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, 2005

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 0-22739

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)*

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

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

Title of each class	Name of each exchange on which registered
None	None

Securities registered Pursuant to Section 12(g) of the Act:
Common Stock (no par value)
(Title of Class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Exchange Act of 1934. 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 Securities Exchange Act of 1934. Yes o 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 ☑ No o

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Securities Exchange Act of 1934. (Check one):
Large accelerated filer ☑ Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes o No ☑

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2005 was $1,949,439,889 based on the last reported sales price of the Common Stock on June 30, 2005, as reported on the NASDAQ National Market System.

The number of shares of the registrant's Common Stock outstanding as of March 13, 2006 was 78,400,284.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement for the Annual Meeting of Shareholders to be held on May 8, 2006, 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, or Annual Report, including "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7, contains forward-looking statements that involve risks, uncertainties and assumptions that could cause our results to differ materially from those expressed or implied by such forward-looking statements. All statements, other than statements of historical fact, are statements that could be deemed "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995, including, without limitation, any projections of revenue, gross margin, expenses, earnings or losses from operations, or other financial items; any statements of the plans, strategies and objectives of management for future operations; any statement concerning developments, performance or industry rankings relating to services; any statements regarding future economic conditions or performance; any statements of expectation or belief; any statements regarding the proposed merger of Remington Oil and Gas Corporation into a wholly owned subsidiary of Helix or the anticipated results (financial or otherwise) thereof; and any statements of assumptions underlying any of the foregoing. The risks, uncertainties and assumptions referred to above include the performance of contracts by suppliers, customers and partners; employee management issues; complexities of global political and economic developments, other risks described herein under the heading "Risk Factors" and, with respect to the proposed Remington merger, actual results could differ materially from Helix's expectations depending on factors such as the combined company's cost of capital, the ability of the combined company to identify and implement cost savings, synergies and efficiencies in the time frame needed to achieve these expectations, prior contractual commitments of the combined companies and their ability to terminate these commitments or amend, renegotiate or settle the same, the combined company's actual capital needs, the absence of any material incident of property damage or other hazard that could affect the need to effect capital expenditures, any unforeseen merger or acquisition opportunities that could affect capital needs, the costs incurred in implementing synergies and the factors that generally affect both Helix's and Remington's respective businesses as further outlined in "Management's Discussion and Analysis of Financial Condition and Results of Operations" herein and in Remington's Annual Report on Form 10-K for the year ended December 31, 2005. Actual actions that the combined company may take may differ from time to time as the combined company may deem necessary or advisable in the best interest of the combined company and its shareholders to attempt to achieve the successful integration of the companies, the synergies needed to make the transaction a financial success and to react to the economy and the combined company's market for its exploration and production. We assume no obligation and do not intend to update these forward-looking statements.

PART I

Item 1. *Business.*

OVERVIEW

Effective March 6, 2006, we changed our name from Cal Dive International, Inc. to Helix Energy Solutions Group, Inc. ("Helix Energy Solutions", "Helix" or the "Company"). We are an energy services company, incorporated in the State of Minnesota, that provides development solutions and related services to the energy market and specializes in the exploitation of marginal fields, including exploration of unproven fields, where we differentiate ourselves by employing our services on our own oil and gas properties as well as providing services to the open market. On January 23, 2006, the Company and Remington Oil and Gas Corporation announced an agreement under which the Company will acquire Remington in a transaction valued at approximately $1.4 billion. Under the terms of the agreement, Remington stockholders will receive $27.00 in cash and 0.436 shares of the Company's common stock for each Remington share. The acquisition is conditioned upon, among other things, the approval of Remington stockholders and customary regulatory approvals. The transaction is expected to be completed in the second quarter of 2006. Remington is an exploration, development and production company with operations in the Gulf of Mexico. In our Oil & Gas Production business segment, our subsidiary Energy Resource Technology, Inc., or ERT, partners or acquires and produces marginal, mature and non-core offshore property interests, offering customers a cost-effective alternative to the standard development and decommissioning process. In 2000, ERT's reservoir engineering and geophysical expertise enabled us to acquire in partnership with the operator, Kerr McGee Oil & Gas Corp., a working interest in *Gunnison*, a Deepwater Gulf oil and natural gas exploration project, which began initial production in December 2003. In 2004, ERT continued to successfully pursue its strategy of acquiring (or partnering in) and developing proved undeveloped and high probability of success exploration reserves, i.e., leases where reserves were judged by the current owner to be too marginal to justify development or for which they were seeking a partner. During 2005, ERT was successful in acquiring a large package of mature properties on the Shelf from Murphy Exploration & Production Company — USA and also equity interests in five additional undeveloped reservoirs in the Deepwater Gulf of Mexico that will be developed over the next few years. Our ability to successfully develop these fields is subject to various risk factors, as described later in this filing. Each of these Deepwater interests is owned in partnership with other producers. Also, in 2004, Helix formed Energy Resource Technology (U.K.) Limited, or ERT (U.K.) Limited, to explore exporting these strategies to the North Sea.

In our Deepwater Contracting business segment, we have positioned ourselves for work in water depths greater than 1,000 feet, referred to as the Deepwater, by continuing to grow our technically advanced fleet of dynamically positioned, or DP, vessels, ROVs and the number of highly experienced support professionals we employ. These DP vessels serve as advanced work platforms for the subsea solutions that enable us to offer a diverse range of DP subsea construction and intervention vessels, as well as robotics, to support most drilling, development, life of field and abandonment requirements for our own, as well as third party, E&P projects. Our ROV subsidiary, Canyon Offshore, Inc., or Canyon, offers survey, engineering, repair, maintenance and international pipe and cable burial services in the Gulf, Europe/West Africa and Asia/Pacific regions.

Our Deepwater Contracting business also includes Wells Ops Inc., and its Aberdeen, Scotland based sister company, known as Well Ops (U.K.) Limited, engineer, manage and conduct well construction, intervention and decommissioning operations in water depths from 200 to 10,000 feet in, the Gulf of Mexico and the North Sea. Saturation diving in the North Sea from the DP vessel, the *Seawell*, is also performed. Utilizing specialty designed vessels, the *Q4000* and the *Seawell*, we believe this well operations service is the global leader in rig alternative subsea well intervention.

Also included in Deepwater Contracting is Reservoir and Well Technical Services. Until 2005, our reservoir and well tech services were an in-house service for our own production. With the acquisition of Helix Energy Limited in 2005, which includes a technical staff of over 200, we have increased the resources that we can bring to our own projects as well as provide a value adding service to our clients. With offices in Aberdeen, Perth, London and Kuala Lumpur, these services provide the market presence in regions we have identified as strategically important to future growth.

In our Production Facilities segment, we participate in the ownership of production facilities in hub locations where there is potential for significant subsea tieback activity. In addition to production from the *Gunnison* reservoir, which is included in our Oil and Gas Production segment, Helix will receive ongoing revenues from its 20% interest in the production facility as satellite prospects are drilled and tied back to the spar. Deepwater Gateway, L.L.C., our second such endeavor, involves a 50% ownership position in the tension-leg platform installed at Anadarko's *Marco Polo* field at Green Canyon Block 608 (which began producing in July 2004). In 2004, we acquired a 20% interest in Independence Hub, LLC, an affiliate of Enterprise Products Partners L.P. Independence Hub, LLC will own the "Independence Hub" platform to be located in Mississippi Canyon Block 920 in a water depth of 8,000 feet. Construction is ongoing and is expected to be complete and come online in early 2007. At both *Gunnison* and *Marco Polo,* we participated in field development planning and performed subsea construction work.

These deepwater services and assets allow us to respond to market demand for the individual services and allow us to control and lower our own cost of development and life of field production enhancement through well intervention.

In our Shelf Contracting business segment, we perform traditional subsea services, including air and saturation diving, salvage work and shallow water pipelay on the Outer Continental Shelf, or OCS, of the Gulf of Mexico, in water depths up to 1,000 feet. We believe that we are the market leader in the diving support business in the Gulf of Mexico OCS, including construction, inspection, maintenance, repair and decommissioning. We also provide these services in select international offshore markets, such as Trinidad and the Middle East. We currently own and operate a diversified fleet of 26 vessels, including 23 surface and saturation diving support vessels capable of operating in water depths of up to 1,000 feet, as well as three shallow-water pipelay vessels. Our customers include major and independent oil and natural gas producers, pipeline transmission companies and offshore engineering and construction firms. 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 in the Gulf of Mexico. In the Gulf of Mexico saturation diving market, which typically covers water depths of 200 to 1,000 feet, we offer our full complement of services via our eight saturation diving vessels and three portable saturation diving systems. We believe that our saturation diving support fleet is the largest in the world. We offer the same range of services through our 15 surface and mixed gas diving vessels in water depths typically less than 300 feet. In addition to our diving operations, we have three vessels dedicated exclusively to pipelay and pipe burial services in water depths of up to approximately 400 feet. We believe the scheduling flexibility offered by our large fleet and the advanced technical expertise of our personnel provides a valuable advantage over our competitors. As a result, we believe that we are a leading provider to most of the largest oil and gas producers operating in the Gulf of Mexico.

In the past year, we have substantially increased the size of our Shelf Contracting fleet and expanded our operating capabilities through as series of strategic acquisitions. In August 2005, we acquired seven vessels and a portable saturation diving system from Torch Offshore. In November 2005, we acquired all of Stolt Offshore’s diving and shallow water pipelay assets operating in the Gulf of Mexico and Trinidad. Upon closing these transactions, we added a total of 13 vessels, including three premium saturation diving vessels and one portable saturation diving system to our fleet.

Significant financial information relating to the Company’s segments for the last three years is contained in footnote 14 of the Consolidated Financial Statements included herein, which financial statements are included in Item 8 hereof.

BUSINESS STRENGTHS AND STRATEGIES

Our overall corporate goal is to increase shareholder value by strengthening our market position to provide a return that leads our Peer Group. Our goal for Return on Invested Capital is 10% or greater. We attempt to achieve our return on capital objective by focusing on the following business strengths and strategies.

Our Strengths

Unique Business Model. We have assembled a company with highly specialized people, assets and methodologies that we believe provide all of the necessary services to maximize the economics from marginal fields. Marginal fields that we target include (i) mature properties on the OCS where we bring our late life field management expertise to bear and (ii) Deepwater properties with reserves that are judged by the current owner to be too marginal to justify development and where we are able to bring our development expertise to bear.

Oil & Gas Production. The strategy of ERT’s oil and gas production business differentiates us from our competitors and helps to offset the cyclical nature of our subsea construction operations. ERT’s oil and gas investments secure utilization of Helix construction vessels. The pending Remington acquisition would bring not only proven producing reserves, but also prospects that we believe will likely generate over $1 billion of life of field services for our vessels.

Fleet of Dynamically Positioned Vessels. We believe our fleet of dynamically positioned, or DP, construction vessels is one of the most capable in the world, with one of the most diverse and technically advanced collections of subsea intervention and construction capabilities. The comprehensive services provided by our DP vessels are both complementary and overlapping, enabling us to provide customers with the redundancy essential for most projects, especially in the Deepwater. We also utilize these capabilities to lower total finding and development costs in both wholly owned properties as well as those in which we are partnered with third parties.

Subsea Well Operations Subsidiary. Establishment of the Well Ops group followed the construction of the purpose-built *Q4000* and the acquisition of the Subsea Well Operations Business Unit of Technip in Aberdeen, Scotland. The mission of these companies is to provide the industry with a single, comprehensive source for addressing current subsea well operations needs and to engineer for future needs using drill rig alternatives. We also use these capabilities to maintain, enhance and abandon our own reservoirs.

Experienced Personnel and Qualified Turnkey Contracting. A key element of our successful growth has been our ability to attract and retain experienced personnel who are among the best in the industry at providing turnkey contracting. We believe the recognized skill of our personnel and our successful operating history uniquely position us to capitalize on the trend in the oil and gas industry of increased outsourcing to contractors and suppliers. This is especially true on a broader scale with smaller, economically challenged reservoirs.

Leader in the Gulf of Mexico OCS Diving Market. We believe our Shelf Contracting business is the leader in the Gulf of Mexico OCS diving market based on the size and quality of our fleet of vessels and diving assets. The size of our fleet and crews provides a distinct advantage over our competitors in that we can respond more quickly to service the traditional spot diving market in the Gulf of Mexico OCS.

High Quality, High Capability Asset Base. We believe that our diverse fleet of Shelf Contracting diving support vessels and systems and pipelay and pipe burial vessels afford us the range of technical capabilities necessary to the execution of the more complex integrated subsea project work that is in high demand in the Gulf of Mexico, and valued even more highly in certain international markets.

Excellent, Long-Standing Customer Relationships with the Top Producers in the Gulf of Mexico. Our Shelf Contracting business has built a reputation as a premium diving services contractor by consistently providing high-quality service to its customers in the Gulf of Mexico for over 30 years. Shelf Contracting has developed a strong and loyal customer base through its ability to provide superior and comprehensive services on schedule, while maintaining a strong safety record.

Production Facilities. At the *Marco Polo* field, our 50% ownership in the production facility allows us to realize a return on investment consisting of both a fixed monthly demand charge and a volumetric tariff charge. In addition, we assisted with the installation of the tension leg platform, or TLP, and the work to develop the surrounding acreage that can be tied back to the platform by our construction vessels. With the acquisition of a 20% interest in Independence Hub, LLC, we are in a good position to secure installation and tie-back work similar to what we achieved at the *Marco Polo* field. We also own a 20% interest in the spar at *Gunnison.* As our track record increases so does the demand for our model.

Our Strategies

Focusing on the Gulf and Global Expansion. We will continue to focus on the Gulf of Mexico, where we have provided marine construction services since 1975 and taken interests in reservoirs since 1992, as well as the North Sea, Southeast Asia and other Deepwater basins worldwide. We expect oil and gas exploration and development activity in the Deepwater Gulf and other Deepwater basins of the world to continue to increase over the next several years.

Focusing on Deepwater "Niche" Services. We will focus on services that provide the best "niche" financial return in the external market and add value to acquired oil and gas properties, particularly in the Deepwater. These include pipelay (acquisition/conversion of the *Caesar*), drilling (conversion of the *Q4000* to drilling) and robotics (pipe burial). The pending Remington acquisition will bring a significant prospect portfolio which we believe will likely generate over $1 billion of life of field services for our vessels. As our Shelf Contracting services do not add value to acquired oil and gas properties, we may sell a minority stake in the Shelf Contracting business as these services are not as critical to unlocking value in marginal fields. We would continue to control this business and retain access to the services. This does not constitute an offer of any securities for sale.

Developing Well Operations Niche. 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. Three 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, the *Q4000* has set a series of well operations "firsts" in increasingly deep water without the use of a rig. In the North Sea, the *Seawell* has provided intervention and abandonment services for approximately 500 North Sea wells since her commissioning in 1987. Competitive advantages of the Helix vessels stem from their lower operating costs, together with an ability to mobilize quickly and to maximize productive 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.

Expanding Ownership in Production Facilities. Along with Enterprise Products Partners L.P., Helix owns 50% of the tension leg production platform installed at the *Marco Polo* field and 20% of the Independence Hub platform, a 105 foot deep draft, semi-submersible platform. We also own a 20% interest in the spar at *Gunnison.* Ownership of these production facilities provides a transmission type return that does not entail any reservoir or commodity price risk. The Company plans to seek additional opportunities to invest in such production facilities as well as evolved models, to be provided on a third party basis, and also to be utilized on our own developments.

Acquiring Mature Oil and Gas Properties. Through ERT we have been acquiring mature or sunset properties since 1992, thereby providing customers a cost effective alternative to the decommissioning process. In the last thirteen years, we have acquired interests in 168 leases and currently are the operator of 61 of 115 active offshore leases. ERT has been able to achieve a significant return on capital by efficiently developing acquired reserves, lowering lease operating expenses and adding new reserves through exploitation drilling and well work. Our customers consider ERT a preferred buyer as a result of ERT's reputation, Helix's financial strength and our salvage expertise. As an industry leader in acquiring mature properties, ERT has a significant flow of potential acquisitions. In June 2005, ERT acquired a large package of mature properties from Murphy Exploration & Production Company — USA for $163.5 million cash and assumption of approximately $32.0 million abandonment liability.

Expanding the Model. The Deepwater Gulf has seen a significant increase in oil and gas exploration, development, and production due, in part, to new technologies that reduce operational costs and risks; the discovery of new, larger oil and gas reservoirs with high production potential; government deepwater incentives; and increasing demand and prices. Along with these larger fields are prospects where the reserves are judged by the current owner to be too marginal to justify development. We first applied the ERT model to the Deepwater with our involvement in the *Gunnison* field. During 2005, ERT was successful in acquiring equity interests in five additional undeveloped reservoirs, in the Deepwater Gulf, that will be developed over the next few years. Through an integrated development approach combining the advantages of application of each of our select services, we can apply a differentiated methodology to the development of these marginal reservoirs. In 2006, ERT will continue to aggressively pursue its strategy of acquiring reserves and develop these reserves utilizing Helix's assets. In January we announced an agreement under which the Company will acquire Remington, pending regulatory and Remington shareholder approval. Remington has a significant prospect inventory, mostly in the Deepwater, which we believe will likely generate over $1 billion of life of field services for our vessels. Through ERT (U.K.) Limited, we plan to expand the model to the North Sea, and eventually to the Asian Continent.

THE INDUSTRY

The offshore oilfield services industry originated in the early 1950's as producers began to explore and develop the new frontier of offshore fields. The industry has grown significantly since the 1970's 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. This is still true today and these standards are still largely adhered to 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 peaked or 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 subsea developments.

In response to the oil and gas industry's ongoing migration to the Deepwater, equipment and vessel requirements have and will continue to change. A new industry set of methodologies will emerge alongside of the current ones. These new methodologies will focus not only on the larger reservoirs in the harsh frontiers, but on the smaller and older reservoirs in the better understood frontiers. We believe there is a niche for new generation vessels such as the *Q4000* and employment of alternative methodologies for development of marginal reservoirs in Deepwater depths.

For now, we try to provide for both sets of methodologies. For marginal reservoirs we find it more efficient to develop our own and work with partners. Therefore, we align our interests in the reservoir and are able to better control the development methodologies.

Defined below are certain terms helpful to understanding the services we perform in support of offshore development:

Bcfe: Billions of cubic feet equivalent, used to describe oil volumes converted to their energy equivalent in natural gas as measured in billions of cubic feet.

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, ROVs 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. Two DP systems (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.

DP-2: Redundancy allows the vessel to maintain position even with failure of one DP system; required for vessels which support both manned diving and robotics and for those working in close proximity to platforms.

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 finding and development costs.

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 economic end of the life of an oil field, including installation, inspection, maintenance, repair, contract operations, well intervention, recompletion and abandonment.

MBbl: When describing oil, refers to 1,000 barrels containing 42 gallons each.

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

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 from the shore to 1,000 feet of water depth.

Peer Group: Defined in this Annual Report as comprising Global Industries, Ltd. (Nasdaq: GLBL), McDermott International, Inc. (NYSE: MDR), Oceaneering International, Inc. (NYSE: OII), Stolt Offshore SA (Nasdaq: SOSA), Technip-Coflexip (NYSE: TKP), Superior Energy Services, Inc. (NYSE: SPN), TETRA Technologies, Inc. (NYSE: TTI) and Subsea 7.

Proved Undeveloped Reserve (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.

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, characterized by projects generally short in duration and often of a turnkey nature. 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 the vessel's ability to transport and fabricate hardware, supplies and equipment necessary to complete subsea projects.

Tension Leg Platform (TLP): A floating Deepwater compliant structure designed for offshore hydrocarbon production.

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.

CONTRACTING SERVICES

We provide a full range of contracting services in both the shallow water and Deepwater including:

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

Deepwater Contracting

In 1994, we began to assemble a fleet of DP vessels in order to deliver subsea services in the Deepwater and Ultra-Deepwater. Today, our fleet consists of two semi-submersible DP MSVs, the *Q4000* and the *Uncle John;* a dedicated well operations vessel, the *Seawell;* four umbilical and pipelay vessels, the *Intrepid,* the *Kestrel* (which is expected to be acquired in March 2006), the *Express* and the *Caesar;* three construction DP DSVs, the *Witch Queen* (through our 40% interest in Offshore Technology Solutions Limited), the *Mystic Viking*, and the *Eclipse;* and an ROV support vessel the *Northern Canyon. Additional assets are chartered as required. The Uncle John, Kestrel,* *Witch Queen*, *Mystic Viking* and *Eclipse* currently perform diving related activities and are accordingly included in our Shelf Contracting segment.

Our subsidiary, Canyon Offshore, Inc., operates ROVs and trenchers 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 Canyon's 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 and internationally. Our 25 ROVs and four trencher systems operate in three regions: the Americas, Europe/West Africa and Asia Pacific.

The mission of the Well Ops group is to provide the industry with a comprehensive source for addressing current subsea well operations needs and to engineer for future needs. Our purpose-built vessels serve as work platforms for subsea well operations services at costs significantly less than drilling rigs.

In both the Gulf of Mexico and North Sea, 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 Ops services. During 2005 two critical production recovery projects were successfully completed by the *Q4000.* These projects for Kerr McGee and Walter Oil & Gas highlighted the value of an asset capable of performing repairs and installations normally requiring a drilling rig and available on short call out. A high volume of less critical intervention and decommissioning work was delayed during the second half of the year by extensive hurricane repair work. Despite the lower than expected utilization on Well Ops projects, 76 days versus the budgeted 106 days, Well Ops met all of the 2005 financial goals, including gross profit. The back log of projects delayed by critical construction work is now approaching 240 days and will be carried into 2006.

The *Seawell* has provided intervention and abandonment services on approximately 500 North Sea wells since her commissioning in 1987, being the only consistent and continuous solution to light well intervention needs in the region, setting many records and "firsts" over the last 17 years. One additional advantage is that the *Seawell* can undertake saturation diving and construction tasks independently or simultaneously with the well intervention activities. Due to these unique capabilities, Well Ops (U.K.) Limited re-negotiated its existing call-off contract with Shell Exploration and Production Limited in 2005 to incorporate utilization of the *Seawell* to service its assets for a minimum of 120 days per annum in 2006 and 2007 with the potential to continue this arrangement until 2010. Competitive advantages of our vessels stem from their lower operating costs and the ability to mobilize quickly for multi-well campaigns of work and maximize productive time by performing a broad range of tasks for intervention, construction, inspection, repair and maintenance.

Well Ops Inc. and Well Ops (U.K.) Limited also collaborate with leading downhole service providers to provide superior, comprehensive solutions to the well operations challenges faced by our customers.

Also included in Deepwater Contracting is Reservoir and Well Technical Services. Until 2005, our reservoir and well tech services were an in-house service for our own production. With the acquisition of Helix Energy Limited in 2005, which includes a technical staff of over 200, we have increased the resources that we can bring to our own projects as well as provide a value adding service to our clients. With offices in Aberdeen, Perth, London and Kuala Lumpur, these services provide the market presence in regions we have identified as strategically important to future growth.

Shelf Contracting

We provide marine contracting services, including saturation, surface and mixed gas diving as well as pipelay and pipe burial services, to the offshore oil and natural gas industry. We believe that we are the market leader in the diving support business in the Gulf of Mexico OCS, including construction, inspection, maintenance, repair and decommissioning. We also provide these services in select international offshore markets, such as Trinidad and the Middle East. We currently own and operate a diversified fleet of 26 vessels, including 23 surface and saturation diving support vessels capable of operating in water depths of up to 1,000 feet, as well as three shallow-water pipelay vessels. Our customers include major and independent oil and natural gas producers, pipeline transmission companies and offshore engineering and construction firms.

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 in the Gulf of Mexico. In the Gulf of Mexico saturation diving market, which typically covers water depths of 200 to 1,000 feet, we offer our full complement of services via our eight saturation diving vessels and three portable saturation diving systems. We believe that our saturation diving support fleet is the largest in the world. We offer the same range of services through our 15 surface and mixed gas diving vessels in water depths typically less than 300 feet. In addition to our diving operations, we have three vessels dedicated exclusively to pipelay and pipe burial services in water depths of up to approximately 400 feet. We believe the scheduling flexibility offered by our large fleet and the advanced technical expertise of our personnel provides a valuable advantage over our competitors. As a result, we believe that we are a leading provider to most of the largest oil and gas producers operating in the Gulf of Mexico.

In the past year we have substantially increased the size of our Shelf Contracting fleet and expanded our operating capabilities through a series of strategic acquisitions. In August 2005, we acquired five diving support vessels, two shallow water pipelay vessels and a portable saturation diving system from Torch Offshore. In November 2005, we acquired all of Stolt Offshore's assets operating in the Gulf of Mexico. In January 2006, we acquired Stolt's shallow water pipelay vessel and expect to acquire the *Kestrel* in March 2006. Upon closing these transactions, we will have added a total of 13 vessels, including three premium saturation diving vessels, and one portable saturation diving system to our fleet.

PRODUCTION FACILITIES

There are a significant number of small discoveries that cannot justify the economics of a dedicated host facility. These are typically developed as subsea tie backs to existing facilities when capacity through the facility is available. We provide over-sized facilities to operators for these fields 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. 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, thus being able to develop some fields that otherwise would be non-commercial to develop. The commercial risk is mitigated since we have a portfolio of reservoirs and the assets to easily redeploy the facility. At the *Marco Polo* field, our 50% ownership in the production facility through Deepwater Gateway, L.L.C. will allow us to realize a return on investment consisting of both a fixed monthly demand charge and a volumetric tariff charge. In addition, we assisted with the installation of the TLP and will work to develop the surrounding acreage that can be tied back to the platform by our construction vessels. Our 20% interest in the Independence Hub platform, scheduled for installation in late 2006, should enable us to repeat the *Marco Polo* strategy. Our production facilities group has evolved to become our development engineering group. In conjunction with our reservoir integrated modeling services, we are able to efficiently assess opportunities and provide the conceptual development most appropriate to the reservoir.

OIL & GAS PRODUCTION

We formed ERT in 1992 to exploit a market opportunity to provide a more efficient solution to offshore abandonment, to expand our off-season asset utilization and to achieve better returns than are likely through pure service contracting. In essence, we transfer the risk of abandonment and through our services we mitigate that risk to yield a lower cost to produce and therefore increase value from the reservoir.

Over the past 14 years, we have identified similar opportunities to transfer and mitigate risk throughout the life of the reservoir. This has led to the assembly of a services set 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 to abandonment. We do not provide all services, but just those key to mitigating certain risks and costs.

ERT now seeks 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. Interests are better aligned creating a more efficient relationship 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. During 2005, we were successful in acquiring equity interests in five 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. In January we announced an agreement under which the Company will acquire Remington, pending regulatory and Remington shareholder approval. In addition to 279 Bcfe of proven reserves as of December 31, 2005, Remington has a significant prospect inventory, mostly in the Deepwater, which we believe will likely generate over $1 billion of life of field services for our vessels.

The benefits of our strategy are fourfold. First, oil and gas revenues counteract the volatility in revenues we experience in offshore construction. Second, in periods of excess capacity, such as in 2002 and 2003, we have the flexibility to be less dependent on the competitive bid market and instead focus on negotiated contracts thus avoiding contractual risks. Third, our oil and gas operations generate significant cash flow and visibility that has partially funded construction and/or modification of assets such as the *Q4000*, the *Intrepid* and the *Caesar*, enabling us to add technical talent to support our expansion into the new Deepwater frontier. Finally, a major objective of our investments in oil and gas properties is to secure backlog for our services in a manner that yields better returns than the typical backlog assembled by the service industry during slow demand cycles.

Within ERT 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. ERT generates income in a number of ways: mitigating abandonment liability risk, lowering development time and cost, mitigating finding (exploration) costs, operating the field more effectively, and having a focus on extending the reservoir life through well exploitation operations. When a company sells an OCS property, they retain the financial responsibility for plugging and decommissioning if their purchaser becomes financially unable to do so. Thus, it becomes important that a property be sold to a purchaser who has the financial wherewithal to perform their contractual obligations. Although there is significant competition in this mature field market, ERT's reputation, supported by Helix's financial strength, has made it the purchaser of choice of many major and independent oil and gas companies. In addition, ERT's reservoir engineering and geophysical expertise and having access to service assets and an ability to impact development costs have made ERT a preferred partner in development projects.

The offshore basins worldwide have seen a significant increase in oil and gas exploration, development and production due, in part, to new technologies that reduce operational costs and risks, the discovery of new, larger oil and gas reservoirs with high production potential, government deepwater incentives, and increasing demand and prices. Along with these larger fields are discoveries where the exploratory well has encountered smaller proven undeveloped reserves that are judged by the current owner to be too marginal to justify development. As an extension of ERT's well exploitation strategy, it is the Company's intent to participate in drilling of high probability of success wells which initially do not possess proven reserves, and thus would be considered exploratory wells. Depending upon the water depth, development of these fields may require state of the art equipment such as the *Q4000*, a more specialized asset such as the *Intrepid* for pipelay, or a combination of Helix contracting assets. At the same time, the market is being revitalized by emerging new small producers. When these producers have opportunities, but insufficient resources or access to services, then ERT is a logical value adding partner.

The current terms of ERT's leases on undeveloped acreage in the offshore Gulf of Mexico are scheduled to expire as shown in the table below. The terms of a lease may be extended by drilling and production operations.

For the Years Ended December 31,
(acreage)

Year	Gross	Net
2006	51,840	18,432
2007	97,920	38,592
2008	34,560	14,078
2009 and Beyond	34,560	12,480
Total	218,880	83,582

The table below sets forth information, as of December 31, 2005, with respect to estimates of net proved reserves and the present value of estimated future net cash flows at such date, prepared in accordance with guidelines established by the Securities and Exchange Commission. The Company's estimates of reserves at December 31, 2005, have been audited by Huddleston & Co., Inc., independent petroleum engineers. All of the Company's reserves are currently located in the United States (55% of such reserves are PUDs). 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.

	Total Proved
Estimated Proved Reserves:	
Natural gas (MMcf)	136,073
Oil and condensate (MBbls)	14,873
Standardized measure of discounted future net cash flows (pre-tax)*	$ 1,063,332,000

* The standardized measure of discounted future net cash flows attributable to our reserves was prepared using constant prices as of the calculation date, discounted at 10% per annum. As of December 31, 2005, we owned an interest in 354 gross (285 net) oil wells 302 gross (154 net) natural gas wells located in federal offshore waters in the Gulf of Mexico.

In January 2006, we announced an agreement under which the Company will acquire Remington, pending regulatory and Remington shareholder approval. Remington has proven reserves of 279 Bcfe as of December 31, 2005.

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: 2005 — Louis Dreyfus Energy Services (10%) and Shell Trading (US) Company (10%); 2004 — Louis Dreyfus Energy Services (11%) and Shell Trading (US) Company (10%); 2003 — Shell Trading (US) Company (10%) and Petrocom Energy Group Ltd. (10%). All of these customers were purchasers of ERT's oil and gas production. We estimate in 2005 we provided subsea services to over 150 customers. Our projects are typically of short duration and are generally awarded shortly before mobilization. Accordingly, we believe backlog is not a meaningful indicator of future business results. A more meaningful measure of our backlog is the potential of our production portfolio to generate work for our services. We do not typically tender in the EPIC market as other contractors do. For that reason, the other contractors are more likely to be our customers and we serve as a contractor's contractor.

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 Stolt Offshore S.A., Subsea 7, and Technip-Coflexip.

ERT encounters 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. Competition includes TETRA Technologies, Inc. and Superior Energy Services, Inc. for Gulf of Mexico mature properties. Small or mid-sized producers, and in some cases financial players, with a focus on acquisition of reserves through PUDs and PDP are often competition on development properties.

TRAINING, SAFETY AND QUALITY ASSURANCE

We have established a corporate culture in which Environment, Health & Safety (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, 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 of both safe and unsafe behaviors at the worksite. In addition to we initiated scheduled Hazard Hunts by Project Management on each vessel, complete with assigned responsibilities and action due dates. To further this continual improvement effort, progressive auditing is done to continue improvement of our EHS management system. Results from this program were evident as our safety performance improved significantly in 2003 through 2005.

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, 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. 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.

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 taxes 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, or 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 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 produced from the leases. The MMS's amendments to these regulations are subject to judicial review. In 2002, the D.C. Circuit reversed a 2000 district court decision and upheld a 1997 MMS gas valuation rule categorically denying allowances for post-production marketing costs such as long-term storage fees and marketer fees; however, the D.C. Circuit decision expressly allows firm demand charges to be deducted. Two trade associations had sought judicial review of the 1997 gas valuation rule and procured a favorable district court decision; however, the D.C. Circuit decision and denial of certorari by the Supreme Court ended the litigation in early 2003. On March 5, 2005, the MMS published a further revision to its gas valuation rule. The 2005 gas rule revision clarifies the deductibility of transportation costs and adopts the 2004 oil valuation rule's cost of capital approach described below. The revisions are not expected to reflect any major changes. We cannot predict what effect these changes will have on our operations but nothing material is anticipated.

In 2004, the MMS further amended its royalty regulations governing the valuation of crude oil produced from federal leases. The MMS's 2000 oil valuation rule had replaced a set of valuation benchmarks based on posted prices and comparable sales with an indexing system based on spot prices at nearby market centers. Among other things, the 2000 oil valuation rule (like the 1997 gas valuation rule) also categorically disallowed deductions for post-production marketing costs. Two industry trade associations sought judicial review of the 2000 oil rule, but voluntarily dismissed their suit after late 2002 negotiations led the MMS to amend its oil valuation rule further in 2004. The amended rule retained indexing for valuation but replaced spot prices with NYMEX future prices, except in the Rocky Mountain Region and California. The 2004 oil valuation rule also liberalized allowances for non-arm's length transportation arrangements by increasing the multiplier used for calculating the cost of capital. While the 2000 oil valuation rule was likely to increase our royalty obligation somewhat, the 2004 oil valuation rule is likely to attenuate that increase.

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, or NGPA, and the regulations promulgated thereunder by the Federal Energy Regulatory Commission, or 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 the FERC from 1985 to the present that affect the economics of natural gas production, transportation and sales. In addition, the 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. These initiatives 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. The ultimate impact of the complex rules and regulations issued by the FERC since 1985 cannot be predicted. We cannot predict what further action the FERC will take on these matters, but we do not believe any such action will materially affect us differently than 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 the 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, 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, or 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 $500,000 or $600 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 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 six vessels over 300 gross tons. Satisfactory evidence of financial responsibility has been provided 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 U.S. 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 of oil or its derivatives. 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, or 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 who 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 December 31, 2005, we had approximately 1,800 employees, nearly 450 of which were salaried personnel. As of that date, we also contracted with third parties to utilize approximately 500 non-U.S. citizens to crew our foreign flag vessels. None of our employees belong to a union or are employed pursuant to any collective bargaining agreement or any similar arrangement. We believe our relationship with our employees and foreign crew members is good.

WEBSITE AND OTHER AVAILABLE INFORMATION

The Company maintains a website on the Internet with the address of www.HelixESG.com. Copies of this Annual Report on Form 10-K for the year ended December 31, 2005, and copies of the Company's Quarterly Reports on Form 10-Q for 2005 and 2006 and any Current Reports on Form 8-K for 2005 and 2006, 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 SEC. Information contained on the Company's website is not part of this report. 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 the Company files 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. The Company is 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 the Company. 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.

Our Contracting Services business is adversely affected by low oil and gas prices and by the cyclicality of the oil and gas industry.

Our Contracting Services business is 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,
- Economic and political conditions in the Middle East and other oil-producing regions,
- Coordination by the Organization of Petroleum Exporting Countries, or OPEC,
- The cost of exploring for and producing oil and gas,
- The sale and expiration dates of offshore leases in the United States and overseas,
- The discovery rate of new oil and gas reserves in offshore areas,
- Technological advances,
- Interest rates and the cost of capital,
- Environmental regulations, and
- Tax policies.

The level of offshore construction activity improved somewhat in 2004 and continued the trend in 2005 following higher commodity prices in 2003 through 2005 and significant damage sustained to the Gulf of Mexico infrastructure in Hurricanes *Katrina and Rita*. We cannot assure you activity levels 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 such 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 and other Deepwater basins of the world, 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 or collision, insurance may not cover a substantial loss of revenues, increased costs and other liabilities, and could have a material adverse effect on our operating performance if we were to lose any of our large vessels.

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 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, but not all, adverse weather conditions. Accordingly, our results in any one quarter are not necessarily indicative of annual results or continuing trends.

If we bid too low on a turnkey contract, we suffer 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, and the performance of third parties such as equipment suppliers. These variations and risks inherent in the marine construction industry may result in our experiencing reduced profitability or losses on projects.

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

Our Oil & Gas Production 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 result in a total loss of our investment. 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 depend on a number of additional factors, including commodity prices, market demand and the political, economic and regulatory climate.

Further, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions; and
- compliance with environmental and other governmental requirements, which may increase our costs or restrict our activities.

Estimates of our oil and gas reserves, future cash flows and abandonment costs may be significantly incorrect.

This Annual Report contains estimates of our proved oil and gas reserves and the estimated future net cash flows there from based upon reports for the year ended December 31, 2004 and 2005, audited by our independent petroleum engineers. These reports rely upon various assumptions, including assumptions required by the Securities and Exchange Commission, 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 expenditures, operating and abandonment expenses and quantities of recoverable oil and gas reserves may vary substantially 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 Securities and Exchange Commission 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.

Our actual development results are likely to differ from our estimates of our proved reserves. We may experience production that is less than estimated and development costs that are greater than estimated in our reserve reports. Such differences may be material.

As a result of the large property acquisitions made in 2005 (Murphy Shelf package and five Deepwater non-producing fields), 55% of our proven reserves as of December 31, 2005 are PUDs. Estimates of our oil and natural gas reserves and the costs associated with developing these reserves may not be accurate. Development of our reserves may not occur as scheduled and the actual results may not be as estimated. Development activity may result in downward adjustments in reserves or higher than estimated costs.

Reserve replacement may not offset depletion.

Oil and gas properties are depleting assets. We replace reserves through acquisitions, exploration and exploitation of current properties. 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.

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, 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. Drilling for oil and gas involves numerous risks, including the risk that the Company will not encounter commercially productive oil or gas reservoirs. If certain exploration efforts are unsuccessful in establishing proved reserves and exploration activities cease, the amounts accumulated as unproved property costs would be charged against earnings as impairments.

The Remington merger is subject to certain conditions to closing that, if not satisfied or waived, will result in the merger not being completed.

Completion of the proposed merger of Remington Oil and Gas Corporation into a wholly owned subsidiary of Helix (“Merger Sub”) is conditioned upon the receipt of (i) the approval by Remington’s stockholders of the merger agreement and the transactions contemplated thereby and (ii) all material governmental authorizations, consents, orders and approvals, including the expiration or termination of the applicable waiting periods, and any extension of the waiting periods, under the HSR Act. Helix and Remington are working to obtain the required regulatory approvals and consents. However, although we expect to receive the required regulatory approvals, we can give no assurance as to when or whether these approvals and consents will be obtained, or the terms and conditions that may be imposed. Further, under the terms of the merger agreement, neither Helix, Merger Sub nor Remington, or any of their respective subsidiaries or affiliates, will be required to sell, license, dispose of, hold separate or to operate in any specified manner, any assets of businesses of Helix, Merger Sub or Remington in order to obtain any required regulatory approvals. Therefore, any conditions or divestiture requirements may delay completion of the merger, may reduce the anticipated benefits of the merger or may cause the merger not to be completed. In limited circumstances, if either party fails to close the transaction, Remington must pay Helix a $45 million breakup fee and reimburse up to $2 million of expenses related to the transaction.

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.

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. We believe that our success and continued growth are also dependent upon our ability to attract and retain skilled personnel. We believe that our wage rates are competitive; however, unionization or a significant increase in the wages paid by other employers could result in a reduction in our workforce, increases in the wage rates we pay, or both. If either of these events occurs for any significant period of time, our revenues 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.

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 all 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 have the effect of discouraging 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 U.S. are subject to risks inherent in foreign operations, including, without limitation:

- the loss of revenue, property and equipment from hazards such as 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 U.S. 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.***

OUR VESSELS

We own a fleet of 34 vessels (two of which are held-for-sale at December 31, 2005) and 29 ROVs and trenchers. We also lease one vessel. We believe that the Gulf market 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) have the capability to provide saturation diving services. Recent developments in our fleet include:

Divestitures:

In April 2005, the *Witch Queen* was contributed for an interest in Offshore Technology Solutions Limited, or OTSL, a company organized in Trinidad & Tobago. A wholly owned subsidiary of Helix owns a non-controlling 40% interest in OTSL.

In July 2005, the *Merlin* was sold to a third party.

In December 2005, the *Mr. Sonny* was sold to a third party.

Pursuant to a consent order with the U.S. Department of Justice permitting the Company to complete the Stolt Offshore acquisitions in November 2005, the Company agreed to divest itself of the *Carrier*, the *Seaway Defender* and a portable saturation diving system acquired out of the Torch Offshore bankruptcy. As a result, these vessels are held for sale at December 31, 2005.

The *Cal Dive Barge I* was retired in 2005 and sold in January 2006 to a third party.

Acquisitions/Investments:

In August 2005, the *Brave*, *Carrier*, *Dancer*, *Fox*, *Express*, *Rider*, and *Sat Star* were purchased out of the Torch Offshore bankruptcy.

In November 2005, the acquisition of the *American Constitution*, *American Diver*, *American Liberty*, *American Sat Star*, *American Triumph*, *American Victory* and *Seaway Defender* from Stolt Offshore was completed.

In January 2006, the *DLB 801* was acquired from Stolt Offshore. Subsequent to that acquisition, the Company sold a one-half undivided interest in the vessel to a pipelay contractor based in Mexico, which is currently operating the vessel under a bareboat charter.

In January 2006, the *Caesar* (formerly known as the *Baron*), a four year old mono-hull vessel, originally built for the cable lay market, was acquired by the Company's subsidiary Vulcan Marine Technology LLC. It is currently under charter to Oceanografia S.A. de C.V. After completion of the charter (anticipated to end in mid-2006), the Company plans to convert the vessel into a deepwater pipelay asset. The vessel is 485 feet long and already has a state-of-the-art, class 2, dynamic positioning system. The conversion program will primarily involve the installation of a conventional 'S' lay pipelay system together with a main crane and a significant upgrade to the accommodation capability. A conversion team has already been assembled with a base at Rotterdam, the Netherlands, and the vessel is likely to enter service at the end of the first quarter of 2007. The estimated capital cost to purchase the vessel and complete the conversion will be approximately $125 million.

In March 2006, the Company expects to acquire the *Kestrel* from Stolt Offshore.

The *Q4000* will be enhanced to include drilling via the addition of a modular-based drilling system for approximately $40 million. These enhancements involve primarily equipment installation and accordingly we believe the vessel will be out of service less than a month. We anticipate this service being available in 2007.

Listing of Vessels, Barges and ROVs

	Flag State	Placed in Service	Length (Feet)	Berths	SAT Diving	DP or Anchor Moored	Crane Capacity (tons)	Class Society (1)
SHELF CONTRACTING								
Pipelay								
DLB 801 (2)	Panama	1/2006	351	230	Capable	Anchor	815	BV
Brave	U.S.	8/2005	275	80	—	Anchor	30 and 50	ABS
Rider	U.S.	8/2005	275	80	—	Anchor	50	ABS
Saturation Diving								
DP DSV *Eclipse*	Bahamas	3/2002	367	109	X	DP	5; 4.3; 92/43; 20.4 A-Frame	DNV
DP DSV *Kestrel* (3)	Vanuatu	3/2006	323	80	X	DP	40; 15; 10; Hydralift HLR 308	ABS
DP DSV *Mystic Viking*	Bahamas	6/2001	253	60	X	DP	50	DNV
DP DSV *Defender* (4)	Panama	11/2005	220	63	X	DP	24 block; 3.9 whip line	ABS
DP MSV *Uncle John*	Bahamas	11/1996	254	102	X	DP	2×100	DNV
DSV *American Constitution*	Panama	11/2005	200	46	X	4 point	20.41	IMC
DSV *Cal Diver I*	U.S.	7/1984	196	40	X	4 point	20	ABS
DSV *Cal Diver II*	U.S.	6/1985	166	32	X	4 point	40 A-Frame	ABS
DSV *Carrier* (4)	Vanuatu	8/2005	270	36	Capable	4 point	—	Lloyds
DSV Sat Star	Vanuatu	8/2005	197	42	—	4 point	20 and 40	ABS
Air Diving								
American Diver	U.S.	11/2005	105	22	—	—	—	ABS (LL only)
American Liberty	U.S.	11/2005	110	22	—	—	1.588	USCG
Cal Diver IV	U.S.	3/2001	120	24	—	—	—	ABS
DSV *American Star*	U.S.	11/2005	165	30	—	4 point	9.072	ABS
DSV American Triumph	U.S.	11/2005	164	32	—	4 point	13.61	ABS (LL only)
DSV American Victory	U.S.	11/2005	165	34	—	4 point	9.072	ABS (LL only)
DSV *Cal Diver V*	U.S.	9/1991	166	34	—	4 point	20 A-Frame	ABS
DSV *Dancer*	U.S.	8/2005	173	34	—	4 point	30	ABS
DSV *Mr. Fred*	U.S.	3/2000	166	36	—	4 point	25	USCG
Fox	U.S.	10/2005	130	42	—	—	—	ABS
Mr. Jack	U.S.	1/1998	120	22	—	—	10	USCG
Mr. Jim	U.S.	2/1998	110	19	—	—	—	USCG
Polo Pony	U.S.	3/2001	110	25	—	—	—	USCG
Sterling Pony	U.S.	3/2001	110	25	—	—	—	USCG
White Pony	U.S.	3/2001	116	25	—	—	—	USCG
DEEPWATER CONTRACTING								
Pipelay								
Caesar (2)	Vanuatu	1/2006	482	220	—	DP	300 and 36	Lloyds
Express	Vanuatu	8/2005	520	132	—	DP	500 and 120	Lloyds
Intrepid	Bahamas	8/1997	381	50	—	DP	400	ABS
Talisman	U.S.	11/2000	195	14	—	—	—	ABS
Well Operations								
Q4000	U.S.	4/2002	312	135	Capable	DP	160 and 360; 600 Derrick	ABS
Seawell	U.K.	7/2002	368	129	X	DP	130	DNV
Robotics								
25 ROVs and 4 Trenchers (6)	—	Various	—	—	—	—	—	—
Northern Canyon (5)	Bahamas	6/2002	276	58	—	DP	50	DNV

Notes:

(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 American Bureau of Shipping, or ABS, Bureau Veritas, or BV, Det Norske Veritas, or DNV, Lloyds Register of Shipping, or Lloyds, and the U.S. Coast Guard, or 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) Acquired in January 2006.

(3) Expected to be acquired in March 2006.

(4) Held for sale at December 31, 2005.

(5) Leased.

(6) Average age of ROV fleet is approximately 3.72 years. One of the ROVs is leased.

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. The *Q4000* is subject to a mortgage that secures the MARAD financing guarantees.

SUMMARY OF NATURAL GAS AND OIL RESERVE DATA

The table below sets forth information, as of December 31, 2005, with respect to estimates of net proved reserves and the present value of estimated future net cash flows at such date, prepared in accordance with guidelines established by the Securities and Exchange Commission. The Company's estimates of reserves at December 31, 2005, have been audited by Huddleston & Co., Inc., independent petroleum engineers. All of the Company's reserves are located in the United States (55% of such reserves are PUDs). 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.

	Total Proved
Estimated Proved Reserves:	
Natural gas (MMcf)	136,073
Oil and condensate (MBbls)	14,873
Standardized measure of discounted future net cash flows (pre-tax)*	$ 1,063,332,000

* The standardized measure of discounted future net cash flows attributable to our reserves was prepared using constant prices as of the calculation date, discounted at 10% per annum. As of December 31, 2005, we owned an interest in 354 gross (285 net) oil wells and 302 gross (154 net) natural gas wells located in federal and state offshore waters in the Gulf of Mexico.

In January 2006, we announced an agreement under which the Company will acquire Remington, pending regulatory and Remington shareholder approval. Remington has proven reserves of 279 Bcfe as of December 31, 2005.

PRODUCTION FACILITIES

Through our interest Deepwater Gateway, L.L.C., a 50/50 venture between us and Enterprise Products Partners L.P., 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 will own the "Independence Hub" platform, a 105 foot deep draft, semi-submersible platform to be located in Mississippi Canyon block 920 in a water depth of 8,000 feet that will serve as a regional hub for natural gas production from multiple Ultra-Deepwater fields in the previously untapped eastern Gulf of Mexico. Installation of the platform is scheduled for late 2006 and first production is expected in 2007. The Independence Hub facility will be capable of processing 1 billion cubic feet per day of gas.

At *Gunnison*, we own a 20% interest in the *Gunnison* truss spar facility, together with the operator Kerr-McGee Oil & Gas Corporation, who owns a 50% interest, and Nexen, Inc., who 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.

FACILITIES

Our corporate headquarters are located at 400 N. Sam Houston Parkway E., Suite 400, Houston, Texas. Our primary subsea and marine services operations are based in Port of Iberia, Louisiana. We own the Aberdeen (Dyce), Scotland facility. All of our other facilities are leased.

Properties and Facilities Summary

Location	Function	Size
Houston, Texas	Helix Energy Solutions Group, Inc. Corporate Headquarters, Project Management, and Sales Office Cal Dive International, Inc. Corporate Headquarters, Project Management, and Sales Office Energy Resource Technology, Inc. Corporate Headquarters Well Ops Inc. Corporate Headquarters, Project Management, and Sales Office	80,000 square feet
Houston, Texas	Canyon Offshore, Inc. Corporate, Management and Sales Office	15,000 square feet
Fourchon, Louisiana	Cal Dive International, Inc. Marine, Operations, Living Quarters	10 acres (Buildings: 2,300 sq. feet)
Lafayette, Louisiana*	Cal Dive International, Inc. Operations, Offices and Warehouse	8 acres (Buildings: 17,500 sq. feet)
Morgan City, Louisiana**	Cal Dive International, Inc. Operations, Offices and Warehouse	28.5 acres (Buildings: 34,500 sq. feet)
New Orleans, Louisiana	Cal Dive International, Inc. Sales Office	2,724 square feet
Port of Iberia, Louisiana	Cal Dive International, Inc. Operations, Offices and Warehouse	23 acres (Buildings: 68,062 sq. feet)
Aberdeen (Dyce), Scotland	Well Ops (U.K.) Limited Corporate Offices and Operations Canyon Offshore Limited Corporate Offices and Sales Office	3.9 acres (Building: 42,463 sq. feet)
Aberdeen (Westhill), Scotland	Helix RDS Limited Corporate Offices	11,333 square feet
Kuala Lumpur, Malaysia	Helix RDS Sdn Bhd Corporate Offices	2,227 square feet
London, England	Helix RDS Limited Corporate Offices	2,200 square feet
Perth, Australia	Helix RDS Pty Ltd Corporate Offices	2,045 square feet
Rotterdam, The Netherlands	Cal Dive International BV Corporate Offices	1,362 square feet
Singapore	Canyon Offshore International Corporate, Operations and Sales	10,000 square feet

* Closed on or about February 28, 2006.

** To be closed on or about March 31, 2006.

Note: Cal Dive International, Inc. is the Shelf Contracting subsidiary of Helix.

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 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 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 are involved in various legal proceedings, primarily involving claims for personal injury under the General Maritime Laws of the United States 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. In that regard, in 1998, one of our subsidiaries entered into a subcontract with Seacore Marine Contractors Limited ("Seacore") to provide a vessel to a Coflexip subsidiary in Canada ("Coflexip"). Due to difficulties with respect to the sea states and soil conditions the contract was terminated and an arbitration to recover damages was commenced. A preliminary liability finding has been made by the arbitrator against Seacore and in favor of the Coflexip subsidiary. We were not a party to this arbitration proceeding. Seacore and Coflexip settled this matter prior to the conclusion of the arbitration proceeding with Seacore paying Coflexip $6.95 million CDN. Seacore has initiated an arbitration proceeding against Cal Dive Offshore Ltd. ("CDO"), a subsidiary of Helix, seeking contribution of one-half of this amount. Because only one of the grounds in the preliminary findings by the arbitrator is applicable to CDO, and because CDO holds substantial counterclaims against Seacore, it is anticipated our subsidiary's exposure, if any, should be less than $500,000.

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	51	Chairman and Chief Executive Officer and Director
Martin R. Ferron	49	President and Director
Bart H. Heijermans	39	Executive Vice President and Chief Operating Officer
James Lewis Connor, III	48	Senior Vice President, General Counsel and Corporate Secretary
A. Wade Pursell	41	Senior Vice President, Chief Financial Officer and Treasurer
Lloyd A. Hajdik	40	Vice President — Corporate Controller and Chief Accounting Officer

Owen Kratz is Chairman and Chief Executive Officer of Helix Energy Solutions Group, Inc. He was appointed Chairman in May 1998 and has served as our Chief Executive Officer since April 1997. Mr. Kratz served as President from 1993 until February 1999, and as 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.

Martin R. Ferron has served on our Board of Directors since September 1998. Mr. Ferron became President in February 1999 and had served as Chief Operating Officer from January 1998 until September 2005. Mr. Ferron has over 25 years of experience in the oilfield industry, including seven in senior management positions with the international operations of McDermott and Oceaneering. Mr. Ferron has a civil engineering degree, a master's degree in marine technology, an MBA and is a chartered civil engineer.

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.

James Lewis Connor, III became Senior Vice President and General Counsel of Helix in May 2002 and Corporate Secretary in July 2002. He had previously served as Deputy General Counsel since May 2000. Mr. Connor has been involved with the oil and gas industry for over 20 years, including nearly 15 years in his capacity as legal counsel to both companies and individuals. Prior to joining Helix, Mr. Connor was a Senior Counsel at El Paso Production Company (formerly Sonat Exploration Company) from 1997 to 2000 and previously from 1995 to 1997 was a senior associate in the oil, gas and energy law section of Hutcheson & Grundy, L.L.P. Mr. Connor received his Bachelor of Science degree from Texas A&M University in 1979 and his law degree, with honors, from the University of Houston in 1991.

A. Wade Pursell is Senior Vice President and Chief Financial Officer of Helix Energy Solutions Group, Inc. In this capacity, which he was appointed to in October 2000, Mr. Pursell oversees the finance, treasury, accounting, tax, 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.

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.

Table of Contents

PART II

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

Our common stock is traded on the Nasdaq National Market under the symbol "HELX." Prior to March 6, 2006, our common stock traded under the symbol "CDIS". The following table sets forth, for the periods indicated, the high and low closing sale prices per share of our common stock:

	Common Stock Price	
	High*	Low*
Calendar Year 2004		
First quarter	$14.00	$11.37
Second quarter	$15.62	$12.51
Third quarter	$18.14	$13.96
Fourth quarter	$21.86	$16.95
Calendar Year 2005		
First Quarter	$26.14	$19.11
Second Quarter	$26.94	$20.57
Third Quarter	$32.18	$25.98
Fourth Quarter	$40.17	$26.40
Calendar Year 2006		
First quarter (through March 13, 2006)	$45.61	$33.00

* Adjusted to reflect the two-for-one stock split effective as the close of business on December 8, 2005.

On March 13, 2006, the closing sale price of our common stock on the Nasdaq National Market was $33.85 per share. As of March 2, 2006, there were an estimated 49 registered shareholders (approximately 44,695 beneficial owners) 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."

Table of Contents

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

The financial data presented below for each of the five years ended December 31, 2005, should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations and the Consolidated Financial Statements and Notes to Consolidated Financial Statements included elsewhere in this Form 10-K (in thousands, except per share amounts).

	2005	2004	2003	2002	2001
Net Revenues	$ 799,472	$ 543,392	$396,269	$302,705	$227,141
Gross Profit	283,072	171,912	92,083	53,792	66,911
Equity in Earnings (Losses) of Investments	13,459	7,927	(87)	—	—
Net Income Before Change in Accounting Principle	152,568	82,659	33,678	12,377	28,932
Cumulative Effect of Change in Accounting Principle, net	—	—	530	—	—
Net Income	152,568	82,659	34,208	12,377	28,932
Preferred Stock Dividends and Accretion	2,454	2,743	1,437	—	—
Net Income Applicable to Common Shareholders	150,114	79,916	32,771	12,377	28,932
Earnings per Common Share (1)					
Basic:					
Earnings per Share Before Change in Accounting Principle	1.94	1.05	0.43	0.17	0.45
Cumulative Effect of Change in Accounting Principle	—	—	0.01	—	—
Earnings Per Share	1.94	1.05	0.44	0.17	0.45
Diluted:					
Net Income Before Change in Accounting Principle	1.86	1.03	0.43	0.17	0.44
Cumulative Effect of Change in Accounting Principle	—	—	0.01	—	—
Earnings Per Share	1.86	1.03	0.44	0.17	0.44
Total Assets	1,660,864	1,038,758	882,842	840,010	494,296
Long-Term Debt (including current maturities of long-term debt)	447,171	148,560	222,831	227,777	99,548
Convertible Preferred Stock	55,000	55,000	24,538	—	—
Shareholders' Equity	629,300	485,292	381,141	337,517	226,349

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

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

Business Overview

The offshore oilfield services industry originated in the early 1950's as producers began to explore and develop the new frontier of offshore fields. The industry has grown significantly since the 1970's 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. This is still true today and these standards are still largely adhered to 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 peaked or 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 subsea developments.

Oil and gas prices, the offshore mobile rig count, and Deepwater construction activity are three of the primary indicators we use to forecast the future performance of our Deepwater and Shelf Contracting business. In addition, more recently, damage sustained to the Gulf of Mexico infrastructure from hurricanes (e.g. *Katrina* and *Rita*) has resulted in significant inspection, repair and maintenance activities for our Shelf Contracting business. Our construction services generally follow successful drilling activities by six to eighteen months on the OCS and twelve months or longer in the Deepwater arena. The level of drilling activity is related to both short- and long-term trends in oil and gas prices. Oil and natural gas prices have been at robust levels for the last three years and offshore drilling activity has increased, but only modestly in the Gulf of Mexico. Our primary leading indicator, the number of offshore mobile rigs contracted, is currently at approximately 130 rigs employed in the Gulf of Mexico, which is comparable with year ago levels. The Deepwater Gulf is principally being developed for oil, with the complexity of developing these reservoirs resulting in significant lead times to first production. In the North Sea, the rig count is currently at 72 rigs employed, which compared to 65 during the first quarter of 2005.

We are an energy services company which provides development solutions and related services to the energy market and specializes in the exploitation of marginal fields, including exploration of unproven fields, where we differentiate ourselves by employing our services on our own oil and gas properties as well as providing services to the open market. On January 23, 2006, the Company and Remington Oil and Gas Corporation announced an agreement under which the Company will acquire Remington in a transaction valued at approximately $1.4 billion. Under the terms of the agreement, Remington stockholders will receive $27.00 in cash and 0.436 shares of the Company's common stock for each Remington share. The acquisition is conditioned upon, among other things, the approval of Remington stockholders and customary regulatory approvals. The transaction is expected to be completed in the second quarter of 2006. Remington is an exploration, development and production company with operations in the Gulf of Mexico.

Our business is 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,
- Economic and political conditions in the Middle East and other oil-producing regions,
- Coordination by the Organization of Petroleum Exporting Countries, or OPEC,
- The cost of exploring for and producing oil and gas,
- The sale and expiration dates of offshore leases in the United States and overseas,
- The discovery rate of new oil and gas reserves in offshore areas,
- Technological advances,

- Interest rates and the cost of capital,
- Environmental regulations, and
- Tax policies.

The level of offshore construction activity improved somewhat in 2004 and continued the trend in 2005 following higher commodity prices in 2003 through 2005, and significant damage sustained to the Gulf of Mexico infrastructure in Hurricanes *Katrina* and *Rita*. We cannot assure you that activity levels will continue to 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 and results of operations.

Product prices impact our oil and gas operations in several respects. Historically, we sought to acquire producing oil and gas properties that were generally in the later stages of their economic life. The sellers' potential abandonment liabilities are a significant consideration with respect to the offshore properties we have purchased to date. Although higher natural gas prices tend to reduce the number of mature properties available for sale, these higher prices typically contribute to improved operating results for ERT. In contrast, lower natural gas prices typically contribute to lower operating results for ERT and a general increase in the number of mature properties available for sale. During 2005 ERT acquired a large package of mature properties from Murphy Exploration & Production Company — USA and also acquired equity interests in five deepwater undeveloped properties. On one such property, ERT agreed to participate in the drilling of an exploratory well to be drilled in 2006 that targets reserves in deeper sands, within the same trapping fault system, of a currently producing well with estimated drilling costs of approximately $19 million. If the drilling is successful, ERT's share of the development cost is estimated to be an additional $16 million, of which $6.4 million has been incurred through December 31, 2005 related to long lead equipment. This equipment can be redeployed if drilling is unsuccessful. Our Deepwater Contracting assets would participate in this development.

In our Production Facilities segment we participate in the ownership of production facilities in hub locations where there is potential for significant subsea tieback activity for our Marine Contracting assets. We have a 50% interest in the TLP at *Marco Polo*, which began production in the second quarter of 2004, and a 20% interest in the Independence Hub semi-submersible which should be online in early 2007.

Regarding deepwater and shelf contracting, vessel utilization is typically lower during the first quarter due to winter weather conditions in the Gulf and the North Sea. Accordingly, we normally plan our drydock inspections and other routine and preventive maintenance programs during this period. During the first quarter, a substantial number of our customers finalize capital budgets and solicit bids for construction projects. The bid and award process during the first two quarters typically leads to the commencement of construction activities during the second and third quarters. As a result, we have historically generated up to 65% of our deepwater and shelf contracting revenues in the last six months of the year. Our operations can also be severely impacted by weather during the fourth quarter. Operation of oil and gas properties and production facilities tends to offset the impact of weather since the first and fourth quarters are typically periods of high demand and strong prices for natural gas. Due to this seasonality, full year results are not likely to be a direct multiple of any particular quarter or combination of quarters.

The following table sets forth for the periods presented average U.S. natural gas and oil prices, our equivalent natural gas production, the average number of offshore rigs under contract in the Gulf, the number of platforms installed and removed in the Gulf and the vessel utilization rates for each of the major categories of our fleet.

	2005				2004				2003			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
U.S. natural gas prices (1)	$ 6.39	$ 6.94	$ 9.74	$ 12.31	$ 5.61	$ 6.08	$ 5.44	$ 6.26	$ 6.25	$ 5.61	$ 4.87	$ 5.06
NYMEX oil prices (2)	$ 49.84	$ 53.17	$ 63.19	$ 60.03	$ 35.15	$ 38.32	$ 43.88	$ 48.28	$ 33.86	$ 28.91	$ 30.20	$ 31.18
ERT oil and gas production (MMcfe)	9,029	8,858	8,430	6,656	10,020	10,043	9,959	9,792	6,780	6,722	7,175	7,241
Rigs under contract in the Gulf (3)	130	132	130	127	117	115	118	122	119	123	129	122
Rigs under contract in N. Sea (3)	65	67	68	70	54	56	57	64	58	65	63	57
Platform installations (4)	35	21	11	3	26	28	26	10	7	21	12	13
Platform removals (4)	11	42	32	6	23	47	67	22	3	11	34	18

	2005				2004				2003			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Our average vessel utilization rate: (5)												
Shelf contracting	50%	54%	65%	85%	42%	49%	50%	65%	60%	59%	68%	51%
Deepwater contracting:												
Pipelay	64%	91%	100%	96%	90%	77%	40%	82%	80%	76%	49%	59%
Well Operations	96%	49%	94%	98%	82%	73%	73%	92%	51%	90%	81%	89%
ROVs	66%	68%	67%	75%	48%	47%	49%	59%	53%	57%	56%	47%

(1) Henry Hub Gas Daily Average (the midpoint index price per Mmbtu for deliveries into a specific pipeline for the applicable calendar day as reported by Platts Gas Daily in the “Daily Price Survey” table).

(2) Per NYMEX Calendar pricing.

(3) Average monthly number of rigs contracted, as reported by Offshore Petrodata — Offshore Rig Locator.

(4) Source: Minerals Management Service; installation and removal of platforms with two or more piles in the Gulf.

(5) 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 days in each quarter.

Critical Accounting Policies

Our results of operations and financial condition, as reflected in the accompanying financial statements and related footnotes, are subject to management’s evaluation and interpretation of business conditions, changing capital market conditions and other factors which could affect the ongoing viability of our business segments and/or our customers. 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.

Accounting for Oil and Gas Properties

ERT acquisitions of producing offshore properties are recorded at the fair value exchanged at closing together with an estimate of its proportionate share of the decommissioning liability assumed in the purchase based upon its 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. Costs incurred relating to unsuccessful exploratory wells are expensed in the period the drilling is determined to be unsuccessful.

The Company evaluates the impairment of its oil and gas properties on a field-by-field basis whenever events or changes in circumstances indicate, but at least annually, an asset’s carrying amount may not be recoverable. Unamortized capital costs are reduced to fair value (based upon discounted cash flows) if the expected undiscounted future cash flows are less than the asset’s net book value. Cash flows are determined based upon proved reserves using prices and costs consistent with those used for internal decision making. Although prices used are likely to approximate market, they do not necessarily represent current market prices.

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, and independent petroleum engineers (Huddleston & Co.) audit, the estimates of our oil and gas reserves presented in this report based on guidelines promulgated under generally accepted accounting principles and in accordance with the rules and regulations of the U.S. Securities and Exchange Commission. The audit of our reserves by the independent petroleum engineers involves their rigorous examination of our technical evaluation 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 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.

Goodwill and Other Intangible Assets

The Company tests for the impairment of goodwill and other indefinite-lived intangible assets on at least an annual basis. The Company's goodwill impairment test involves a comparison of the fair value of each of the Company's reporting units 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. The Company completed its annual goodwill impairment test as of November 1, 2005. The Company's goodwill impairment test involves a comparison of the fair value of each of the Company's reporting units with its carrying amount. Goodwill of $73.9 million and $69.2 million related to the Company's Deepwater Contracting segment as of December 31, 2005 and 2004, respectively. Goodwill of $27.8 million and $15.0 million related to the Company's Shelf Contracting segment as of December 31, 2005 and 2004, respectively. None of the Company's goodwill was impaired based on the impairment test performed as of November 1, 2005 (the annual impairment test excluded the goodwill and other indefinite-lived intangible assets acquired in the Stolt Offshore and Helix Energy Limited acquisitions which closed in November 2005). See footnote 5 for goodwill and intangible assets related to the acquisitions. The Company will continue to test its 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.

Property and Equipment

Property 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 footnote 2 to the Consolidated Financial Statements included herein.

For long-lived assets to be held and used, excluding goodwill, the Company bases its 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, the Company determines 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. The Company's marine vessels are assessed on a vessel by vessel basis, while the Company's ROVs are grouped and assessed by asset class. If an impairment has occurred, the Company recognizes 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. The Company recorded an impairment charge of $1.9 million (included in Shelf Contracting cost of sales in the accompanying consolidated statement of operations) in December 2004 on certain Shelf Contracting vessels that met the impairment criteria. These assets were subsequently sold in December 2005 and January 2006, respectively, for an aggregate gain on the disposals of approximately $322,000.

Assets are classified as held for sale when the Company has a plan for disposal of certain assets and those assets meet the held for sale criteria. During the fourth quarter of 2004, the Company classified a certain Shelf Contracting vessel and other Deepwater Contracting property and equipment intended to be disposed of within a twelve month period as assets held for sale totaling $5.0 million (included in other current assets in the accompanying consolidated balance sheet at December 31, 2004).

In July 2005, the Company completed the sale of a certain Shelf Contracting DP ROV Support vessel, the *Merlin*, for $2.3 million in cash that was previously included in assets held for sale. The Company recorded an additional impairment of $790,000 on the vessel in June 2005.

In March 2005, the Company completed the sale of certain Deepwater Contracting property and equipment for $4.5 million that were previously included in assets held for sale. Proceeds from the sale consisted of $100,000 cash and a $4.4 million promissory note bearing interest at 6% per annum due in semi-annual installments beginning September 30, 2005 through March 31, 2010. In addition to the asset sale, the Company entered into a five year services agreement with the purchaser whereby the Company has committed to provide the purchaser with a specified amount of services for its Gulf of Mexico fleet on an annual basis ($8 million per year). The measurement period related to the services agreement begins with the twelve months ending June 30, 2006 and continues every six months until the contract ends on March 31, 2010. Further, the promissory note stipulates that should the Company not meet its annual services commitment the purchaser can defer its semi-annual principal and interest payment for six months. The Company determined that the estimated gain on the sale of approximately $2.5 million should be deferred and recognized as the principal and interest payments are received from the purchaser over the course of the promissory note. The first installment on the $4.4 million promissory note was received in October 2005 and $210,000 was recognized as a partial gain on the sale.

Recertification Costs and Deferred Drydock Charges

The Company's Deepwater 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 where other routine repairs and maintenance are performed and, at times, major replacements and improvements are performed. The Company expenses routine repairs and maintenance as they are incurred. Recertifcation costs can be accounted for in one of three ways: (1) defer and amortize, (2) accrue in advance, or (3) expense as incurred. The Company defers and amortizes recertification costs over the length of time in which the recertification is expected to last, which is generally 30 months. 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 the Company makes regarding the specific cost incurred and the period that the incurred cost will benefit.

The Company accounts for regulatory (U.S. Coast Guard, American Bureau of Shipping and Det Norske Veritas) related drydock inspection and certification expenditures by capitalizing the related costs and amortizing them over the 30-month period between regulatory mandated drydock inspections and certification. As of December 31, 2005 and 2004, capitalized deferred drydock charges (included in other assets, net) totaled $18.3 million and $10.0 million, respectively. During the years ended December 31, 2005, 2004 and 2003, drydock amortization expense was $8.9 million, $4.9 million and $4.1 million, respectively.

Accounting for Decommissioning Liabilities

Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations*, addresses the financial accounting and reporting obligations and retirement costs related to the retirement of tangible long-lived assets. Among other things, SFAS No. 143 requires oil and gas companies to reflect decommissioning liabilities (dismantlement and abandonment of oil and gas wells and offshore platforms) on the face of the balance sheet at fair value on a discounted basis. ERT historically has purchased producing offshore oil and gas properties that are in the later stages of production. In conjunction with acquiring these properties, ERT assumes an obligation associated with decommissioning the property in accordance with the 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, ERT will estimate the plug and abandonment liability. ERT personnel prepare detailed cost estimates to plug and abandon wells and remove necessary equipment in accordance with regulatory guidelines. ERT currently calculates the discounted value of the abandonment liability (based on the estimated year the abandonment will occur) in accordance with SFAS No. 143 and capitalizes that portion as part of the basis acquired and records the related abandonment liability at fair value. Decommissioning liabilities were $121.4 million and $82.0 million at December 31, 2005 and 2004, respectively.

On an ongoing basis, ERT personnel monitor the status of wells on the properties, and as fields deplete and no longer produce, ERT 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, ERT and Helix management personnel review and update the abandonment estimates and assumptions for changes, among other things, in market conditions, interest rates and historical experience.

The adoption of SFAS No. 143 resulted in a cumulative effect adjustment as of January 1, 2003 to record (i) a $33.1 million decrease in the carrying values of proved properties, (ii) a $7.4 million decrease in accumulated depreciation, depletion and amortization of property and equipment, (iii) a $26.5 million decrease in decommissioning liabilities and (iv) a $0.3 million increase in deferred income tax liabilities. The net impact of items (i) through (iv) was to record a gain of $0.5 million, net of tax, as a cumulative effect adjustment of a change in accounting principle in the Company's consolidated statements of operations upon adoption on January 1, 2003. The Company has no material assets that are legally restricted for purposes of settling its decommissioning liabilities other than $27.0 million of restricted cash held in escrow included in Other Assets, net in the accompanying consolidated balance sheet (see *Liquidity and Capital Resources — Investing Activities*).

Revenue Recognition

The Company typically earns the majority of deepwater and shelf contracting revenues during the summer and fall months. Revenues are derived from billings under contracts (which are typically of short duration) that provide for either lump-sum turnkey charges or specific time, material and equipment charges which are billed in accordance with the terms of such contracts. The Company recognizes revenue as it is earned at estimated collectible amounts. Revenues generated from specific time, materials and equipment charges contracts are generally earned on a dayrate basis and recognized as amounts are earned in accordance with contract terms. Revenues generated in the pre-operation mode before a contract commences are deferred and recognized on a straight line basis in accordance with contract terms. Direct and incremental costs associated with pre-operation activities are similarly deferred and recognized over the estimated contract period.

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, or achievement of certain contractual milestones if provided for in the contract. Contract price and cost estimates are reviewed periodically as work progresses and adjustments are reflected in the period in which such estimates are revised. Provisions for estimated losses on such contracts are made in the period such losses are determined. The Company recognizes additional contract revenue related to claims when the claim is probable and legally enforceable. Unbilled revenue represents revenue attributable to work completed prior to year-end which has not yet been invoiced. All amounts included in unbilled revenue at December 31, 2005 are expected to be billed and collected within one year.

The Company records 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. The Company may have an interest with other producers in certain properties. In this case the Company uses the entitlements method to account for sales of production. Under the entitlements method the Company may receive more or less than its entitled share of production. If the Company receives more than its entitled share of production, the imbalance is treated as a liability. If the Company receives less than its entitled share, the imbalance is recorded as an asset. As of December 31, 2005 the net imbalance was a $2.0 million asset and was included in

Other Current Assets ($5.0 million) and Accrued Liabilities ($3.0 million) in the accompanying consolidated balance sheet.

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. The Company establishes an allowance for uncollectible accounts receivable based on historical experience and any specific customer collection issues that the Company has identified. Uncollectible accounts receivable are written off when a settlement is reached for an amount that is less that the outstanding historical balance or when the Company has determined the balance will not be collected.

Foreign Currency

The functional currency for the Company's foreign subsidiaries, Well Ops (U.K.) Limited and Helix Energy Limited, is the applicable local currency (British Pound). 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 the balance sheet date and the resulting translation adjustment, which was an unrealized loss in 2005 of $11.4 million and an unrealized gain in 2004 of $10.8 million, and is included as accumulated other comprehensive income (loss), as a component of shareholders' equity. Beginning in 2004, deferred taxes have not been provided on foreign currency translation adjustments for operations where the Company considers its undistributed earnings of its 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.

Canyon Offshore, the Company's ROV subsidiary, has operations in the Europe/West Africa and Asia/Pacific regions. Canyon conducts the majority of its affairs in these regions in U.S. dollars which it considers the functional currency. When currencies other than the U.S. dollar are to be paid or received the resulting gain or loss from translation is recognized in the statements of operations. These amounts for the years ended December 31, 2005 and 2004, respectively, were not material to the Company's results of operations or cash flows.

Accounting for Price Risk Management Activities

The Company's 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. All derivatives are reflected in our balance sheet at their fair market value.

There are two types of hedging activities: hedges of cash flow exposure and hedges of fair value exposure. The Company engages 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 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 in oil and gas production revenues.

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 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. We discontinue hedge accounting prospectively 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.

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 2005 and 2004, the Company entered into various cash flow hedging swap and costless collar contracts to stabilize cash flows relating to a portion of the Company's oil and gas production. All of these qualified for hedge accounting. The aggregate fair value of the hedge instruments was a net liability of $13.4 million and $876,000 as of December 31, 2005 and 2004, respectively. For the years ended December 31, 2005, 2004 and 2003, the Company recorded unrealized (losses) gains of approximately $(8.1) million, $846,000 and $1.2 million, net of taxes of $4.4 million, $456,000 and $654,000, respectively, in 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 hedged item is sold. During 2005, 2004 and 2003, the Company reclassified approximately $14.1 million, $11.1 million and $14.6 million, respectively, of losses from other comprehensive income to Oil and Gas Production 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 the third quarter of 2005 as reported in that period's earnings as a reduction of oil and gas production revenues. Hedge ineffectiveness resulted from ERT's projected inability to deliver contractual oil and gas production in fourth quarter 2005 due primarily to the effects of Hurricanes *Katrina* and *Rita.*

Equity Investments

Our equity investments in unconsolidated subsidiaries include our investments in Deepwater Gateway, L.L.C., Independence Hub, LLC and Offshore Technology Solutions Limited ("OTSL"), a Trinidad and Tobago entity. We review our equity investments for impairment and record an adjustment when we believe the decline in fair value is other than temporary. The fair value of the asset is measured using quoted market prices or, in the absence of quoted market prices, fair value is based on an estimate of discounted cash flows. In determining whether the decline is other than temporary, we consider the cyclical nature of the industry in which the investment operates, its historical performance, its performance in relation to its peers and the current economic environment. We will monitor the fair value of our investments for impairment and will record an adjustment if we believe a decline is other than temporary. During 2005, 2004 and 2003 no impairment indicators existed.

Income Taxes

Deferred income taxes are based on the difference between financial reporting and tax bases of assets and liabilities. The Company utilizes 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. The Company considers the undistributed earnings of its principal non-U.S. subsidiaries to be permanently reinvested. At December 31, 2005, the Company's principal non-U.S. subsidiaries had an accumulated deficit of approximately $4.3 million in earnings and profits. These losses are primarily due to timing differences related to fixed assets. The Company has not provided deferred U.S. income tax on the losses. See footnote 9 to the Consolidated Financial Statements included herein for discussion of net operating loss carry forwards and deferred income taxes.

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. The Company incurs worker's compensation claims in the normal course of business, which management believes are substantially covered by insurance. The Company, its insurers and legal counsel analyze each claim for potential exposure and estimate the ultimate liability of each claim.

Recently Issued Accounting Principles

In December 2004, the FASB issued SFAS No. 123 (revised 2004), *Share-Based Payment* ("SFAS No. 123R"), which replaces SFAS No. 123, *Accounting for Stock-Based Compensation*, ("SFAS No. 123") and supercedes APB Opinion No. 25, *Accounting for Stock Issued to Employees.* SFAS No. 123R requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values beginning with the first interim period in fiscal 2006, with early adoption encouraged. The pro forma disclosures previously permitted under SFAS No. 123 no longer will be an alternative to financial statement recognition. The Company adopted SFAS No. 123R on January 1, 2006. Under SFAS No. 123R, the Company will continue to use the Black-Scholes fair value model for valuing share-based payments, and amortize compensation cost on a straight line basis over the respective vesting period. The Company selected the prospective method which requires that compensation expense be recorded for all unvested stock options and restricted stock beginning in 2006 as the requisite service is rendered. In addition to the compensation cost recognition requirements, SFAS No. 123R also requires the tax deduction benefits for an award in excess of recognized compensation cost be reported as a financing cash flow rather than as an operating cash flow, which was required under SFAS No. 95. The adoption did not have a material impact on the Company's consolidated results of operations and earnings per share.

In September 2004, the EITF of the FASB reached a consensus on issue No. 04-08, *The Effect of Contingently Convertible Instruments on Diluted Earnings per Share* ("EITF 04-08"), which is effective for reporting periods ending after December 15, 2004. Contingently convertible instruments within the scope of EITF 04-08 are instruments that contain conversion features that are contingently convertible or exercisable based on (a) a market price trigger or (b) multiple contingencies if one of the contingencies is a market price trigger for which the instrument may be converted or share settled based on meeting a specified market condition. EITF 04-08 requires companies to include shares issuable under convertible instruments in diluted earnings per share computations (if dilutive) regardless of whether the market price trigger (or other contingent feature) has been met. In addition, prior period earnings per share amounts presented for comparative purposes must be restated. The Company adopted EITF 04-08 in 2005. The adoption did not have a material impact on the Company's earnings per share for the years ended December 31, 2005, 2004 and 2003.

Results of Operations

In the fourth quarter of 2005, we modified our segment reporting from three reportable segments to four reportable segments. Our operations are conducted through the following primary reportable segments: Deepwater Contracting, Shelf Contracting, Oil and Gas Production and Production Facilities. The realignment of reportable segments was attributable to organizational changes within the Company as it is related to separating Marine Contracting into two reportable segments — Deepwater Contracting and Shelf Contracting. Deepwater Contracting operations include deepwater pipelay, well operations and robotics. Shelf Contracting operations consist of assets deployed primarily for diving-related activities and shallow water construction. As a result, segment disclosures for 2004 and 2003 have been restated to conform to the current period presentation. All intercompany transactions between the segments have been eliminated.

Comparison of Years Ended 2005 and 2004

Revenues. During the year ended December 31, 2005, the Company's revenues increased 47% to $799.5 million compared to $543.4 million for the year ended December 31, 2004. Of the overall $256.1 million increase, $126.4 million was generated by the Deepwater Contracting segment, $97.1 million by the Shelf Contracting segment and $32.5 million generated by the Oil and Gas Production segment. Deepwater Contracting revenues increased $126.4 million from $175.4 million for 2004 to $301.9 million for 2005 due primarily to improved market demand resulting in significantly improved utilization rates and contract pricing for all divisions within the segment (Deepwater, Well Operations and ROVs). Shelf Contracting revenues increased $97.1 million from $124.6 million for 2004 to $221.8 million for 2005 also due to improved market demand, much of which was the result of damages sustained in Hurricanes *Katrina* and *Rita*. This resulted in significantly improved utilization rates and contract pricing for all divisions within the segment (shallow water pipelay, diving and portable SAT systems). Further, Shelf

Contracting's revenues increased in 2005 compared with 2004 directly as a result of the acquisition of the Torch and Stolt vessels in the third and fourth quarter of 2005, with much of the impact attributable to the fourth quarter.

Oil and Gas Production revenue for the year ended December 31, 2005 increased $32.5 million, or 13%, to $275.8 million from $243.3 million during 2005. Production decreased 17% (33.0 Bcfe for the year ended December 31, 2005 compared to 39.8 Bcfe in 2004) primarily due to production shut-ins due to Hurricanes *Katrina* and *Rita* in the third and fourth quarters of 2005. The average realized natural gas price of $8.29 per Mcf, net of hedges in place, during 2005 was 35% higher than the $6.13 per Mcf realized in 2004 while average realized oil prices, net of hedges in place, increased 39% to $49.15 per barrel compared to $35.34 per barrel realized during 2004.

Gross Profit. Gross profit of $283.1 million for the year ended December 31, 2005 represented a 65% increase compared to the $171.9 million recorded in the prior year. Deepwater Contracting gross profit increased to $69.4 million, for the year ended December 31, 2005, from $11.1 million in the prior year. The increase was primarily attributable to improved utilization rates and contract pricing for all divisions within the segment. Shelf Contracting gross profit increased to $71.2 million, for the year ended December 31, 2005, from $25.4 million in the prior year. As previously discussed, the increase was primarily attributable to improved utilization rates and contract pricing for all divisions within the segment. Shelf Contracting gross profit in 2004 was impacted by asset impairments on certain vessels totaling $3.9 million for conditions meeting the Company's asset impairment criteria. Oil and Gas Production gross profit increased $7.0 million, to $142.5 million, due to the aforementioned higher commodity price increases, offset by decreased production levels.

Gross margins of 35% in 2005 were 3 points better than the 32% in 2004. Deepwater Contracting margins increased 17 points to 23% for the year ended December 31, 2005, from 6% in the prior year, due to the factors noted above. Shelf Contracting margins increased 12 points to 32% in 2005 from 20% in 2004, due to the factors noted above. In addition, margins in the Oil and Gas Production segment decreased 4 points to 52% in 2005 from 56% in 2004, due primarily to impairment analysis on certain properties and expensed well work which resulted in $4.8 million of impairments, inspection and repair costs of approximately $7.1 million as a result of Hurricanes *Katrina* and *Rita* (no insurance recoveries recorded as of December 31, 2005), and $5.7 million of expensed seismic data purchased for ERT's offshore property acquisitions.

As discussed above, the Company sustained damage to certain of its oil and gas production facilities in Hurricanes *Katrina* and *Rita*. The Company estimates future total repair and inspection costs resulting from hurricanes will range from $5 million to $8 million, net of expected insurance reimbursement. These costs, and any related insurance reimbursements, will be recorded as incurred over the next year.

Selling & Administrative Expenses. Selling and administrative expenses of $62.8 million for the year ended December 31, 2005 were $13.9 million higher than the $48.9 million incurred in 2004 due primarily to increased incentive compensation as a result of increased profitability. Selling and administrative expenses at 8% of revenues for 2005 was slightly lower than the 9% of revenues in 2004.

Equity in Earnings of Investments. Equity in earnings of the Company's 50% investment in Deepwater Gateway, L.L.C. increased to $10.6 million in 2005 compared with $7.9 million in 2004. The increase was attributable to the demand fees which commenced following the March 2004 mechanical completion of the *Marco Polo* tension leg platform, owned by Deepwater Gateway, L.L.C., as well as production tariff charges which commenced in the third quarter of 2004 as *Marco Polo* began producing. Further, equity in earnings from the Company's 40% minority ownership interest in OTSL in 2005 totaled approximately $2.8 million.

Other (Income) Expense. The Company reported other expense of $7.6 million for the year ended December 31, 2005 compared to other expense of $5.3 million for the year ended December 31, 2004. Net interest expense of $7.0 million in 2005 was higher than the $5.6 million incurred in 2004 due primarily to higher levels of debt associated with the Company's $300 million Convertible Senior Notes which closed in March 2005. Offsetting the increase in interest expense was $2.0 million of capitalized interest in 2005, compared with $243,000 in 2004, which related to the Company's investment in *Gunnison* and Independence Hub, and interest income of $5.5 million in 2005 compared to $439,000 in 2004.

Income Taxes. Income taxes increased to $75.0 million for the year ended December 31, 2005 compared to $43.0 million in 2004, primarily due to increased profitability. The effective tax rate of 33% in 2005 was lower than the 34% effective tax rate for 2004 due to the Company's ability to realize foreign tax credits and oil and gas percentage depletion due to improved profitability both domestically and in foreign jurisdictions, and implementation of the Internal Revenue Code section 199 manufacturing deduction as it primarily related to oil and gas production. In 2004, the company recognized a benefit for its research and development credits in the first quarter of 2004 as a result of the conclusion of the Internal Revenue Service ("IRS") examination of the Company's income tax returns for 2001 and 2002, and the tax cost or benefit of U.S. and U.K. branch operations.

Net Income. Net income of $150.1 million for 2005 was $70.2 million greater than 2004 as a result of the factors described above.

Comparison of Years Ended 2004 and 2003

Revenues. During the year ended December 31, 2004, the Company's revenues increased 37% to $543.4 million compared to $396.3 million for the year ended December 31, 2003. Of the overall $147.1 million increase, $106.0 million was generated by the Oil and Gas Production segment due to increased oil and gas production and higher commodity prices. Deepwater Contracting revenues increased $48.0 million from $127.4 million for 2003 to $175.4 million for 2004 due primarily to slightly increased utilization and improved contract pricing for the Company's Well Operations division and improved performance from the Company's ROV division. Shelf Contracting revenues decreased $6.9 million from $131.5 million for 2003 to $124.6 million for 2004 due primarily to decreased vessel utilization.

Oil and Gas Production revenue for the year ended December 31, 2004 increased $106.0 million, or 77%, to $243.3 million from $137.3 million during 2003. Production increased 43% (39.8 Bcfe for the year ended December 31, 2004 compared to 27.9 Bcfe in 2003) primarily as a result of our successful well exploitation program, bringing a subsea PUD development online late in 2003, and *Gunnison* wells coming online throughout 2004 and provided 21% of total production. The average realized natural gas price of $6.13 per Mcf, net of hedges in place, during 2004 was 23% higher than the $4.98 per Mcf realized in 2003 while average realized oil prices, net of hedges in place, increased 28% to $35.34 per barrel compared to $27.63 per barrel realized during 2003.

Gross Profit. Gross profit of $171.9 million for the year ended December 31, 2004 represented an 87% increase compared to the $92.1 million recorded in the prior year with the Oil and Gas Production segment contributing 87% of the increase. Deepwater Contracting gross profit increased to $11.1 million, for the year ended December 31, 2004, from breakeven million in the prior year. The increase was primarily attributable to improved contract pricing for the Company's Well Operations division and improved performance from the Company's ROV division. Shelf Contracting gross profit of $25.4 million in 2004 was comparable to the $25.7 million in 2003. The segment experienced lower utilization, however, Shelf Contracting was able to offset lower utilization rates with higher margin lump sum contracts in 2004. Further offsetting the increase in Shelf Contracting gross profit was asset impairments on certain Shelf vessels totaling $3.9 million for conditions that met the Company's asset impairment criteria. Oil and Gas Production gross profit increased $69.3 million, to $135.4 million, due to the aforementioned higher levels of production and commodity price increases.

Gross margins of 32% in 2004 were 9 points better than the 23% in 2003. Deepwater Contracting margins increased 6 points to 6% for the year ended December 31, 2004, from breakeven in the prior year, due to the factors noted above. Shelf Contracting margins were 20% in both 2004 and 2003 due to the factors noted above. In addition, margins in the Oil and Gas Production segment increased 8 points to 56% for the year ended December 31, 2004, from 48% in 2003, due primarily to the higher oil and gas commodity prices.

Selling & Administrative Expenses. Selling and administrative expenses of $48.9 million for the year ended December 31, 2004 were $13.0 million higher than the $35.9 million incurred in 2003 due primarily to an increase in the 2004 Deepwater and Shelf Contracting compensation program, which is based on certain individual performance criteria and the Company's profitability, and the ERT incentive compensation program, which is tied directly to the Oil and Gas Production segment profitability that was significantly higher in 2004 compared to 2003. Selling and administrative expenses at 9% of revenues for 2004 matched that of the prior year.

Equity in Earnings of Investments. Equity in earnings of the Company's 50% investment in Deepwater Gateway, L.L.C. increased to $7.9 million in 2004 compared with a loss of $87,000 in 2003. The increase was attributable to the demand fees which commenced following the March 2004 mechanical completion of the *Marco Polo* tension leg platform, owned by Deepwater Gateway, L.L.C., as well as production tariff charges which commenced in the third quarter of 2004 as *Marco Polo* began producing.

Other (Income) Expense. The Company reported other expense of $5.3 million for the year ended December 31, 2004 compared to other expense of $3.4 million for the year ended December 31, 2003. Net interest expense of $5.6 million in 2004 was higher than the $2.4 million incurred in 2003, due primarily to $243,000 of capitalized interest in 2004, compared with $3.4 million in 2003, which related to the Company's investment in *Gunnison* and construction of the *Marco Polo* tension leg platform, both of which were online at different times during 2004.

Income Taxes. Income taxes increased to $43.0 million for the year ended December 31, 2004 compared to $19.0 million in 2003, primarily due to increased profitability. The effective tax rate of 34.2% in 2004 is lower than the 36.1% effective tax rate for 2003 due to the benefit recognized by the Company for its research and development credits in the first quarter of 2004 as a result of the conclusion of the IRS examination of the Company's income tax returns for 2001 and 2002, and the tax cost or benefit of U.S. and U.K. branch operations.

Net Income. Net income of $79.9 million for 2004 was $47.1 million greater than 2003 as a result of the factors described above. Further, convertible preferred stock dividends and accretion increased from $1.4 million in 2003 to $2.7 million in 2004 as a result of the Series A-2 Tranche of convertible preferred stock issued in June 2004 to the existing holder. See *Liquidity and Capital Resources — Financing Activities.*

Liquidity and Capital Resources

Total debt as of December 31, 2005 was $447.2 million comprised primarily of $300 million of Convertible Senior Notes which mature in 2025 and $134.9 million of MARAD debt which matures in 2027. See further discussion below under *"Financing Activities"*. In addition, the Company had $91.1 million of unrestricted cash as of December 31, 2005, as well as a $150 million, undrawn revolving credit facility. The majority of the unrestricted cash was utilized for the previously announced acquisition of certain assets of Stolt Offshore not purchased as of December 31, 2005 and the purchase of the mono-hull vessel, the *Caesar* in January 2006.

On January 23, 2006 the Company and Remington Oil and Gas Corporation announced an agreement under which the Company will acquire Remington in a transaction valued at approximately $1.4 billion. Under the terms of the agreement, Remington stockholders will receive $27.00 in cash and 0.436 shares of the Company's common stock for each Remington share. The acquisition is conditioned upon, among other things, the approval of Remington stockholders and customary regulatory approvals. The transaction is expected to be completed in the second quarter of 2006. In limited circumstances, if either party fails to close the transaction, Remington must pay the Company a $45 million breakup fee and reimburse up to $2 million of expenses related to the transaction. The Company expects to fund the cash portion of the Remington acquisition (approximately $814 million) through a senior secured term debt facility which has been underwritten by a bank.

During 2005, the Company acquired equity interests in five deepwater undeveloped properties. The capital commitments for these developments will occur over the next few years. We believe internally generated cash flow and borrowings under existing credit facilities will provide the necessary capital to meet these and other obligations.

Operating Activities. Net cash provided by operating activities was $242.4 million during 2005, an increase of $15.6 million over the $226.8 million generated during 2004 due primarily to an increase in profitability ($69.9 million). Further, operating cash flow increased due to an increase in accounts payable and accrued liabilities ($21.3 million). The increases related to increased trade payables due to increased contracting activity volume, increased incentive compensation accruals resulting from increased profitability, increased ERT royalty accruals and increased ERT hedge liability accruals. Cash flow from operations was negatively impacted by an increase in trade accounts receivable of approximately $89.8 million due primarily to increased revenues in 2005 compared with 2004 in the Deepwater Contracting, Shelf Contracting and Oil and Gas Production segments. Further, cash flow from operations was negatively impacted by approximately $18 million of cash used to fund regulatory dry dock activity in 2005.

Net cash provided by operating activities was $226.8 million during 2004, an increase of $139.4 million over the $87.4 million generated during 2003 due primarily to an increase in profitability ($48.5 million), a $37.5 million increase in depreciation and amortization (including the non-cash asset impairment charge in 2004) resulting from the aforementioned increase in production levels (including the *Gunnison* wells that began producing in December 2003). Further an increase in trade payables and accrued liabilities of $53.1 million due primarily to higher accruals for ERT royalties as a result of increased production and higher accruals for ERT and Marine Contracting incentive compensation also contributed to the increase in operating cash flow. Cash flow from operations was negatively impacted by an increase in other current assets ($28.3 million) primarily for prepaid insurance and current deferred taxes.

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. We incurred $539.1 million of capital investments during 2005, $82.3 million during 2004 and $95.4 million in 2003.

We incurred $428.1 million of capital expenditures and business acquisitions during 2005 compared to $50.1 million during the comparable prior year period. Included in the capital acquisitions and expenditures during 2005 was $163.5 million for the Murphy properties , $85.6 million for the acquisition of the Torch Offshore assets, $42.9 million for the GOM Stolt Offshore assets, $32.7 million for the purchase of Helix Energy Limited (the cash portion of which was approximately $27.1 million), $79.0 million for ERT well exploitation programs and further *Gunnison* field development, $14.6 million for Canyon Offshore ROV and trencher systems, and the balance primarily related to vessel upgrades on certain Deepwater Contracting and Shelf Contracting vessels.

We incurred $50.1 million of capital expenditures during the year ended December 31, 2004 compared to $93.2 million during the prior year. Included in the capital expenditures during 2004 was $5.5 million for the purchase of an intervention riser system, $14.8 million for ERT well exploitation programs, $19.6 million for further *Gunnison* field development, $6.7 million for the purchase of an operations facility in Aberdeen, Scotland to serve as our UK headquarters and $3.5 million for the purchase and upgrade of a trencher system for our ROV division. Included in the capital expenditures during 2003 was $17.5 million for the purchase of ROV units to support the Canyon MSA agreement with Technip/Coflexip to provide robotic and trenching services, $39.6 million related to *Gunnison* development costs, including the spar, as well as $39.7 million relating to ERT's 2003 well exploitation program.

During 2005, we invested $111.1 million in our Production Facilities segment which consists of our investments in Deepwater Gateway, L.L.C. and Independence Hub, LLC. In June 2002, Helix, along with Enterprise Products Partners L.P. ("Enterprise"), formed Deepwater Gateway, L.L.C. (a 50/50 venture accounted for by Helix under the equity method of accounting) 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. The Company's investment in Deepwater Gateway, L.L.C. totaled $117.2 million as of December 31, 2005 ($72.0 million of which was contributed in 2005). Included in the investment account was capitalized interest and insurance paid by the Company totaling approximately $2.2 million. In August 2002, the Company along with Enterprise, completed a limited recourse project financing for this venture. In accordance with terms of the term loan of $144 million, Deepwater Gateway, L.L.C. had the right to repay the principal amount plus any accrued interest due under its term loan at any time without penalty. Deepwater Gateway, L.L.C. repaid in full its term loan in March 2005. The Company and Enterprise made equal cash contributions ($72 million each) to Deepwater Gateway, L.L.C. to fund the repayment. Upon repayment of the term loan, the Company's $7.5 million of restricted cash was released from escrow and the escrow agreement was terminated. Further, the Company received cash distributions from Deepwater Gateway, L.L.C. totaling $21.1 million in 2005.

In December 2004, the Company acquired a 20% interest (accounted for by the Company under the equity method of accounting) in Independence Hub, LLC ("Independence"), an affiliate of Enterprise. Independence will own the "Independence Hub" platform to be located in Mississippi Canyon block 920 in a water depth of 8,000 feet. The Company's investment was $50.8 million as of December 31, 2005, and its total investment is expected to be approximately $83 million ($39.1 million of which was contributed in 2005). Further, the Company is party to a guaranty agreement with Enterprise to the extent of the Company's ownership in Independence. The agreement states, among other things, that the Company and Enterprise guarantee performance under the Independence Hub Agreement between Independence and the producers group of exploration and production companies up to $397.5 million, plus applicable attorneys' fees and related expenses. the Company has estimated the fair value of its share of the guarantee obligation to be immaterial at December 31, 2005 based upon the remote possibility of payments being made under the performance guarantee.

In July 2005, the Company acquired a 40% minority ownership interest in Offshore Technology Solutions Limited ("OTSL") in exchange for the Company's DP DSV, *Witch Queen*. The Company's investment in OTSL totaled $11.5 million at December 31, 2005. 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. The Company accounts for its investment in OTSL under the equity method of accounting.

Further, in conjunction with its investment in OTSL, the Company entered into a one year, unsecured $1.5 million working capital loan, bearing interest at 6% per annum, with OTSL. Interest is due quarterly beginning September 30, 2005 with a lump sum principal payment due to the Company on June 30, 2006.

In the third and fourth quarters of 2005, OTSL contracted the *Witch Queen* to the Company for certain services to be performed in the U.S. Gulf of Mexico. The Company incurred costs under its contract with OTSL totaling approximately $11.1 million during the third and fourth quarters of 2005.

As of December 31, 2005, the Company had $27.0 million of restricted cash, included in other assets, net in the accompanying consolidated balance sheet, all of which related to ERT's escrow funds for decommissioning liabilities associated with the SMI 130 field acquisitions in 2002. Under the purchase agreement, ERT is 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. ERT may use the restricted cash for decommissioning the related fields.

In January 2002, the Company purchased Canyon, a supplier of remotely operated vehicles (ROVs) and robotics to the offshore construction and telecommunications industries. In connection with the acquisition, the Company committed to purchase the redeemable stock in Canyon at a price to be determined by Canyon's performance during the years 2002 through 2004 from continuing employees at a minimum purchase price of $13.53 per share (or $7.5 million). The Company also agreed to make future payments relating to the tax impact on the date of redemption, whether or not employment continued. As they are employees, any share price paid in excess of the $13.53 per share was recorded as compensation expense. These remaining shares were classified as long-term debt in the accompanying balance sheet and have been adjusted to their estimated redemption value at each reporting period based on Canyon's performance. In March 2005, the Company purchased the final one-third of the redeemable shares at the minimum purchase price of $13.53 per share. Consideration included approximately $337,000 of contingent consideration relating to tax gross-up payments paid to the Canyon employees in accordance with the purchase agreement. This gross-up amount was recorded as goodwill in the period paid.

In April 2000, ERT acquired a 20% working interest in *Gunnison,* a Deepwater Gulf of Mexico prospect of Kerr-McGee Oil & Gas Corp. 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 ERT totaled $28.1 million and $20.3 million in the years ended December 31, 2005 and 2004, respectively. The Company's Chief Executive Officer, as a Class A limited partner of OKCD, personally owns approximately 67% of the partnership. Other executive officers of the Company own approximately 6% combined of the partnership. In 2000, OKCD also awarded Class B limited partnership interests to key Helix employees.

As an extension of ERT's well exploitation and PUD strategies, ERT agreed to participate in the drilling of an exploratory well (Tulane prospect) to be drilled in 2006 that targets reserves in deeper sands, within the same trapping fault system, of a currently producing well with estimated drilling costs of approximately $19 million. If the drilling is successful, ERT's share of the development cost is estimated to be an additional $16 million, of which $6.4 million had been incurred through December 31, 2005 related to long lead equipment. This equipment can be redeployed if drilling is unsuccessful. The Company's Deepwater Contracting assets would participate in this development.

In March 2005, ERT acquired a 30% working interest in a proven undeveloped field in Atwater Valley Block 63 (Telemark) of the Deepwater Gulf of Mexico for cash and assumption of certain decommissioning liabilities. In December 2005, ERT was advised by Norsk Hydro USA Oil and Gas, Inc., that they will not pursue their development plan for Telemark. ERT did not support that development plan and is currently developing its own plans based on the marginal field methodologies that were envisaged when the working interest was acquired. Any revised development plan will have to be approved by the MMS.

In April 2005, ERT entered into a participation agreement to acquire a 50% working interest in the Devil's Island discovery (Garden Banks Block 344 E/2) in 2,300 feet water depth. This deepwater development is operated by Amerada Hess and will be drilled in 2006. The field will be developed via a subsea tieback to Baldpate Field (Garden Banks Block 260). Under the participation agreement, ERT will pay 100% of the drilling costs and a disproportionate share of the development costs to earn 50% working interest in the field. Helix's Deepwater Contracting assets would participate in this development.

Also, in April 2005, ERT acquired a 37.5% working interest in the Bass Lite discovery (Atwater Blocks 182, 380, 381, 425 and 426) in 7,500 feet water depth along with varying interests in 50 other blocks of exploration acreage in the eastern portion of the Atwater lease protraction area from BHP Billiton. The Bass Lite discovery contains proved undeveloped gas reserves in a sand discovered in 2001 by the Atwater 426 #1 well. In October 2005, ERT exchanged 15% of its working interest in Bass Lite for a 40% working interest in the Tiger Prospect located in Green Canyon Block 195. ERT paid $1.0 million in the exchange with no corresponding gain or loss recorded on the transaction.

In June 2005, ERT acquired a mature property package on the Gulf of Mexico shelf from Murphy Exploration & Production Company — USA ("Murphy"), a wholly owned subsidiary of Murphy Oil Corporation. The acquisition cost to ERT included both cash ($163.5 million) and the assumption of the estimated abandonment liability from Murphy of approximately $32.0 million. The acquisition represents essentially all of Murphy's Gulf of Mexico Shelf properties consisting of eight operated and eleven non-operated fields. ERT estimates proved reserves of the acquisition to be approximately 75 BCF equivalent. The results of the acquisition are included in the accompanying statements of operations since the date of purchase.

In February 2006, ERT entered into a participation agreement with Walter Oil & Gas for a 20% interest in the Huey prospect in Garden Banks Blocks 346/390 in 1,835 feet water depth. Drilling of the exploration well is expected to begin March 2006. If successful, the development plan would consist of a subsea tieback to the Baldplate Field (Garden Banks 260). Under the participation agreement, ERT has committed to pay 32% of the costs to casing point to earn the 20% interest in the potential development, with ERT's share of drilling costs of approximately $6.7 million.

As of December 31, 2005, the Company had spent $31.5 million and had committed to an additional estimated $78 million for development and drilling costs related to the above property transactions.

In a bankruptcy auction held in June 2005, Helix was the high bidder for seven vessels, including the *Express*, and a portable saturation system for approximately $85 million, subject to the terms of an amended and restated asset purchase agreement, executed in May 2005, with Torch Offshore, Inc. and its wholly owned subsidiaries, Torch Offshore, L.L.C. and Torch Express, L.L.C. 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 $85.6 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* (Deepwater Contracting segment) and the portable saturation system (included in assets held for sale in other current assets in the accompanying consolidated balance sheet), are included in the Shelf Contracting segment. The results of the acquired vessels are included in the accompanying condensed consolidated statements of operations since the date of the purchase, August 31, 2005.

In April 2005, the Company agreed to acquire the diving and shallow water pipelay assets of Stolt Offshore that operate in the waters of the Gulf of Mexico (GOM) and Trinidad. The transaction included: seven diving support vessels; two diving and pipelay vessels (the *Kestrel* and the *DB 801);* a portable saturation diving system; various general diving equipment and Louisiana operating bases at the Port of Iberia and Fourchon. 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, the Company received clearance from the U.S. Department of Justice to close the asset purchase from Stolt. Under the terms of the clearance, the Company will divest two diving support vessels and a portable saturation diving system from the combined asset package acquired through this transaction and the Torch transaction which closed August 31, 2005. These assets were included in assets held for sale totaling $7.8 million (included in other current assets in the accompanying consolidated balance sheet) as of December 31, 2005. On November 1, 2005, the Company closed the transaction to purchase the Stolt diving assets operating in the Gulf of Mexico. The Shelf Contracting assets include: seven diving support vessels, a portable saturation diving system, various general diving equipment and Louisiana operating bases at the Port of Iberia and Fourchon. The acquisition was accounted for as a business purchase with the acquisition price allocated to the assets acquired and liabilities assumed based upon their estimated fair values, with the excess being recorded as goodwill. The preliminary allocation of the purchase price resulted in $12.0 million allocated to vessels (including the asset held for sale at December 31, 2005), $10.1 million allocated to the portable saturation diving system and various general diving equipment and inventory, $4.3 million to operating bases at the Port of Iberia and Fourchon, $3.7 million allocated to a customer-relationship intangible asset (amortized over 8 years on a straight line basis) and goodwill of approximately $12.8 million. The results of the acquisition are included in the accompanying statements of operations since the date of the purchase. The Company acquired the *DB 801* in January 2006 for approximately $38.0 million. The Company subsequently sold a 50% interest in the vessel in January 2006 for total consideration of approximately $23.5 million. The purchaser has an option to purchase the remaining 50% interest in the vessel beginning in January 2009. This will result in a subsequent revision to the purchase price allocation of the Stolt acquisition. The *Kestrel* is expected to be acquired by the Company in March 2006 for approximately $40 million. The preliminary allocation of the purchase price was based upon preliminary valuations and 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 which are not yet finalized relate to identifiable intangible assets and residual goodwill. The final valuation of net assets is expected to be completed no later than one year from the acquisition date. The total transaction value for all of the assets is expected to be approximately $120 million.

On November 3, 2005, the Company 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), 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 Lampur (Malaysia) and Perth (Australia). The acquisition was accounted for as a business purchase with the acquisition price allocated to the assets acquired and liabilities assumed based upon their estimated fair values, with the excess being recorded as goodwill. The preliminary allocation of the purchase price resulted in $8.9 million allocated to net working capital, equipment and other assets acquired, $1.1 million allocated to patented technology (to be amortized over 20 years), $7.1 million allocated to a customer-relationship intangible asset (to be amortized over 12 years), $2.1 million allocated to covenants-not-to-compete (to be amortized over 3.5 years), $6.3 million allocated to trade name (not amortized, but tested for impairment on an annual basis) and goodwill of approximately $7.2 million. Resulting amounts are included in the Deepwater Contracting segment. The preliminary allocation of the purchase price was based upon preliminary valuations and 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 which are not yet finalized relate to identifiable intangible assets and residual goodwill. The final valuation of net assets is expected to be completed no later than one year from the acquisition date. The results of Helix Energy Limited are included in the accompanying statements of operations since the date of the purchase.

On January 23, 2006, the Company and Remington Oil and Gas Corporation announced an agreement under which the Company will acquire Remington in a transaction valued at approximately $1.4 billion. Under the terms of the agreement, Remington stockholders will receive $27.00 in cash and 0.436 shares of the Company’s common stock for each Remington share. The acquisition is conditioned upon, among other things, the approval of

Remington stockholders and customary regulatory approvals. The transaction is expected to be completed in the second quarter of 2006. In limited circumstances, if Remington fails to close the transaction, it must pay the Company a $45 million breakup fee and reimburse up to $2 million of expenses related to the transaction. The Company expects to fund the cash portion of the Remington acquisition (approximately $814 million) through a senior secured term facility which has been underwritten by a bank.

Financing Activities. We have financed seasonal operating requirements and capital expenditures with internally generated funds, borrowings under credit facilities, the sale of equity and project financings.

Convertible Senior Notes

On March 30, 2005, the Company 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 the Company’s common stock based on the specified conversion rate, subject to adjustment. As a result of the Company’s 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. The Company 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, the Company 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 the Company 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 Helix’s common stock for at least 20 trading days in the period of 30 consecutive trading day 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 the Company has called the Convertible Senior Notes for redemption and the redemption has not yet occurred.

To the extent the Company does 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, the Company will satisfy its 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 Helix’s 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 Helix’s common stock for the trading days during the cash settlement period.

Approximately 118,000 shares underlying the Convertible Senior Notes were included in the calculation of diluted earnings per share because the Company’s share price as of December 31, 2005, 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, the Company 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, L.L.C. to enable it to repay its term loan, $163.5 million related to the ERT acquisition of the Murphy properties in June 2005 and to partially fund the approximately $85.6 million purchase of the Torch vessels acquired in August 2005.

MARAD Debt

At December 31, 2005, $134.9 million was outstanding on the Company's 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 payable in equal semi-annual installments which began in August 2002 and matures 25 years from such date. We made two payments each during 2005 and 2004 totaling $4.3 million and $2.9 million, respectively. The MARAD Debt is collateralized by the *Q4000*, with Helix 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 the Company 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, 2005, we were in compliance with these covenants.

In September 2005, the Company 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, the Company terminated the interest rate swap and received cash proceeds of approximately $1.5 million representing a gain on the interest rate differential. This gain will be deferred and amortized over the remaining life of the MARAD Debt as an adjustment to interest expense.

Revolving Credit Facility

In August 2004, the Company entered into a four year, $150 million revolving credit facility with a syndicate of banks, with Bank of America, N.A. as administrative agent and lead arranger. The amount available under the facility may be increased to $250 million at any time upon the agreement of the Company and the existing or additional lenders. The credit facility is secured by the stock in certain Company subsidiaries and contains a negative pledge on assets. The new facility bears interest at LIBOR plus 75 – 175 basis points depending on Company leverage and contains financial covenants relative to the Company's level of debt to EBITDA, as defined in the credit facility, fixed charge coverage and book value of assets coverage. As of December 31, 2005, the Company was in compliance with these covenants and there was no outstanding balance under this facility.

Other

The Company had a $35 million term loan facility which was obtained to assist Helix in funding its portion of the construction costs of the spar for the *Gunnison* field. The loan was repaid in full in August 2004, and the loan agreement was subsequently cancelled and terminated.

In connection with the acquisition of Helix Energy Limited (see *Investing Activities* above), on November 3, 2005 the Company entered into two year notes payable to former owners totaling approximately 3.1 million British Pounds, or approximately $5.6 million, (approximately $5.4 million at December 31, 2005). The notes bear interest at a LIBOR based floating rate with payments due quarterly beginning January 31, 2006. Principal amounts are due in November 2007.

In connection with borrowings under credit facilities and long-term debt financings, the Company has paid deferred financing costs totaling $11.7 million, $4.6 million and $208,000 in the years ended December 31, 2005, 2004 and 2003, respectively.

On January 8, 2003, Helix 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 Helix common stock at $15.00 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 Helix common stock at $15.27 per share. In the event the holder of the convertible preferred stock elects to redeem into Helix common stock and Helix's common stock price is below the conversion prices, unless the Company has 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 Helix's option. Helix paid these dividends in 2005 and 2004 on the last day of the respective quarter 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 the discretion of the Company. In the event the Company is unable to deliver registered common shares, Helix could be required to redeem in cash.

In August 2003, Canyon Offshore, Ltd. (a U.K. subsidiary — "COL") (with a parent guarantee from Helix) completed a capital lease with a bank refinancing the construction costs of a newbuild 750 horsepower trenching unit and a ROV. COL received proceeds of $12 million for the assets and agreed to pay the bank sixty monthly installment payments of $217,174 (resulting in an implicit interest rate of 3.29%). No gain or loss resulted from this transaction. COL has an option to purchase the assets at the end of the lease term for $1. The proceeds were used to reduce the Company's revolving credit facility, which had initially funded the construction costs of the assets. This transaction was accounted for as a capital lease with the present value of the lease obligation (and corresponding asset) being reflected on the Company's consolidated balance sheet beginning in the third quarter of 2003.

In April 2005, 2004 and 2003, the Company purchased approximately one-third each year of the redeemable stock in Canyon related to the Canyon purchase at the minimum purchase price of $13.53 per share ($2.4 million, $2.5 million and $2.7 million, respectively).

During 2005, 2004 and 2003, we made payments of $2.9 million, $3.6 million and $2.4 million separately on capital leases related to Canyon. The only other financing activity during 2005, 2004 and 2003 involved the exercise of employee stock options ($8.7 million, $11.0 million and $3.6 million, respectively).

The following table summarizes our contractual cash obligations as of December 31, 2005 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
MARAD debt	134,927	3,641	7,837	8,638	114,811
Revolving debt	—	—	—	—	—
Capital leases	6,852	2,828	4,024	—	—
Helix Energy Limited loan notes	5,393	—	5,393	—	—
Acquisition of Stolt assets(3)	78,000	78,000	—	—	—
Investments in Independence Hub, LLC	32,200	32,200	—	—	—
Drilling and development costs	78,000	78,000	—	—	—
Property and equipment(4)	130,000	130,000	—	—	—
Operating leases	17,869	4,025	3,940	3,139	6,765
Total cash obligations	$ 783,241	$ 328,694	$21,194	$11,777	$421,576

(1) Excludes Helix guarantee of performance related to the construction of the Independence Hub platform under Independence Hub, LLC (estimated to be immaterial at December 31, 2005), and unsecured letters of credit outstanding at December 31, 2005 totaling $6.7 million. These letters of credit primarily guarantee various contract bidding and insurance activities. The Company has estimated decommissioning costs of $15.0 million for 2006 and $106.3 million thereafter which are excluded from table above as the amounts are not contractually committed at December 31, 2005.

(2) Maturity 2025. Can be converted prior to stated maturity if closing sale price of Helix's 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 closing price on that 30th trading day (i.e. $38.56 per share).

(3) In April 2005, the Company announced that it had reached an agreement (subject to certain regulatory approvals) to acquire certain assets of Stolt Offshore for approximately $120 million. The Company acquired the *DB 801* in January 2006 for approximately $38.0 million. The Company subsequently sold a 50% interest in the vessel in January 2006 for total consideration of approximately $23.5 million. The Company is expected to acquire the *Kestrel* in March 2006 for approximately $40 million.

(4) At December 31, 2005 the Company had committed to purchase a certain Deepwater Contracting vessel (the *Caesar)* to be converted into a deepwater pipelay vessel. Total purchase price and conversion costs are estimated to be approximately $125 million to be incurred over the next year. Further, the Company had committed approximately $5 million of the $40 million related to the upgrade of the *Q4000.*

In addition, in connection with our business strategy, we regularly evaluate acquisition opportunities (including additional vessels as well as interest in offshore natural gas and oil properties). We believe internally generated cash flow, borrowings under existing credit facilities and use of project financings along with other debt and equity alternatives will provide the necessary capital to meet these obligations and achieve our planned growth.

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

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

Interest Rate Risk. Because only 1% of the Company's debt (i.e. the Helix Energy Limited loan notes) at December 31, 2005 was based on floating rates, changes in interest would, assuming all other things equal, have a minimal impact on the fair market value of the debt instruments.

Commodity Price Risk. The Company has utilized derivative financial instruments with respect to a portion of 2005 and 2004 oil and gas production to achieve a more predictable cash flow by reducing its exposure to price fluctuations. The Company does not enter into derivative or other financial instruments for trading purposes.

As of December 31, 2005, the Company has the following volumes under derivative contracts related to its oil and gas producing activities:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:			
January to December 2006	Collar	125 MBbl	$ 44.00 – $70.48
January to December 2007	Collar	50 MBbl	$ 40.00 – $62.15
Natural Gas:			
January to December 2006	Collar	718,750 MMBtu	$8.16 – $14.40

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.

Subsequent to December 31, 2005, the Company entered into additional natural gas costless collars for the period of January 2007 through March 2007. The contract covers 600,000 MMBtu per month at a weighted average price of $8.00 to $16.24.

Foreign Currency Exchange Rates. Because we operate in various oil and gas exploration and production 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 Energy Limited). The functional currency for Well Ops (U.K.) Limited and Helix Energy Limited is the applicable local currency (British Pound). 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 the years ended December 31, 2005 and 2004, respectively, did not have a material effect on reported amounts of revenues or net income.

Assets and liabilities of Well Ops (U.K.) Limited and Helix Energy Limited 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 (loss) in the shareholders' equity section of our balance sheet. Approximately 10% of our assets are impacted by changes in foreign currencies in relation to the U.S. dollar. We recorded unrealized (losses) gains of $(11.4) million and $10.8 million to our equity account in the years ended December 31, 2005 and 2004, respectively, to reflect the net impact of the strengthening (2005) and the decline (2004) of the U.S. dollar against the British Pound. Beginning in 2004, deferred taxes have not been provided on foreign currency translation adjustments for operations where the Company considers its undistributed earnings of its 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.

Canyon Offshore, the Company's ROV subsidiary, has operations in the Europe/West Africa and Asia/Pacific regions. Canyon conducts the majority of its operations in these regions in U.S. dollars which it considers 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 years ended December 31, 2005 and 2004, respectively, were not material to the Company's results of operations or cash flows.

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

INDEX TO FINANCIAL STATEMENTS

Management's Report on Internal Control Over Financial Reporting

Management of Helix Energy Solutions Group, Inc., together with its consolidated subsidiaries (the "Company"), is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed under the supervision of the Company's principal executive and principal financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with U.S. generally accepted accounting principles.

As of the end of the Company's 2005 fiscal year, management conducted an assessment of the effectiveness of the Company's internal control over financial reporting using the criteria set forth in the framework established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management has determined that the Company's internal control over financial reporting as of December 31, 2005 is effective.

Our internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of the Company; provide reasonable assurances that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. generally accepted accounting principles, and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of the Company; and 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 our financial statements.

Management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2005 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report appearing on page 57, which expresses an unqualified opinion on management's assessment and on the effectiveness of Company's internal control over financial reporting as of December 31, 2005.

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. (formerly Cal Dive International, Inc.) and Subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of operations, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the 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, 2005 and 2004, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Helix Energy Solutions Group, Inc.'s internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 14, 2006 expressed an unqualified opinion thereon.

As discussed in Note 2 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" in 2003.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 14, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that Helix Energy Solutions Group, Inc. (formerly Cal Dive International, Inc.) maintained effective internal control over financial reporting as of December 31, 2005, 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. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, management's assessment that Helix Energy Solutions Group, Inc. maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Helix Energy Solutions Group, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, 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, 2005 and 2004, and the related consolidated statements of operations, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2005 and our report dated March 14, 2006 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 14, 2006

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2005	December 31, 2004
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 91,080	$ 91,142
Accounts receivable —		
Trade, net of allowance for uncollectible accounts $585 and $7,768	197,046	95,732
Unbilled revenue	31,012	18,977
Deferred income taxes	8,861	12,992
Other current assets	44,054	35,118
Total current assets	372,053	253,961
Property and equipment	1,259,014	861,281
Less — Accumulated depreciation	(342,652)	(276,864)
	916,362	584,417
Other assets:		
Equity investments	179,556	67,192
Goodwill, net	101,731	84,193
Other assets, net	91,162	48,995
	$1,660,864	$1,038,758
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 99,445	$ 56,047
Accrued liabilities	145,752	75,502
Current maturities of long-term debt	6,468	9,613
Total current liabilities	251,665	141,162
Long-term debt	440,703	138,947
Deferred income taxes	167,295	133,777
Decommissioning liabilities	106,317	79,490
Other long term liabilities	10,584	5,090
Total liabilities	976,564	498,466
Convertible preferred stock	55,000	55,000
Commitments and contingencies		
Shareholders' equity:		
Common stock, no par, 240,000 shares authorized, 104,898 and 104,040 shares issued	233,537	212,608
Retained earnings	408,748	258,634
Treasury stock, 27,204 shares, at cost	(3,741)	(3,741)
Unearned compensation	(7,515)	—
Accumulated other comprehensive (loss) income	(1,729)	17,791
Total shareholders' equity	629,300	485,292
	$1,660,864	$1,038,758

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,		
	2005	2004	2003
	(In thousands, except per share amounts)		
Net revenues	$ 799,472	$543,392	$396,269
Cost of sales	516,400	371,480	304,186
Gross profit	283,072	171,912	92,083
Gain on sale of assets	1,405	—	—
Selling and administrative expenses	62,790	48,881	35,922
Income from operations	221,687	123,031	56,161
Equity in earnings (losses) of investments	13,459	7,927	(87)
Net interest expense and other	7,559	5,265	3,403
Income before income taxes and change in accounting principle	227,587	125,693	52,671
Provision for income taxes	75,019	43,034	18,993
Income before change in accounting principle	152,568	82,659	33,678
Cumulative effect of change in accounting principle, net	—	—	530
Net income	152,568	82,659	34,208
Preferred stock dividends and accretion	2,454	2,743	1,437
Net income applicable to common shareholders	$ 150,114	$ 79,916	$ 32,771
Earnings per common share			
Basic:			
Earnings per share before change in accounting principle	$ 1.94	$ 1.05	$ 0.43
Cumulative effect of change in accounting principle	—	—	0.01
Earnings per share	$ 1.94	$ 1.05	$ 0.44
Diluted:			
Earnings per share before change in accounting principle	$ 1.86	$ 1.03	$ 0.43
Cumulative effect of change in accounting principle	—	—	0.01
Earnings per share	$ 1.86	$ 1.03	$ 0.44
Weighted average common shares outstanding:			
Basic	77,444	76,409	75,479
Diluted	82,205	79,062	75,688

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	Treasury Stock		Unearned Compensation	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
	Shares	Amount		Shares	Amount			
					(In thousands)			
Balance, December 31, 2002	102,120	$ 195,405	$ 145,947	(27,204)	$ (3,741)	$ —	$ (94)	$ 337,517
Comprehensive income:								
Net income	—	—	34,208	—	—	—	—	34,208
Foreign currency translation adjustments	—	—	—	—	—	—	5,044	5,044
Unrealized gain on commodity hedges, net	—	—	—	—	—	—	1,215	1,215
Comprehensive income								40,467
Convertible preferred stock dividends	—	—	(981)	—	—	—	—	(981)
Accretion of preferred stock costs	—	—	(456)	—	—	—	—	(456)
Activity in company stock plans, net	800	3,940	—	—	—	—	—	3,940
Tax benefit from exercise of stock options	—	654	—	—	—	—	—	654
Balance, December 31, 2003	102,920	199,999	178,718	(27,204)	(3,741)	—	6,165	381,141
Comprehensive income:								
Net income	—	—	82,659	—	—	—	—	82,659
Foreign currency translations adjustments	—	—	—	—	—	—	10,780	10,780
Unrealized gain on commodity hedges, net	—	—	—	—	—	—	846	846
Comprehensive income								94,285
Convertible preferred stock dividends	—	—	(1,620)	—	—	—	—	(1,620)
Accretion of preferred stock costs	—	—	(1,123)	—	—	—	—	(1,123)
Activity in company stock plans, net	1,120	10,481	—	—	—	—	—	10,481
Tax benefit from exercise of stock options	—	2,128	—	—	—	—	—	2,128
Balance, December 31, 2004	104,040	212,608	258,634	(27,204)	(3,741)	—	17,791	485,292
Comprehensive income:								
Net income	—	—	152,568	—	—	—	—	152,568
Foreign currency translations adjustments	—	—	—	—	—	—	(11,393)	(11,393)
Unrealized loss on commodity 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
Tax benefit from exercise of stock options	—	4,402	—	—	—	—	—	4,402
Balance, December 31, 2005	104,898	$ 233,537	$ 408,748	(27,204)	$ (3,741)	$ (7,515)	$ (1,729)	$ 629,300

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, 2005	2004	2003
		(In thousands)	
Cash flows from operating activities:			
Net income	$ 152,568	$ 82,659	$ 34,208
Adjustments to reconcile net income to net cash provided by operating activities:			
Cumulative effect of change in accounting principle	—	—	(530)
Depreciation and amortization	110,683	104,405	70,793
Asset impairment charge	790	3,900	—
Equity in (earnings) losses of investments, net of distributions	(2,851)	(469)	87
Amortization of deferred financing costs	1,126	1,344	340
Amortization of unearned compensation	1,406	—	—
Deferred income taxes	42,728	42,046	18,493
Tax benefit of stock option exercises	4,402	2,128	654
(Gain) loss on sale of assets	(1,405)	100	45
Changes in operating assets and liabilities:			
Accounts receivable, net	(107,163)	(17,397)	(20,256)
Other current assets	(6,997)	(23,294)	5,038
Accounts payable and accrued liabilities	64,625	43,292	(9,808)
Other noncurrent, net	(17,480)	(11,907)	(11,648)
Net cash provided by operating activities	242,432	226,807	87,416
Cash flows from investing activities:			
Capital expenditures	(361,487)	(50,123)	(93,160)
Acquisition of businesses, net of cash acquired	(66,586)	—	(407)
Investments in production facilities	(111,060)	(32,206)	(1,917)
Distributions from equity investments, net	10,492	—	—
(Increase) decrease in restricted cash	(4,431)	(20,133)	73
Proceeds from (payments on) sales of property	5,617	(100)	200
Other, net	(2,470)	—	—
Net cash used in investing activities	(529,925)	(102,562)	(95,211)
Cash flows from financing activities:			
Borrowings on Convertible Senior Notes	300,000	—	—
Sale of convertible preferred stock, net of transaction costs	—	29,339	24,100
Borrowings under MARAD loan facility	2,836	—	—
Repayment of MARAD borrowings	(4,321)	(2,946)	(2,767)
Repayments on line of credit	—	(30,189)	(22,402)
Deferred financing costs	(11,678)	(4,550)	(208)
Borrowings on term loan	—	—	5,730
Repayments of term loan borrowings	—	(35,000)	—
Borrowings on capital leases	—	—	12,000
Capital lease payments	(2,859)	(3,647)	(2,430)
Preferred stock dividends paid	(2,200)	(1,620)	(981)
Redemption of stock in subsidiary	(2,438)	(2,462)	(2,676)
Exercise of stock options	8,726	11,038	3,570
Net cash provided by (used in) financing activities	288,066	(40,037)	13,936
Effect of exchange rate changes on cash and cash equivalents	(635)	556	237
Net (decrease) increase in cash and cash equivalents	(62)	84,764	6,378
Cash and cash equivalents:			
Balance, beginning of year	91,142	6,378	—
Balance, end of year	$ 91,080	$ 91,142	$ 6,378

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

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization

Effective March 6, 2006, Cal Dive International, Inc. changed its name to Helix Energy Solutions Group, Inc. ("Helix" or the "Company"). Helix, headquartered in Houston, Texas is an energy services company specializing in Marine Contracting development on the Outer Continental Shelf and in the Deepwater (including subsea construction, provision of production facilities, well operations and reservoir and well engineering) and providing oil and gas companies with alternatives to traditional approaches including equity or production sharing in offshore properties through our Oil & Gas Production and Production Facilities segments. Within its Deepwater and Shelf Contracting segments, Helix operates primarily in the Gulf of Mexico (Gulf), the North Sea and Asia/Pacific regions, with services that cover the lifecycle of an offshore oil or gas field. Helix's current diversified fleet of 33 vessels (one of which is leased) and 29 remotely operated vehicles (ROVs) and trencher systems perform services that support drilling, well completion, intervention, construction and decommissioning projects involving pipelines, production platforms, risers and subsea production systems. The Company also has a significant investment in offshore oil and gas production (through its wholly owned subsidiary Energy Resource Technology, Inc.) as well as production facilities. Operations in the Production Facilities segment began in 2004 with the *Marco Polo* field coming online and the completion of the tension leg platform owned by Deepwater Gateway, L.L.C.. The Production Facilities segment is currently accounted for under the equity method of accounting and includes the Company's 50% investment in Deepwater Gateway, L.L.C., and its 20% investment in Independence Hub, LLC. Helix's customers include major and independent oil and gas producers, pipeline transmission companies and offshore engineering and construction firms. See discussion of segment reporting in footnote 14.

2. Summary of Significant Accounting Policies

Principles of Consolidation

The accompanying consolidated financial statements include the accounts of the Company and its majority owned subsidiaries. All significant intercompany accounts and transactions have been eliminated. The Company accounts for its 50% interest in Deepwater Gateway, L.L.C., its 20% interest in Independence Hub, LLC and its 40% interest in Offshore Technology Solutions Limited ("OTSL"), a Trinidad and Tobago entity, under the equity method of accounting as the Company does not have voting or operational control of these entities.

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. See footnote 13 for discussion of two-for-one stock split in December 2005.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles 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. On an ongoing basis the Company evaluates its estimates including those related to bad debts, investments, intangible assets and goodwill, property plant and equipment, oil and gas reserves, decommissioning liabilities, income taxes, worker's compensation insurance and contingent liabilities. The Company bases its estimates on historical experience and on various other assumptions believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results could differ from those estimates.

Goodwill and Other Intangible Assets

The Company tests for the impairment of goodwill and other indefinite-lived intangible assets on at least an annual basis. The Company's goodwill impairment test involves a comparison of the fair value of each of the

Company's reporting units 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. The Company completed its annual goodwill impairment test as of November 1, 2005. The Company's goodwill impairment test involves a comparison of the fair value of each of the Company's reporting units with its carrying amount. Goodwill of $73.9 million and $69.2 million related to the Company's Deepwater Contracting segment as of December 31, 2005 and 2004, respectively. Goodwill of $27.8 million and $15.0 million related to the Company's Shelf Contracting segment as of December 31, 2005 and 2004, respectively. None of the Company's goodwill was impaired based on the impairment test performed as of November 1, 2005 (the annual impairment test excluded the goodwill and other indefinite-lived intangible assets acquired in the Stolt Offshore and Helix Energy Limited acquisitions which closed in November 2005). The Company will continue to test its 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.

Property and Equipment

Property 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.

All of the Company's interests in oil and gas properties are located offshore in United States waters. The Company follows the successful efforts method of accounting for its 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.

Energy Resource Technology, Inc. ("ERT") acquisitions of producing offshore properties are recorded at the value exchanged at closing together with an estimate of its proportionate share of the discounted decommissioning liability assumed in the purchase based upon its working interest ownership percentage. In estimating the decommissioning liability assumed in offshore property acquisitions, the Company performs detailed estimating procedures, including engineering studies. The resulting decommissioning liability is reflected on the face of the balance sheet at fair value on a discounted basis. All capitalized costs are amortized on a unit-of-production basis (UOP) based on the estimated remaining oil and gas reserves. Properties are periodically assessed for impairment in value, with any impairment charged to expense.

The evaluation of the Company's oil and gas reserves is critical to the management of its 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 the producing oil and gas properties in decommissioning liabilities. The Company's 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.

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following is a summary of the components of property and equipment (dollars in thousands):

	Estimated Useful Life	2005	2004
Vessels	15 to 30 years	$ 609,558	$506,262
Offshore oil and gas leases and related equipment	UOP	601,866	328,071
Machinery, equipment, buildings and leasehold improvements	5 to 30 years	47,590	26,948
Total property and equipment		$ 1,259,014	$861,281

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 $24.0 million, $17.0 million and $14.7 million for the years ended December 31, 2005, 2004 and 2003, respectively.

For long-lived assets to be held and used, excluding goodwill, the Company bases its 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, the Company determines 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. The Company's marine vessels are assessed on a vessel by vessel basis, while the Company's ROVs are grouped and assessed by asset class. If an impairment has occurred, the Company recognizes 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 an estimate of discounted cash flows. The Company recorded an impairment charge of $1.9 million (included in Shelf Contracting cost of sales) in December 2004 on certain Shelf Contracting vessels that met the impairment criteria. These assets were subsequently sold in December 2005 and January 2006, respectively, for an aggregate gain on the disposals of approximately $322,000.

Assets are classified as held for sale when the Company has a plan for disposal of certain assets and those assets meet the held for sale criteria. During the fourth quarter of 2004, the Company classified a certain Shelf Contracting vessel and other Deepwater Contracting property and equipment intended to be disposed of within a twelve month period as assets held for sale totaling $5.0 million (included in other current assets at December 31, 2004).

In July 2005, the Company completed the sale of a certain Shelf Contracting DP ROV Support vessel, the *Merlin*, for $2.3 million in cash that was previously included in assets held for sale. The Company recorded an additional impairment of $790,000 on the vessel in June 2005.

In March 2005, the Company completed the sale of certain Deepwater Contracting property and equipment for $4.5 million that was previously included in assets held for sale. Proceeds from the sale consisted of $100,000 cash and a $4.4 million promissory note bearing interest at 6% per annum due in semi-annual installments beginning September 30, 2005 through March 31, 2010. In addition to the asset sale, the Company entered into a five year services agreement with the purchaser whereby the Company has committed to provide the purchaser with a specified amount of services for its Gulf of Mexico fleet on an annual basis ($8 million per year). The measurement period related to the services agreement begins with the twelve months ending June 30, 2006 and continues every six months until the contract ends on March 31, 2010. Further, the promissory note stipulates that should the Company not meet its annual services commitment the purchaser can defer its semi-annual principal and interest payment for six months. The Company determined that the estimated gain on the sale of approximately $2.5 million should be deferred and recognized as the principal and interest payments are received from the purchaser over the course of the promissory note. The first installment on the $4.4 million promissory note was received in October 2005 and $210,000 was recognized as a partial gain on the sale.

Recertification Costs and Deferred Drydock Charges

The Company's Deepwater 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 where other routine repairs and maintenance are performed and, at times, major replacements and improvements are performed. The Company expenses routine repairs and maintenance as they are incurred. Recertification costs can be accounted for in one of three ways: (1) defer and amortize, (2) accrue in advance, or (3) expense as incurred. The Company defers and amortizes recertification costs over the length of time in which the recertification is expected to last, which is generally 30 months. 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 the Company makes regarding the specific cost incurred and the period that the incurred cost will benefit.

The Company accounts for regulatory (U.S. Coast Guard, American Bureau of Shipping and Det Norske Veritas) related drydock inspection and certification expenditures by capitalizing the related costs and amortizing them over the 30-month period between regulatory mandated drydock inspections and certification. As of December 31, 2005 and 2004, capitalized deferred drydock charges (included in other assets, net) totaled $18.3 million and $10.0 million, respectively. During the years ended December 31, 2005, 2004 and 2003, drydock amortization expense was $8.9 million, $4.9 million and $4.1 million, respectively.

Accounting for Decommissioning Liabilities

On January 1, 2003, the Company adopted Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations*, which addresses the financial accounting and reporting obligations and retirement costs related to the retirement of tangible long-lived assets. Among other things, SFAS No. 143 requires oil and gas companies to reflect decommissioning liabilities (dismantlement and abandonment of oil and gas wells and offshore platforms) on the face of the balance sheet at fair value on a discounted basis. Prior to January 1, 2003, the Company reflected this liability on the balance sheet on an undiscounted basis.

The adoption of SFAS No. 143 resulted in a cumulative effect adjustment as of January 1, 2003 to record (i) a $33.1 million decrease in the carrying values of proved properties, (ii) a $7.4 million decrease in accumulated depreciation, depletion and amortization of property and equipment, (iii) a $26.5 million decrease in decommissioning liabilities and (iv) a $0.3 million increase in deferred income tax liabilities. The net impact of items (i) through (iv) was to record a gain of $0.5 million, net of tax, as a cumulative effect adjustment of a change in accounting principle in the Company's consolidated statements of operations upon adoption on January 1, 2003. The Company has no material assets that are legally restricted for purposes of settling its decommissioning liabilities other than the $27.0 million of restricted cash in escrow (see *Statement of Cash Flow Information* in this footnote).

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The pro forma effects of the application of SFAS No. 143 are presented below (in thousands, except per share amounts):

	Year Ended December 31, 2003
Net income applicable to common shareholders as reported	$ 32,771
Cumulative effect of accounting change	(530)
Pro forma net income applicable to common shareholders	$ 32,241
Pro forma earnings per common share applicable to common shareholders:	
Basic	$ 0.43
Diluted	0.43
Earnings per common share applicable to common shareholders as reported:	
Basic	$ 0.44
Diluted	0.44

The following table describes the changes in the Company's asset retirement obligations for the year ended 2005 (in thousands):

Asset retirement obligation at December 31, 2004	$ 82,030
Liability incurred during the period	36,119
Liabilities settled during the period	(1,913)
Revision in estimated cash flows	(583)
Accretion expense (included in depreciation and amortization)	5,699
Asset retirement obligation at December 31, 2005	$121,352

Foreign Currency

The functional currency for the Company's foreign subsidiaries, Well Ops (U.K.) Limited and Helix Energy Limited, is the applicable local currency (British Pound). Results of operations for these subsidiaries are translated into U.S. dollars using average exchange rates during the period. Assets and liabilities of this foreign subsidiary are translated into U.S. dollars using the exchange rate in effect at the balance sheet date and the resulting translation adjustment, which was an unrealized (loss) gain of $(11.4) million and $10.8 million, respectively, is included in accumulated other comprehensive income (loss), a component of shareholders' equity. Beginning in 2004, deferred taxes were not provided on foreign currency translation adjustments for operations where the Company considers its undistributed earnings of its 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, 2005 and 2004 were not material to the Company's results of operations or cash flows.

Canyon Offshore, the Company's ROV subsidiary, has operations in the United Kingdom and Southeast Asia sectors. Canyon conducts the majority of its operations in these regions in U.S. dollars which it considers 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 years ended December 31, 2005 and 2004 were not material to the Company's results of operations or cash flows.

Accounting for Price Risk Management Activities

The Company's price risk management activities involve the use of derivative financial instruments to hedge the impact of market price risk exposures primarily related to the Company's oil and gas production. All derivatives are reflected in the Company's balance sheet at fair market value.

There are two types of hedging activities: hedges of cash flow exposure and hedges of fair value exposure. The Company engages 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 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 in oil and gas production revenues.

The Company formally documents all relationships between hedging instruments and hedged items, as well as its 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. The Company also assesses, 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. The Company discontinues hedge accounting if it determines 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.

The fair value of hedging instruments reflects the Company's 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, the Company utilizes other valuation techniques or models to estimate market values. These modeling techniques require the Company to make estimations of future prices, price correlation and market volatility and liquidity. The Company's actual results may differ from its estimates, and these differences can be positive or negative.

During 2005 and 2004, the Company entered into various cash flow hedging swap and costless collar contracts to stabilize cash flows relating to a portion of the Company's expected oil and gas production. All of these qualified for hedge accounting. The aggregate fair value of the hedge instruments was a net liability of $13.4 million and $876,000 as of December 31, 2005 and 2004, respectively. For the years ended December 31, 2005, 2004 and 2003, the Company recorded unrealized (losses) gains of approximately $(8.1) million, $846,000 and $1.2 million, net of taxes of $4.4 million, $456,000 and $654,000, respectively, in 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 hedged item is sold. During 2005, 2004 and 2003, the Company reclassified approximately $14.1 million, $11.1 million and $14.6 million, respectively, of losses from other comprehensive income to Oil and Gas Production 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 the third quarter of 2005 as reported in that period's earnings as a reduction of oil and gas productive revenues. Hedge ineffectiveness resulted from ERT's projected inability to deliver contractual oil and gas production in fourth quarter 2005 due primarily to the effects of Hurricanes *Katrina* and *Rita.*

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

As of December 31, 2005, the Company has the following volumes under derivative contracts related to its oil and gas producing activities:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:			
January to December 2006	Collar	125 MBbl	$ 44.00 — $70.48
January to December 2007	Collar	50 MBbl	$ 40.00 — $62.15
Natural Gas:			
January to December 2006	Collar	718,750 MMBtu	$ 8.16 — $14.40

Subsequent to December 31, 2005, the Company entered into additional natural gas costless collars for the period of January 2007 through March 2007. The contract covers 600,000 MMBtu per month at a weighted average price of $8.00 to $16.24.

Equity Investments

The Company periodically reviews its investments in Deepwater Gateway, L.L.C., Independence Hub, LLC and OTSL for impairment. Recognition of a loss would occur when the decline in an investment is deemed other than temporary. In determining whether the decline is other than temporary, the Company considers the cyclical nature of the industry in which the investments operate, their historical performance, their performance in relation to their peers and the current economic environment. During 2005, 2004 and 2003 no impairment indicators existed.

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 outstanding common stock. The calculation of diluted EPS is similar to basic EPS except that 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 the basic and diluted per share amounts for the Company was as follows (in thousands, except per share amounts):

	Years Ended December 31,		
	2005	2004	2003
Income before change in accounting principle	$ 152,568	$82,659	$33,678
Cumulative effect of change in accounting principle, net	—	—	530
Preferred stock dividends and accretion	(2,454)	(2,743)	(1,437)
Net income applicable to common shareholders	$ 150,114	$79,916	$32,771
Weighted-average common shares outstanding:			
Basic	77,444	76,409	75,479
Effect of dilutive stock options	772	609	209
Effect of restricted shares	240	—	—
Effect of convertible notes	118	—	—
Effect of convertible preferred stock	3,631	2,044	—
Diluted	82,205	79,062	75,688
Basic Earnings Per Share:			
Income before change in accounting principle	$ 1.97	$ 1.08	$ 0.45
Cumulative effect of change in accounting principle, net	—	—	0.01
Preferred stock dividends and accretion	(0.03)	(0.03)	(0.02)
	$ 1.94	$ 1.05	$ 0.44
Diluted Earnings Per Share:			
Income before change in accounting principle	$ 1.89	$ 1.05	$ 0.45
Cumulative effect of change in accounting principle, net	—	—	0.01
Preferred stock dividends and accretion	(0.03)	(0.02)	(0.02)
	$ 1.86	$ 1.03	$ 0.44

Stock options to purchase approximately 2,054,000 shares for the year ended December 31, 2003 were not dilutive and, therefore, were not included in the computations of diluted income per common share amounts. There were no antidilutive stock options in the years ended December 31, 2005 and 2004, respectively. In addition, approximately 1,020,000 shares attributable to the convertible preferred stock were excluded in the year ended December 31, 2004, calculation of diluted EPS, as the effect was antidilutive. Net income for the diluted earnings per share calculation for the years ended December 31, 2005 and 2004 were adjusted to add back the preferred stock dividends and accretion on the 3,631,000 shares and 2,044,000 shares, respectively.

Stock Based Compensation Plans

The Company used the intrinsic value method of accounting for its stock-based compensation programs through December 31, 2005. 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. The following table reflected the Company's pro forma results if the fair value method had been used for the accounting for these plans (in thousands, except per share amounts):

	For the Years Ended December 31,		
	2005	2004	2003
Net income applicable to common shareholders:			
As reported	$ 150,114	$79,916	$32,771
Add back: Stock-based employee compensation cost included in reported net income, net of tax	914	—	—
Deduct: Total stock-based compensation costs determined under the fair value method, net of tax	(2,566)	(2,368)	(3,331)
Pro Forma	$ 148,462	$77,548	$29,440
Earnings per common share:			
Basic:			
As reported	$ 1.94	$ 1.05	$ 0.44
Pro forma	$ 1.92	$ 1.02	$ 0.39
Diluted:			
As reported	$ 1.86	$ 1.03	$ 0.44
Pro forma	$ 1.84	$ 1.00	$ 0.39

For the purposes of pro forma disclosures, the fair value of each option grant was estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions used: expected dividend yields of 0 percent; expected lives ranging from three to ten years, risk-free interest rate assumed to be 4.0 percent in 2004 and 2003, and expected volatility to be 56 percent in 2004 and 2003. There have been no stock option grants in 2005. The fair value of shares issued under the Employee Stock Purchase Plan was based on the 15% discount received by the employees. The weighted average per share fair value of the options granted in 2004 and 2003 was $8.80, and $6.37, respectively. The estimated fair value of the options is amortized to pro forma expense over the vesting period. See footnote 12 for discussion of restricted share awards in 2005 and 2006. See ***Recently Issued Accounting Principles*** in this footnote for a discussion of the Company's adoption of SFAS No. 123 (revised 2004), *Share-Based Payment* ("SFAS No. 123R").

Revenue Recognition

The Company typically earns the majority of deepwater contracting and shelf contracting revenues during the summer and fall months. Revenues are derived from billings under contracts (which are typically of short duration) that provide for either lump-sum turnkey charges or specific time, material and equipment charges which are billed in accordance with the terms of such contracts. The Company recognizes revenue as it is earned at estimated collectible amounts. Revenues generated from specific time, materials and equipment charges contracts are generally earned on a dayrate basis and recognized as amounts are earned in accordance with contract terms. Revenues generated in the pre-operation mode before a contract commences are deferred and recognized on a straight line basis in accordance with contract terms. Direct and incremental costs associated with pre-operation activities are similarly deferred and recognized over the estimated contract period.

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, or achievement of certain contractual milestones if provided for in the contract. Contract price and cost estimates are reviewed periodically as work progresses and adjustments are reflected in the period in which such estimates are revised. Provisions for estimated losses on such contracts are made in the period such losses are determined. The Company recognizes additional contract revenue related to claims when the claim is probable and legally enforceable. Unbilled revenue represents revenue attributable to work completed prior to year-end which has not yet been invoiced. All amounts included in unbilled revenue at December 31, 2005 are expected to be billed and collected within one year.

The Company records 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. The Company may have an interest with other producers in certain properties. In this case the Company uses the entitlements method to account for sales of production. Under the entitlements method the Company may receive more or less than its entitled share of production. If the Company receives more than its entitled share of production, the imbalance is treated as a liability. If the Company receives less than its entitled share, the imbalance is recorded as an asset.

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. The Company establishes an allowance for uncollectible accounts receivable based on historical experience and any specific customer collection issues that the Company has identified. Uncollectible accounts receivable are written off when a settlement is reached for an amount that is less that the outstanding historical balance or when the Company has determined the balance will not be collected.

Major Customers and Concentration of Credit Risk

The market for the Company's 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. The Company's customers consist primarily of major, well-established oil and pipeline companies and independent oil and gas producers and suppliers. The Company performs ongoing credit evaluations of its customers and provides allowances for probable credit losses when necessary. The percent of consolidated revenue of major customers was as follows: 2005 — Louis Dreyfus Energy Services (10%) and Shell Trading (US) Company (10%); 2004 — Louis Dreyfus Energy Services (11%) and Shell Trading (US) Company (10%); and 2003 — Shell Trading (US) Company (10%) and Petrocom Energy Group, Ltd. (10%). All of these customers were purchasers of ERT's oil and gas production. In March 2004, the Company elected not to renew its alliance with Horizon Offshore, Inc. As part of the settlement of outstanding trade accounts receivable with Horizon, the Company obtained exclusive use of a Horizon spoolbase facility for a period of five years. Utilization of the spoolbase facility was valued at approximately $2.0 million with the Company offsetting a corresponding amount of trade accounts receivable in exchange for the utilization agreement. The value of the spoolbase facility is being amortized over the five year term of the agreement.

Income Taxes

Deferred income taxes are based on the differences between financial reporting and tax bases of assets and liabilities. The Company utilizes 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. The Company considers the undistributed earnings of its principal non-U.S. subsidiaries to be permanently reinvested. At December 31, 2005, the Company's principal non-U.S. subsidiaries had an accumulated deficit of approximately $4.3 million in earnings and profits. These losses are primarily due to timing differences related to fixed assets. The Company has not provided deferred U.S. income tax on the losses.

Statement of Cash Flow Information

The Company defines cash and cash equivalents as cash and all highly liquid financial instruments with original maturities of less than three months. As of December 31, 2005, the Company had $27.0 million of restricted cash included in other assets, net, all of which related to ERT's escrow funds for decommissioning liabilities associated with the South Marsh Island 130 ("SMI 130") field acquisitions in 2002. Under the purchase agreement for those acquisitions, ERT is 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. ERT may use the restricted cash for decommissioning the related fields. Additionally, $7.5 million was included in restricted cash in other assets, net at December 31, 2004 related to the Company's investment in Deepwater Gateway, L.L.C. The Company was required to escrow up to $22.5 million related to its guarantee under the term loan agreement for Deepwater Gateway, L.L.C. The term loan of $144 million related to Deepwater Gateway, L.L.C. was repaid in full in March 2005. As a result in March 2005, the escrow agreement was canceled and the $7.5 million was released from restricted cash. See footnote 6.

Non-cash investing activities for the years ended December 31, 2005 and 2004 included $28.5 million and $8.9 million, respectively, related to accruals of capital expenditures. Amounts were not significant in 2003. The accruals have been reflected in the consolidated balance sheet as an increase in property and equipment and accounts payable.

During the years ended December 31, 2005, 2004 and 2003, the Company made cash payments for interest charges totaling $10.0 million, $3.2 million and $2.7 million, respectively, net of capitalized interest.

Recently Issued Accounting Principles

In December 2004, the FASB issued SFAS No. 123R, which replaces SFAS No. 123, *Accounting for Stock-Based Compensation*, ("SFAS No. 123") and supercedes APB Opinion No. 25, *Accounting for Stock Issued to Employees.* SFAS No. 123R requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values beginning with the first interim period in fiscal 2006, with early adoption encouraged. The pro forma disclosures previously permitted under SFAS No. 123 no longer will be an alternative to financial statement recognition. The Company adopted SFAS No. 123R on January 1, 2006. Under SFAS No. 123R, the Company will continue to use the Black-Scholes fair value model for valuing share-based payments, and amortize compensation cost on a straight line basis over the respective vesting period. The Company selected the prospective method which requires that compensation expense be recorded for all unvested stock options and restricted stock beginning in 2006 as the requisite service is rendered. In addition to the compensation cost recognition requirements, SFAS No. 123R also requires the tax deduction benefits for an award in excess of recognized compensation cost be reported as a financing cash flow rather than as an operating cash flow, which was required under SFAS No. 95. The adoption did not have a material impact on the Company's consolidated results of operations and earnings per share.

In September 2004, the EITF of the FASB reached a consensus on issue No. 04-08, *The Effect of Contingently Convertible Instruments on Diluted Earnings per Share* ("EITF 04-08"), which is effective for reporting periods ending after December 15, 2004. Contingently convertible instruments within the scope of EITF 04-08 are instruments that contain conversion features that are contingently convertible or exercisable based on (a) a market price trigger or (b) multiple contingencies if one of the contingencies is a market price trigger for which the instrument may be converted or share settled based on meeting a specified market condition. EITF 04-08 requires companies to include shares issuable under convertible instruments in diluted earnings per share computations (if dilutive) regardless of whether the market price trigger (or other contingent feature) has been met. In addition, prior period earnings per share amounts presented for comparative purposes must be restated. The Company adopted EITF 04-08 in 2005. The adoption did not have a material impact on the Company's earnings per share for the years ended December 31, 2005, 2004 and 2003.

3. Offshore Property Transactions

The Company follows the successful efforts method of accounting for its 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. For the year ended December 31, 2005, impairments and unsuccessful capitalized well work totaling $4.8 million were expensed as a result of an analysis on certain properties (which resulted in non-cash property writeoffs totaling $10.5 million). Further, the Company expensed $5.7 million of purchased seismic data related to its offshore property acquisitions during the year ended December 31, 2005. Finally, the Company incurred inspection and repair costs in 2005 totaling approximately $7.1 million related to Hurricanes *Katrina* and *Rita*. As of December 31, 2005 no recoveries from insurance have been recorded.

As an extension of ERT's well exploitation and PUD strategies, ERT agreed to participate in the drilling of an exploratory well (Tulane prospect) to be drilled in 2006 that targets reserves in deeper sands, within the same trapping fault system, of a currently producing well with estimated drilling costs of approximately $19 million. If the drilling is successful, ERT's share of the development cost is estimated to be an additional $16 million, of which $6.4 million had been incurred through December 31, 2005 related to long lead equipment. This equipment can be redeployed if drilling is unsuccessful. Helix's Deepwater Contracting assets would participate in this development.

In March 2005, ERT acquired a 30% working interest in a proven undeveloped field in Atwater Valley Block 63 (Telemark) of the Deepwater Gulf of Mexico for cash and assumption of certain decommissioning liabilities. In December 2005, ERT was advised by Norsk Hydro USA Oil and Gas, Inc. that Norsk Hydro will not pursue their development plan for the deepwater discovery. ERT did not support that development plan and is currently developing its own plans based on the marginal field methodologies that were envisaged when the working interest was acquired. Any revised development plan will have to be approved by the Minerals Management Service ("MMS").

In April 2005, ERT entered into a participation agreement to acquire a 50% working interest in the Devil's Island discovery (Garden Banks Block 344 E/2) in 2,300 feet water depth. This deepwater development is operated by Amerada Hess and will be drilled in 2006. The field will be developed via a subsea tieback to Baldpate Field (Garden Banks Block 260). Under the participation agreement, ERT will pay 100% of the drilling costs and a disproportionate share of the development costs to earn 50% working interest in the field. Helix's Deepwater Contracting assets would participate in this development.

Also in April 2005, ERT acquired a 37.5% working interest in the Bass Lite discovery (Atwater Blocks 182, 380, 381, 425 and 426) in 7,500 feet water depth along with varying interests in 50 other blocks of exploration acreage in the eastern portion of the Atwater lease protraction area from BHP Billiton. The Bass Lite discovery contains proved undeveloped gas reserves in a sand discovered in 2001 by the Atwater 426 #1 well. In October 2005, ERT exchanged 15% of its working interest in Bass Lite for a 40% working interest in the Tiger Prospect located in Green Canyon Block 195. ERT paid $1.0 million in the exchange with no corresponding gain or loss recorded on the transaction.

In February 2006, ERT entered into a participation agreement with Walter Oil & Gas for a 20% interest in the Huey prospect in Garden Banks Blocks 346/390 in 1,835 feet water depth. Drilling of the exploration well is expected to begin March 2006. If successful, the development plan would consist of a subsea tieback to the Baldplate Field (Garden Banks 260). Under the participation agreement, ERT has committed to pay 32% of the costs to casing point to earn the 20% interest in the potential development, with ERT's share of drilling costs of approximately $6.7 million.

As of December 31, 2005, the Company had spent $31.5 million and had committed to an additional estimated $78 million for development and drilling costs related to the above property transactions.

In June 2005, ERT acquired a mature property package on the Gulf of Mexico shelf from Murphy Exploration & Production Company — USA ("Murphy"), a wholly owned subsidiary of Murphy Oil Corporation. The acquisition cost to ERT 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. ERT estimated proved reserves of the acquisition to be approximately 75 BCF equivalent. The results of the acquisition are included in the accompanying statements of operations since the date of purchase. Unaudited pro forma combined operating results of the Company and the Murphy acquisition for the years ended December 31, 2005 and 2004, respectively, were as follows (in thousands, except per share data).

	Years Ended December 31,	
	2005	2004
Net revenues	$829,205	$610,338
Income before income taxes	232,145	135,780
Net income	155,531	89,216
Net income applicable to common shareholders	153,077	86,473
Earnings per common share:		
Basic	$ 1.98	$ 1.13
Diluted	$ 1.89	$ 1.11

ERT production activities are regulated by the federal government and require significant third-party involvement, such as refinery processing and pipeline transportation. The Company records revenue from its offshore properties net of royalties paid to the MMS. Royalty fees paid totaled approximately $34.0 million, $26.7 million and $16.4 million for the years ended December 31, 2005, 2004 and 2003 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 the Company to fulfill such bonding requirements through an insurance policy.

4. Related Party Transactions

In April 2000, ERT acquired a 20% working interest in *Gunnison*, a Deepwater Gulf of Mexico prospect of Kerr-McGee Oil & Gas Corp. 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 ERT totaled $28.1 million and $20.3 million in the years ended December 31, 2005 and 2004, respectively. The Company's Chief Executive Officer, as a Class A limited partner of OKCD, personally owns approximately 67% of the partnership. Other executive officers of the Company own approximately 6% combined of the partnership. In 2000, OKCD also awarded Class B limited partnership interests to key Helix employees.

In connection with the acquisition of Helix Energy Limited, the Company 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 $5.4 million at December 31, 2005). The notes bear interest at a LIBOR based floating rate with payments due quarterly beginning January 31, 2006. Principal amounts are due in November 2007.

During 2003, the Company was paid $2.2 million, by Ocean Energy, Inc. ("Ocean"), an oil and gas industry customer, for marine contracting services. A member of the Company's board of directors was a member of senior management of Ocean (now part of Devon Energy Corp.).

5. Acquisition of Businesses and Assets

2005

Torch Offshore, Inc.

In a bankruptcy auction held in June 2005, Helix was the high bidder for seven vessels, including the *Express*, and a portable saturation system for approximately $85 million, subject to the terms of an amended and restated asset purchase agreement, executed in May 2005, with Torch Offshore, Inc. and its wholly owned subsidiaries, Torch Offshore, L.L.C. and Torch Express, L.L.C. 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 $85.6 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* (Deepwater Contracting segment) and the portable saturation system (included in assets held for sale in other current assets in the accompanying consolidated balance sheet), are included in the Shelf Contracting segment. The results of the acquired vessels are included in the accompanying condensed consolidated statements of operations since the date of the purchase, August 31, 2005.

Stolt Offshore, Inc.

In April 2005, the Company agreed to acquire the diving and shallow water pipelay assets of Stolt Offshore that operate in the waters of the Gulf of Mexico (GOM) and Trinidad. The transaction included: seven diving support vessels; two diving and pipelay vessels (the *Kestrel* and the *DB 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, the Company received clearance from the U.S. Department of Justice to close the asset purchase from Stolt. Under the terms of the clearance, the Company will divest two diving support vessels and a portable saturation diving system from the combined asset package acquired through this transaction and the Torch transaction which closed August 31, 2005. These assets were included in assets held for sale totaling $7.8 million (included in other current assets in the accompanying consolidated balance sheet) as of December 31, 2005. On November 1, 2005, the Company closed the transaction to purchase the Stolt diving assets operating in the Gulf of Mexico. The assets include: seven diving support vessels, a portable saturation diving system, various general diving equipment and Louisiana operating bases at the Port of Iberia and Fourchon. The acquisition was accounted for as a business purchase with the acquisition price allocated to the assets acquired and liabilities assumed based upon their estimated fair values, with the excess being recorded as goodwill. The preliminary allocation of the purchase price resulted in $12.0 million allocated to vessels (including the asset held for sale at December 31, 2005), $10.1 million allocated to the portable saturation diving system and various general diving equipment and inventory, $4.3 million to operating bases at the Port of Iberia and Fourchon, $3.7 million allocated to a customer-relationship intangible asset (to be amortized over 8 years on a straight line basis) and goodwill of approximately $12.8 million. The results of the acquisition are included in the accompanying statements of operations since the date of the purchase. The Company acquired the *DB 801* in January 2006 for approximately $38.0 million. The Company subsequently sold a 50% interest in the vessel in January 2006 for total consideration of approximately $23.5 million. This will result in a subsequent revision to the purchase price allocation of the Stolt acquisition. The purchaser has an option to purchase the remaining 50% interest in the vessel beginning in January 2009. The *Kestrel* is expected to be acquired by the Company in March 2006 for approximately $40 million. The preliminary allocation of the purchase price was based upon preliminary valuations and 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 which are not yet finalized relate to identifiable intangible assets and residual goodwill. The final valuation of net assets is expected to be completed no later than one year from the acquisition date. The total transaction value for all of the assets is expected to be approximately $120 million.

Unaudited pro forma combined operating results of the Company and the Stolt acquisition for the years ended December 31, 2005 and 2004, respectively, were as follows (in thousands, except per share data).

	Years Ended December 31,	
	2005	2004
Net revenues	$ 1,039,615	$705,843
Income before income taxes	236,078	86,241
Net income	158,260	56,714
Net income applicable to common shareholders	155,806	53,971
Earnings per common share:		
Basic	$ 2.01	$ 0.71
Diluted	$ 1.93	$ 0.70

Helix Energy Limited

On November 3, 2005, the Company 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), 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 Lampur (Malaysia) and Perth (Australia). The acquisition was accounted for as a business purchase with the acquisition price allocated to the assets acquired and liabilities assumed based upon their estimated fair values, with the excess being recorded as goodwill. The preliminary allocation of the purchase price resulted in $8.9 million allocated to net working capital, equipment and other assets acquired, $1.1 million allocated to patented technology (to be amortized over 20 years), $7.1 million allocated to a customer-relationship intangible asset (to be amortized over 12 years), $2.1 million allocated to covenants-not-to-compete (to be amortized over 3.5 years), $6.3 million allocated to trade name (not amortized, but tested for impairment on an annual basis) and goodwill of approximately $7.2 million. Resulting amounts are included in the Deepwater Contracting segment. The preliminary allocation of the purchase price was based upon preliminary valuations and 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 which are not yet finalized relate to identifiable intangible assets and residual goodwill. The final valuation of net assets is expected to be completed no later than one year from the acquisition date. The results of Helix Energy Limited are included in the accompanying statements of operations since the date of the purchase.

2002

Canyon Offshore, Inc.

In January 2002, Helix purchased Canyon, a supplier of remotely operated vehicles (ROVs) and robotics to the offshore construction and telecommunications industries. In connection with the acquisition, the Company committed to purchase the redeemable stock in Canyon at a price to be determined by Canyon's performance during the years 2002 through 2004 from continuing employees at a minimum purchase price of $13.53 per share (or $7.5 million). The Company also agreed to make future payments relating to the tax impact on the date of redemption, whether or not employment continued. As they are employees, any share price paid in excess of the $13.53 per share was recorded as compensation expense. These remaining shares were classified as long-term debt in the accompanying balance sheet and have been adjusted to their estimated redemption value at each reporting period based on Canyon's performance. In March 2005, the Company purchased the final one-third of the redeemable shares at the minimum purchase price of $13.53 per share. Consideration included approximately

$337,000 of contingent consideration relating to tax gross-up payments paid to the Canyon employees in accordance with the purchase agreement. This gross-up amount was recorded as goodwill in the period paid.

6. Equity Investments

In June 2002, Helix, along with Enterprise Products Partners L.P. ("Enterprise"), formed Deepwater Gateway, L.L.C. to design, construct, install, own and operate a tension leg platform ("TLP") production hub primarily for Anadarko Petroleum Corporation's *Marco Polo* field discovery in the Deepwater Gulf of Mexico. Helix's share of the construction costs was approximately $120 million. The Company's investment in Deepwater Gateway, L.L.C. totaled $117.2 million as of December 31, 2005. Included in the investment account was capitalized interest and insurance paid by the Company totaling approximately $2.2 million. In August 2002, the Company along with Enterprise, completed a limited recourse project financing for this venture. In accordance with terms of the term loan, Deepwater Gateway, L.L.C. had the right to repay the principal amount plus any accrued interest due under its term loan at any time without penalty. Deepwater Gateway, L.L.C. repaid in full its term loan in March 2005. The Company and Enterprise made equal cash contributions ($72 million each) to Deepwater Gateway, L.L.C. to fund the repayment. Further, the Company received cash distributions from Deepwater Gateway, L.L.C. totaling $21.1 million in 2005.

Summary balance sheets of Deepwater Gateway, L.L.C. as of December 31, 2005 and 2004 were as follows (in thousands):

	2005	2004
ASSETS		
Current assets	$ 3,070	$ 5,047
Noncurrent assets	228,689	250,508
	$231,759	$255,555
LIABILITIES AND MEMBERS' EQUITY		
Current liabilities	$ 373	$ 25,164
Noncurrent liabilities	440	122,397
Members' equity	230,946	107,994
	$231,759	$255,555

Summary statements of operations of Deepwater Gateway, L.L.C. for the years ended December 31, 2005, 2004 and 2003 were as follows (in thousands):

	2005	2004	2003
Revenues	$32,411	$26,740	$ —
Operating expenses	596	247	187
Depreciation	8,028	6,018	—
Operating income (loss)	23,787	20,475	(187)
Interest expense	(2,833)	(4,475)	—
Interest income, net of other expense	198	118	47
Net Income (Loss)	$21,152	$16,118	$(140)

Deepwater Gateway, L.L.C. operated as a development stage enterprise in 2003. In 2004, Deepwater Gateway, L.L.C. exited development stage.

In December 2004, Helix acquired a 20% interest (accounted for by Helix under the equity method of accounting) in Independence Hub, LLC (“Independence”), an affiliate of Enterprise. Independence will own the “Independence Hub” platform to be located in Mississippi Canyon block 920 in a water depth of 8,000 feet. Helix’s investment was $50.8 million as of December 31, 2005, and its total investment is expected to be approximately $83 million. Further, Helix is party to a guaranty agreement with Enterprise to the extent of Helix’s ownership in Independence. The agreement states, among other things, that Helix and Enterprise guarantee performance under the Independence Hub Agreement between Independence and the producers group of exploration and production companies up to $397.5 million, plus applicable attorneys’ fees and related expenses. Helix has estimated the fair value of its share of the guarantee obligation to be immaterial at December 31, 2005 based upon the remote possibility of payments being made under the performance guarantee.

In July 2005, the Company acquired a 40% minority ownership interest in OTSL in exchange for the Company’s DP DSV, *Witch Queen*. The Company’s investment in OTSL totaled $11.5 million at December 31, 2005. 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. Effective December 31, 2003, the Company adopted and applied the provisions of FASB Interpretation (“FIN”) No. 46, *Consolidation of Variable Interest Entities*, as revised December 31, 2003, 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. OTSL qualified as a variable interest entity (“VIE”) under FIN 46 through December 31, 2005. The Company has determined that it was not the primary beneficiary of OTSL and, thus, has not consolidated the financial results of OTSL. The Company accounts for its investment in OTSL under the equity method of accounting.

Further, in conjunction with its investment in OTSL, the Company entered into a one year, unsecured $1.5 million working capital loan, bearing interest at 6% per annum, with OTSL. Interest is due quarterly beginning September 30, 2005 with a lump sum principal payment due to the Company on June 30, 2006.

In the third and fourth quarters of 2005, OTSL contracted the *Witch Queen* to the Company for certain services to be performed in the U.S. Gulf of Mexico. The Company incurred costs under its contract with OTSL totaling approximately $11.1 million during the third and fourth quarters of 2005.

7. Accrued Liabilities

Accrued liabilities consisted of the following as of December 31, 2005 and 2004 (in thousands):

	2005	2004
Accrued payroll and related benefits	$ 27,982	$20,195
Workers’ compensation claims	2,035	2,767
Insurance claims to be reimbursed	6,133	9,485
Royalties payable	46,555	26,196
Decommissioning liability	15,035	2,540
Hedging liability	8,814	876
Income taxes payable	7,288	797
Deposits	10,000	—
Other	21,910	12,646
Total accrued liabilities	$145,752	$75,502

8. Long-Term Debt

Convertible Senior Notes

On March 30, 2005, the Company 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 the Company's common stock based on the specified conversion rate, subject to adjustment. As a result of the Company's 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. This ratio results in an initial conversion price of approximately $32.14 per share. The Company 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, the Company 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 the Company 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 Helix's common stock for at least 20 trading days in the period of 30 consecutive trading day 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 the Company has called the Convertible Senior Notes for redemption and the redemption has not yet occurred.

To the extent the Company does 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, the Company will satisfy its 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 Helix's 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 Helix's common stock for the trading days during the cash settlement period.

Approximately 118,000 shares underlying the Convertible Senior Notes were included in the calculation of diluted earnings per share because the Company's share price as of December 31, 2005, 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, the Company 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, L.L.C. to enable it to repay its term loan, $163.5 million related to the ERT acquisition of the Murphy properties in June 2005 and to partially fund the approximately $85.6 million purchase of the Torch vessels acquired in August 2005 (see footnote 5).

MARAD Debt

At December 31, 2005, $134.9 million was outstanding on the Company's 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 Helix 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, the Company 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, Helix is 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, 2005, the Company was in compliance with these covenants.

In September 2005, the company 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, the Company terminated the interest rate swap and received cash proceeds of approximately $1.5 million representing a gain on the interest rate differential. This gain will be deferred and amortized over the remaining life of the MARAD Debt as an adjustment to interest expense.

Revolving Credit Facility

In August 2004, the Company entered into a four-year, $150 million revolving credit facility with a syndicate of banks, with Bank of America, N.A. as administrative agent and lead arranger. The amount available under the facility may be increased to $250 million at any time upon the agreement of the Company and the existing or additional lenders. The credit facility is secured by the stock in certain Company subsidiaries and contains a negative pledge on assets. The facility bears interest at LIBOR plus 75-175 basis points depending on Company leverage and contains financial covenants relative to the Company's level of debt to EBITDA, as defined in the credit facility, fixed charge coverage and book value of assets coverage. As of December 31, 2005, the Company was in compliance with these covenants and there was no outstanding balance under this facility.

Other

In August 2003, Canyon Offshore, Ltd. (a U.K. subsidiary — "COL") (with a parent guarantee from Helix) completed a capital lease with a bank refinancing the construction costs of a newbuild 750 horsepower trenching unit and a ROV. COL received proceeds of $12 million for the assets and agreed to pay the bank sixty monthly installment payments of $217,174 (resulting in an implicit interest rate of 3.29%). No gain or loss resulted from this transaction. COL has an option to purchase the assets at the end of the lease term for $1. The proceeds were used to reduce the Company's revolving credit facility, which had initially funded the construction costs of the assets. This transaction was accounted for as a capital lease with the present value of the lease obligation (and corresponding asset) reflected on the Company's consolidated balance sheet.

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

In connection with the acquisition of Helix Energy Limited, the Company 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 $5.4 million at December 31, 2005). The notes bear interest at a LIBOR based floating rate with payments due quarterly beginning January 31, 2006. Principal amounts are due in November 2007.

The Company incurred interest expense, net of amounts capitalized, of $12.6 million, $5.6 million and $2.6 million for the years ended December 31, 2005, 2004 and 2003, respectively. The Company capitalized interest totaling $2.0 million, $243,000 and $3.4 million during the years ended December 31, 2005, 2004 and 2003, respectively.

Scheduled maturities of Long-term Debt and Capital Lease Obligations outstanding as of December 31, 2005 were as follows (in thousands):

	MARAD Debt	Convertible Senior Notes	Revolver	Capital Leases	Loan Notes	Total
2006	$ 3,640	$ —	$ —	$ 2,828	$ —	$ 6,468
2007	3,823	—	—	2,519	5,393	11,735
2008	4,014	—	—	1,505	—	5,519
2009	4,214	—	—	—	—	4,214
2010	4,424	—	—	—	—	4,424
Thereafter	114,811	300,000	—	—	—	414,811
Long-term debt	134,926	300,000	—	6,852	5,393	447,171
Current maturities	(3,640)	—	—	(2,828)	—	(6,468)
Long-term debt, less current maturities	$ 131,286	$ 300,000	$ —	$ 4,024	$ 5,393	$440,703

Deferred financing costs of $18.7 million related to the Convertible Senior Notes, the MARAD Debt and the revolving credit facility, respectively, are being amortized over the life of the respective agreements and are included in other assets, net, as of December 31, 2005.

The Company had unsecured letters of credit outstanding at December 31, 2005 totaling approximately $6.7 million. These letters of credit primarily guarantee various contract bidding and insurance activities.

Table of Contents

9. Income Taxes

Helix and its subsidiaries, including acquired companies from their respective dates of acquisition, file a consolidated U.S. federal income tax return. The Company conducts its 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 percent 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 the Company's effective rate were as follows:

	Years Ended December 31,		
	2005	2004	2003
Statutory rate	35.0%	35.0%	35.0%
Foreign provision	—	0.9	0.4
Percentage depletion in excess of basis	(0.7)	—	—
Research and development tax credits	—	(1.3)	—
IRC Section 199 deduction	(0.5)	—	—
Other	(0.8)	(0.4)	0.7
Effective rate	33.0%	34.2%	36.1%

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

	Years Ended December 31,		
	2005	2004	2003
Current	$32,291	$ 988	$ 500
Deferred	42,728	42,046	18,493
	$75,019	$43,034	$18,993

	2005	2004	2003
Domestic	$68,957	$41,260	$20,492
Foreign	6,062	1,774	(1,499)
	$75,019	$43,034	$18,993

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

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, 2005 and 2004, is as follows (in thousands):

	2005	2004
Deferred tax liabilities		
Depreciation	$ 159,360	$ 136,328
Equity investments in production facilities	28,264	23,152
Prepaid and other	10,693	6,657
Total deferred tax liabilities	$ 198,317	$ 166,137
Deferred tax assets		
Net operating loss carry forward	$ (2,079)	$ (3,706)
Decommissioning liabilities	(26,915)	(28,711)
R&D credit carry forward	—	(4,455)
Reserves, accrued liabilities and other	(10,537)	(8,263)
Total deferred tax assets	$ (39,531)	$ (45,135)
Net deferred tax liability	$ 158,786	$ 121,002

At December 31, 2005, the Company had $6.9 million of net operating losses. The net operating losses were incurred in the United Kingdom. The use of these net operating losses is also restricted to the taxable trading profits of the entity generating the loss. The U.K. losses have an indefinite carryforward period.

During the years ended December 31, 2005, 2004 and 2003, the Company paid $22.5 million, $252,000 and $0, respectively, in income taxes.

The Company filed for a change in its tax method of accounting for the timing differences that arise from the abandonment obligations assumed in certain offshore property acquisitions. The 2004 financial statements include an adjustment to account for the estimated amount of deferred tax liability related to this timing difference as required under the current tax accounting rules.

The Company considers the undistributed earnings of its principal non-U.S. subsidiaries to be permanently reinvested. At December 31, 2005, the Company's principal non-U.S. subsidiaries had an accumulated deficit of approximately $4.3 million in earnings and profits. These losses are primarily due to timing differences related to fixed assets. The Company has not provided deferred U.S. income tax on the losses.

10. Convertible Preferred Stock

On January 8, 2003, Helix 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 Helix 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 Helix common stock at $15.27 per share. In the event the holder of the convertible preferred stock elects to redeem into Helix common stock and Helix's common stock price is below the conversion prices unless the Company has 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 Helix's option. Helix paid these dividends in 2005 and 2004 on the last day of the respective quarter 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 the discretion of the Company. In the event the Company is unable to deliver registered common shares, Helix 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 the Company's diluted earnings per share using the if converted method based on the lower of the Company's share price at the beginning of the applicable period or the applicable conversion price ($15.00 and $15.27).

11. Commitments and Contingencies

Lease Commitments

The Company leases several facilities, ROVs and a vessel under noncancelable operating leases. Future minimum rentals under these leases are approximately $17.9 million at December 31, 2005 with $4.0 million due in 2006, $2.0 million in 2007, $1.9 million in 2008, $1.7 million in 2009, $1.4 million in 2010 and $6.8 million thereafter. Total rental expense under these operating leases was approximately $7.9 million, $8.9 million and $8.1 million for the years ended December 31, 2005, 2004 and 2003, respectively.

Insurance

The Company carries 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 million on the *Q4000* and $500,000 on the *Intrepid*, *Seawell* and *Express.* Other vessels carry deductibles between $250,000 and $350,000. The Company also carries Protection and Indemnity insurance which covers liabilities arising from the operation of the vessel 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 $1 million annual aggregate. In addition to the liability policies named above, the Company carries various layers of Umbrella Liability for total limits of $300,000,000 excess of primary limits. The Company's self insured retention on its medical and health benefits program for employees is $130,000 per participant.

The Company incurs workers' compensation and other insurance claims in the normal course of business, which management believes are covered by insurance. The Company, its insurers and legal counsel analyze each claim for potential exposure and estimate the ultimate liability of each claim. Amounts accrued and receivable from insurance companies, above the applicable deductible limits, are reflected in other current assets in the consolidated balance sheet. Such amounts were $6.1 million and $9.5 million as of December 31, 2005 and 2004, respectively. See related accrued liabilities at footnote 7. The Company has not incurred any significant losses as a result of claims denied by its insurance carriers.

Litigation and Claims

The Company is involved in various routine legal proceedings, primarily involving claims for personal injury under the General Maritime Laws of the United States and the Jones Act as a result of alleged negligence. In addition, the Company from time to time incurs other claims, such as contract disputes, in the normal course of business. In that regard, in 1998, one of the Company's subsidiaries entered into a subcontract with Seacore Marine Contractors Limited ("Seacore") to provide the *Sea Sorceress* to a Coflexip subsidiary in Canada ("Coflexip"). Due to difficulties with respect to the sea and soil conditions, the contract was terminated and an arbitration to recover damages was commenced. A preliminary liability finding has been made by the arbitrator against Seacore and in favor of the Coflexip subsidiary. The Company was not a party to this arbitration proceeding. Seacore and Coflexip settled this matter prior to the conclusion of the arbitration proceeding with Seacore paying Coflexip $6.95 million CDN. Seacore has initiated an arbitration proceeding against Cal Dive Offshore Ltd. ("CDO"), a subsidiary of Helix, seeking contribution of one-half of this amount. One of the grounds in the preliminary findings by the arbitrator is applicable to CDO, and CDO holds substantial counterclaims against Seacore.

Although the above discussed matters have the potential of significant additional liability, the Company believes the outcome of all such matters and proceedings will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

The Company sustained damage to certain of its oil and gas production facilities in Hurricanes *Katrina* and *Rita* (see footnote 3). The Company estimates future total repair and inspection costs resulting from the hurricanes will range from $5 million to $8 million net of expected insurance reimbursement. These costs, and any related insurance reimbursements, will be recorded as incurred over the next year.

Commitments

At December 31, 2005, the Company had committed to purchase a certain Deepwater Contracting vessel (the *Caesar)* to be converted into a deepwater pipelay vessel. Total purchase price and conversion costs are estimated to be approximately $125 million to be incurred over the next year. Further, the Company will upgrade the *Q4000* to include drilling via the addition of a modular-based drilling system for approximately $40 million, of which approximately $5 million had been committed at December 31, 2005.

12. Employee Benefit Plans

Defined Contribution Plan

The Company sponsors a defined contribution 401(k) retirement plan covering substantially all of its employees. The Company's 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. The Company's costs related to this plan totaled $963,000, $691,000 and $785,000 for the years ended December 31, 2005, 2004 and 2003, respectively.

Stock-Based Compensation Plans

During 1995, the Board of Directors and shareholders approved the 1995 Long-Term Incentive Plan, as amended (the Incentive Plan). Under the 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 who are likely to make a significant positive impact on the reported net income of the Company as well as non-employee members of the Board of Directors. The Incentive Plan is administered by a committee which determines, subject to approval of the Compensation Committee of the Board of Directors, the type of award to be made to each participant and sets forth in the related award agreement the terms, conditions and limitations applicable to each award. The committee may grant stock options, stock appreciation rights, or stock and cash awards. Awards granted to employees under the Incentive Plan vest 20% per year for a five year period or 33% per year for a three year period, have a maximum exercise life of three, five or ten years and, subject to certain exceptions, are not transferable.

On January 3, 2005, the Company granted certain key executives and selected management employees 188,132 restricted shares under the Incentive Plan. The shares vest 20% per year for a five year period. The market value (based on the quoted price of the common stock on the date of the grant) of the restricted shares was $19.56 per share, or $3.7 million, at the date of the grant and was recorded as unearned compensation, a component of shareholders' equity through December 31, 2005. Upon adoption of SFAS No. 123R in 2006, awards will be amortized directly to expense and additional paid in capital (a component of Common Stock). The balance in unearned compensation was reversed in January 2006.

On September 1, 2005, a certain key executive of the Company was granted 120,138 restricted shares under the Incentive Plan. The shares vest in two tranches. Tranche 1 (100,000 restricted shares) vests with respect to two-thirds of such shares after two years and fully vests after three years. Tranche 2 (20,138 restricted shares) vests 20% per year for a five year period. The market value (based on the quoted share price of the common stock on the date of the grant) of the restricted shares was $31.04 per share, or $3.7 million, at the date of grant and was recorded as unearned compensation, a component of shareholders' equity through December 31, 2005.

On November 1, 2005, a certain key executive of the Company was granted 58,072 restricted shares under the Incentive Plan. The shares vest in two tranches. Tranche 1 (41,916 restricted shares) vests on February 1, 2007. Tranche 2 (16,156 restricted shares) vests upon successful completion of a specific, company-identified corporate objective. The market value (based on the quoted share price of the common stock on the date of the grant) of the restrictive shares was $30.95 per share, or $1.8 million, at the date of the grant and was recorded as unearned compensation, a component of shareholders' equity through December 31, 2005.

The amounts related to restricted share grants are being charged to expense over the respective vesting periods. Amortization of unearned compensation totaled $1.4 million in the year ended December 31, 2005.

On January 3, 2006, the Company granted certain key executives and select management employees 196,820 restricted shares under the Incentive Plan. The shares vest 20% per year for a five year period. The market value (based on the quoted price of the common stock on the date of the grant) of the restricted shares was $35.89 per share, or $7.1 million, at the date of the grant.

Effective May 12, 1998, the Company adopted a qualified, non-compensatory Employee Stock Purchase Plan ("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 percent 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 10 percent of an employee's base salary. Under this plan 79,878, 93,580 and 105,144 shares of common stock were purchased in the open market at a weighted average share price of $23.11, $13.58 and $10.87 during 2005, 2004 and 2003, respectively.

All of the options outstanding at December 31, 2005, have exercise prices as follows: 178,000 shares at $8.57, 120,660 shares at $9.32, 200,000 shares at $10.69, 337,348 shares at $10.92, 235,560 shares at $12.18, 160,000 shares at $13.38, and 486,336 shares ranging from $8.23 to $13.91 and a weighted average remaining contractual life of 5.82 years.

Options outstanding are as follows:

	2005		2004		2003	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Options outstanding, Beginning of year	2,599,894	$10.65	3,446,204	$10.19	3,981,492	$ 9.76
Granted	—	—	337,000	12.63	367,980	8.95
Exercised	(858,070)	10.17	(1,119,818)	9.85	(631,514)	6.69
Terminated	(23,920)	10.82	(63,492)	10.43	(271,754)	10.19
Options outstanding, December 31,	1,717,904	$10.91	2,599,894	$10.65	3,446,204	$10.19
Options exercisable, December 31,	1,066,316	$10.94	1,428,348	$10.58	1,872,790	$10.35

13. Shareholders' Equity

The Company's 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 Helix's 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.

Included in accumulated other comprehensive income (loss) at December 31, 2005 was an unrealized loss on commodity hedges, net, of $(8.7) million and an unrealized gain on foreign currency translation adjustments of $7.0 million.

14. Business Segment Information (in thousands)

In the fourth quarter of 2005, the Company modified its segment reporting from three reportable segments to four reportable segments. The Company's operations are conducted through the following primary reportable segments: Deepwater Contracting, Shelf Contracting, Oil and Gas Production and Production Facilities. The realignment of reportable segments was attributable to organizational changes within the Company as it is related to separating Marine Contracting into two reportable segments — Deepwater Contracting and Shelf Contracting. Deepwater Contracting operations include deepwater pipelay, well operations and robotics. Shelf Contracting operations consist of assets deployed primarily for diving-related activities and shallow water construction. Certain operating segments have been aggregated into the Deepwater Contracting reportable segment. As a result, segment disclosures for 2004 and 2003 have been restated to conform to the current period presentation. This segment realignment did not result in the re-allocation of the Company's goodwill between segments as the respective reporting unit structure did not change. All intercompany transactions between the segments have been eliminated.

The Company evaluates its performance based on income before income taxes of each segment. Segment assets are comprised of all assets attributable to the reportable segment. The Company's Production Facilities segment (Deepwater Gateway, L.L.C. and Independence Hub, LLC) are all accounted for under the equity method of accounting.

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following summarizes certain financial data by business segment:

	Year Ended December 31,		
	2005	2004	2003
Revenues —			
Deepwater contracting	$ 328,315	$ 197,688	$150,486
Shelf contracting	223,211	126,546	134,935
Oil and gas production	275,813	243,310	137,279
Intercompany elimination	(27,867)	(24,152)	(26,431)
Total	$ 799,472	$ 543,392	$396,269
Income (loss) from operations —			
Deepwater contracting	$ 42,333	$ (8,916)	$ (13,094)
Shelf contracting (1), (2)	60,078	14,610	15,622
Oil and gas production	123,104	117,682	53,633
Production facilities equity investments (3)	(977)	(345)	—
Total	$ 224,538	$ 123,031	$ 56,161
Net interest expense and other —			
Deepwater contracting	$ 8,571	$ 4,663	$ 2,744
Shelf contracting	(45)	—	42
Oil and gas production	(1,117)	602	617
Production facilities equity investments	150	—	—
Total	$ 7,559	$ 5,265	$ 3,403
Equity in earnings (losses) of production facilities investments	$ 10,608	$ 7,927	$ (87)
Income (loss) before income taxes —			
Deepwater contracting	$ 33,762	$ (13,579)	$ (15,838)
Shelf contracting	60,123	14,610	15,580
Oil and gas production	124,221	117,080	53,016
Production facilities equity investments	9,481	7,582	(87)
Total	$ 227,587	$ 125,693	$ 52,671
Provision (benefit) for income taxes —			
Deepwater contracting	$ 9,949	$ (7,574)	$ (5,061)
Shelf contracting	21,009	5,166	5,383
Oil and gas production	40,734	42,787	18,701
Production facilities equity investments	3,327	2,655	(30)
Total	$ 75,019	$ 43,034	$ 18,993

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Year Ended December 31,		
	2005	2004	2003
Identifiable assets —			
Deepwater contracting	$ 736,852	$ 597,257	$466,632
Shelf contracting	277,446	145,226	156,463
Oil and gas production	478,522	229,083	225,230
Production facilities equity investments	168,044	67,192	34,517
Total	$ 1,660,864	$ 1,038,758	$882,842
Capital expenditures —			
Deepwater contracting	$ 90,037	$ 21,016	$ 18,938
Shelf contracting	32,383	1,792	2,631
Oil and gas production	238,698	27,315	71,591
Production facilities equity investments	111,429	32,206	1,917
Total	$ 472,547	$ 82,329	$ 95,077
Depreciation and amortization —			
Deepwater contracting	$ 25,102	$ 20,227	$ 18,171
Shelf contracting (1)	15,734	19,032	14,731
Oil and gas production	70,637	69,046	37,891
Total	$ 111,473	$ 108,305	$ 70,793

(1) Included pre-tax $790,000 and $3.9 million of asset impairment charges in 2005 and 2004, respectively.

(2) Included $2.8 million equity in earnings from investment in OTSL.

(3) Represents selling and administrative expense of Production Facilities incurred by the Company. See Equity in Earning of Production Facilities investments for earning contribution.

Intercompany segment revenues during 2005, 2004 and 2003 were as follows:

	Year Ended December 31,		
	2005	2004	2003
Deepwater Contracting	$26,431	$22,246	$23,044
Shelf Contracting	1,436	1,906	3,387
Total	$27,867	$24,152	$26,431

During the years ended December 31, 2005 and 2004, the Company derived approximately $83.2 million and $77.1 million, respectively, of its revenues from the U.K. sector utilizing approximately $168.4 million and $136.7 million, respectively, of its total assets in this region. The majority of the remaining revenues were generated in the U.S. Gulf of Mexico.

15. Supplemental Oil and Gas Disclosures (Unaudited)

The following information regarding the Company's 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 the Company's oil and gas producing activities and the aggregate amount of related accumulated depletion, depreciation and amortization as of the dates indicated are presented below. The Company has no capitalized costs related to unproved properties.

	2005	2004	2003
Gunnison (net of accumulated depletion, depreciation and amortization)	$ 100,020	$ 107,335	$104,378
Proved developed properties being amortized	375,563	201,392	188,113
Less — Accumulated depletion, depreciation and amortization	(160,651)	(136,066)	(96,086)
Net capitalized costs	$ 314,932	$ 172,661	$196,405

Included in capitalized costs proved developed properties being amortized is the Company's estimate of its 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.

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:

	Year Ended December 31,		
	2005	2004	2003
Exploration costs	$ 5,728	$ —	$ —
Proved property acquisition costs	219,956	—	2,687
Development costs	67,193	38,373	79,289
Total costs incurred	$292,877	$38,373	$81,976

Results of Operations For Oil and Gas Producing Activities

	Year Ended December 31,		
	2005	2004	2003
Revenues	$ 275,813	$243,310	$137,279
Production (lifting) costs	62,700	39,454	33,907
Depreciation, depletion and amortization	70,637	69,046	37,891
Selling and administrative	19,372	17,745	12,465
Pretax income from producing activities	123,104	117,065	53,016
Income tax expense	40,734	42,787	18,701
Results of oil and gas producing activities	$ 82,370	$ 74,278	$ 34,315

Estimated Quantities of Proved Oil and Gas Reserves

Proved oil and gas reserve quantities are based on estimates prepared by Company engineers in accordance with guidelines established by the U.S. Securities and Exchange Commission. The Company's estimates of reserves at December 31, 2005, have been audited by Huddleston & Co., independent petroleum engineers. All of the Company's reserves are located in the United States. 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, 2003, 7,608,000 Bbls of oil and 28,888,000 Mcf of gas were undeveloped, 72% of which is attributable to *Gunnison.* As of December 31, 2004, 4,088,358 Bbls of oil and 16,842,700 MCf of gas were undeveloped, 41% of which is attributable to *Gunnison.* As of December 31, 2005 7,113,914 Bbls of oil and 80,752,300 MCf of gas were undeveloped.

Reserve Quantity Information	Oil (MBbls)	Gas (MMcf)	Total (MMcfe)
Total proved reserves at December 31, 2002	12,037	85,225	157,447
Revision of previous estimates	1,942	(5,545)	6,107
Production	(1,952)	(16,208)	(27,920)
Purchases of reserves in place	6	2,657	2,693
Sales of reserves in place	—	—	—
Extensions and discoveries	488	8,531	11,459
Total proved reserves at December 31, 2003	12,521	74,660	149,786
Revision of previous estimates	(1,412)	(2,184)	(10,656)
Production	(2,593)	(25,957)	(41,515)
Purchases of reserves in place	—	—	—
Sales of reserves in place	(1)	(697)	(703)
Extensions and discoveries	2,002	7,382	19,394
Total proved reserves at December 31, 2004	10,517	53,204	116,306
Revision of previous estimates	(403)	(1,124)	(3,542)
Production	(2,473)	(18,137)	(32,975)
Purchases of reserves in place	6,653	91,089	131,007
Sales of reserves in place	—	—	—
Extensions and discoveries	579	11,041	14,515
Total proved reserves at December 31, 2005	14,873	136,073	225,311

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 the Company's interest in proved oil and gas reserves as of December 31:

	2005	2004	2003
Future cash inflows	$ 2,131,985	$ 756,668	$ 807,868
Future costs —			
Production	(311,163)	(125,350)	(127,530)
Development and abandonment	(450,558)	(146,131)	(145,268)
Future net cash flows before income taxes	1,370,264	485,187	535,070
Future income taxes	(433,335)	(144,263)	(154,046)
Future net cash flows	936,929	340,924	381,024
Discount at 10% annual rate	(209,867)	(54,185)	(71,586)
Standardized measure of discounted future net cash Flows	$ 727,062	$ 286,739	$ 309,438

Changes in Standardized Measure of Discounted Future Net Cash Flows

Principal changes in the standardized measure of discounted future net cash flows attributable to the Company's proved oil and gas reserves are as follows:

	2005	2004	2003
Standardized measure, beginning of year	$ 286,739	$ 309,438	$ 211,727
Sales, net of production costs	(213,113)	(203,856)	(103,372)
Net change in prices, net of production costs	194,965	92,395	102,319
Changes in future development costs	(63,621)	(17,474)	(3,339)
Development costs incurred	67,193	38,373	79,289
Accretion of discount	40,808	43,048	21,173
Net change in income taxes	(214,936)	3,770	(37,127)
Purchases of reserves in place	575,320	—	4,994
Extensions and discoveries	80,720	55,743	21,224
Sales of reserves in place	—	(3,077)	—
Net change due to revision in quantity estimates	(12,442)	(32,025)	11,312
Changes in production rates (timing) and other	(14,571)	404	1,238
Standardized measure, end of year	$ 727,062	$ 286,739	$ 309,438

16. Allowance for Uncollectible Accounts

The following table sets forth the activity in the Company's Allowance for Uncollectible Accounts for each of the three years in the period ended December 31, 2005 (in thousands):

	2005	2004	2003
Beginning balance	$ 7,768	$ 7,462	$ 6,390
Additions	2,577	2,745	2,688
Deductions	(9,760)	(2,439)	(1,616)
Ending balance	$ 585	$ 7,768	$ 7,462

See footnote 2 for a detailed discussion regarding the Company's accounting policy on Accounts Receivable and Allowance for Uncollectible Accounts.

17. Subsequent Events

On January 6, 2006 the Company and Remington Oil and Gas Corporation announced an agreement under which the Company will acquire Remington in a transaction valued at approximately $1.4 billion. Under the terms of the agreement, Remington stockholders will receive $27.00 in cash and 0.436 shares of the Company's common stock for each Remington share. The acquisition is conditioned upon, among other things, the approval of Remington stockholders and customary regulatory approvals. The transaction is expected to be completed in the second quarter of 2006. In limited circumstances, if Remington fails to close the transaction, it must pay the Company a $45 million breakup fee and reimburse up to $2 million of expenses related to the transaction. The Company expects to fund the cash portion of the Remington acquisition (approximately $814 million) through a senior secured term facility which has been underwritten by a bank.

At December 31, 2005 the Company had committed to purchase a certain Deepwater Contracting vessel (the *Caesar)* to be converted into a deepwater pipelay vessel. Total purchase price and conversion costs are estimated to be approximately $125 million to be incurred over the next year.

18. 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 the Company's services has been performed during the summer and fall months. As a result, historically a disproportionate portion of the Company's revenues and net income is earned during such period. The following is a summary of consolidated quarterly financial information for 2005 and 2004.

	Quarter Ended			
	March 31	June 30	September 30	December 31
	(in thousands, except per share data)			
Fiscal 2005 Revenues	$ 159,575	$166,531	$ 209,338	$ 264,028
Gross profit	51,873	52,419	82,928	95,852
Net income	25,961	26,577	43,221	56,810
Net income applicable to common shareholders	25,411	26,027	42,671	56,006
Earnings per common share:				
Basic	0.33	0.34	0.55	0.72
Diluted	0.32	0.32	0.53	0.69
Fiscal 2004 Revenues	$ 120,714	$127,701	$ 131,987	$ 162,990
Gross profit	31,741	41,415	45,726	53,030
Net income	14,009	18,592	23,787	26,271
Net income applicable to common shareholders	13,645	18,208	22,794	25,269
Earnings per common share:				
Basic:	0.18	0.24	0.30	0.33
Diluted:	0.18	0.24	0.29	0.32

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.***

None.

Item 9A. ***Controls and Procedures.***

The Company's management, with the participation of the Company's principal executive officer (CEO) and principal financial officer (CFO), evaluated the effectiveness of the Company's 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, 2005. Based on this evaluation, the CEO and CFO have concluded that the Company's disclosure controls and procedures were effective as of the end of the fiscal year ended December 31, 2005 to ensure that information that is required to be disclosed by the Company in the reports it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms.

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 the Annual Report on Form 10-K on page 55 and page 57, respectively. There were no changes in the Company's internal control over financial reporting that occurred during the fiscal quarter ended December 31, 2005 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. ***Other Information.***

None.

PART III

Item 10. ***Directors and Executive Officers of the Registrant.***

Except as set forth below, the information required by this Item is incorporated by reference to the Company's definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with the Company's 2006 Annual Meeting of Shareholders. See also "Executive Officers of the Registrant" appearing in Part I of this Report.

Code of Ethics

The Company has 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 the Company's 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 the Company's definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with the Company's 2006 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 the Company's definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with the Company's 2006 Annual Meeting of Shareholders.

Item 13. ***Certain Relationships and Related Transactions.***

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with the Company's 2006 Annual Meeting of Shareholders.

Item 14. ***Principal Accounting Fees and Services.***

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with the Company's 2006 Annual Meeting of Shareholders.

PART IV

Item 15. *Exhibits and Financial Statement Schedules.*

(1) ***Financial Statements.***

The following financial statements included on pages 54 through 93 in this Annual Report are for the fiscal year ended December 31, 2005.

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, 2005 and 2004

Consolidated Statements of Operations for the Years Ended December 31, 2005, 2004 and 2003

Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2005, 2004 and 2003

Consolidated Statements of Cash Flows for the Years Ended December 31, 2005, 2004 and 2003

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.
2.3	Asset Purchase Agreement by and between Cal Dive International, Inc., as Buyer, and Stolt Offshore Inc. and S&H Diving LLC, as Sellers, dated April 11, 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 April 13, 2005.
2.4	Amendment to Asset Purchase Agreement by and between Cal Dive International, Inc., as Buyer, and Stolt Offshore Inc., S&H Diving LLC and SCS Shipping Limited, as Sellers, dated November 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 November 4, 2005.
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 December 14, 2005.3.2 Second Amended and Restated By-Laws of Cal Dive International, Inc., 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 December 1, 2005.
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").

Exhibits

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 by and among Bank of America, N.A., et al., as Lenders, and Helix Energy Solutions Group, Inc., as Borrower, dated August 16, 2004, incorporated by reference to Exhibit 4.1 to the registrant's Annual Report on 10-Q for the fiscal quarter ended September 30, 2004, filed by the registrant with the Securities and Exchange Commission on November 5, 2004 (the "2004 Form 10-Q").

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 4.1 to the Form S-1.

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 2002 Form 10-K/A.

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 2003 Form S-3.

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 2002 Form 10-K/A.

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 2002 Form 10-K/A.

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 Second Amendment to Credit Agreement dated March 21, 2005, made by and between Company and Bank of America, N.A., et al., incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on March 23, 2005.

Exhibits

4.15 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").

4.16 Form of 3.25% Convertible Senior Note due 2025 (filed as Exhibit A to Exhibit 4.15).

4.17 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.

4.18 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").

4.19 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.

4.20 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.

4.21 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.

4.22 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.

4.23 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 4.22).

4.24 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.

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 Employment Agreement between James Lewis Connor, III and Company dated May 1, 2002, incorporated by reference to Exhibit 10.6 to the registrant's Annual Report on Form 10-K for the fiscal year ended December 31, 2003, filed by the registrant with the Securities and Exchange Commission on March 15, 2004 (the "2003 Form 10-K").

10.6 First Amendment to Employment Agreement between James Lewis Connor, III and Company dated January 1, 2004, incorporated by reference to Exhibit 10.6 to the registrant's Annual Report on Form 10-K for the fiscal year ended December 31, 2004, filed by the registrant with the Securities and Exchange Commission on March 15, 2005 (the "2004 Form 10-K").

10.7 Cal Dive International, Inc. 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.

10.8 Employment Agreement by and between Cal Dive International, Inc. 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.

Exhibits

21.1	Subsidiaries of registrant — As of December 31, 2005, the registrant had thirteen subsidiaries: Energy Resource Technology, Inc.; Canyon Offshore, Inc.; Cal Dive ROV, Inc.; Cal Dive I-Title XI, Inc.; Cal Dive Offshore, Ltd.; Well Ops (U.K.) Limited; Well Ops Inc.; ERT (U.K.) Limited; Cal Dive HR Services Limited; Cal Dive Trinidad & Tobago Ltd.; Canyon Offshore Ltd.; Canyon Offshore International Corp.; and Well Ops PTE Limited.
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*	Section 1350 Certification by Owen Kratz, Chief Executive Officer
32.2*	Section 1350 Certification by A. Wade Pursell, Chief Financial Officer

* Filed 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.

/s/ HELIX ENERGY SOLUTIONS GROUP, INC.

By: /s/ A. WADE PURSELL
A. Wade Pursell
Senior Vice President,
Chief Financial Officer

March 14, 2006

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	Chairman, Chief Executive Officer and Director (principal executive officer)	March 14, 2006
/s/ MARTIN R. FERRON Martin R. Ferron	President and Director	March 14, 2006
/s/ A. WADE PURSELL A. Wade Pursell	Senior Vice President and Chief Financial Officer (principal financial officer)	March 14, 2006
/s/ LLOYD A. HAJDIK Lloyd A. Hajdik	Vice President — Corporate Controller and Chief Accounting Officer (principal accounting officer)	March 14, 2006
/s/ GORDON F. AHALT Gordon F. Ahalt	Director	March 14, 2006
/s/ BERNARD J. DUROC-DANNER Bernard J. Duroc-Danner	Director	March 14, 2006
/s/ JOHN V. LOVOI John V. Lovoi	Director	March 14, 2006
/s/ T. WILLIAM PORTER T. William Porter	Director	March 14, 2006
/s/ WILLIAM L. TRANSIER William L. Transier	Director	March 14, 2006
/s/ ANTHONY TRIPODO Anthony Tripodo	Director	March 14, 2006

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.

2.3 Asset Purchase Agreement by and between Cal Dive International, Inc., as Buyer, and Stolt Offshore Inc. and S&H Diving LLC, as Sellers, dated April 11, 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 April 13, 2005.

2.4 Amendment to Asset Purchase Agreement by and between Cal Dive International, Inc., as Buyer, and Stolt Offshore Inc., S&H Diving LLC and SCS Shipping Limited, as Sellers, dated November 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 November 4, 2005.

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 December 14, 2005. 3.2 Second Amended and Restated By-Laws of Cal Dive International, Inc., 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 December 1, 2005.

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 by and among Bank of America, N.A., et al., as Lenders, and Helix Energy Solutions Group, Inc., as Borrower, dated August 16, 2004, incorporated by reference to Exhibit 4.1 to the registrant's Annual Report on 10-Q for the fiscal quarter ended September 30, 2004, filed by the registrant with the Securities and Exchange Commission on November 5, 2004 (the "2004 Form 10-Q").

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 4.1 to the Form S-1.

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 2002 Form 10-K/A.

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 2003 Form S-3.

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 2002 Form 10-K/A.

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 2002 Form 10-K/A.
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	Second Amendment to Credit Agreement dated March 21, 2005, made by and between Company and Bank of America, N.A., et al., incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on March 23, 2005.
4.15	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”).
4.16	Form of 3.25% Convertible Senior Note due 2025 (filed as Exhibit A to Exhibit 4.15).
4.17	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.
4.18	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”).
4.19	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.
4.20	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.
4.21	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.
4.22	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.
4.23	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 4.22).
4.24	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.
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	Employment Agreement between James Lewis Connor, III and Company dated May 1, 2002, incorporated by reference to Exhibit 10.6 to the registrant's Annual Report on Form 10-K for the fiscal year ended December 31, 2003, filed by the registrant with the Securities and Exchange Commission on March 15, 2004 (the "2003 Form 10-K").
10.6	First Amendment to Employment Agreement between James Lewis Connor, III and Company dated January 1, 2004, incorporated by reference to Exhibit 10.6 to the registrant's Annual Report on Form 10-K for the fiscal year ended December 31, 2004, filed by the registrant with the Securities and Exchange Commission on March 15, 2005 (the "2004 Form 10-K").
10.7	Cal Dive International, Inc. 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.
10.8	Employment Agreement by and between Cal Dive International, Inc. 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.
21.1	Subsidiaries of registrant — As of December 31, 2005, the registrant had thirteen subsidiaries: Energy Resource Technology, Inc.; Canyon Offshore, Inc.; Cal Dive ROV, Inc.; Cal Dive I-Title XI, Inc.; Cal Dive Offshore, Ltd.; Well Ops (U.K.) Limited; Well Ops Inc.; ERT (U.K.) Limited; Cal Dive HR Services Limited; Cal Dive Trinidad & Tobago Ltd.; Canyon Offshore Ltd.; Canyon Offshore International Corp.; and Well Ops PTE Limited.
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*	Section 1350 Certification by Owen Kratz, Chief Executive Officer
32.2*	Section 1350 Certification by A. Wade Pursell, Chief Financial Officer

* Filed herewith.

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. (formerly Cal Dive International, Inc.) of our reports dated March 14, 2006, with respect to the consolidated financial statements of Helix Energy Solutions Group, Inc. and Subsidiaries, Helix Energy Solutions Group, Inc. management's assessment of the effectiveness of internal control over financial reporting, 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, 2005.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 14, 2006

Exhibit 23.2

[Letterhead of Huddleston & Co., Inc.]

March 13, 2006

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 14, 2006 concerning the proved reserves as of December 31, 2005 attributable to Energy Resource Technology, 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/ B.P. HUDDLESTON
Name: B.P. Huddleston, P.E.
Title: Chairman

EXHIBIT 31.1

SECTION 302 CERTIFICATION

I, Owen Kratz, the Principal Executive Officer of Helix Energy Solutions Group, Inc., 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(s) 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(s) 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 registrant's board of directors:

(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 controls.

Date: March 14, 2006

/s/ OWEN KRATZ
Owen Kratz
Chairman and Chief Executive Officer

EXHIBIT 31.2

SECTION 302 CERTIFICATION

I, A. Wade Pursell, the Principal Financial Officer of Helix Energy Solutions Group, Inc., 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(s) 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(s) 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 registrant's board of directors:

(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 controls.

Date: March 14, 2006

/s/ A. WADE PURSELL
A. Wade Pursell
Senior Vice President and Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO 18 U.S.C. §1350,
AS ADOPTED PURSUANT TO
§906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Annual Report of Helix Energy Solutions Group, Inc. (“HELX”) on Form 10-K for the period ended December 31, 2005, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Owen Kratz, Chairman and Chief Executive Officer of HELX, hereby certify pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(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 HELX.

Date: March 14, 2006

/s/ OWEN KRATZ
Owen Kratz
Chairman and Chief Executive Officer

EXHIBIT 32.2

**CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. §1350,
AS ADOPTED PURSUANT TO
§906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the accompanying Annual Report of Helix Energy Solutions Group, Inc. (“HELX”) on Form 10-K for the period ended December 31, 2005, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, A. Wade Pursell, Senior Vice President and Chief Financial Officer of HELX, hereby certify pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(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 HELX.

Date: March 14, 2006

/s/ A. WADE PURSELL
A. Wade Pursell
Senior Vice President and Chief Financial Officer