securities and Exchange Commission on November 7, 2006 (the "2006 Form 10-Q").
10.8	Employment Agreement between Alisa B. Johnson and Company dated September 18, 2006, incorporated by reference to Exhibit 10.2 to the 2006 Form 10-Q.
10.9	Employment Letter from the Company to Robert P. Murphy dated December 21, 2006, incorporated by reference to Exhibit 10.9 to the 2006 Form 10-K
10.10	Master Agreement between the Company and Cal Dive International, Inc. dated December 8, 2006, incorporated by reference to Exhibit 10.10 to the 2006 Form 10-K.
10.11	Tax agreement between the Company and Cal Dive International, Inc. dated December 14, 2006, incorporated by reference to Exhibit 10.11 to the 2006 Form 10-K.
10.12	Registration Rights Agreement dated as of December 21, 2007 by and among Helix Energy Solutions Group, Inc., the Guarantors named therein and Banc of America Securities LLC, as representative of the Initial Purchasers, incorporated by reference to Exhibit 10.1 to December 2007 8-K.
10.13	Purchase Agreement dated as of December 18, 2007 by and among Helix Energy Solutions Group, Inc., the Guarantors named therein and Banc of America Securities LLC, and the other Initial Purchasers named therein incorporated by reference to Exhibit 10.2 to the December 2007 8-K.
10.14	Amendment No. 1 to Credit Agreement, dated as of November 29, 2007, by and among Helix, as borrower, Bank of America, N.A., as administrative agent, and the lenders named thereto incorporated by reference to Exhibit 10.3 to the December 2007 8-K.
10.15	Letter Agreement by and between Helix Energy Solutions Group, Inc. and Martin R. Ferron dated February 8, 2008 incorporated by reference to Exhibit 10.1 to the registrants Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on February 8, 2008 (the "February 2008 8-K").
21.1*	List of Subsidiaries of the Company.
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of Huddleston & Co., Inc..
31.1*	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Owen Kratz, Chief Executive Officer.
31.2*	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by A. Wade Pursell, Chief Financial Officer
32.1**	Certification of Helix's Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes — Oxley Act of 2002

* Filed herewith.

** Furnished herewith.

Exhibit 21.1

Subsidiaries of Helix Energy Solutions Group, Inc.
As of December 31, 2006

Name of Subsidiary	Jurisdiction of Formation
Canyon Offshore, Inc.	Texas
Canyon Offshore Limited	Scotland
Canyon Offshore International Corp	Texas
Helix Energy Solutions BV	The Netherlands
Helix Energy Solutions (U.K.) Limited	Scotland
Well Ops (U.K.) Limited	Scotland
Helix HR Services Limited	Scotland
Well Ops PTE Limited	Singapore
Helix Energy Limited	Scotland
Helix RDS Limited	Scotland
Helix RDS Pty Limited	Australia
Well Ops, Inc.	Texas
Energy Resource Technology GOM, Inc.	Delaware
CKB Petroleum, Inc.	Texas
CKB & Associates, Inc.	Texas
Box Brothers Realty Investments Company	Texas
CB Farms, Inc.	Texas
Box Resources, Inc.	Texas
Energy Resource Technology (U.K.) Limited	Scotland
Cal Dive I-Title XI, Inc.	Texas
Helix Vessel Holdings LLC	Delaware
Neptune Vessel Holdings LLC	Delaware
Vulcan Marine Holdings LLC	Delaware
Vulcan Marine Technology LLC	Delaware
Cal Dive Offshore Ltd.	Cayman
Helix Oil & Gas, Inc.	Delaware
Kommandor LLC (50% interest)	Delaware
Cal Dive International, Inc. (58.5% interest)	Delaware
Helix Energy Services Pte. Limited.	Singapore
Well Ops SEA Pty Ltd (d/b/a Seatrac)	Australia
Helix Energy Services Pty Ltd	Australia
Helix Ingleside LLC	Delaware
Helix Energy Services (Cyprus) Limited	Cyprus

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statement Forms S-3 (Nos. 333-103451 and 333-125276) and in the related Prospectuses and Forms S-8 (Nos. 333-126248, 333-58817, 333-50289 and 333-50205) of Helix Energy Solutions Group, Inc. of our reports dated February 28, 2008, with respect to the consolidated financial statements of Helix Energy Solutions Group, Inc. and subsidiaries, and the effectiveness of internal control over financial reporting of Helix Energy Solutions Group, Inc., included in this Annual Report (Form 10-K) for the year ended December 31, 2007.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 28, 2008

Exhibit 23.2

[Letterhead of Huddleston & Co., Inc.]
February 28, 2008

Helix Energy Solutions Group, Inc.
400 North Sam Houston Parkway East
Suite 400
Houston, TX 77060

Re: Helix Energy Solutions Group, Inc.
Securities and Exchange Commission
Form 10-K
Consent Letter

Gentlemen:

The firm of Huddleston & Co., Inc. consents to the naming of it as experts and to the incorporation by reference of its report letter dated February 18, 2008 concerning the proved reserves as of January 1, 2008 attributable to Energy Resource Technology GOM, Inc. in the Annual Report of Helix Energy Solutions Group, Inc. on Form 10-K to be filed with the Securities and Exchange Commission. Huddleston & Co., Inc. has no interests in Helix Energy Solutions Group, Inc. or in any of its affiliated companies or subsidiaries and is not to receive any such interest as payment for such report and has no director, officer, or employee employed or otherwise connected with Helix Energy Solutions Group, Inc. We are not employed by Helix Energy Solutions Group, Inc. on a contingent basis.

Very truly yours,

HUDDLESTON & CO., INC.

By: /s/ PETER D. HUDDLESTON
Name: Peter D. Huddleston, P.E.
Title: President

EXHIBIT 31.1

CERTIFICATION

I, Owen Kratz, certify that:

1. I have reviewed this annual report on Form 10-K of Helix Energy Solutions Group, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 29, 2008

/s/ OWEN KRATZ
Owen Kratz
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, A. Wade Pursell, certify that:

1. I have reviewed this annual report on Form 10-K of Helix Energy Solutions Group, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

(a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 29, 2008

/s/ A. WADE PURSELL
A. Wade Pursell
Executive Vice President and
Chief Financial Officer

EXHIBIT 32.1

**CERTIFICATION OF CEO AND CFO PURSUANT TO 18 U.S.C.
SECTION 1350
(Adopted Pursuant to Section 906 of Sarbanes-Oxley Act of 2002)**

Pursuant to section 1350 of chapter 63 of title 18 of the United States Code, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, Owen Kratz, as Chief Executive Officer, and A. Wade Pursell, as Chief Financial Officer, each hereby certifies that the annual report of Helix Energy Solutions Group, Inc. ("Helix") on Form 10-K for the period ended December 31, 2007, as filed with the Securities and Exchange Commission on the date hereof (the "Report"):

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Helix.

Date: February 29, 2008

/s/ OWEN KRATZ
Owen Kratz
President and Chief Executive Officer

/s/ A. WADE PURSELL
A. Wade Pursell
Executive Vice President and
Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to Helix and will be retained by Helix and furnished to the Securities and Exchange Commission or its staff upon request.

This certification accompanies the Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.