HELIX ENERGY SOLUTIONS GROUP INC
Form 10-K
February 26, 2010

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

Form 10-K

(Mark One)

R	ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
	For the fiscal year ended December 31, 2009
	or
£	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) of the Securities Exchange Act of 1934
	For the transition period from to

Commission File Number 001-32936

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

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

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

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

Title of each class	Name of each exchange on which registered
Common Stock (no par value)	New York Stock Exchange

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). £ Yes £ No

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

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

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant based on the last reported sales price of the Registrant's Common Stock on June 30, 2009 was approximately $1.0 billion.

The number of shares of the registrant's Common Stock outstanding as of February 19, 2010 was 104,691,894.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement for the Annual Meeting of Shareholders to be held on May 12, 2010, are incorporated by reference into Part III hereof.

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Forward Looking Statements

This Annual Report on Form 10-K ("Annual Report") contains various statements that contain forward-looking information regarding Helix Energy Solutions Group, Inc. and represent our expectations and beliefs concerning future events. This forward looking information is intended to be covered by the safe harbor for "forward-looking statements" provided by the Private Securities Litigation Reform Act of 1995 as set forth in Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements, included herein or incorporated herein by reference, that are predictive in nature, that depend upon or refer to future events or conditions, or that use terms and phrases such as "achieve," "anticipate," "believe," "estimate," "expect," "forecast," "plan," "project," "propose," "strategy," "predict," "envision," "hope," "intend," "will," "cont "potential," "should," "could" and similar terms and phrases are forward-looking statements. Included in forward-looking statements are, among other things:

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

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Although we believe that the expectations reflected in these forward-looking statements are reasonable and are based on reasonable assumptions, they do involve risks, uncertainties and other factors that could cause actual results to be materially different from those in the forward-looking statements. These factors include, among other things:

- impact of the weak economic conditions and the future impact of such conditions on the oil and gas industry and the demand for our services;
- uncertainties inherent in the development and production of oil and gas and in estimating reserves;
- the geographic concentration of our oil and gas operations;
- uncertainties regarding our ability to replace depletion;
- unexpected capital expenditures (including the amount and nature thereof);
- impact of oil and gas price fluctuations and the cyclical nature of the oil and gas industry;
- the effects of indebtedness, which could adversely restrict our ability to operate, could make us vulnerable to general adverse economic and industry conditions, could place us at a competitive disadvantage compared to our competitors that have less debt and could have other adverse consequences to us;
- the effectiveness of our derivative activities;
- the results of our continuing efforts to control or reduce costs and improve performance;
- the success of our risk management activities;
- the effects of competition;
- the availability (or lack thereof) of capital (including any financing) to fund our business strategy and/or operations and the terms of any such financing;
- the impact of current and future laws and governmental regulations, including tax and accounting developments;
- the effect of adverse weather conditions and/or other risks associated with marine operations;
- the effect of environmental liabilities that are not covered by an effective indemnity or insurance;
- the potential impact of a loss of one or more key employees; and
- the impact of general, market, industry or business conditions.

Our actual results could differ materially from those anticipated in any forward-looking statements as a result of a variety of factors, including those discussed in "Risk Factors" beginning on page 18 of this Annual Report. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these risk factors. Forward-looking statements are only as of the date they are made, and other than as required under the securities laws, we assume no obligation to update or revise these forward-looking statements or provide reasons why actual results may differ.

PART I

Item 1. Business

OVERVIEW

Helix Energy Solutions Group, Inc. ("Helix") is an international offshore energy company, incorporated in the state of Minnesota in 1979, that provides field development solutions and other contracting services to the energy market as well as to our own oil and gas properties. Our Contracting Services segment utilizes our vessels, offshore equipment and methodologies to deliver services that may reduce finding and development ("F&D") costs and encompass the complete lifecycle of an offshore oil and gas field. Our Oil and Gas segment engages in prospect generation, exploration, development and production activities. Our primary operations are located in the Gulf of Mexico, North Sea, Asia Pacific and West Africa regions. Unless the context indicates otherwise, as used in this Annual Report, the terms “Company,” “we,” “us” and “our” refer collectively to Helix and its subsidiaries. Until June 2009, Cal Dive International, Inc. (collectively with its subsidiaries referred to as “Cal Dive” or “CDI”) was a majority-owned subsidiary of Helix. Helix sold substantially all its remaining ownership interests in Cal Dive during 2009 (see “Contracting Services Operations – Shelf Contracting” below).

In December 2008, we announced the intention to focus and shape the future of the Company around our deepwater construction and well intervention services. For additional information regarding this strategy announcement and about our deepwater construction and well intervention services see sections titled “The Industry and Our Strategy,” “Contracting Services” and “Contracting Services Operations” all included elsewhere within Item 1. “Business” of this Annual Report.

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Our principal executive offices are located at 400 North Sam Houston Parkway East, Suite 400, Houston, Texas 77060; phone number 281-618-0400. Our common stock trades on the New York Stock Exchange ("NYSE") under the ticker symbol "HLX". Our Chief Executive Officer submitted the annual CEO certification to the NYSE as required under its listed Company Manual in April 2009. Our principal executive officer and our principal financial officer have made the certifications required under Section 302 of the Sarbanes-Oxley Act, which are included as exhibits to this report.

Please refer to the subsection "— Certain Definitions" on page 8 for definitions of additional terms commonly used in this Annual Report.

CONTRACTING SERVICES

We seek to provide services and methodologies which we believe are critical to finding and developing offshore reservoirs and maximizing production economics. Our "life of field" services are organized in three disciplines: subsea construction, well operations and production facilities. We have disaggregated our contracting services operations into three reportable segments: Contracting Services (which includes subsea construction, well operations and drilling); Shelf Contracting, which we ceased reporting as a business segment in June 2009 (see "Contracting Services Operations – Shelf Contracting" below); and Production Facilities.

Subsea Construction

For over 30 years, we have supported offshore oil and natural gas infrastructure projects by providing our services, which include the construction and maintenance of pipelines, production platforms, risers and subsea production systems primarily in the Gulf of Mexico, North Sea, Asia Pacific, West Africa and Middle East regions. Our subsea construction services include pipelay and robotics in water depths exceeding 1,000 feet. We also provide construction services periodically from our well intervention vessels. Historically we performed traditional subsea services, including air and saturation diving, salvage work and shallow water pipelay on the Outer Continental Shelf ("OCS") of the Gulf of Mexico in water depths up to 1,000 feet through Cal Dive, a majority-owned subsidiary until June 2009, at which time we sold a substantial amount of our remaining ownership interest in Cal Dive reducing ownership of Cal Dive to approximately 26%. In September 2009 we sold substantially all our remaining ownership interest in Cal Dive. The financial results of Cal Dive are consolidated in our accompanying financial statements through June 10, 2009 and are recorded under the equity method from June 10, 2009 until September 23, 2009 (see Item 8. Financial Statements and Supplementary Data" — Note 3 — "Ownership of Cal Dive International Inc.").

Well Operations

We engineer, manage and conduct well construction, intervention, drilling and decommissioning operations in water depths ranging primarily from approximately 200 feet to 10,000 feet. Over the long term, we expect an increased demand for these services caused by the growing number of subsea tree installations, coupled with our lower cost solutions as compared to an offshore rig. Accordingly, we constructed a newbuild vessel (the "Well Enhancer") that joined our fleet in October 2009 and is performing work in the North Sea. We also expanded geographically in Australia and Asia in 2007 with the acquisition of Seatrac Pty Ltd. ("Seatrac"), an established Australian well operations company now named Well Ops SEA Pty Limited ("WOSEA").

Production Facilities

We own interests in certain production facilities in hub locations where there is potential for significant subsea tieback activity. Ownership of production facilities enables us to earn a transmission company type return through tariff charges while providing construction work for our vessels. We own a 50% interest in the Marco Polo tension leg platform (“TLP”), which is located in 4,300 feet of water in the Gulf of Mexico, through Deepwater Gateway, L.L.C. (“Deepwater Gateway”). Enterprise Products Partners L.P. owns the remaining 50% of Deepwater Gateway. We also own a 20% interest in Independence Hub, LLC (“Independence Hub”), an affiliate of Enterprise Products Partners L.P. Independence Hub owns a 105-foot deep draft, semi-submersible platform, which was installed during 2007. The Independence Hub platform is located in a water depth of 8,000 feet and serves as a regional hub for up to one billion cubic feet of natural gas production per day from multiple ultra-deepwater fields in the eastern Gulf of Mexico. Finally, through an approximate 81% owned consolidated entity, we are nearing completion of the conversion of a vessel into a ship shaped dynamically-positioned floating production unit capable of processing up to 45,000 barrels of oil and 70 MMcf of natural gas per day, which we intend to initially use to handle the future oil and gas production from our Phoenix field in the deepwater of the Gulf of Mexico (see Item 2. Properties – Significant Oil and Gas Properties).

Our contracting services has consisted of three of our business segments: Contracting Services, Shelf Contracting (until June 2009) and Production Facilities. We ceased reporting the results of our former Shelf Contracting segment in June 2009 when Cal Dive was deconsolidated from our financial statements following the reduction of our ownership of Cal Dive to below 50%. Our fourth business segment is Oil and Gas (see below). Significant financial information relating to our operations by segments and by geographic areas for the last three years is contained in Item 8. Financial Statements and Supplementary Data “— Note 18 — Business Segment Information.”

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OIL AND GAS

We formed our oil and gas operations in 1992 to develop and provide more efficient solutions for the abandonment requirements of companies operating offshore, to expand the asset utilization of our contracting services assets and to achieve incremental returns. We have evolved this business model to include not only mature oil and gas properties but also proved and unproved reserves yet to be developed and explored. In July 2006, we acquired Remington Oil and Gas Corporation ("Remington"), an exploration, development and production company with operations located primarily in the Gulf of Mexico. As of December 31, 2009, we had approximately 578 Bcfe of estimated proved reserves with approximately 98% associated with properties located in the Gulf of Mexico. As discussed in "The Industry and Our Strategy" below, in December 2008, we announced that we intend to seek the potential sale of part or all of our oil and gas operations; however, until any potential disposition occurs, we believe that owning interests in reservoirs, particularly in deepwater, provides the following:

- a potential backlog for our service assets as a hedge against cyclical service asset utilization;
- potential utilization for new non-conventional applications of service assets to hedge against lack of initial market acceptance and utilization risk; and
- incremental returns.

Our oil and gas operations include an experienced team of personnel providing expertise in geology, geophysics, reservoir engineering, drilling, production engineering, facilities management, lease operations and petroleum land management. We seek to maximize returns on our oil and gas investments by lowering F&D costs, reducing development time, operating our fields more effectively, and extending the reservoir life through well exploitation operations. Our reservoir engineering and geophysical expertise, along with our access to contracting services assets that may positively impact a project's development costs, have enabled us to partner with many other oil and gas companies in offshore development projects.

THE INDUSTRY AND OUR STRATEGY

In December 2008, we announced our intention to focus and shape the future direction of the Company around our deepwater construction and well intervention services that comprise our Contracting Services business. We intend to achieve this strategic focus by seeking and evaluating strategic opportunities to sell certain non-core assets, such as:

- all or a portion of our oil and gas assets;
- our ownership interests in one or more of our production facilities; and
- our remaining interest in CDI.

We also announced that economic and financial market conditions may affect the timing of any strategic dispositions by us and, therefore, a degree of patience would be required in order to execute any transactions. We continue to focus on reducing debt levels through monetization of non-core assets and allocation of free cash flow in order to accelerate our strategic goals.

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Since the announcement of our strategy to monetize certain of our non-core business assets, we have:

- Sold five oil and gas properties for approximately $68 million in gross proceeds;
- Sold a total of 15.2 million shares of CDI common stock held by us to CDI for $100 million in separate transactions in January and June 2009 (Note 3);
- Sold Helix RDS Limited, our subsurface reservoir consulting business for $25 million in April 2009; and
- Sold a total of 45.8 million shares of CDI common stock held by us to third parties in two separate public secondary offerings for approximately $404.4 million, net of underwriting fees in June 2009 and September 2009.

Demand for our contracting services operations is primarily influenced by the condition of the oil and gas industry and, in particular, the willingness of oil and gas companies to make capital expenditures for offshore exploration, drilling and production operations. Generally, spending for our contracting services fluctuates directly with the direction of oil and natural gas prices. The performance of our oil and gas operations is also largely dependent on the prevailing market prices for oil and natural gas, which are impacted by global economic conditions, hydrocarbon production and excess capacity, geopolitical issues, weather and several other factors.

Global economic conditions deteriorated significantly in 2008 with declines in the oil and natural gas market accelerating during the fourth quarter of 2008. Although we currently are experiencing a weak economic environment, we believe that the long-term industry fundamentals are positive based on the following factors: (1) long term increasing world demand for oil and natural gas; (2) peaking global production rates; (3) globalization of the natural gas market; (4) increasing number of mature and small reservoirs; (5) increasing ratio of contribution to global production from marginal fields; (6) increasing offshore activity, particularly in deepwater; and (7) increasing number of subsea developments. Our current strategy of combining Contracting Services Operations and Oil and Gas operations allows us to focus on trends (4) through (7) in that we pursue long-term sustainable growth by applying specialized subsea services to the broad external offshore market but with a complementary focus on fields and new reservoirs in which we have an equity stake.

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

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

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

As stated previously, we will focus on services which are critical to lowering F&D costs, particularly on fields in the deepwater. In connection with this strategy, in December 2006, we sold a minority stake (26.5%) in our Shelf Contracting business through a carve-out initial public offering. Our interest in CDI was further reduced through CDI's acquisition of Horizon Offshore, Inc. ("Horizon") in December 2007 and was 57.2% at December 31, 2008. In January 2009, CDI acquired 13.6 million shares of its outstanding common shares from us, reducing our ownership in CDI to approximately 51%. We subsequently sold additional shares of CDI stock held by us in two separate public secondary offerings in June 2009 and September 2009, respectively. We currently own less than 1% of CDI. See Item 8. Financial Statements and Supplementary Data "— Note 3 — Ownership of Cal Dive International, Inc."

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Generate Prospects and Focus Exploration Drilling on Select Deepwater Prospects. Our oil and gas operations continue to function normally following our December 2008 announcement that all or a portion of such properties may be sold. This means we will continue to generate prospects and drill in areas we believe are likely to contain oil and natural gas reserves and where our contracting services assets can be utilized and incremental returns will be achieved through control of and application of our development services and methodologies. To minimize our F&D costs, we may utilize the Q4000 for some of our deepwater drilling needs once regulatory approval has been obtained. Additionally, we plan to seek partners on these prospects to mitigate risk associated with the cost of drilling and development work.

Continue Exploitation Activities and Converting PUD/PDNP Reserves into Production. Over the years, our oil and gas operations have been able to achieve incremental operating returns and increased operating cash flow due in part to our ability to convert proved undeveloped reserves (“PUD”) and proved developed non-producing reserves (“PDNP”) into producing assets through successful exploitation drilling and well work. As of December 31, 2009, the PUD category for our U.S. Gulf of Mexico properties totaled approximately 352 Bcfe or 62% of our total domestic estimated proved reserves. All of our U.K proved reserves totaling approximately 12 Bcfe are considered to be PUD at December 31, 2009. We will focus on cost effectively developing these reserves to generate oil and gas production, or alternatively, selling full or partial interests in them to fund our core service business and/or retire outstanding debt.

Certain Definitions

Defined below are certain terms helpful to understanding our business:

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

Deepwater: Water depths exceeding 1,000 feet.

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

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

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

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

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

G&G: Geological and geophysical.

IRM: Inspection, repair and maintenance.

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

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

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

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

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

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

MSV: Multipurpose support vessel.

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

Peer Group-Contracting Services: For purposes of this Annual Report on Form 10-K, FMC Technologies, Inc. (NYSE: FTI), Global Industries, Ltd. (NASDAQ: GLBL), McDermott International, Inc. (NYSE: MDR), Oceaneering International, Inc. (NYSE: OII), Cameron International Corporation (NYSE: CAM), Pride International, Inc. (NYSE: PDE), Oil States International, Inc. (NYSE: OIS), Rowan Companies, Inc. (NYSE: RDC), and Tidewater Inc. (NYSE: TDW).

Peer Group-Oil and Gas: For purposes of this Annual Report on Form 10-K, ATP Oil & Gas Corporation (NASDAQ: ATPG), W&T Offshore, Inc. (NYSE: WTI), and Mariner Energy, Inc. (NYSE: ME).

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

Proved Developed Shut-In (PDSI): Proved developed oil and gas reserves associated with wells that exhibited calendar year production, but were not online January 1, 2009.

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

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

QHSE: Quality, Health, Safety and Environmental programs to protect the environment, safeguard employee health and eliminate injuries.

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

ROVDrill: ROV deployed coring system developed to take advantage of existing ROV technology. The coring package, deployed with the ROV system, is capable of taking cores from the seafloor in water depths up to 3,000m. Because the system operates from the seafloor there is no need for surface drilling strings and the larger support spreads required for conventional coring.

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

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

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

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

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

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

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

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

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

CONTRACTING SERVICES OPERATIONS

We provide a full range of contracting services primarily in the Gulf of Mexico, North Sea, Asia Pacific and West Africa regions primarily in deepwater. Our services include:

- Development. Installation of subsea pipelines, flowlines, control umbilicals, manifold assemblies, risers; pipelay and burial; installation and tie-in of riser and manifold assembly; commissioning, testing and inspection; and cable and umbilical lay and connection;

- Production. Inspection, repair and maintenance (IRM) of production structures, risers, pipelines and subsea equipment; well intervention; life of field support; and intervention engineering; and

- Decommissioning. Decommissioning and remediation services; plugging and abandonment services; platform salvage and removal services; pipeline abandonment services; and site inspections.

We provide offshore services and methodologies that we believe are critical to finding and developing offshore reservoirs and maximizing production economics. These “life of field” services are represented by three disciplines: (1) construction, (2) well operations and (3) production facilities. As of December 31, 2009, our contracting services operations’ backlog supported by written agreements or contracts totaled $251.0 million, of which $216.7 million is expected to be completed in 2010. These backlog contracts are cancellable without penalty in many cases. Backlog is not a reliable indicator of total annual revenue for our Contracting Services businesses as contracts may be added, cancelled and in many cases modified while in progress.

Subsea Construction

Construction services which we believe are critical to the development of fields in the deepwater include the use of umbilical lay and pipelay vessels and ROVs. We currently own three subsea umbilical lay and pipelay vessels. The Intrepid is a 381-foot DP-2 vessel capable of laying rigid and flexible pipe (up to 8 inches in diameter) and umbilicals. The Express is a 502-foot DP-2 vessel also capable of laying rigid and flexible pipe (up to 14 inches in diameter) and umbilicals. In January 2006, we acquired the Caesar, a mono-hull built in 2002 for the cable lay market. The Caesar is 485 feet long and has a state-of-the-art DP-2 system. In January 2010, the Caesar arrived in the Gulf of Mexico after its conversion into a subsea pipelay asset capable of laying rigid pipe up to 36 inches in diameter. The Caesar will undergo additional capital improvements in the United States before being placed in service in our fleet, which is expected to occur in the first half of 2010. Our total investment in the Caesar is expected to range between $290 million and $300 million (including capitalized interest of approximately $24 million) when it is completed. We also periodically provide construction services from our well intervention vessels, Seawell, Q4000 and the newly completed Well Enhancer, which was placed in service in October 2009.

We operate ROVs, trenchers and ROVDrills designed for offshore construction. As marine construction support in the Gulf of Mexico and other areas of the world moves to deeper waters, use of ROV systems is increasing and the scope of their services is more significant. Our vessels add value by supporting deployment of our ROVs. We provide our customers with vessel availability and schedule flexibility to meet the technological challenges of these subsea construction developments in the Gulf of Mexico and internationally. Our 39 ROVs and five trencher systems operate in three regions: the Americas, Europe/West Africa and Asia Pacific.

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The results of our Subsea division are reported under our Contracting Services segment. See Item 8. Financial Statements and Supplementary Data "— Note 18 — Business Segment Information."

Shelf Contracting

Our former Shelf Contracting segment represented the operations and results of CDI while CDI was a consolidated, majority-owned subsidiary of Helix. We deconsolidated CDI on June 10, 2009 when our ownership interest in CDI decreased below 50% (see Item 8. Financial Statement and Supplementary Data "— Note 3 — Ownership of Cal Dive International, Inc."). Shelf Contracting services provided by CDI included manned diving services, pipelay and pipebury services, platform installation and salvage service. Shelf Contracting also performed saturation, surface and mixed gas diving which enabled us to provide a full complement of manned diving services in water depths of up to 1,000 feet.

See Item 8. Financial Statements and Supplementary Data "— Note 18 — Business Segment Information."
For the results of our former Shelf Contracting services segment.

Well Operations

We engineer, manage and conduct well construction, intervention, drilling and decommissioning operations in water depths ranging from 200 to 10,000 feet. The increased number of subsea wells installed and the periodic shortfall in both rig availability and equipment have resulted in an increased demand for Well Operations services in the regions in which we operate.

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 sleeves, log wells 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 vessel, the Q4000, has set a series of well operations "firsts" in increasingly deeper water without the use of a traditional drilling rig. In the North Sea, the Seawell has provided intervention and abandonment services for over 700 North Sea subsea wells since 1987. Competitive advantages of our vessels are derived from their lower operating costs, together with an ability to mobilize quickly and to maximize production time by performing a broad range of tasks related to intervention, construction, inspection, repair and maintenance. These services provide a cost advantage in the development and management of subsea reservoir developments. With the expected long-term increased demand for these services due to the growing number of subsea tree installations, we have the potential for significant backlog for both these working assets and, as a result, we constructed a newbuild vessel, the Well Enhancer. The Well Enhancer joined our fleet in October 2009 in the North Sea region. Additional limited capital expenditures remain to be incurred to upgrade certain capabilities of the Well Enhancer. We have incurred total costs of $233 million on the Well Enhancer through December 31, 2009 and its total cost is expected to be between $250 million and $260 million (including capitalized interest of approximately $16 million) when the remaining capital upgrades are completed. Our operations expanded within Australia and Asia following the acquisition of a well established Australian well operations company in 2006. In February 2010, we announced the formation of a joint venture with Australian-based engineering and construction company Clough Limited, to provide a range of subsea services to offshore operators in the Asia Pacific region. Services provided by the joint venture, named Clough Helix Pty Ltd, will include subsea well intervention and well abandonment, SURF (subsea infrastructure, umbilical, riser and flowline installation), saturation and air diving and subsea inspection, repair and maintenance services.

The results of Well Operations are reported under our Contracting Services segment. See Item 8. Financial Statements and Supplementary Data "— Note 18 — Business Segment Information."

Production Facilities

We own interests in certain production facilities in hub locations where there is potential for significant subsea tieback activity. There are a significant number of small discoveries that cannot justify the economics of a dedicated host facility. These discoveries are typically developed as subsea tie backs to existing facilities when capacity through the facility is available.

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We have historically invested in over-sized facilities that allow operators of these fields to tie back without burdening the operator of the hub reservoir. We are positioned to facilitate the tie back of certain of these smaller reservoirs to these hubs through our services. Ownership of production facilities enables us to earn a transmission company type return through tariff charges while periodically providing construction work for our vessels. We own a 50% interest in Deepwater Gateway which owns the Marco Polo TLP, is located in 4,300 feet of water in the Gulf of Mexico. We also own a 20% interest in Independence Hub which owns the Independence Hub platform, a 105-foot deep draft, semi-submersible platform located in a water depth of 8,000 feet that serves as a regional hub for up to one billion cubic feet of natural gas production per day from multiple ultra-deepwater fields in the previously untapped eastern Gulf of Mexico.

When a hub is not feasible, we intend to apply an integrated application of our services in a manner that cumulatively lowers development costs to a point that allows for a small dedicated facility to be used. This strategy will permit the development of some fields that otherwise would be non-commercial to develop. The commercial risk is mitigated because we have a portfolio of reservoirs and the assets to redeploy the facility. For example, through an approximate 81% owned and consolidated entity, we are nearing completion of conversion of a vessel (the Helix Producer I) into a ship-shaped dynamically positioned floating production unit capable of processing up to 45,000 barrels of oil and 70 MMcf of natural gas per day. We intend this unit to first be utilized on the Phoenix field, which we acquired in 2006 after the hurricanes of 2005 destroyed the TLP which was being used to produce the field. We believe the Helix Producer I will be ready to process first production from the Phoenix field around mid-year 2010. Once production in the Phoenix area ceases, this re-deployable facility is expected to be moved to a new location, contracted to a third party, or used to produce other internally-owned reservoirs.

The results of production facilities services are reported under our Production Facilities segment. See Item 8. Financial Statements and Supplementary Data "— Note 18 — Business Segment Information."

OIL & GAS OPERATIONS

We formed our oil and gas operations in 1992 to develop and provide more efficient solutions for offshore abandonment requirements, to expand the utilization of our contracting services assets and to achieve incremental returns. We have evolved this business model to include not only mature oil and gas properties but also proved and unproved reserves yet to be developed and explored. In July 2006, we acquired Remington Oil and Gas Corporation ("Remington"), an exploration, development and production company with operations located primarily in the Gulf of Mexico. This acquisition led to the assembly of services that allows us to create value at key points in the life of a reservoir from exploration through development, life of field management and operating through abandonment. As of December 31, 2009, our estimated proved reserves totaled approximately 578 Bcfe with approximately 98% of such reserves associated with properties located in the Gulf of Mexico.

As announced in December 2008, we are seeking to monetize the value of our oil and gas assets through the disposition of all or a portion of our oil and gas operations. Although this is our intention, until such time as an acceptable offer is made for our properties, we will continue to build on their value by operating them consistent with our past practices. We cannot provide assurances that the sale of all or any portion of our oil and gas operations will be completed or that we will be able to negotiate an acceptable price or acceptable terms. Also, all material dispositions of assets and/or investments in our non-core businesses require obtaining approval from our Board of Directors. We believe that owning interests in oil and gas reservoirs, particularly in the Deepwater, provides the following:

- a potential backlog for our service assets as a hedge against cyclical service asset utilization;
- potential utilization for new non-conventional applications of service assets to hedge against lack of initial market acceptance and utilization risk; and

- incremental returns.

Our oil and gas operations are currently involved in all stages of a reservoir's life. This complete life-cycle involvement allows us to meaningfully improve the economics of a reservoir that would otherwise be considered non-commercial or non-impact and has identified us as a value adding partner to many producers. Our expertise, along with similarly aligned interests, allows us to develop more efficient relationships with other producers. With a historical focus on acquiring non-impact reservoirs or mature fields, we have been successful in acquiring equity interests in several Deepwater undeveloped reservoirs. In the event we continue to own and operate our oil and gas assets, developing these fields over the next few years will require significant capital commitments by us and/or others and may provide significant backlog for our construction assets.

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Our oil and gas operations have a significant prospect inventory, mostly in the Deepwater, which we believe will generate significant life of field services for our vessels. To minimize F&D costs, we may utilize the Q4000 for some of our Deepwater future drilling needs. Our Oil and Gas segment has a proven track record of developing prospects into production in the U.S. Gulf of Mexico. We plan to seek partners on these prospects to mitigate risk associated with the costs of drilling and development.

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

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

The results of our oil and gas operations are reported under our Oil and Gas segment. See Item 8. Financial Statements and Supplementary Data "— Note 18 — Business Segment Information."

GEOGRAPHIC AREAS

Revenue by geographic region during is as follows (in thousands):

	Year Ended December 31,		
	2009	2008	2007
United States	$ 923,481	$ 1,394,108	$ 1,261,844
United Kingdom	124,896	160,186	205,529
India	233,466	214,288	36,433
Other	179,844	345,492	228,614
Total	$ 1,461,687	$ 2,114,074	$ 1,732,420

We include the property and equipment, net of accumulated depreciation, in the geographic region in which it is legally owned. The following table provides our property and equipment, net of depreciation, by geographic region (in thousands):

	Year Ended December 31,		
	2009	2008	2007
United States	$ 2,564,673	$ 3,170,866	$ 3,014,283
United Kingdom	284,637	206,009	187,551
Other	14,396	41,568	41,073
Total	$ 2,863,706	$ 3,418,443	$ 3,242,907

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, those whose total represented 10% or more of our consolidated revenues, was as follows: 2009—Shell Offshore, Inc. (12%); 2008 — Louis Dreyfus Energy Services (10%) and Shell Offshore, Inc. (12%); and 2007 — Louis Dreyfus Energy Services (14%) and Shell Offshore, Inc. (10%). These customers were purchasers of our oil and gas production. We estimate that in 2009 we provided subsea services to over 200 customers.

Our contracting services projects have historically been of short duration and are generally awarded shortly before mobilization. As a result, no significant backlog existed prior to 2007. Beginning in 2007, we entered into several long-term contracts for certain of our Deepwater and Well Operations vessels. In addition, our production portfolio inherently provides a backlog of work for our services that we can complete at our option based on market conditions. As of December 31, 2009, our contracting services operations' backlog supported by written agreements or contracts totaled $251.0 million, of which $216.7 million is expected to be completed in 2010. These backlog contracts are cancellable without penalty in many cases. Backlog is not a reliable indicator of total annual revenue for our Contracting Services businesses as contracts may be added, cancelled and in many cases modified while in progress.

COMPETITION

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

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

TRAINING, SAFETY AND QUALITY ASSURANCE

We have established a corporate culture in which QHSE remains among the highest of priorities. Our corporate goal, based on the belief that all accidents can be prevented, is to provide an incident-free workplace by focusing on correct and safe behavior. Our QHSE 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 QHSE programs are among the best in the industry. We have introduced a company-wide effort to enhance and provide continuous improvements to our behavioral based safety process, as well as our training programs, that continue to focus on safety through open communication. The process includes the documentation of all daily observations, collection of data and data treatment to provide the mechanism of understanding both safe and unsafe behaviors at the worksite. In addition, we initiated scheduled Hazard Hunts by project management on each vessel, complete with assigned responsibilities and action due dates. Our Contracting Services business has ISO accreditation such as ISO 9001 (Quality Management Systems) and ISO 14001 (Environmental Management System).

GOVERNMENT REGULATION

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

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

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

The MMS requires lessees of OCS properties to post bonds or provide other adequate financial assurance in connection with the plugging and abandonment of wells located offshore and the removal of all production facilities. Operators on the OCS are currently required to post an area-wide bond of $3.0 million, or $0.5 million per producing lease. We have provided adequate financial assurance for our offshore leases as required by the MMS.

We acquire production rights to offshore mature oil and gas properties under federal oil and gas leases, which the MMS administers. These leases contain relatively standardized terms and require compliance with detailed MMS regulations and orders pursuant to the Outer Continental Shelf Lands Act (“OCSLA”). These MMS directives are subject to change. The MMS has promulgated regulations requiring offshore production facilities located on the OCS to meet stringent engineering and construction specifications. The MMS also has issued regulations restricting the flaring or venting of natural gas and prohibiting the burning of liquid hydrocarbons without prior authorization. Similarly, the MMS has promulgated other regulations governing the plugging and abandonment of wells located offshore and the removal of all production facilities. Finally, under certain circumstances, the MMS may require any operations on federal leases to be suspended or terminated or may expel unsafe operators from existing OCS platforms and bar them from obtaining future leases. Suspension or termination of our operations or expulsion from operating on our leases and obtaining future leases could have a material adverse effect on our financial condition and results of operations.

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

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

Sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation remain subject to extensive federal and state regulation. Several major regulatory changes have been implemented by Congress and FERC since 1985 that affect the economics of natural gas production, transportation and sales. In addition, as a result of the Energy Policy Act of 2005, 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. In addition, however, changes in FERC rules and regulations may also affect the intrastate transportation of natural gas, as well as the sale of natural gas in interstate and intrastate commerce, 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, and to prevent fraud and manipulation of interstate transportation markets. We cannot predict what further action FERC will take on these matters, but we do not believe any such action will materially adversely affect us differently from other companies with which we compete.

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

ENVIRONMENTAL REGULATION

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

The Oil Pollution Act of 1990, as amended (“OPA”), imposes a variety of requirements on “Responsible Parties” related to the prevention of oil spills and liability for damages resulting from such spills in waters of the United States. A “Responsible Party” includes the owner or operator of an onshore facility, a vessel or a pipeline, and the lessee or permittee of the area in which an offshore facility is located. OPA imposes liability on each Responsible Party for oil spill removal costs and for other public and private damages from oil spills. Failure to comply with OPA may result in the assessment of civil and criminal penalties. OPA establishes liability limits of $350 million for onshore facilities, all removal costs plus $75 million for offshore facilities, and the greater of $854,400 or $1,000 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.

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

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

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

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

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

We operate in foreign jurisdictions that have various types of governmental laws and regulations relating to the discharge of oil or hazardous substances and the protection of the environment. Pursuant to these laws and regulations,

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

EMPLOYEES

We rely on the high quality of our workforce. As of January 31, 2010, we had approximately 1,550 employees, nearly 680 of which were salaried personnel. As of December 31, 2009, we also contracted with third parties to utilize 200 non-U.S. citizens to crew our foreign flag vessels. Except for a very limited number of our workshop employees in Australia, our employees do not belong to a union nor are they employed pursuant to any collective bargaining agreement or any similar arrangement. We believe our relationship with our employees and foreign crew members is favorable.

WEBSITE AND OTHER AVAILABLE INFORMATION

We maintain a website on the Internet with the address of www.HelixESG.com. Copies of this Annual Report for the year ended December 31, 2009, and copies of our Quarterly Reports on Form 10-Q for 2009 and 2010 and any Current Reports on Form 8-K for 2009 and 2010, 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. In addition, the Investor Relations portion of our website contains copies of our Code of Conduct and Business Ethics and our Code of Ethics for Chief Executive Officer and Senior Financial Officers. We make our website content available for informational purposes only. Information contained on our website is not part of this report and should not be relied upon for investment purposes. Please note that prior to March 6, 2006, the name of the Company was Cal Dive International, Inc.

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

Item 1A. Risk Factors.

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

Risks Relating to General Corporate Matters

Business Risks

Our results of operations could be adversely affected if our business assumptions do not prove to be accurate or if adverse changes occur in our business environment, including the following areas:

- general global economic and business conditions, which affect demand for oil and natural gas and, in turn, our business;
- our ability to manage risks related to our business and operations;
- our ability to compete against companies that provide more services and products than we do, including "integrated service companies";

- our ability to attract and retain skilled, trained personnel to provide technical services and support for our business;
- our ability to procure sufficient supplies of materials essential to our business in periods of high demand, and to reduce our commitments for such materials in periods of low demand;
- consolidation by our customers, which could result in loss of a customer; and
- changes in laws or regulations, including laws relating to the environment or to the oil and gas industry in general, and other factors, many of which are beyond our control.

Economic downturn and lower oil and natural gas prices could negatively impact our business.

Our operations are affected by local, national and worldwide economic conditions and the condition of the oil and gas industry. Certain economic data indicates the United States economy and the worldwide economy may require some time to recover from the recent downturn. The consequences of a prolonged period of economic decline or little or no economic growth will likely result in a lower level of economic activity and increased uncertainty regarding the direction of energy prices and the capital and commodity markets, which will likely contribute to decreased offshore exploration and drilling. A lower level of offshore exploration and drilling could have a material adverse effect on the demand for our services. In addition, a general decline in the level of economic activity might result in lower commodity prices, which may also adversely affect our revenues from our oil and gas business and indirectly, our service business. The extent of the impact of these factors on our results of operations and cash flow depends on the length and severity of the decreased demand for our services and lower commodity prices.

Continued market deterioration could also jeopardize the performance of certain counterparty obligations, including those of our insurers, customers and financial institutions. Although we assess the creditworthiness of our counterparties, prolonged business decline or disruptions as a result of economic slow down or lower commodity prices could lead to changes in a counterparty's liquidity and increase our exposure to credit risk and bad debts. In the event any such party fails to perform, our financial results could be adversely affected and we could incur losses and our liquidity could be negatively impacted.

Lack of access to the credit market could negatively impact our ability to operate our business and to execute our business strategy.

Due to the changes in the global credit market during fiscal 2009, there has been deterioration in the credit and capital markets and access to financing is limited and uncertain. If the capital and credit markets continue to experience weakness and the availability of funds remains limited, we may incur increased costs associated with any additional financing we may require for future operations. Because of uncertainty in the market and an inability to access the capital markets our customers may curtail their capital and operating expenditure programs, which could result in a decrease in demand for our vessels and a reduction in fees and/or utilization. In addition, certain of our customers could experience an inability to pay suppliers, including us, in the event they are unable to access the capital markets as needed to fund their business operations. Likewise, our suppliers may be unable to sustain their current level of operations, fulfill their commitments and/or fund future operations and obligations, each of which could adversely affect our operations. Continued lower levels of economic activity and weakness in the credit markets could also adversely affect our ability to implement our strategic objectives and dispose of all or any portion of the oil and gas assets or the production facilities.

In addition, some financial institutions and insurance companies have reported significant deterioration in their financial condition during fiscal 2009. Our forward-looking statements assume that our lenders, insurers and other financial institutions will be able to fulfill their obligations under our various credit agreements, insurance policies and contracts. If any of our significant financial institutions were unable to perform under such agreements, and if we were unable to find suitable replacements at a reasonable cost, our results of operations, liquidity and cash flows could be adversely impacted.

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

As of December 31, 2009, we had approximately $1.4 billion of consolidated indebtedness outstanding. The significant level of indebtedness may have an adverse effect on our future operations, including:

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

A continuing period of weak economic activity may make it increasingly difficult to comply with our covenants and other restrictions in agreements governing our debt. Our ability to comply with these covenants and other restrictions is affected by the current economic conditions and other events beyond our control. If we fail to comply with these covenants and other restrictions, it could lead to an event of default, the possible acceleration of our repayment of outstanding debt and the exercise of certain remedies by the lenders, including foreclosure on our pledged collateral.

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

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

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

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

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

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

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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.

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 of Mexico, North Sea, West Africa or Asia Pacific regions, levels of competition may increase and our business could be adversely affected. In the exploration and production business, some of the larger integrated companies may be better able to respond to industry changes including price fluctuations, oil and gas demand, political change and government regulations.

In addition, in a few countries, the national oil companies have formed subsidiaries to provide oilfield services for them, competing with services provided by us. To the extent this practice expands, our business could be adversely impacted.

Government Regulation, including recent legislative initiatives, may affect demand for our services.

Numerous federal and state regulations affect our operations. Current regulations are constantly reviewed by the various agencies at the same time that new regulations are being considered and implemented. In addition, because we hold federal leases, the federal government requires us to comply with numerous additional regulations that focus on government contractors. The regulatory burden upon the oil and gas industry increases the cost of doing business and consequently affects our profitability. Potential legislation and/or regulatory actions could increase our costs and reduce our liquidity, delay our operations or otherwise alter the way we conduct our business. Exploration and development activities and the production and sale of oil and gas are subject to extensive federal, state, local and international regulations.

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 domestic and foreign governmental agencies issue rules and regulations to implement and enforce such laws that are often complex and costly to comply with and that carry substantial administrative, civil and possibly criminal penalties for failure to comply. Under these laws and regulations, we may be liable for remediation or removal costs, damages and other costs associated with releases of hazardous materials, including oil into the environment, and such liability may be imposed on us even if the acts that resulted in the releases were in compliance with all applicable laws at the time such acts were performed.

A variety of regulatory developments, proposals or requirements and legislative initiatives have been introduced in the domestic and international regions in which we operate that are focused on restricting the emission of carbon dioxide, methane and other greenhouse gases.

On June 26, 2009, the U.S. House of Representatives approved adoption of the “American Clean Energy and Security Act of 2009,” also known as the “Waxman-Markey Cap-and-Trade legislation,” or “ACESA.” The purpose of ACESA is to control and reduce emissions of greenhouse gases in the United States. The U.S. Senate has begun work on its own legislation for controlling and reducing emissions of greenhouse gases in the United States. For legislation to become law, both chambers of U.S. Congress would be required to approve identical legislation. It is not possible at this time to predict whether or when the Senate may act on climate change legislation, how any bill approved by the Senate would be reconciled with ACESA, or how federal legislation may be reconciled with state and regional requirements.

In 2007, the U.S. Supreme Court held in Massachusetts, et al. v. EPA that greenhouse gases are an “air pollutant” under the federal Clean Air Act and thus subject to future regulation. In December 2009, the U.S. Environmental Protection Agency (the “EPA”) issued an “endangerment and cause or contribute finding” for greenhouse gases under the federal Clean Air Act, which will allow the EPA to draft rules that directly regulate greenhouse gas emissions.

Recently, the EPA issued the Final Mandatory Reporting of Greenhouse Gases Rule. This rule became effective December 29, 2009 and will require the collection of information beginning in January 2010 with annual reporting to begin in 2011 for covered facilities. The rule requires reporting of greenhouse gas emissions from large sources and suppliers in

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the United States and the EPA has stated that it will use the information to guide development of the policies and programs to reduce emissions.

These regulatory developments and legislative initiatives may curtail production and demand for fossil fuels such as oil and gas in areas of the world where our customers operate and thus adversely affect future demand for our products and services, which may in turn adversely affect our future results of operations. In addition, changes in environmental laws and regulations, or claims for damages to persons, property, natural resources or the environment, could result in substantial costs and liabilities, and thus there can be no assurance that we will not incur significant environmental compliance costs in the future. Such environmental liability could substantially reduce our net income and could have a significant impact on our financial ability to carry out our operations.

In 2009, U.S. Customs and Border Protection ("CBP") issued a proposed modification to its prior rulings regarding the application of the Jones Act to the carriage by foreign flag vessels of items relating to certain offshore activities on the OCS. While CBP subsequently withdrew these proposed modifications, we are aware that the parent agency of CBP, the Department of Homeland Security ("DHS"), may be preparing a notice of proposed rulemaking respecting the same subject matter. If DHS proposes a change to the application of the Jones Act similar to that originally proposed by CBP, and such proposal is adopted, this development could potentially lead to operational delays or increased operating costs in instances where we would be required to hire coastwise qualified vessels that we currently do not own, in order to transport certain merchandise to projects on the OCS. This could increase our costs of compliance and doing business and make it more difficult to perform pipelay or well operation services.

Beginning in 2011, the federal government has proposed to levy a tax on offshore production and to repeal a number of existing tax preferences for domestic oil and gas producers. The tax preferences include, but are not limited, to the elimination of the immediate expensing of intangible drilling costs, the use of percentage depletion methodology in respect to oil and gas wells, the ability to claim the domestic manufacturing deduction against income derived from oil and gas production and other preference items. The elimination of one or all of these tax preferences may have an adverse impact on our financial results in future years. In addition, it is uncertain as to whether we will be able to recoup these additional tax costs from our customers.

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

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

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

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

We have a history of growing through acquisitions of large assets and acquisitions of companies. We must plan and manage our acquisitions effectively to achieve revenue growth and maintain profitability in our evolving market. If we fail to effectively manage current and future acquisitions, our results of operations could be adversely affected. Our growth has placed 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.

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

In addition to the 6,000 shares of preferred stock held by Fletcher International, Ltd. pursuant to 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 Articles of Incorporation give our board of directors the authority, without any action by our shareholders, to fix the rights and preferences on up to 4,994,000 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 arrangements with all of our executive officers that require cash payments in the event of a "change of control." Any or all of the provisions or factors described above may discourage a takeover proposal or tender offer not approved by management and the board of directors and could result in shareholders who may wish to participate in such a proposal or tender offer receiving less for their shares than otherwise might be available in the event of a takeover attempt.

Risks Relating to our Contracting Services Operations

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

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

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

A sustained period of low drilling and production activity or 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. Insurance may not be sufficient or effective under all circumstances or against all hazards to which we may be subject. A successful claim for which we are not fully insured could have a material adverse effect on us. Moreover, we cannot assure you that we will be able to maintain adequate insurance in the future at rates that we consider reasonable. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased substantially and could escalate further. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. For example, insurance carriers are now requiring broad exclusions for losses due to war risk and terrorist acts and limitations for wind storm damages. As construction activity expands into deeper water in the Gulf of Mexico and other deepwater basins of the world and with our divestiture of Cal Dive, a greater percentage of our revenues will be from deepwater construction projects that are larger and more complex, and thus riskier,

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than shallow water projects. As a result, our revenues and profits are increasingly dependent on our larger vessels. The current insurance on our vessels, in some cases, is in amounts approximating book value, which could be less than replacement value. In the event of property loss due to a catastrophic marine disaster, mechanical failure, collision or other event, insurance may not cover a substantial loss of revenues, increased costs and other liabilities, and therefore, the loss of any of our large vessels could have a material adverse effect on us.

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

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

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

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

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

Risks Relating to our Oil and Gas Operations

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

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

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

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

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

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

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

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

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

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

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

If the prices for crude oil and natural gas decrease from current levels, and we have not entered into additional forward sale or financial hedge contracts to stabilize our cash flows, our oil and gas revenues may decrease in 2010 and beyond, perhaps significantly, absent offsetting increases in production amounts.

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

Oil and gas prices can fluctuate significantly and have a direct impact on our revenues. To manage our exposure to the risks inherent in such a volatile market, from time to time we have forward sold for future physical delivery a portion of our future production. This means that a portion of our production is sold at a fixed price as a shield against dramatic price declines that could occur in the market. We have hedged over 50% of our anticipated production for 2010 with a combination of costless collar and swap financial contracts. We may from time to time engage in other hedging activities that limit our upside potential from price increases. These hedging activities may limit our benefit from commodity price increases.

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We are vulnerable to risks associated with the Gulf of Mexico because we currently operate almost exclusively in that area and our proved reserves are concentrated in a limited number of fields.

Our concentration of oil and gas properties in the Gulf of Mexico makes us more vulnerable to the risks associated with operating in that area than our competitors with more geographically diverse operations. These risks include:

- tropical storms and hurricanes, which are common in the Gulf of Mexico during certain times of the year;
- extensive governmental regulation (including regulations that may, in certain circumstances, impose strict liability for pollution damage); and
- interruption or termination of operations by governmental authorities based on environmental, safety or other considerations.

Any event affecting this area in which we operate our oil and gas properties may have an adverse effect on our results of operations and cash flow. We also may incur substantial liabilities to third parties or governmental entities, which could have a material adverse effect on our results of operations and financial condition.

Additionally, approximately 98% of our estimated proved reserves are located in the Gulf of Mexico and we have one field, Bushwood located at Garden Banks Blocks 462, 463, 506 and 507, that represents approximately half of our total estimated proved reserves and related estimated discounted future net revenues as of December 31, 2009. If the proved reserves at Bushwood are affected by any combination of adverse factors our future estimates of proved reserves could be decreased, perhaps significantly, which may have an adverse effect on our future results of operations and cash flows. Separately, without Bushwood's future reserve potential, the value that we may be able to realize in any potential disposition of our oil and gas business would likely be significantly diminished.

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

This Annual Report contains estimates of our proved oil and gas reserves and the estimated future net cash flows therefrom based upon reports for the years ended December 31, 2009 and 2008, prepared and/or audited by our independent petroleum engineers. These reports rely upon various assumptions, including assumptions required by the SEC, as to oil and gas prices, drilling and operating expenses, capital expenditures, abandonment costs, taxes and availability of funds. The process of estimating oil and gas reserves is complex, requiring significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. As a result, these estimates are inherently imprecise. Actual future production, cash flows, development and production expenditures, operating and abandonment expenses and quantities of recoverable oil and gas reserves may vary from those estimated in these reports. Any significant variance in these assumptions could materially affect the estimated quantity and value of our proved reserves. You should not assume that the present value of future net cash flows from our proved reserves referred to in this Annual Report is the current market value of our estimated oil and gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on the average of oil and gas prices on the first day of the month for the past twelve months and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the net present value estimate. In addition, if costs of abandonment are materially greater than our estimates, they could have an adverse effect on financial position, cash flows and results of operations.

Approximately 85% of our total estimated proved reserves are either PDNP, PDSI or PUD and those reserves may not ultimately be produced or developed.

As of December 31, 2009, approximately 17% of our total estimated proved reserves were PDNP, 5% were PDSI and approximately 63% were PUD. These reserves may not ultimately be developed or produced. Furthermore, not all of our PUD or PDNP may be ultimately produced during the time periods we have planned, at the costs we have budgeted, or at all, which in turn may have a material adverse effect on our results of operations.

Reserve replacement may not offset depletion.

Oil and gas properties are depleting assets. We replace reserves through acquisitions, exploration and exploitation of current properties. Approximately 85% of our proved reserves at December 31, 2009 are PUD, PDSI and PDNP. Further, our proved producing reserves at December 31, 2009 are expected to experience annual decline rates ranging from 30% to 40% over the next ten years. If we are unable to acquire additional properties or if we are unable to find additional reserves through exploration or exploitation of our properties, our future cash flows from oil and gas operations could decrease.

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

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

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

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

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

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

Other Risks

Other risk factors could cause actual results to be different from the results we expect. The market price for our common stock, as well as other companies in the oil and natural gas industry, has been historically volatile, which could restrict our access to capital markets in the future. Other risks and uncertainties may be detailed from time to time in our filings with the SEC.

Many of these risks are beyond our control. In addition, future trends for pricing, margins, revenue and profitability remain difficult to predict in the industries we serve and under current market, economic and political conditions.

Forward-looking statements speak only as of the date they are made and, except as required by applicable law, we do not assume any responsibility to update or revise any of our forward-looking statements.

Item 1B. Unresolved Staff Comments.

None.

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Item 2. Properties.

We own a fleet of seven vessels and 39 ROVs, five trenchers, and two ROVDrills. We also lease five vessels and one ROV. We believe that the market in the Gulf of Mexico requires specially designed and/or equipped vessels to competitively deliver subsea construction and well operations services. Currently all of our vessels, both owned and leased, have DP capabilities specifically designed to respond to the deepwater market requirements. Two of our vessels have built-in saturation diving systems.

Divestitures

In March and April 2008, we sold a total 30% working interest in the Bushwood discoveries (Garden Banks Blocks 463, 506 and 507) and other Outer Continental Shelf oil and gas properties (East Cameron Blocks 371 and 381), in two separate transactions to affiliates of a private independent oil and gas company for total cash consideration of approximately $183.4 million (which included the purchasers' share of incurred capital expenditures on these fields), and additional potential cash payments of up to $20 million based upon exceeding specified field production milestones. The new co-owners will also pay their pro rata share of all future capital expenditures related to the exploration, development and decommissioning of these fields. Decommissioning liabilities will be shared on a pro rata share basis between the new co-owners and us. Proceeds from the sale of these properties were used to partially repay our outstanding revolving loans in April 2008. As a result of these sales, we recognized a pre-tax gain of $91.6 million in the first half of 2008.

In May 2008, we sold all our interests in our onshore proved and unproved oil and gas properties located in the states of Texas, Mississippi, Louisiana, New Mexico and Wyoming ("Onshore Properties") to an unrelated third party. We sold these Onshore Properties for cash proceeds of $47.3 million and recorded a related loss of $11.9 million in the second quarter of 2008. Proceeds from the sale of these properties were used to reduce our outstanding revolving loans in May 2008. Included in the cost basis of the Onshore Properties was $8.1 million of allocated goodwill from our Oil and Gas segment.

In December 2008, we announced the sale of all our interests in the Bass Lite field (Atwater Block 426), a 17.5% working interest, to our joint interest owners in the field for approximately $49 million. The sale had an effective date of November 1, 2008. Proceeds from the sale were used to fund our working capital requirements.

In 2009 the following divestitures were made in accordance with our announcement in December 2008 to attempt to monetize the value of our non-core assets see "The Industry and Our Strategy" above.   Since that announcement, we have:

- Sold five oil and gas properties for approximately $68 million in gross proceeds;
- Sold a total of approximately 15.2 million shares of CDI common stock held by us to CDI for $100 million in separate transactions in January and June 2009 (Note 3);
- Sold Helix RDS Limited, our subsurface reservoir consulting business for $25 million in April 2009; and
- Sold a total of 45.8 million shares of CDI common stock held by us to third parties in two separate public secondary offerings for approximately $404.4 million, net of underwriting fees in June 2009 and September 2009.

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OUR VESSELS

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

	Flag State	Placed in Service(2)	Length (Feet)	Berths	SAT Diving	DP	Crane Capacity (tons)
CONTRACTING SERVICES:							
Pipelay —							
Caesar (3)(4)	Vanuatu	1/2006	482	220	—	DP	300 and 36
Express (4)	Vanuatu	8/2005	531	132	—	DP	396 and 150
Intrepid (4)	Bahamas	8/1997	381	89	—	DP	400
Floating Production Unit —							
Helix Producer I (5)	Bahamas	—	528	95	—	DP	26 and 26
Well Operations —							
Q4000 (6)	U.S.	4/2002	312	135	—	DP	160 and 360; 600 Derrick
Seawell	U.K.	7/2002	368	129	Capable	DP	130 and 65 Derrick
Well Enhancer	U.K.	10/2009	432	120	Capable	DP	100 and 150 Derrick
Robotics —							
39 ROVs, 5 Trenchers and 2 ROVDrills (4), (7)	—	Various	—	—	—	—	—
Olympic Canyon (8)	Norway	4/2006	304	87	—	DP	150
Olympic Triton (8)	Norway	11/2007	311	87	—	DP	150
Seacor Canyon (8)	Majuro Marshall Island	4/2007	221	40	—	DP	20
Island Pioneer (8)	Vanuatu	5/2008	312	110	—	DP	140

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

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

(3) Vessel conversion started in March 2007. Vessel expected to be commissioned into our fleet in the first half of 2010.

(4) Subject to vessel mortgages (US ROVs and trenchers only) securing our Senior Credit Facilities described in Item 8. Financial Statements and Supplementary Data “— Note 10 — Long-term Debt.”

(5)

Former ferry vessel near completion into DP floating production unit for initial use on our Phoenix field. See Production Facilities on page 30.

(6) Subject to vessel mortgage securing our MARAD debt described in Item 8. Financial Statements and Supplementary Data "— Note 10 — Long-term Debt."

(7) Average age of our fleet of ROVs, trenchers and ROV Drills is approximately 5.3 years.

(8) Leased.

The following table details the average utilization rate for our vessels by category (calculated by dividing the total number of days the vessels in this category generated revenues by the total number of calendar days in the applicable period) for the years ended December 31, 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
Contracting Services:			
Pipelay	79%	92%	79%
Well operations	82%	70%	71%
ROVs	68%	73%	78%

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

PRODUCTION FACILITIES

We own a 50% interest in Deepwater Gateway, a limited liability company in which Enterprise Products Partners L.P. is the other member, which owns the Marco Polo TLP installed on Green Canyon Block 608 in 4,300 feet of water. Deepwater Gateway 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, an affiliate of Enterprise Products Partners L.P., that owns the Independence Hub platform, a 105 foot deep draft, semi-submersible platform located in Mississippi Canyon Block 920 in a water depth of 8,000 feet that serves as a regional hub for natural gas production from multiple ultra-Deepwater fields in the previously untapped eastern Gulf of Mexico. First production began in July 2007. The Independence Hub facility is capable of processing up to 1 billion cubic feet (Bcf) per day of gas.

Further, we, along with Kommandor Rømø, a Danish corporation, formed a joint venture company called Kommandor LLC and converted a ferry vessel into a floating production unit named the Helix Producer I. The total cost of the vessel and initial conversion was approximately $170 million. We provided $98.9 million in interim construction financing to the joint venture. During 2009, $58.8 million of this amount was converted to equity in our investment in Kommandor LLC. Our remaining loan balance to Kommandor LLC totaled $25.7 million at December 31, 2009. Kommandor Rømø provided a $5.0 million loan to Kommandor LLC, the remaining balance of which was $3.7 million at December 31, 2009.

Total equity contributions and indebtedness guarantees provided by Kommandor Rømø are expected to total $42.5 million. The remaining costs to complete the project will be provided by us through equity contributions. Under the terms of the operating agreement for the joint venture, Kommandor Rømø elected not to make further contributions to the joint venture, thus the ownership interests in the joint venture were adjusted based on the relative contributions of each member to the total of all contributions and project financing guarantees.

As noted above, completion of the initial conversion of the Helix Producer I was completed in April 2009, and we have chartered the vessel from Kommandor LLC, and are currently installing, at 100% our cost, processing facilities and a disconnectable fluid transfer system on the vessel for initial use on our Phoenix field expected to commence production around mid-year 2010. The cost of these additional facilities is estimated to range between $190 million and $200 million (including capitalized interest of $16 million) when the work is completed. When completed, the Helix Producer I will be capable of processing up to 45,000 barrels of oil and 70 MMcf of natural gas daily. As of December 31, 2009, approximately $269 million of costs related to the purchase of the Helix Producer I ($20 million), conversion of the Helix Producer I and construction of the additional facilities had been incurred, with an additional $12.1 million committed. The total estimated cost of the vessel, initial conversion and the additional facilities will range between approximately $360 million and $370 million. The results of Kommandor LLC are consolidated within our Production Facilities segment.

SUMMARY OF NATURAL GAS AND OIL RESERVE DATA

Recent Accounting Rules Activities

In December 2008, the SEC announced that it had approved revisions designed to modernize the oil and gas company reserve reporting requirements. In January 2010, the FASB issued Accounting Standards Update 2010-03 “Oil and Gas Reserve Estimation and Disclosures.” We adopted these rules on December 31, 2009 in conjunction with our year end 2009 proved reserve estimates and have implemented the newly mandated authoritative guidance issued by the

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FASB on extractive activities for oil and gas reserves estimation and disclosures. The objective of the new guidance is to align the oil and gas reserve estimation and disclosure requirements with the requirements of the SEC. The most significant amendments to the requirements included the following.

- Commodity prices - estimates of proved reserves and related discounted cash flows now based on an average twelve month commodity price based on the price of oil and gas on the first day of each month for the year the reserve report relates;
- Disclosure of Unproved Reserves - Probable and Possible reserves may be disclosed separately from proved reserves on a voluntary basis. We elected not to disclose Probable and Possible reserves;
- Proved Undeveloped Reserve Guidelines – Reserves maybe classified as proved undeveloped reserves if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years, unless specific circumstances justify a longer time;
- Reserves Estimation Using New Techniques – Reserves may be estimated through a use of reliable techniques in addition to traditional flow test and production history;
- Reserves Personnel and Estimation Process – Additional disclosure is required regarding the qualifications of the chief technical person who oversees the reserve estimation process and/or the independence of the preparer of our estimated proved reserves. We must also disclose our significant internal controls over the reserve estimation process;
- Disclosure by Geographic Area – Reserves in foreign countries must be presented separately if such reserves represent more than 15% of our total estimated oil and gas proved reserves; and
- Non Traditional Resources- The definition of oil and gas producing activities has been expanded to include other marketable products.

One effect of adoption of these rules included the application of lower prices at December 31, 2009 for both oil and natural gas than what would have been used under the previous rule (year end price). Generally, adoption of these new regulations had little effect on our estimates of reserves at December 31, 2009; however, the rule requiring development of proved undeveloped reserves within five years could significantly impact future estimates of our proved reserves (see “Proved Undeveloped Reserves” below).

Internal Controls Over Reserve Estimation Process

Our policies regarding internal controls over the recording of reserves estimates requires reserves to be in compliance with the SEC definitions and guidance and prepared in accordance with generally accepted petroleum engineering principles. Responsibility for compliance in reserves bookings is delegated to our Vice President – Reservoir Engineering.

Our Vice President – Reservoir Engineering, located in our Dallas, Texas office, prepares all reserves estimates for all of our oil and gas properties.

Our Vice President – Reservoir Engineering is the technical person primarily responsible for overseeing the preparation of our reserves estimates. Our Vice President – Reservoir Engineering has a Bachelor of Science degree in Engineering and over 15 years of industry experience with positions of increasing responsibility in engineering and evaluations.

We employ full-time experienced reserve engineers and geologists who are responsible for determining proved reserves in conformance with SEC guidelines. Engineering reserve estimates were prepared by us based upon our interpretation of production performance data and sub-surface information derived from the drilling of existing wells. Our internal reservoir engineers analyzed 100% of our oil and gas fields on an annual basis (107 fields as of December 31, 2009). We consider any field with discounted future net revenues of 1% or greater of the total discounted future net revenues of all our fields to be significant.

Lastly we engage a third party independent reservoir engineer to review and audit our reserve estimation process and the results of this process. At December 31, 2009 we engaged the independent reservoir engineer to prepare their own estimates of our proved reserves at December 31, 2009. Their proved reserve estimates are included in this Form 10-K. The same independent reservoir engineer audited substantially all of our estimates of proved reserves at December 31, 2008 and 2007. See Independent Petroleum Engineer below

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Independent Petroleum Engineer

We have historically engaged a third party independent petroleum engineer to audit our internal estimates of U.S. proved oil and natural gas reserves. However, the estimates of our U.S. proved oil and natural gas reserves at December 31, 2009 were prepared by the independent petroleum engineering firm of Huddleston & Co., Inc. ("Huddleston"). We prepared the proved reserve estimates associated with our one property in the United Kingdom. Huddleston performed engineering audits of our estimates of proved reserves at December 31, 2008 and 2007.

An "engineering audit," as we use the term, is a process involving an independent petroleum engineering firm's extensive visits, collection and examination of all geologic, geophysical, engineering, production and economic data requested by the independent petroleum engineering firm. Our use of the term "engineering audit" is intended only to refer to the collective application of the procedures which Huddleston was engaged to perform and may be defined and used differently by other companies. The process for Huddleston to prepare their estimates of proved oil and natural gas reserves is substantially the same as during their audit of our internal reserves (discussed below). The primary difference between the audit and preparation of the reserve report is that in the culmination of the audit, Huddleston represented in its audit report that it believed our methodologies are consistent with the methodologies required by the SEC, Society of Petroleum Engineers ("SPE") and FASB while in the preparation of the 2009 reserve report we simply publish Huddleston's estimates of our proved oil and natural gas reserves, also in compliance with the guidelines provided by the SEC, SPE and FASB.

The engineering audit of our estimated proved oil and natural gas reserves (applicable for 2008 and 2007) by the independent petroleum engineers involves their rigorous examination of our technical evaluation, interpretation and extrapolations of well information such as flow rates and reservoir pressure declines as well as other technical information and measurements. Our internal reservoir engineers interpret this data to determine the nature of the reservoir and ultimately the quantity of proved oil and gas reserves attributable to a specific property. Our proved reserves in this Form 10-K for the years ended December 31, 2008 and 2007 include only quantities that we expected to recover commercially using the then mandated year-end prices, costs, existing regulatory practices and technology. While we are reasonably certain that the proved reserves will be produced, the timing and ultimate recovery can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and changes in projections of long-term oil and gas prices. Revisions can include upward or downward changes in the previously estimated volumes of proved reserves for existing fields due to evaluation of (1) already available geologic, reservoir or production data or (2) new geologic or reservoir data obtained from wells. Revisions can also include changes associated with significant changes in development strategy, oil and gas prices, or the related production equipment/facility capacity. Huddleston also examined our estimates with respect to reserve categorization, using the definitions for proved reserves set forth in Regulation S-X Rule 4-10(a) and subsequent SEC staff interpretations and guidance.

In the conduct of the engineering audits in 2008 and 2007, Huddleston did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties or sales of production. However, if in the course of the examination something came to the attention of Huddleston which brought into question the validity or sufficiency of any such information or data, Huddleston did not rely on such information or data until it had satisfactorily resolved its questions relating thereto or had independently verified such information or data. Furthermore, in instances where decline curve analysis was not adequate in determining proved producing reserves, Huddleston evaluated our volumetric analysis, which included the analysis of production and pressure data. Each of the PUDs analyzed by Huddleston included volumetric analysis, which took into consideration recovery factors relative to the geology of the location and similar reservoirs. Where applicable, Huddleston examined data related to well spacing, including potential drainage from offsetting producing wells in evaluating proved reserves for un-drilled well locations.

Huddleston prepared proved reserve estimates for all of our U.S oil and gas properties at December 31, 2009. Huddleston's report on proved reserves is included herein as Exhibit 99.1 to this Form 10-K. In 2008, the engineering audit by Huddleston included 100% of our producing properties together with essentially all of our non-producing and undeveloped properties in the U.S. Properties for analysis were selected by us and Huddleston based on discounted future net revenues. All of our significant properties were included in the engineering audit and such audited properties constituted approximately 97% of the total discounted future net revenues. Huddleston also analyzed the methods utilized by us in the preparation of all of the estimated reserves and revenues. Huddleston represented in its audit report that it

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believes our methodologies are consistent with the methodologies required by the SEC, Society of Petroleum Engineers ("SPE") and FASB. There were no limitations imposed, nor limitations encountered by us or Huddleston.

The table below sets forth the approximate estimate of our proved reserves as of December 31, 2009. 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, 2009		
	Proved Developed Reserves	Proved Undeveloped Reserves	Total Proved Reserves
United States:			
Gas (Bcf)	125	262	387
Oil (MMBbls)	15	15	30
Total (Bcfe)	214	342	566
United Kingdom:			
Gas (Bcf)	—	12	12
Oil (MMBbls)	—	—	—
Total (Bcfe)	—	12	12
Total:			
Gas (Bcf)	125	274	399
Oil (MMBbls)	15	15	30
Total (Bcfe)	214	364	578

Proved Undeveloped Reserves ("PUDs")

At December 31, 2009, our PUDs totaled 274 Bcf of natural gas and 15 MMBbls of crude oil for a total of 364 Bcfe. Our PUD's represent 63% of our total estimates of proved oil and natural gas reserves. All estimates of oil and natural gas reserves are inherently imprecise and subject to change as new technical information about the properties is obtained. Estimates of proved reserves for wells with little or no production history are less reliable than those based on a long production history. Subsequent evaluation of the same reserves may result in variations which may be substantial. This is especially valid as it pertains to PUD reserves.

Our most substantial PUDs are located at our Bushwood field (see "Significant Oil and Gas Properties" below). Our Bushwood field has PUDs totaling approximately 200 Bcfe representing approximately 74% of its total estimated proved reserves. We had substantial changes in our Bushwood PUD reserves in 2009 including a reclassification of 59 Bcfe from proved developed producing (PDP) to PUD based on well production history of our Noonan gas wells in field and new geologic data gathered throughout the year. Separately, we also converted approximately 23 Bcfe of our PUDs to proved developed – non producing in 2009. These PUDs were associated with our Danny oil reservoir where production commenced in early February 2010.

Costs incurred to develop PUDs totaled $ 53.2 million in 2009, $154.4 million in 2008 and $98.4 million in 2007. All PUD drilling locations are expected to be drilled pursuant with the newly enacted requirements (see "Recent Accounting Rules Activity" above). Accordingly, estimated future development costs related to the development of PUDs are approximately $442 million at December 31, 2009.

For additional information regarding estimates of oil and gas reserves, including estimates of proved developed and proved undeveloped reserves, the standardized measure of discounted future net cash flows, and the changes in discounted future net cash flows, see Item 8. Financial Statements and Supplementary Data "— Note 20— Supplemental Oil and Gas Disclosures."

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Significant Oil and Gas Properties

Our oil and gas properties consist primarily of interests in developed and undeveloped oil and gas leases. As of December 31, 2009, we had exploration, development and production operations in the United States, exclusively in the Gulf of Mexico. In December 2006, we acquired the Camelot field, located in the North Sea, in which we subsequently sold a 50% interest in June 2007. In February 2010, we acquired our joint interest partner and as a result we own a 100% interest in the Camelot field. We are now obligated to pay the entire abandonment obligation for the field (estimated to range between $10-15 million). The acquired entity had secured its field abandonment obligations with a $10 million letter of credit which was fully collateralized with cash. Camelot is our only oil and gas property in the United Kingdom.

Our U.S. operations accounted for over 99% of our 2009 production and approximately 98% of total proved reserves at December 31, 2009 (85% of such total reserves are PUDs, PDSI, and PDNP). Further, our proved producing reserves at December 31, 2009 are expected to experience annual decline rates ranging from 30% to 40% over the next ten years. The following table provides a brief description of our domestic and international oil and gas properties we consider most significant to us at December 31, 2009:

	Development Location	Net Total Proved Reserves (Bcfe)	Net Proved Reserves Mix		2009 Net Production (Bcfe)	Average WI%	Expected First Production
			Oil %	Gas %			
United States Offshore:							
Deepwater							
Bushwood(1)	U.S. GOM	270	11	89	6	51	Producing
Phoenix(2)	U.S. GOM	42	79	21	-	70	PDSI 2010
Gunnison(3)	U.S. GOM	24	66	34	5	19	Producing
Jake (4)	U.S. GOM	6	23	77	-	25	PUD 2011
Outer Continental Shelf							
East Cameron 346	U.S. GOM	35	80	20	2	75	Producing
High Island A557	U.S. GOM	20	69	31	3	100	Producing
South Timbalier 86/63	U.S. GOM	29	36	64	3	91	Producing
South Pass 89	U.S. GOM	23	39	61	1	27	Producing
Mobile 863	U.S. GOM	20	-	100	-	83	PUD 2010
West Cameron 170	U.S. GOM	11	29	71	1	55	Producing
South Marsh Island 130	U.S. GOM	11	73	27	3	100	Producing
Ship Shoal 223/224	U.S. GOM	9	36	64	1	51	Producing
East Cameron 339	U.S. GOM	8	79	21	4	100	Producing
Eugene Island 302	U.S. GOM	9	62	38	-	58	PUD 2010
United Kingdom Offshore(5)	UK Offshore	12	-	100	-	50	PUD 2011

(1) Garden Banks Blocks 462, 463, 506 and 507 (formerly Noonan/Danny). Although the Bushwood field is currently producing, there remains a significant amount of PUD reserves that will need to be developed in order to sustain future production from the field.

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

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

(4) Green Canyon Block 490.

(5) Consists of our only property in the United Kingdom, Camelot. Our interest increased to 100% in February 2010 when we agreed to assume our joint interest partners interest in the field as discussed above.

United States Offshore

Deepwater

The estimated proved reserves associated with our four fields in the Deepwater of the Gulf of Mexico totaled approximately 341 Bcfe or approximately 59% of our total estimated proved reserves at December 31, 2009. We are the operator over areas representing approximately 57% of our Deepwater proved reserves (approximately 43% of total proved reserves). We operate the Phoenix field and portions of the Bushwood field. Gunnison, a non-operated field, has been producing since December 2003. In 2009, we participated in the discovery at the Jake Prospect, which is expected to be developed and commence production in 2011. Our net production from our Deepwater properties totaled approximately 12.3 Bcfe in 2009 as compared to 8 Bcfe in 2008.

Outer Continental Shelf

Our estimated proved reserves for our 102 fields in the Gulf of Mexico on the OCS totaled approximately 225 Bcfe or 39% of our total estimated proved reserves as of December 31, 2009. Our net production from the OCS properties totaled approximately 31.3 Bcfe in 2009. Our largest field on the OCS is East Cameron Block 346, whose total estimated proved reserve represents approximately 16% of our aggregated OCS estimated proved reserves (or approximately 6% of total estimated proved reserves). The South Timbalier Blocks 86/63 field represents approximately 13% of our total estimated OCS proved reserves (or approximately 5% of our total estimated proved reserves). No other individual OCS field comprised over 5% of total estimated proved reserves. We are the operator of 80% of our OCS properties whose composite estimated proved reserves totals approximately 179 Bcfe.

As long as we continue to have interests in our oil and gas properties, we will continue to advance our development activities and may pursue additional future exploration opportunities primarily in the Deepwater of the Gulf of Mexico.

United Kingdom Offshore

In December 2006, we acquired the Camelot field, located in the North Sea, of which we subsequently sold a 50% interest in June 2007. In February 2010, we acquired our joint interest partner and as a result we own a 100% interest in the Camelot field. We are now obligated to pay the entire abandonment obligation for the field (estimated to range between $10-$15 million). Camelot is our only developed oil and gas property in the United Kingdom. The results of our UK operations were immaterial for each of the three years ended December 31, 2009, 2008 and 2007, respectively.

Production, Price and Cost Data

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

	Year Ended December 31,		
	2009	2008	2007
Production:			
Gas (Bcf)	27	31	42
Oil (MMBbls)	3	3	4
Total (Bcfe)	44	47	65

Average sales prices realized (including hedges):						
Gas (per Mcf)	$	4.48	$	9.29	$	7.69
Oil (per Bbl)	$	67.11	$	92.22	$	67.68
Total (per Mcfe)	$	7.00	$	11.43	$	8.93
Average production cost per Mcfe	$	2.74	$	2.60	$	1.83
Average depletion and amortization per Mcfe	$	3.87	$	4.21	$	3.54

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Productive Wells

The number of productive oil and gas wells in which we held interest as of December 31, 2009 is as follows:

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
United States – Offshore	276	218	302	156	578	374

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

The following table summarizes non-producing wells and wells with multiple completions as of December 31, 2009:

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Not producing (shut-in)	51	33	144	83	195	116
Multiple completions	16	7	53	22	69	29

Developed and Undeveloped Acreage

The developed and undeveloped acreage (including both leases and concessions) that we held at December 31, 2009 is as follows:

	Undeveloped		Developed	
	Gross	Net	Gross	Net
United States – Offshore	235,186	196,255	457,165	257,633
United Kingdom – Offshore	25,406	12,703	9,778	4,889
Total	260,592	208,958	466,943	262,522

Developed acreage is acreage spaced or assignable to productive wells. A gross acre is an acre in which a working interest is owned. A net acre is deemed to exist when the sum of fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Undeveloped acreage is considered to be those leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and natural gas regardless of whether or not such acreage contains proved reserves. Included within undeveloped acreage are those leased acres (held by production under the terms of a lease) that are not within the spacing unit containing, or acreage assigned to, the productive well so holding such lease. The current terms of our leases on undeveloped acreage are scheduled to expire as shown in the table below (the terms of a lease may be extended by drilling and production operations):

Offshore

	Gross	Net
2010	73,686	60,339
2011	30,872	21,416
2012	27,275	21,515
2013	30,760	30,760
2014	5,760	5,760
2015 and beyond	66,833	56,465
Total	235,186	196,255

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Drilling Activity

The following table shows the results of oil and gas wells drilled in the United States for each of the years ended December 31, 2009, 2008 and 2007:

	Net Exploratory Wells			Net Development Wells		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2009	0.3	—	0.3	—	—	—
Year ended December 31, 2008	0.4	0.6	1.0	2.4	—	2.4
Year ended December 31, 2007	10.8	1.1	11.9	6.4	1.0	7.4

No wells were drilled in the United Kingdom in 2009, 2008 and 2007.

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

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

At December 31, 2009, we had one development well in progress at our Gunnison field. For more information regarding our oil and gas operations see Item 8. Financial Statements and Supplementary Data "— Note 6 — Oil and Gas Properties."

FACILITIES

Our corporate headquarters are located at 400 North Sam Houston Parkway, East, Suite 400, Houston, Texas. We own the Aberdeen (Dyce), Scotland facility and our Spoolbase in Ingleside, Texas. All other facilities are leased.

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Properties and Facilities Summary

Location	Function	Size
Houston, Texas	Helix Energy Solutions Group, Inc. Corporate Headquarters, Project Management, and Sales Office	92,300 square feet
	Helix Subsea Construction, Inc. Corporate Headquarters	
	Energy Resource Technology GOM, Inc. Corporate Headquarters	
	Helix Well Ops, Inc. Corporate Headquarters, Project Management, and Sales Office	
	Kommandor LLC (1) Corporate Headquarters	
Houston, Texas	Canyon Offshore, Inc. Corporate, Management and Sales Office	1.0 acre (Building: 24,000 square feet)
Dallas, Texas	Energy Resource Technology GOM, Inc. Dallas Office	25,000 square feet
Ingleside, Texas	Helix Ingleside LLC Spoolbase	120 acres
Dulac, Louisiana	Energy Resource Technology GOM, Inc. Shore Base	20 acres 1,720 square feet
Aberdeen (Dyce), Scotland	Helix Well Ops (U.K.) Limited Corporate Offices and Operations	3.9 acres (Building: 42,463 square feet)
	Canyon Offshore Limited Corporate Offices, Operations and Sales Office	
	Energy Resource Technology U.K. Limited Corporate Offices	
Perth, Australia	Well Ops SEA Pty Ltd Corporate Offices	1.0 acre (Building: 12,040 square feet)
	Helix ESG Pty Ltd. Corporate Offices	
Rotterdam, The Netherlands	Helix Energy Solutions BV Corporate Offices	21,600 square feet
Singapore	Canyon Offshore International Corp Corporate, Operations and Sales	22,486 square feet
	Helix Offshore Crewing Service Pte. Ltd. Corporate Headquarters	

(1) Kommandor LLC is a joint venture in which we owned approximately 81% at December 31, 2009. Kommandor LLC is included in our consolidated results as of December 31, 2009.

Item 3. Legal Proceedings.

Insurance and Litigation

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

On December 2, 2005, we received an order from the U.S. Department of the Interior Minerals Management Service ("MMS") that the price threshold for both oil and gas was exceeded for 2004 production and that royalties were due on such production notwithstanding the provisions of the Outer Continental Shelf Deep Water Royalty Relief Act of 2005 ("DWRRA"), which was intended to stimulate exploration and production of oil and natural gas in the deepwater Gulf of Mexico by providing relief from the obligation to pay royalty on certain federal leases up to certain specified production volumes. Our oil and gas leases affected by this dispute are Garden Banks Blocks 667, 668 and 669 ("Gunnison"). On May 2, 2006, the MMS issued another order that superseded the December 2005 order, and claimed that royalties on gas production are due for 2003 in addition to oil and gas production in 2004. The order also sought interest on all royalties allegedly due. We filed a timely notice of appeal with respect to both the December 2005 Order and the May 2006 Order. We received an additional order from the MMS dated September 30, 2008 stating that the price thresholds for oil and gas were exceeded for 2005, 2006 and 2007 production and that royalties and interest are payable as well as an additional order from the MMS dated August 28, 2009 stating the price thresholds for oil and natural gas were exceeded for 2008 and that royalties and interest are payable. We appealed these orders on the same basis as the previous orders.

Other operators in the Deepwater of the Gulf of Mexico who received notices similar to ours sought royalty relief under the DWRRA, including Kerr-McGee, the operator of Gunnison. In March of 2006, Kerr-McGee filed a lawsuit in federal district court challenging the enforceability of price thresholds in certain deepwater Gulf of Mexico leases, including the Gunnison leases. On October 30, 2007, the federal district court in the Kerr-McGee case entered judgment in favor of Kerr-McGee and held that the Department of the Interior exceeded its authority by including the price thresholds in the subject leases. The government appealed the district court's decision. On January 12, 2009, the United States Court of Appeals for the Fifth Circuit affirmed the decision of the district court in favor of Kerr-McGee, holding that the DWRRA unambiguously provides that royalty suspensions up to certain production volumes established by Congress apply to leases that qualify under the DWRRA. After the appellate court denied a request by the plaintiff for rehearing, the plaintiff subsequently petitioned the United States Supreme Court for a writ of certiorari for the Supreme Court to review the Fifth Circuit Court's decision. In October 2009, the United States Supreme Court announced its decision to deny the plaintiff's writ of certiorari, concluding the litigation in this dispute.

In March 2009, we were notified of a third party's intention to terminate an international construction contract based on a claimed breach of that contract by one of our subsidiaries. As there are substantial defenses to this claimed breach, we cannot at this time determine if we have any exposure under the contract. In 2010, we will continue to assess our potential exposure to damages under this contract as the circumstances warrant. Under the terms of the contract, our potential liability is generally capped for actual damages at approximately $27 million Australian dollars ("AUD") (approximately $24.3 million U.S. dollars at December 31, 2009) and for liquidated damages at approximately $5 million AUD (approximately $4.5 million U.S. dollars at December 31, 2009). At December 31, 2009, we have a $4.0 million AUD (approximately $3.6 million U.S. dollars at December 31, 2009) receivable against our counterparty for work performed prior to the termination of the contract. We continue to pursue payment for this work as well as other claims against our counterparty. We have filed a counterclaim that in the aggregate approximates $12.0 million U.S. dollars.

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

None.

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Executive Officers of the Company

The executive officers of Helix are as follows:

Name	Age	Position
Owen Kratz	55	President and Chief Executive Officer and Director
Bart H. Heijermans	43	Executive Vice President and Chief Operating Officer
Robert P. Murphy	51	Executive Vice President — Oil & Gas
Anthony Tripodo	57	Executive Vice President and Chief Financial Officer
Alisa B. Johnson	52	Executive Vice President, General Counsel and Corporate Secretary
Lloyd A. Hajdik	44	Senior Vice President — Finance and Chief Accounting Officer

Owen Kratz is President and Chief Executive Officer of Helix. He was named Executive Chairman in October 2006 and served in that capacity until February 2008 when he resumed the position of President and Chief Executive Officer. He was appointed Chairman in May 1998 and served as the Company's Chief Executive Officer from April 1997 until October 2006. Mr. Kratz served as President from 1993 until February 1999, and has served as a Director since 1990. He served as Chief Operating Officer from 1990 through 1997. Mr. Kratz joined Helix in 1984 and held various offshore positions, including saturation diving supervisor, and management responsibility for client relations, marketing and estimating. From 1982 to 1983, Mr. Kratz was the owner of an independent marine construction company operating in the Bay of Campeche. Prior to 1982, he was a superintendent for Santa Fe and various international diving companies, and a diver in the North Sea. Mr. Kratz is also Chairman of the Board of Directors of Cal Dive International, Inc. Mr. Kratz has a Bachelor of Science degree from State University of New York (SUNY) Brockport.

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

Robert P. Murphy was elected as Executive Vice President — Oil & Gas of Helix on February 28, 2007, and as President and Chief Operating Officer of Helix Oil & Gas, Inc., a wholly owned subsidiary, on November 29, 2006. Mr. Murphy joined Helix on July 1, 2006 when Helix acquired Remington Oil & Gas Corporation, where Mr. Murphy served as President, Chief Operating Officer and was on the Board of Directors. Prior to joining Remington, Mr. Murphy was Vice President — Exploration of Cairn Energy USA, Inc, of which Mr. Murphy also served on the Board of Directors. Mr. Murphy received a Bachelor of Science degree in Geology from The University of Texas at Austin, and has a Master of Science in Geosciences from the University of Texas at Dallas.

Anthony Tripodo was elected as Executive Vice President and Chief Financial Officer on June 28, 2008. Mr. Tripodo oversees the finance, treasury, accounting, tax, information technology, administration and corporate planning functions. Mr. Tripodo was a director of Helix from February 2003 until June 2008. Prior to joining Helix, Mr. Tripodo was the Executive Vice President and Chief Financial Officer of Tesco Corporation. From 2003 through the end of 2006, he was a Managing Director of Arch Creek Advisors LLC, a Houston based investment banking firm. From 2002 to 2003, Mr. Tripodo was Executive Vice President of Veritas DGC, Inc., an international oilfield service company specializing in geophysical services. Prior to becoming Executive Vice President, he was President of Veritas DGC's North and South American Group. From 1997 to 2001, he was Executive Vice President, Chief Financial Officer and Treasurer of Veritas. Previously, Mr. Tripodo served 16 years in various executive capacities with Baker Hughes, including serving as Chief Financial Officer of both the Baker Performance Chemicals and Baker Oil Tools divisions. Mr. Tripodo graduated Summa Cum Laude with a Bachelor of Arts degree from St. Thomas University (Miami).

Alisa B. Johnson joined the Company as Senior Vice President, General Counsel and Secretary of Helix in September 2006, and in November 2008 became Executive Vice President, General Counsel and Secretary of the Company. Ms. Johnson has been involved with the energy industry for over 19 years. Prior to joining Helix, Ms. Johnson worked for Dynegy Inc. for nine years, at which company she held various legal positions, including Senior Vice President and Group General Counsel — Generation. From 1990 to 1997, Ms. Johnson held various legal positions at Destec

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Entergy, Inc. Prior to that Ms. Johnson was in private law practice. Ms. Johnson received her Bachelor of Arts degree Cum Laude from Rice University and her law degree Cum Laude from the University of Houston.

Lloyd A. Hajdik joined the Company in December 2003 as Vice President — Corporate Controller. Mr. Hajdik became Chief Accounting Officer in February 2004 and in November 2008 he became Senior Vice President – Finance and Chief Accounting Officer. Prior to joining Helix, Mr. Hajdik served in a variety of accounting and finance-related roles of increasing responsibility with Houston-based companies, including NL Industries, Inc., Compaq Computer Corporation (now Hewlett Packard), Halliburton's Baroid Drilling Fluids and Zonal Isolation product service lines, Cliffs Drilling Company and Shell Oil Company. Mr. Hajdik was with Ernst & Young LLP in the audit practice from 1989 to 1995. Mr. Hajdik graduated Cum Laude from 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.

PART II

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

Our common stock is traded on the New York Stock Exchange ("NYSE") under the symbol "HLX." The following table sets forth, for the periods indicated, the high and low sale prices per share of our common stock:

	Common Stock Prices	
	High	Low
2008		
First Quarter	$42.83	$28.26
Second Quarter	$41.81	$30.54
Third Quarter	$41.68	$28.47
Fourth Quarter	$25.16	$3.91
2009		
First Quarter	$9.47	$2.21
Second Quarter	$12.65	$4.80
Third Quarter	$16.11	$8.76
Fourth Quarter	$16.92	$10.79
2010		
First Quarter(1)	$13.51	$9.98

(1) Through February 24, 2010

On February 24, 2010, the closing sale price of our common stock on the NYSE was $11.04 per share. As of February 17, 2010, there were an estimated 355 registered shareholders and 26,688 beneficial stockholders 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."

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Shareholder Return Performance Graph

The following graph compares the cumulative total shareholder return on our common stock for the period since December 31, 2004 to the cumulative total shareholder return for (i) the stocks of 500 large-cap corporations maintained by Standard & Poor’s (“S&P 500”), assuming the reinvestment of dividends; (ii) the Philadelphia Oil Service Sector index (“OSX”), a price-weighted index of leading oil service companies, assuming the reinvestment of dividends; and (iii) a peer group selected by us (the “Peer Group”) consisting of the following companies: Global Industries, Ltd., Oceaneering International, Inc., Cameron International Corporation, Pride International, Inc., Oil States International, Inc., FMC Technologies, Inc., McDermott International, Inc., Rowan Companies, Inc., Tidewater Inc., ATP Oil & Gas Corporation, W&T Offshore, Inc. and Mariner Energy, Inc. The returns of each member of the Peer Group have been weighted according to each individual company’s equity market capitalization as of December 31, 2009 and have been adjusted for the reinvestment of any dividends. We believe that the members of the Peer Group provide services and products more comparable to us than those companies included in the OSX. The graph assumes $100 was invested on December 31, 2004 in our common stock at the closing price on that date price and on December 31, 2004 in the three indices presented. We paid no cash dividends during the period presented. The cumulative total percentage returns for the period presented were as follows: our stock — (42.4%); the Peer Group — 131.6%; the OSX — 58.4%; and S&P 500- 3.0%. These results are not necessarily indicative of future performance.

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

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	As of December 31,					
	2004	2005	2006	2007	2008	2009
Helix	$ 100.0	$ 177.8	$ 154.3	$ 200.8	$ 33.6	$ 57.6
Peer Group Index	$ 100.0	$ 159.7	$ 200.5	$ 312.1	$ 116.1	$ 231.6
Oil Service Index	$ 100.0	$ 146.3	$ 163.0	$ 247.4	$ 96.9	$ 158.4
S&P 500	$ 100.0	$ 105.3	$ 121.9	$ 128.8	$ 79.5	$ 103.0

Source: Bloomberg

Issuer Purchases of Equity Securities

Period	(a) Total number of shares purchased	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced program (2)	(d) Maximum number of shares that may yet be purchased under the program (3)
October 1 to October 31, 2009(1)	64,983	$ 15.01	63,000	619,569
November 1 to November 30, 2009(1)	168,265	14.32	168,000	451,569
December 1 to December 31, 2009(1)				451,569
	233,248	$ 14.51	231,000	451,569

(1) Represents shares delivered to the Company by employees in satisfaction of minimum withholding taxes and upon forfeiture of restricted shares.
(2) In June 2009, we announced that we intend to purchase 1.5 million share of our common stock as permitted under our senior credit facility (Note 15).
(3) Amount as of December 31, 2009. In January 2010, we issued approximately 0.5 million shares to certain of our employees. These grants will increase the number of shares available for repurchase by a corresponding amount (Note 13).

Item 6. Selected Financial Data.

The financial data presented below for each of the five years ended December 31, 2009, should be read in conjunction with Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data included elsewhere in this Annual Report on Form 10-K.

	Year Ended December 31, 2009				
	2009 (1)	2008	2007	2006(2)	2005

(amounts in thousands, except per share data)

Net revenues	$1,461,687	$2,114,074	$1,732,420	$1,328,136	$ 793,860
Gross profit	243,162	372,191	505,907	503,478	281,737
Operating income (loss) (3)	203,815	(414,222)	411,279	392,061	221,233
Equity in earnings of investments	32,329	31,854	19,573	17,927	13,425
Income (loss) from continuing operations	166,170	(580,245)	343,639	338,816	152,199
Income (loss) from discontinued operations, net of taxes	9,581	(9,812)	1,347	4,806	369
Net income (loss), including noncontrolling interests(4)	175,751	(590,057)	344,986	343,622	152,568
Net income loss applicable to noncontrolling interests	(19,697)	(45,873)	(29,288)	(725)	
Net income (loss) applicable to Helix	156,054	(635,930)	315,698	342,897	152,568
Preferred stock dividends and accretion	(54,187)	(3,192)	(3,716)	(3,358)	(2,454)
Net income (loss) applicable to Helix common shareholders(4)	$ 101,867	$ (639,122)	$ 311,982	$ 339,539	$ 150,114

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	Year Ended December 31, 2009				
	2009 (1)	2008	2007	2006(2)	2005
	(amounts in thousands, except per share data)				
Basic earnings (loss) per share of common stock (4):					
Continuing operations	$ 0.92	(6.94)	$ 3.40	$ 3.92	$ 1.93
Discontinued operations	0.09	(0.11)	0.02	0.06	
Net income per common share	$ 1.01	$ (7.05)	$ 3.42	$ 3.98	$ 1.93
Diluted earnings (loss) per share of common stock (4):					
Continuing operations	$ 0.87	$ (6.94)	$ 3.25	$ 3.74	$ 1.85
Discontinued operations	0.09	(0.11)	0.01	0.05	0.01
Net income per common share	$ 0.96	$ (7.05)	$ 3.26	$ 3.79	$ 1.86
Weighted average common shares outstanding(4):					
Basic	99,136	90,650	90,086	84,613	77,444
Diluted	105,720	90,650	95,647	89,714	81,965

(1) Excludes the results of Cal Dive subsequent to June 10, 2009 following its deconsolidation from our consolidated financial statements (Notes 1, 2 and 3).

(2) Includes effect of the Remington acquisition since July 1, 2006.

(3) Total oil and gas property impairment charges totaled $120.6 million, $920.0 million, $64.1 million and $0.8 million for each of the years ending December 31, 2009, 2008, 2007, and 2005, respectively. There were no impairments in 2006. We recorded a total of $55.9 million of oil and gas property impairment charge in the fourth quarter of 2009. Our impairments in 2008 included $896.9 million of impairment charges to reduce goodwill ($704.3 million) and certain oil and gas properties ($192.6 million) to their estimated fair value in fourth quarter of 2008. Also includes exploration expenses totaling $24.4 million in 2009 ($21.5 million in fourth quarter of 2009), $32.9 million in 2008, $26.7 million in 2007, $43.1 million in 2006, $6.5 million in 2005.

(4) Includes $77.3 million of gains on the sales of Cal Dive common stock held by us in 2009 (Note 3). Also includes the impact of gains on subsidiary equity transactions of $98.5 million and $96.5 million for the year ended December 31, 2007 and 2006, respectively. The gains were derived from the difference in the value of our investment in CDI immediately before and after its issuance of stock related to its acquisition of Horizon and its initial public offering.

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

	As of December 31,				
	2009 (1)	2008(2)	2007	2006(3)	2005
	(In thousands)				

Working capital	$ 197,072	$ 287,225	$ 48,290	$ 310,524	$ 120,388
Total assets	3,779,533	5,067,066(2)	5,449,515	4,287,783	1,660,864
Long-term debt and capital leases (including current maturities)	1,360,739	2,027,226	1,758,186	1,431,235	447,171
Convertible preferred stock	6,000(4)	55,000	55,000	55,000	55,000
Total controlling interest shareholders' equity	1,405,257	1,191,149(2)	1,829,951	1,556,314	629,300
Noncontrolling interests	22,205	322,627	263,926	59,802	
Total equity	1,427,462	1,513,776	2,093,877(5)	1,616,116(5)	629,300

(1) Reflects deconsolidation of Cal Dive effective June 10, 2009 (Notes 1,2 and 3).

(2) Includes the $907.6 million of impairment charges recorded in fourth quarter to reduce goodwill, intangible assets with indefinite lives and certain oil and gas properties to their estimated fair values. See Item 8. Financial Statements and Supplementary Data "— Note 2 — Summary of Significant Accounting Policies." for additional information.

(3) Includes effect of the Remington acquisition since July 1, 2006.

(4) The holder of the convertible preferred stock redeemed $49 million of our convertible preferred stock into 12.8 million shares of our common stock in 2009. See Item 8. Financial Statements and Supplementary Data "— Note 12 — Convertible Preferred Stock" for additional information.

(5) Total equity amount includes a January 1, 2006 $34.9 million cumulative effect on change of accounting principle to reflect the adoption of ASC Topic No. 470-20.

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

The following management's discussion and analysis should be read in conjunction with our historical consolidated financial statements located in Item 8. "Financial Statements and Supplementary Data" of this report. Any reference to Notes in the following management's discussion and analysis refers to the Notes to Consolidated Financial Statements located in Item 8. "Financial Statements and Supplementary Data" of this report. The results of operations reported and summarized below are not necessarily indicative of future operating results. This discussion also contains forward-looking statements that reflect our current views with respect to future events and financial performance. Our actual results may differ materially from those anticipated in these forward-looking statements as a result of certain factors, such as those set forth under Item 1A. "Risk Factors" and located earlier in this report.

Executive Summary

Our Business

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

Our Strategy

In December 2008, we announced our intention to focus and shape the future direction of the Company around our deepwater construction and well intervention services that comprise our Contracting Services business. We intend to achieve this strategic focus by seeking and evaluating strategic opportunities to sell certain non-core assets, such as:

- all or a portion of our oil and gas assets;
- our ownership interests in one or more of our production facilities; and
- our remaining interest in CDI.

We also announced that economic and financial market conditions may affect the timing of any strategic dispositions by us and therefore a degree of patience would be required in order to execute any transactions. We continue to focus on reducing debt levels through monetization of non-core assets and allocation of free cash flow in order to accelerate our strategic goals.

Since the announcement of our strategy to monetize certain of our non core business assets, we have:

- Sold five oil and gas properties for approximately $68 million in gross proceeds;
- Sold a total of 15.2 million shares of CDI common stock held by us to CDI for $100 million in separate transactions in January and June 2009 (Note 3);
- Sold Helix RDS Limited, our subsurface reservoir consulting business for $25 million in April 2009; and
- Sold a total of 45.8 million shares of CDI common stock held by us to third parties in two separate public secondary offerings for approximately $404.4 million, net of underwriting fees in June 2009 and September 2009.

Demand for our contracting services operations is primarily influenced by the condition of the oil and gas industry, and in particular, the willingness of oil and gas companies to make capital expenditures for offshore exploration, drilling and production operations. Generally, spending for our contracting services fluctuates directly with the direction of oil and natural gas prices. The performance of our oil and gas operations is also largely dependent on the prevailing market prices for oil and natural gas, which are impacted by global economic conditions, hydrocarbon production and excess capacity, geopolitical issues, weather and several other factors.

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Economic Outlook and Industry Influences

The continued economic downturn and general weakness in the equity and credit capital markets has led to continued uncertainty regarding the outlook of the global economy. This uncertainty coupled with the negative near-term outlook for global demand for oil and natural gas resulted in commodity price declines in 2008. Prices for oil increased in the second and third quarters of 2009 but remain significantly lower than the high prices achieved in second and third quarters of 2008. Natural gas prices continued to decline in 2009 with prices reaching near decade low levels in the third quarter of 2009. Natural gas prices increased moderately in the fourth quarter of 2009 and now compare favorably with prices in effect before the price decreases in the second and third quarters of 2009 but still significantly below the record high prices received in 2008. A decline in oil and gas prices negatively impacts our operating results and cash flow. Further, our contracting services operations are negatively impacted by declining commodity prices, which has resulted in some of our customers, primarily oil and gas companies, to announce reductions in near term capital spending. The long-term fundamentals for our business remain generally favorable as the continual effort to replenish oil and gas production should drive demand for our services. In addition, our subsea construction operations primarily support capital projects with long lead times that are less likely to be impacted by temporary economic downturns. Separately, we have hedged significant portion of our anticipated oil and natural gas production for 2010 through the placement of swap and costless collar financial hedge contracts (Note 2).

At December 31, 2009, we had cash on hand of $270.7 million and $385.8 million available for borrowing under our revolving credit facilities. Our capital expenditures for 2010 are expected to total approximately $200 million and reflect the final construction payments for our Well Enhancer, Caesar and Helix Producer I vessels and the development of two of our significant deepwater oil and gas properties expected to commence production in 2010 (one achieved first production on February 2, 2010 and the other's initial production is expected around mid-year 2010). If we successfully implement our business plan, we believe we have sufficient liquidity without incurring additional indebtedness beyond the existing capacity under the Revolving Credit Facility.

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

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

Global economic conditions deteriorated significantly over the second half of 2008 with declines in the oil and gas market accelerating during the fourth quarter of 2008 and continuing into 2009. Oil prices partially recovered in the second and third quarters of 2009 and natural gas prices increased in the fourth quarter of 2009 but the current price for both commodities remains low relative to amounts realized in 2008. Predicting the timing and sustainability of any recovery in pricing is subjective and highly uncertain. Although we are still feeling the effects of the recent recession, we believe that the long-term industry fundamentals are positive based on the following factors: (1) long term increasing world demand for oil and natural gas; (2) peaking global production rates; (3) globalization of the natural gas market; (4) increasing number of mature and small reservoirs; (5) increasing offshore activity, particularly in deepwater; and (6) increasing number of subsea developments. Our strategy of combining contracting services operations and oil and gas operations allows us to focus on trends (4) through (6) in that we pursue long-term sustainable growth by applying specialized subsea services to the broad external offshore market but with a complementary focus on marginal fields and new reservoirs in which we currently have an equity stake.

Business Activity Summary

Over the last few years we have continued to evolve our model by completing a variety of transactions and actions that we believe will continue to have significant impacts on our results of operations and financial condition. In 2005, we acquired a significant mature property package in the Gulf of Mexico OCS from Murphy Oil Corporation for $163.5 million cash and assumption of abandonment liability of $32 million. In 2006, we acquired Remington, an exploration, development and production company, for approximately $1.4 billion in cash and Helix common stock and the assumption of $358.4 million of liabilities. In March 2006, we changed our name from Cal Dive International, Inc. to Helix Energy Solutions Group, Inc., leaving the "Cal Dive" name to our former Shelf Contracting subsidiary (see "Reduction in Ownership of Cal Dive" below), and in December 2006 completed a carve-out initial public offering of Cal Dive, selling a 26.5% stake and receiving pre-tax net proceeds of $264.4 million and a pre-tax dividend of $200 million from additional borrowings under the Cal Dive revolving credit facility.

During 2006 we committed to four capital projects that have expanded and will continue to significantly expand our contracting services capabilities:

- conversion of the Caesar into a deepwater pipelay vessel; the Caesar is expected to be commissioned into our fleet in the first half of 2010;
- upgrading of the Q4000 to include drilling capability;
- conversion of a ferry vessel into a DP floating production unit (Helix Producer I); the Helix Producer I is expected to commence service around mid-year 2010; and
- construction of a multi-service DP dive support/well intervention vessel (Well Enhancer). The Well Enhancer joined our fleet in October 2009.

During 2007, we successfully completed the drilling of exploratory wells in our Bushwood prospect located in Garden Banks Blocks 462, 463, 506 and 507 in the Gulf of Mexico. In January 2009, we announced an additional discovery at the Bushwood field (see "Oil and Gas Operations" in Item 2. "Properties" elsewhere in this Form 10-K). Initial sustained production from Bushwood commenced in January 2009. Production from the Bushwood field increased subsequent to year end 2009 following completion of long delayed repairs of a third party pipeline providing service to the field and our development of a substantial portion of our proved undeveloped oil reserves at the field. Oil production from the Danny reservoir within the Bushwood field commenced in early February 2010. We are currently working to restore production at the Phoenix field at Green Canyon Blocks 236, 237, 238 and 282 around mid-year 2010 using the Helix Producer I as the field's production unit.

Reduction in Ownership of Cal Dive

At December 31, 2008, we owned 57.2% of Cal Dive. In January 2009, we sold approximately 13.6 million shares of Cal Dive common stock held by us to Cal Dive for $86 million. This transaction constituted a single transaction and was not part of any planned set of transactions that would result in us having a noncontrolling interest in Cal Dive, and reduced our ownership in Cal Dive to approximately 51%. Since we retained control of CDI immediately after the transaction, the approximate $2.9 million loss on this sale was treated as a reduction of our equity in the accompanying consolidated balance sheet.

In June 2009, we sold 22.6 million shares of Cal Dive held by us pursuant to an underwritten secondary public offering ("Offering"). Proceeds from the Offering totaled approximately $182.9 million, net of underwriting fees. Separately, pursuant to a Stock Repurchase Agreement with Cal Dive, simultaneously with the closing of the

Offering, Cal Dive repurchased from us approximately 1.6 million shares of its common stock for net proceeds of $14 million at $8.50 per share, the Offering price. Following the closing of these two transactions, our ownership of Cal Dive common stock was reduced to approximately 26%.

Because these transactions reduced our ownership in Cal Dive to less than 50%, the $59.4 million gain resulting from the sale of these shares is reflected in "Gain on sale of Cal Dive common stock" in the accompanying consolidated statement of operations. Because we no longer held a controlling interest in Cal Dive, we ceased consolidating Cal Dive effective June 10, 2009, the closing date of the Offering, and we commenced accounting for our remaining ownership interest in Cal Dive under the equity method of accounting until September 23, 2009 as discussed below.

On September 23, 2009, we sold 20.6 million shares of Cal Dive common stock held by us pursuant to a second secondary public offering ("Second Offering"). On September 24, 2009, the underwriters sold an additional 2.6 million shares of Cal Dive common stock held by us pursuant to their overallotment option under the terms of the Second Offering. The price for the Second Offering was $10 per share, with resulting proceeds totaling approximately $221.5 million, net of underwriting fees. We recorded a $17.9 million gain associated with the Second Offering transactions which was recorded as a component of "Gain on sale of Cal Dive common stock" in the accompanying consolidated statement of operations.

For more information regarding the reduction in our ownership in Cal Dive see Notes 1, 2 and 3 .

Results of Operations

Our operations are conducted through two lines of business: contracting services and oil and gas. We have disaggregated our contracting services operations into three reportable segments in accordance with FASB Codification ("ASC") Topic No. 280 Segment Reporting. As a result, our reportable segments consisted of the following: Contracting Services, Shelf Contracting, and Production Facilities as well as Oil and Gas. As discussed below, in June 2009, we ceased consolidating our Shelf Contracting segment, which represented the results and operations of Cal Dive, following the sale of a substantial amount of our remaining ownership of Cal Dive (Note 3). Each line item within our consolidated statement of operations for the year ended December 31, 2009 is impacted significantly when compared to the year ended December 31, 2008 as a result of the deconsolidation of the Cal Dive results. Our 2009 consolidated results include Cal Dive's results through June 10, 2009, while we recorded our approximate 26% share of Cal Dive's results for the period June 11, 2009 through September 23, 2009 to equity in earnings of investments as required under the equity method of accounting. We continued to disclose the operating results of the Shelf Contracting business as a segment through June 10, 2009.

All material intercompany transactions between the segments have been eliminated in our consolidated financial statements, including our consolidated results of operations.

Contracting Services Operations

We seek to provide services and methodologies, which we believe are critical to finding and developing offshore reservoirs and maximizing production economics. The Contracting Services segment includes operations such as subsea construction, well operations, robotics and drilling. The Cal Dive assets, representing our former Shelf Contracting segment, are deployed primarily for diving-related activities and shallow water construction. Our Contracting Services business operates primarily in the Gulf of Mexico, the North Sea, Asia Pacific and West Africa regions, with services that cover the lifecycle of an offshore oil or gas field. As of December 31, 2009, our contracting services operations had backlog of approximately $251 million, including $217 million for 2010. These backlog contracts are cancellable without penalty in many cases. Backlog is not a reliable indicator of total annual revenue for our Contracting Services businesses as contracts may be added, cancelled and in many cases modified while in progress.

Oil and Gas Operations

In 1992 we began our oil and gas operations to provide a more efficient solution to offshore abandonment, to expand our off-season asset utilization of our contracting services business and to achieve incremental returns. We have evolved this business model to include not only mature oil and gas properties but also proved and unproved reserves yet to be developed and explored. By owning oil and gas reservoirs and prospects, we are able to utilize the services we otherwise provide to third parties to create value at key points in the life of our own reservoirs including during the exploration and development stages, the field management stage and the abandonment stage. It is also a feature of our business model to opportunistically monetize part of the created reservoir value, through sales of working interests, in order to help fund field development and reduce gross profit deferrals from our Contracting Services operations. Therefore the reservoir value we create is realized through oil and gas production and/or monetization of working interest stakes.

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Discontinued Operations

On April 27, 2009, we sold Helix RDS Limited, our former reservoir technology consulting company, to a subsidiary of Baker Hughes Incorporated for $25 million. We have presented the results of Helix RDS as discontinued operations in the accompanying condensed consolidated financial statements (Note 2). Helix RDS was previously a component of our Contracting Services business. We recognized an $8.3 million gain on the sale of Helix RDS. The operating results of Helix RDS were immaterial for all periods presented in this Form 10-K.

Comparison of Years Ended December 31, 2009 and 2008

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

	Year Ended December 31, 2009	Year Ended December 31, 2008	Increase/ (Decrease)
Revenues (in thousands) –			
Contracting Services	$ 796,158	$ 961,926	$ (165,768)
Shelf Contracting(1)	404,709	856,906	(452,197)
Oil and Gas	385,338	545,853	(160,515)
Production facilities	17,248		17,248
Intercompany elimination	(141,766)	(250,611)	108,845
	$1,461,687	$ 2,114,074	$ (652,387)
Gross profit (loss) (in thousands) –			
Contracting Services	$ 148,375	$ 208,448	$ (60,073)
Shelf Contracting(1)	92,728	254,007	(161,279)
Oil and Gas(2)	21,788	(60,601)	82,389
Production facilities	(3,478)		(3,478)
Corporate	(2,797)	(3,652)	855
Intercompany elimination	(13,454)	(26,011)	12,557
	$ 243,162	$ 372,191	$ (129,029)
Gross Margin –			
Contracting Services	19%	22%	(3)pts
Shelf Contracting(1)	23%	30%	(7)pts
Oil and Gas (2)	6%	(11)%	17pts
Production facilities	(20)%		(20) pts
Total company	17%	18%	(1)pt
Number of vessels(3)/ Utilization(4) –			
Contracting Services:			
Pipelay	7/79%	9/92%	
Well operations	3/82%	2/70%	
ROVs/Trenchers/ROVDrill Units	47/68%	46/73%	
Shelf Contracting	N/A	30/60%	

1)

Represented by our former majority-owned subsidiary, CDI. At December 31, 2008 our ownership interest in CDI was approximately 57.2%. We consolidated CDI until June 2009, at which time we deconsolidated CDI from our financial statements after we reduced our ownership interest in CDI to below 50% (see “Reduction in Ownership of Cal Dive” above and Note 3).

2) Included asset impairment charges of oil and gas properties totaling $120.6 million in 2009 and $215.7 million in 2008. These impairments charges included $55.9 million in 2009 and $192.6 in 2008 recorded in the respective fourth quarter periods. These impairment charges do not have any impact on current or future cash flow.

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

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

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Intercompany segment revenues during the years ended December 31, 2009 and 2008 were as follows (in thousands):

	Year Ended December 31, 2009	2008	Increase/ (Decrease)
Contracting Services	$ 120,048	$ 195,207	$ (75,159)
Production Facilities	13,853		13,853
Shelf Contracting(1)	7,865	55,404	(47,539)
	$ 141,766	$ 250,611	$ (108,845)

1) Represented by our former majority-owned subsidiary, CDI. At December 31, 2008 our ownership interest in CDI was approximately 57.2%. We consolidated CDI until June 2009, at which time we deconsolidated CDI from our financial statements after we reduced our ownership interest in CDI to below 50% (see "Reduction in Ownership of Cal Dive" above and Note 3).

Intercompany segment profit (which only relates to intercompany capital projects) during the years ended December 31, 2009 and 2008 were as follows (in thousands):

	Year Ended December 31, 2009	2008	Increase/ (Decrease)
Contracting Services	$ 13,205	$ 20,945	$ (7,740)
Shelf Contracting(1)	365	5,066	(4,701)
Production Facilities	(116)		(116)
	$ 13,454	$ 26,011	$ (12,557)

1) Represented by our former majority-owned subsidiary, CDI. At December 31, 2008 our ownership interest in CDI was approximately 57.2%. We consolidated CDI until June 2009, at which time we deconsolidated CDI from our financial statements after we reduced our ownership interest in CDI to below 50% (see "Reduction in Ownership of Cal Dive" above and Note 3).

As disclosed in Item 2 "Properties" elsewhere in this Form 10-K, virtually all of our oil and gas operations are located in the U.S. Gulf of Mexico. We have one property located offshore of the United Kingdom, Camelot, that is capable of production but has been shut-in for substantially all of both 2009 and 2008. Revenues associated with our U.K oil and gas operations totaled $1.0 million in 2009 and $3.9 million in 2008 on production volumes of 0.2 Bcfe and 0.3 Bcfe, respectively. The total operating costs associated with our U.K oil and gas operations totaled $3.7 million in 2009 and $4.1 million in 2008.

The following table details various financial and operational highlights related to our Oil and Gas segment for the periods presented:

	Year Ended December 31, 2009	2008	Increase/ (Decrease)
Oil and Gas information–			
Oil production volume (MBbls)	2,741	2,752	(11)
Oil sales revenue (in thousands)	$ 183,973	$ 253,762	$ (69,789)
Average oil sales price per Bbl (excluding hedges)	$ 64.15	$ 98.62	$ (34.47)

Average realized oil price per Bbl (including hedges)	$ 67.11	$ 92.22	$ (25.11)
Decrease in oil sales revenue due to:			
Change in prices (in thousands)	$ (69,100)		
Change in production volume (in thousands)	(689)		
Total decrease in oil sales revenue (in thousands)	$ (69,789)		
Gas production volume (MMcf)	27,334	30,823	(3,489)
Gas sales revenue (in thousands)	$ 122,335	$ 287,033	$ (164,698)
Average gas sales price per mcf (excluding hedges)	$ 4.15	$ 9.50	$ (5.35)
Average realized gas price per mcf (including hedges)	$ 4.48	$ 9.31	$ (4.83)
Decrease in gas sales revenue due to:			
Change in prices (in thousands)	$ (149,083)		
Change in production volume (in thousands)	(15,615)		
Total decrease in gas sales revenue (in thousands)	$ (164,698)		

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	Year Ended December 31, 2009	2008	Increase/ (Decrease)
Total production (MMcfe)	43,782	47,332	(3,550)
Price per Mcfe	$ 7.00	$ 11.43	$ (4.43)
Oil and Gas revenue information (in thousands)-			
Oil and gas sales revenue	$ 306,308	$ 540,795	$ (234,487)
Miscellaneous revenues(1)	$ 79,030	$ 5,058	$ 73,972

(1) Miscellaneous revenues primarily relate to fees earned under our process handling agreements. The amount in 2009 also includes $73.5 million of previously accrued royalty payments involved in a legal dispute that were reversed in January 2009 following a favorable ruling by the Fifth District Court of Appeals, which rendered the probability of being required to make this payments remote. The final resolution of the legal dispute occurred in October 2009, when the U.S. Supreme Court denied the plaintiff's petition for a writ of certiorari. For additional information regarding the resolution of our royalty dispute See Item 3. "Legal Proceedings" and Note 6 – Oil and Gas Properties located elsewhere in this Annual Report on Form 10-K.

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

	Year Ended December 31, 2009 Total	2009 Per Mcfe	2008 Total	2008 Per Mcfe
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$ 78,348	$ 1.79	$ 81,742	$ 1.73
Workover (3)	9,790	0.22	10,772	0.23
Transportation	8,209	0.19	5,487	0.12
Repairs and maintenance	13,469	0.31	21,032	0.44
Overhead and company labor	10,020	0.23	5,521	0.12
Sub Total	$ 119,836	$ 2.74	$ 124,554	$ 2.64
Depletion and amortization	$ 154,052	$ 3.52	$ 186,038	$ 3.93
Abandonment	4,369	0.10	15,985	0.34
Accretion	15,204	0.35	13,065	0.28
Impairments (4)	69,038	1.58	181,524	3.84
Net hurricane (reimbursements) costs (5)	(23,332)	(0.53)	52,361	1.11
Total	$ 339,167	$ 7.76	$ 573,527	$ 12.14

(1) Excludes exploration expense of $24.4 million and $32.9 million for the years ended December 31, 2009 and 2008, respectively. Exploration expense is not a component of lease operating expense. Also excludes the impairment charge to goodwill of $704.3 million in fourth quarter of 2008.

(2) Includes production taxes.

(3) Excludes all hurricane-related costs and charges resulting from Hurricane Ike in September 2008 (see (5) below).

(4) Includes impairment charges for certain oil and gas properties exclusive of hurricane related charges discussed in (5) below.

(5) Amounts related to damages sustained from Hurricane Ike in September 2008 (Note 4). Hurricane-related impairments and adjustments to asset retirement obligations totaled $51.5 million in 2009 and $34.2 million in 2008.

Revenues. Our total revenues decreased by 31% in 2009 as compared to 2008 primarily reflecting the disposition of our Shelf Contracting business operations in June 2009 (see “Reduction of Cal Dive Ownership” above and Note 3). Excluding the effect of removing revenues associated with our former Shelf Contracting business our total revenues decreased by 16%.

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Contracting Services revenues decreased 17% in 2009 as compared to 2008. The decrease reflects lower activity levels related to a reduction of services provided to a customer under a long term construction contract in India as our pipelay vessel, the Express, completed its services in the second quarter of 2009. The Express departed India for a regulatory drydock in Spain and then redeployed to the Gulf of Mexico for internal use. Further, we experienced a substantial reduction in the average day rate realized by our Q4000 vessel deployed as an accommodation vessel in the Gulf of Mexico in the third quarter of 2009 and an almost complete loss of revenues in our Southeast Asia well intervention operations caused by equipment repair issues. These decreases were partially offset by higher results from our robotics subsidiary and our well operations vessels, including the Q4000 in the first half of 2009. We experienced strong results throughout the first half of 2009 but experienced softening in the market as expected over the second half of 2009. As a result, during the third and particularly the fourth quarter of 2009 we utilized some of our vessels to complete work necessary to enhance our oil and gas operations. This contributed to our decrease in revenues in 2009 as compared to 2008.

Oil and Gas revenues decreased by 29% in 2009 as compared to 2008. The decrease is attributable to significant reductions in the realized prices of both oil (27%) and natural gas (52%) as compared to amounts realized in 2008. Our production was adversely affected in the third quarter of 2008 as a result of Hurricanes Gustav and Ike. Although our production recovered somewhat, production of both oil and natural gas has continued to be affected by ongoing repairs to third party pipelines. Repairs to a key third party pipeline were completed in early January 2010 which should benefit our production as we progress into 2010 as this particular pipeline provides service to our Noonan gas reservoir within the Bushwood field where production has been curtailed since it commenced sustained production in January 2009. Further, our natural gas derivative contracts for 2009 were marked-to-market and changes in their fair value were included in “Gain on oil and gas derivative contracts” in the accompanying consolidated statements of operations rather than revenues as previously reported when such contracts qualified for hedge accounting treatment.

Our oil and gas revenues for the year ended December 31, 2009 benefitted from $73.5 million of previously accrued royalty payments that were in dispute. Following a favorable appellate judicial ruling in January 2009, we reversed these amounts as oil and gas revenues in the first quarter of 2009 and began accounting for the additional oil and gas revenues associated with the previously disputed royalty net revenue interest and we are no longer accruing any additional royalty reserves (Note 6).

Gross Profit. Gross profit for 2009 decreased $129.0 million as compared to 2008. Excluding the effect of our former Shelf Contracting business, our continuing businesses gross profit increased $32.3 million in 2009 as compared to 2008. This increase primarily reflects reduced year over year impairment charges associated with our Oil and Gas segment, which totaled $120.6 million in 2009 and $215.7 million in 2008. After considering the reduction in impairment charges our Oil and Gas segment gross profit decreased by 8% as a result of lower commodity prices realized and lower natural gas production, as described in Revenues above, offset partially by the $23.3 million of insurance reimbursement in excess of hurricane related costs incurred during the year ended December 31, 2009. See Note 6 for a discussion of our oil and gas impairment charges for 2009 and 2008.

In addition, Contracting Services gross profit decreased 29% because of the factors stated above in revenues. Our Contracting Services gross margin decreased by three points. The decline in gross margin was primarily due to lower vessel utilization (in particular our pipelay vessels), lower day rates realized on work performed by the Q4000, and Express out of service days related to a regulatory drydock and transit costs to redeploy the Express from India back to the Gulf of Mexico for internal use. Most of these declines occurred in the second half of 2009.

Gain on Sale of Assets, Net. Gain on sale of assets, net, was $2.0 million in 2009 as compared to a gain of $73.5 million in 2008. The gain on sale in 2008 primarily related to the sale of a 30% working interest in the Bushwood discoveries (Garden Banks Blocks 463, 506 and 507) and other Outer Continental Shelf oil and gas properties (East

Cameron blocks 371 and 381). Offsetting this gain was a loss of $11.9 million related to the sale of all our interest in our Onshore Properties. Included in the cost basis of our Onshore Properties was $8.1 million of goodwill allocated from our Oil and Gas segment. In the fourth quarter of 2008 we recorded a $6.7 million loss associated with our sale of the Bass Lite field as Atwater Block 426.

Selling and Administrative Expenses. Selling and administrative expenses totaled $130.9 million in 2009, which was $46.3 million lower than amounts incurred in 2008. Selling and administrative expenses associated with our former Shelf Contracting business totaled $33.7 million for the period prior to its deconsolidation in June 2009 and $74.5 million in 2008.

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Excluding the selling and administrative expenses associated with our former Shelf Contracting business, our selling and administrative expenses decreased $5.5 million in 2009 as compared to 2008. The decrease in the comparable years reflects $7.4 million of expenses related to the separation agreements between the Company and two of our former executive officers in 2008 and the enactment of certain administrative cost saving measures in 2009 offset in part by increased bad debt expense and legal costs.

Equity in Earnings of Investments. Equity in earnings of investments increased by $0.5 million in 2009 as compared to 2008. This increase primarily reflects $8.1 million related to our approximate 26% ownership interest in Cal Dive that was accounted for under the equity method accounting following its deconsolidation in June 2009. The equity in the earnings for Cal Dive covers the period from June 11, 2009 through September 23, 2009, at which time we sold substantially all our remaining ownership interest in Cal Dive (Note 3). The remainder of our equity in earnings of investments included a decrease of $13.2 million in the equity in earnings of Deepwater Gateway between the comparable years reflecting reduced throughput at the facility as a result of ongoing hurricane related repairs that have affected production from the fields processed through the Marco Polo TLP. This decrease was offset in part by a $2.3 million increase in the earnings of our 20% investment in Independence Hub.

Net Interest Expense and Other. We reported net interest and other expense of $51.5 million in 2009 as compared to $111.1 million in 2008. Interest and other expense associated with Cal Dive totaled $6.6 million prior to deconsolidation in June 2009, while Cal Dive accounted for $22.3 million of interest and other expense in 2008. Excluding Cal Dive, gross interest expense totaling $99.2 million was lower than the $114.5 million incurred in 2008 primarily reflecting lower interest rates and lower levels of debt since year end 2008. Contributing to the decrease in interest expense was a $6.0 million increase in capitalized interest, which totaled $48.1 million in 2009 and $42.1 million in 2008. We recorded $3.3 million of unrealized gains associated with mark-to-market adjustments related to our foreign exchange contracts in 2009 as compared to a net unrealized loss of $1.1 million in 2008. Interest income decreased to $0.9 million in 2009 from $2.4 million in 2008. The decrease in interest income includes a net reduction of $0.5 million associated with the deconsolidation of Cal Dive.

Provision for Income Taxes. Income taxes increased to $95.8 million in 2009 compared to $86.8 million in 2008. This increase is primarily due to increased profitability. The effective tax rate of 36.6% for 2009 was higher than the (17.6)% for 2008. The effective tax rate for 2008 is not representative of a normal effective tax rate because of the $704.3 million non-deductible goodwill and indefinite-lived intangible assets impairment charge. Excluding the effect of the goodwill and other intangible asset impairment charges, the effective tax rate would have been 41.2% for 2008. The adjusted effective tax rate decreased as a result of the deconsolidation of CDI in 2009 and the absence of non-deductible goodwill in the current year period, which caused an increase in the prior year rate. In 2008, we allocated $8.1 million of goodwill to the cost basis attributable to certain sales of oil and gas properties that for income tax purposes was non-deductible.

Comparison of Years Ended December 31, 2008 and 2007

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

	Year Ended December 31,		Increase/
	2008	2007	(Decrease)
Revenues (in thousands) –			
Contracting Services	$ 961,926	$ 673,808	$ 288,118
Shelf Contracting(1)	856,906	623,615	233,291
Oil and Gas	545,853	584,563	(38,710)
Intercompany elimination	(250,611)	(149,566	(101,045)
	$2,114,074	$ 1,732,420	$ 381,654

Gross profit (loss) (in thousands) –						
Contracting Services	$	208,448	$	187,975	$	20,473
Shelf Contracting(1)		254,007		227,398		26,609
Oil and Gas(2)		(60,601)		120,861		(181,462)
Corporate		(3,652)		(7,319		3,667
Intercompany elimination		(26,011)		(23,008		(3,003)
	$	372,191	$	505,907	$	(133,716)

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	Year Ended December 31, 2008	2007	Increase/ (Decrease)
Gross Margin –			
Contracting Services	22%	28%	(6)pts
Shelf Contracting(1)	30%	36%	(6)pts
Oil and Gas (2)	(11)%	21%	(32)pts
Total company	18%	29%	(11)pts
Number of vessels(3)/ Utilization(4) –			
Contracting Services:			
Pipelay	9/92%	6/79%	
Well operations	2/70%	2/71%	
ROVs/Trenchers/ROVDrill Units	46/73%	39/78%	
Shelf Contracting	30/60%	34/65%	

1) Represented by our former majority owned subsidiary, CDI. At December 31, 2008 and 2007, our ownership interest in CDI was approximately 57.2% and 58.5%, respectively. See Note 3 for discussion of transactions in which we sold substantially all our remaining ownership of CDI in 2009.

2) Includes asset impairment charges of oil and gas properties totaling $215.7 million ($192.6 million in fourth quarter of 2008). These impairment charges do not have any impact on current or future cash flow.

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

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

Intercompany segment revenues during the years ended December 31, 2008 and 2007 were as follows (in thousands):

	Year Ended December 31, 2008	2007	Increase/ (Decrease)
Contracting Services	$195,207	$115,864	$ 79,343
Shelf Contracting	55,404	33,702	21,702
	$250,611	$149,566	$ 101,045

Intercompany segment profit (which only relates to intercompany capital projects) during the years ended December 31, 2008 and 2007 were as follows (in thousands):

	Year Ended December 31, 2008	2007	Increase/ (Decrease)
Contracting Services	$ 20,945	$ 10,026	$ 10,919
Shelf Contracting	5,066	12,982	(7,916)

	$ 26,011	$ 23,008	$ 3,003

Revenues associated with our U.K oil and gas operations totaled $3.9 million in 2008 and $2.7 million in 2007 on production volumes of 0.3 Bcfe and 0.6 Bcfe, respectively. The total operating costs associated with our U.K oil and gas operations totaled $4.1 million in 2008 and $7.3 million in 2007.

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

	Year Ended December 31, 2008	Year Ended December 31, 2007	Increase/ (Decrease)
Oil and Gas information–			
Oil production volume (MBbls)	2,752	3,723	(971)
Oil sales revenue (in thousands)	$ 253,762	$ 251,955	$ 1,807
Average oil sales price per Bbl (excluding hedges)	$ 98.62	$ 70.17	$ 28.45
Average realized oil price per Bbl (including hedges)	$ 92.22	$ 67.68	$ 24.54
Increase (decrease) in oil sales revenue due to:			
Change in prices (in thousands)	$ 91,372		
Change in production volume (in thousands)	(89,565)		
Total increase in oil sales revenue (in thousands)	$ 1,807		
Gas production volume (MMcf)	30,823	42,163	(11,340)
Gas sales revenue (in thousands)	$ 287,033	$ 324,282	$ (37,249)
Average gas sales price per mcf (excluding hedges)	$ 9.50	$ 7.46	$ 2.04
Average realized gas price per mcf (including hedges)	$ 9.31	$ 7.69	$ 1.62
Increase (decrease) in gas sales revenue due to:			
Change in prices (in thousands)	$ 68,342		
Change in production volume (in thousands)	(105,591)		
Total decrease in gas sales revenue (in thousands)	$ (37,249)		
Total production (MMcfe)	47,332	64,500	(17,168)
Price per Mcfe	$ 11.43	$ 8.93	$ 2.50
Oil and Gas revenue information (in thousands)-			
Oil and gas sales revenue	$ 540,795	$ 576,237	$ (35,442)
Miscellaneous revenues(1)	$ 5,058	$ 5,667	$ (609)

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

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

	Year Ended December 31,			
	2008		2007	
	Total	Per Mcfe	Total	Per Mcfe
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$81,742	$1.73	$80,410	$1.25
Workover	10,772	0.23	11,840	0.18
Transportation	5,487	0.12	4,560	0.07
Repairs and maintenance	21,032	0.44	12,191	0.19
Overhead and company labor	5,521	0.12	9,031	0.14
Subtotal	$124,554	$2.64	$118,032	$1.83
Depletion and amortization	$186,038	$3.93	$217,382	$3.37
Abandonment	15,985	0.34	21,073	0.33
Accretion	13,065	0.28	10,701	0.17
Impairments (3)	181,524	3.84	64,072	0.99
Net hurricane costs	52,361	1.11		
Total	$573,527	$12.14	$431,260	$6.69

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(1) Excludes exploration expense of $32.9 million and $26.7 million for the years ended December 31, 2008 and 2007, respectively. Exploration expense is not a component of lease operating expense. Also excludes the impairment charge to goodwill of $704.3 million in fourth quarter of 2008.

(2) Includes production taxes.

(3) Includes impairment charges for certain oil and gas properties exclusive of hurricane related impairment charges in (4) below.

(4) Reflects costs associated with hurricane damages caused by Hurricane Ike in September 2008. Amount includes property impairment charges related to the hurricane of $34.2 million. See Note 4 for additional information related to our hurricane costs and subsequent insurance recoveries related to Hurricane Ike.

Revenues. During the year ended December 31, 2008 our consolidated net revenues increased by 22% compared to 2007. Contracting Services gross revenues increased 43% over 2007 amounts primarily reflecting the following:

- the addition of two chartered subsea construction vessels as well as an overall increase in utilization of our subsea construction vessels;
- commencing performance of several longer term contracts;
- increases in the utilization and rates realized for our well operations vessels;
- strong performance by our robotics division driven by a higher number of ROVs in our fleet and additional services required following Hurricanes Gustav and Ike; and
- increased sales by our Shelf Contracting business (see below), resulting from its acquisition of Horizon in December 2007 and increased work following Hurricanes Gustav and Ike.

Our increases were partially offset by the following negative factors:

- an increase in the number of out-of-service days for the Q4000 associated with marine and drilling upgrades. The Q4000 was out of service for most of the first half of 2008;
- weather related downtime associated with Hurricanes Gustav and Ike.

Gross revenues for our Shelf Contracting business increased 37% in 2008 compared to 2007 primarily reflecting the revenue contribution of the Horizon assets that were acquired in December 2007 partially offset by lower vessel utilization related to winter seasonality and harsh weather conditions which continued into May 2008, and weather downtime associated with Hurricanes Gustav and Ike. Following the storm, our Shelf Contracting revenues benefitted from the increased scope of work associated with the storms including inspections, repairs and reclamation projects.

Oil and Gas revenues decreased 7% during 2008 as compared to the prior year. The decrease is primarily associated with the loss of production following the shut-in of many of our oil and gas properties following Hurricanes Gustav and Ike. Our production rates in 2008 were 27% lower than the same period last year; however our current net daily production is approximately 90% of pre-storm production volumes after adjusting for the sale of one major deepwater property in December 2008. The decrease in our revenues was partially offset by substantially higher oil and natural gas prices realized over the amounts received in 2007, which reflects near historical high prices for both oil and natural gas over the first half of 2008. Prices of both oil and natural gas decreased significantly during the second half of 2008, with price reductions accelerating in the fourth quarter of 2008.

Gross Profit. The Contracting Services gross profit increase was primarily attributable to improved contract pricing for the well operations and ROV divisions. These increases were partially offset by lower margins realized on certain longer term deepwater pipelay projects reflecting the delays in delivery of the Caesar and processing of certain change orders which prevented revenue recognition under the percentage-of-completion method (Note 2). We also recorded approximately $9.8 million of estimated losses on two contracts in which we believe the future revenue benefits will be exceeded by the estimated future costs to service the contracts (Note 2). The gross profit increase within Shelf Contracting was primarily attributable to the initial deployment of Horizon's assets that were acquired in December 2007 and additional work following Hurricanes Gustav and Ike, offset by increased depreciation associated with Horizon assets and weather-related delays over the first five months of 2008 and during Hurricanes Gustav and Ike. Our 2007 Shelf Contracting operations were adversely effected by an higher number of out-of-service days referred to above, lower vessel utilization as a result of seasonal weather in the fourth quarter 2007, and increased depreciation and deferred drydock amortization.

The decrease in the gross profit for our oil and gas operations in 2008 as compared to 2007 reflects the following key factors :

- impairment expense of approximately $215.7 million ($192.6 million recorded in the fourth quarter of 2008) related to our proved oil and gas properties primarily as a result of downward reserve revisions reflecting lower oil and natural gas prices, weak end of life well performance for some of our domestic properties, fields lost as a result of Hurricanes Gustav and Ike and the reassessment of the economics of some of our marginal fields in light of our announced business strategy to exit the oil and gas exploration and production business; we also recorded a $14.6 million asset impairment charge associated with the Devil's Island Development well (Garden Banks Block 344) that was determined to be non-commercial in January 2008. Asset impairment expense in 2007 totaled $64.1 million, which included $20.9 million for the costs incurred on the Devil's Island well through December 31, 2007;
- a decrease of $31.3 million in depletion expense in 2008 because of lower production which is primarily attributed to the effects Hurricanes Gustav and Ike had on our production during the latter part of the year. This decrease was partially offset by higher rates resulting from a reduction in estimated proved reserves for a number of our producing fields at December 31, 2008;
- approximately $8.8 million of exploration expense (all in fourth quarter of 2008) compared to $9.0 million in 2007 related to reducing the carrying value of our unproved properties primarily due to management's assessment that exploration activities for certain properties will not commence prior to the respective lease expiration dates;
- approximately $16.0 million of plug and abandonment overruns primarily related to properties damaged by the hurricanes, partially offset by insurance recoveries of $7.8 million; and
- approximately $18.8 million of dry hole exploration expense reflecting the conclusion that two exploratory wells previously classified as suspended wells (Note 6) no longer met the requirements to continue to be capitalized primarily as a result of the discontinuing of plans to progress the development of these wells in light of our announcement in December 2008 of our intention to pursue a sale of all or a portion of our oil and gas assets. In 2007, our dry hole expense totaled $10.3 million, of which $5.9 million was related to our South Marsh Island Block 123 #1 well.

Goodwill and other intangible asset impairments. In the fourth quarter of 2008 we recorded a $704.3 million of impairment charge to write off the remaining oil and gas goodwill following our annual assessment of goodwill, which took into account the significant decrease in our common stock price as well as the stock prices of our identified peers and the rapid reduction in oil and natural gas commodity prices. We also recorded an $8.3 million impairment charge in the fourth quarter of 2008 to write off the goodwill associated with our 2005 acquisition of Helix Energy Limited as well as a related $2.4 million impairment charge to write off its indefinite life asset (trademark). These amounts are reflected as a component of income (loss) from discontinued operations in the accompanying consolidated statement of operations as Helix Energy Limited was sold in April 2009. We separately recorded $8.1 million of reductions of goodwill associated with dispositions of oil and gas properties in 2008, which are included as a component of the gain or loss on sale of assets, net as discussed below.

Gain on Sale of Assets, Net. The net gain on sale of assets increased by $23.1 million during 2008 as compared to 2007. In 2008 our oil and gas property sales included:

- $91.6 million gain related to the sale of a 30% working interest in the Bushwood discoveries (Garden Banks Blocks 463, 506 and 507) and East Cameron Blocks 371 and 381;

- $11.9 million loss related to the sale of all our onshore properties; included in the cost basis of our onshore properties was goodwill of $8.1 million; and
- $6.7 million loss related to the sale of our interest in the Bass Lite field in December 2008; there was no goodwill associated with this sale as all goodwill was previously written off. The sale of the remainder (approximately 10%) of our original 17.5% interest closed in January 2009 and will be reflected in our first-quarter 2009 results.

On September 30, 2007, we sold a 30% working interest in the Phoenix oilfield (Green Canyon Blocks 236/237), the Boris oilfield (Green Canyon Block 282) and the Little Burn oilfield (Green Canyon Block 238) to Sojitz GOM Deepwater, Inc. (“Sojitz”) for a cash payment of $51.2 million and recognized a gain of $40.4 million in 2007. We also recognized the following gains in 2007:

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

Selling and Administrative Expenses. Selling and administrative expenses of $177.2 million in 2008 were $32.2 million higher than the $145.0 million incurred in 2007. The increase was due primarily to higher overhead (primarily related to CDI's Horizon acquisition) to support our growth. We also recognized approximately $7.4 million of expenses related to the separation agreements between the Company and two of its former executive officers (Note 21). Selling and administrative expenses as a percent of revenues were approximately 8.4% for both 2008 and 2007.

Equity in Earnings of Investments, Net of Impairment Charge. Equity in earnings of investments increased $12.3 million during 2008 as compared to 2007. Equity in earnings related to our 20% investment in Independence Hub increased $9.3 million as we reached mechanical completion in March 2007 and began receiving demand fees and tariffs as production began in the third quarter of 2007. In addition, equity in earnings of our 50% investment in Deepwater Gateway decreased by $3.5 million in 2008 as compared to 2007 due to downtime at the Marco Polo TLP following Hurricanes Gustav and Ike. These increases were offset by second quarter 2007 equity losses from CDI's 40% investment in Offshore Technology Solutions Limited ("OTSL") and a related non-cash asset impairment charge together totaling $11.8 million.

Net Interest Expense and Other. Net interest and other expense increased to $89.5 million in 2008 as compared to $67.0 million in the prior year. Gross interest expense of $137 million during 2008 was higher than the $107.8 million incurred in 2007 because of higher levels of indebtedness as a result of our Senior Unsecured Notes and CDI's term loan, both of which closed in December 2007. Offsetting the increase in interest expense was $42.1 million of capitalized interest and $2.4 million of interest income in 2008, compared with $31.8 million of capitalized interest and $9.2 million of interest income in 2007. We expect interest expense to decrease in 2009 as a result of lower expected interest rates on our variable rate debt instruments. See Note 10 for detailed description of these notes. Our other income (expense) includes gains (losses) associated with transactions denominated in foreign currencies. Our foreign currency losses totaled $(10.0) million in 2008 and $(0.5) million in 2007.

Provision for Income Taxes. Income taxes decreased to $86.8 million in 2008 compared to $171.9 million in 2007. This decrease is primarily due to lower profitability in 2008. The effective tax rate of (17.6)% is not representative of a normal effective tax rate because of the $704.3 million non-deductible goodwill and indefinite-lived intangible assets impairment charge as discussed above. Excluding the goodwill and other intangible asset impairment charges, the effective tax rate of 41.2% for 2008 was higher than the 33.3% effective tax rate for same period 2007 primarily reflecting the additional deferred tax expense recorded as a result of the increase in the equity earnings of CDI in excess of our tax basis. In 2008, we allocated $8.1 million of goodwill to the cost basis attributable to certain sales of oil and gas properties that for income tax purposes was non-deductible.

Liquidity and Capital Resources

Overview

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

	2009	2008
Net working capital	$ 197,072	$ 287,225

Long-term debt(1)	$1,348,315	$1,933,686

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

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The carrying amount of our debt, including current maturities as of December 31, 2009 and 2008 follow (amount in thousands):

	2009	2008
Term Loan (matures July 2013)	$ 414,766	$ 419,093
Revolving Credit Facility (matures November 2012)		349,500
Convertible Senior Notes (matures March 2025) (1)	273,064	265,184
Senior Unsecured Notes (matures January 2016)	550,000	550,000
MARAD Debt (matures August 2027)	119,235	123,449
Cal Dive Term Loan (2)		315,000
Loan Notes(3)	3,674	5,000
Total	$ 1,360,739	$ 2,027,226

(1) Net of the unamortized debt discount resulting from adoption of FSP APB 14-1 on January 1, 2009. The notes will increase to $300 million face amount through accretion of non-cash interest charges through 2012.
(2) We deconsolidated Cal Dive from our financial statements in June 2009 (Note 3).
(3) Assumed to be current, represents the loan provided by Kommandor RØMØ to Kommandor LLC (Note 9).

	Year Ended December 31,		
	2009	2008	2007
Net cash provided by (used in):			
Operating activities	$ 415,547	$ 437,719	$ 416,326
Investing activities	$ (68,532)	$ (557,974)	$ (739,654)
Financing activities	$ (298,579)	$ 256,216	$ 206,445

Our current requirements for cash primarily reflect the need to fund capital expenditures to allow the growth of our current lines of business and to service our existing debt. We also intend to repay debt with any additional free cash flow from operations and/or cash received from any dispositions of our non core business assets. Historically, we have funded our capital program, including acquisitions, with cash flow from operations, borrowings under credit facilities and use of project financing along with other debt and equity alternatives.

We continue to focus on improving our balance sheet by increasing our liquidity through reductions in planned capital spending and potential additional dispositions of our non-core business assets. We also have a reasonable basis for estimating our future cash flow supported by our remaining Contracting Services backlog and the significant hedged portion of our estimated oil and gas production for 2010. We believe that internally generated cash flow and available borrowing capacity under our amended Revolving Credit Facility (see “Amendment of Senior Credit Facility” below and Note 10) will be sufficient to fund our operations over at least the next twelve months. In the first half of 2009, we repaid all remaining borrowings under our revolving credit facility, which totaled $349.5 million.

During 2009, we completed the following transactions related to dispositions of non-core business assets:

· Sold five oil and gas properties for approximately $24 million;
· Sold a total of 15.2 million shares of CDI common stock held by us to CDI for $100 million in separate transactions in January and June 2009;
· Sold Helix RDS Limited, our subsurface reservoir consulting business for $25 million in April 2009; and
·

Sold a total of 45.8 million shares of CDI common stock held by us to third parties in two separate public secondary offerings for approximately $404.4 million, net of underwriting fees in June 2009 and September 2009. For additional information regarding the sales of CDI common shares by us see “Reduction of Cal Dive Ownership” above and Note 3.

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

- In July 2007, we purchased the remaining 42% of WOSEA for $10.1 million. We now own 100% of this company (see "Note 5 —Acquisitions" in Item 8. Financial Statements and Supplementary Data for a detailed discussion of WOSEA).
- In December 2007, we issued $550 million of 9.5% Senior Unsecured Notes due 2016 ("Senior Unsecured Notes"). Proceeds from the offering were used to repay outstanding indebtedness under our senior secured credit facilities. For additional information on the terms of the Senior Unsecured Notes, see "Note 10 — Long-term Debt" in Item 8. Financial Statements and Supplementary Data.
- In July 2006, we borrowed $835 million in a term loan ("Term Loan") and entered into a new $300 million revolving credit facility (Note 10). The proceeds of the Term Loan were used to fund the cash portion of the acquisition of Remington. We also issued approximately 13.0 million shares of our common stock to the Remington shareholders.
- In December 2006, we completed an IPO of our Shelf Contracting business segment (Cal Dive), selling 26.5% of that company and receiving pre-tax net proceeds of $264.4 million (Note 3). Proceeds from the offering were used for general corporate purposes, including the repayment of $71.0 million of borrowing under our Revolving Credit Facility (Note 10).
- In October 2006, we initially invested $15 million for a 50% interest in Kommandor LLC, a Delaware limited liability company, to convert a ferry vessel into a dynamically-positioned minimal floating production system. We have consolidated the results of Kommandor LLC (Note 9). We named the vessel the Helix Producer I.
- Also in October 2006, we acquired the original 58% interest in WOSEA for total consideration of approximately $12.7 million (including $180,000 of transaction costs), with approximately $9.1 million paid to existing shareholders and $3.4 million for subscription of new WOSEA shares (Note 5).

In accordance with our Senior Credit Facilities, Senior Unsecured Notes, the Convertible Senior Notes and the MARAD debt, we are required to comply with certain covenants and restrictions, including certain financial ratios such as collateral coverage, interest coverage, consolidated leverage, the maintenance of minimum net worth, working capital and debt-to-equity requirements. As of December 31, 2009, we were in compliance with these covenants. The Senior Credit Facilities and Senior Unsecured Notes also contain provisions that limit our ability to incur certain types of additional indebtedness. These provisions effectively prohibit us from incurring any additional secured indebtedness or indebtedness guaranteed by the Company. The Senior Credit Facilities do permit us to incur certain unsecured indebtedness, and also provide for our subsidiaries to incur project financing indebtedness (such as our MARAD loans) secured by the underlying asset, provided that the indebtedness is not guaranteed by us. Upon the occurrence of certain dispositions or the issuance or incurrence of certain types of indebtedness, we may be required to prepay a portion of the Term Loan equal to the amount of proceeds received from such occurrences. Such prepayments will be applied first to the Term Loan, and any excess will then be applied to the Revolving Loans.

A prolonged period of weak economic activity may make it difficult to comply with our covenants and other restrictions in agreements governing our debt. Our ability to comply with these covenants and other restrictions is affected by the continued weak economic conditions and other events beyond our control. If we fail to comply with these covenants and other restrictions, it could lead to an event of default, the possible acceleration of our repayment of outstanding debt and the exercise of certain remedies by the lenders, including foreclosure on our pledged collateral.

As of December 31, 2009, our liquidity totaled $656.5 million, including cash of $270.7 million and $385.8 million of available borrowing capacity under our Revolving Credit Facility. As of February 23, 2010 our liquidity totals approximately $591.3 million, including $205.8 million of cash and cash equivalents and $385.5 million of available borrowing capacity under our Revolving Credit Facility.

We amended our Senior Credit Facility in October 2009 and again in February 2010. In October 2009 the Senior Credit Facility was amended to, among other things, extend its maturity from July 2011 to November 2012. In February 2010, the Senior Credit Facility was once again amended, to among other things, modify the consolidated leverage ratio test and to include an additional senior secured debt leverage ratio test for periods beginning on or after March 31, 2010. See Note 10 for additional information related to our long-term debt, including more information regarding the recent amendments of our Senior Credit Facility and our requirements and obligations under the debt agreements including our covenants and collateral security.

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Working Capital

Net cash flows from operating activities decreased $22.2 million in 2009 as compared to 2008 primarily reflecting significantly lower revenues, which were mostly offset by an increase in our working capital cash flow, including lower income taxes paid and higher amounts collected on our accounts receivable balances.

Net cash flows from operating activities increased $21.4 million in 2008 as compared to 2007 primarily reflecting significantly lower income taxes paid and increased gross profit from Contracting Services and Shelf Contracting businesses. These increases were partially offset by lower operating results for our Oil and Gas business reflecting the effects of Hurricanes Gustav and Ike had on its production during the third and fourth quarters of 2008 as well as our increased funding of our working capital requirements.

Investing Activities

Capital expenditures have consisted principally of the purchase or construction of DP vessels, acquisition of select businesses, improvements to existing vessels, acquisition of oil and gas properties and investments in our Production Facilities. Significant sources (uses) of cash associated with investing activities for the years ended December 31, 2009, 2008 and 2007 were as follows (in thousands):

	Year Ended December 31,		
	2009	2008	2007
Capital expenditures:			
Contracting services	$(204,228)	$(258,184)	$(286,362)
Shelf contracting	(39,569)	(83,108)	(30,301)
Oil and gas	(137,168)	(404,308)	(519,632)
Production facilities	(42,408)	(109,454)	(106,086)
Acquisition of businesses, net of cash acquired:			
Horizon Offshore Inc. (1)			(137,431)
WOSEA(2)			(10,067)
Sales of short-term investments			285,395
Investments in production facilities	(1,657)	(846)	(17,459)
Distributions from equity investments, net(3)	6,742	11,586	6,679
Proceeds from insurance reimbursements		13,200	
Proceeds from sale of Cal Dive common stock	418,168		
Reduction in cash from deconsolidation of Cal Dive	(112,995)		
Proceeds from sale of properties (4)	23,717	274,230	78,073
Other, net	(6)	(614)	(1,248)
Net cash used in investing activities	(89,404)	(557,498)	(738,439)
Net cash provided by (used in)discontinued operations(5)	20,872	(476)	(1,215)

Net cash used in investing activities	$(68,532)	$(557,974)	$(739,654)

(1) Acquisition by our former majority owned subsidiary, CDI (Note 3).

(2) For additional information related to these acquisitions, see Note 5.

(3) Distributions from equity investments is net of undistributed equity earnings from our investments. Gross distributions from our equity investments are detailed in Note 8.

(4) For additional information related to sales of properties, see Note 6.

(5) Amount for 2009 included the sale of Helix RDS for $25 million, see Note 1.

Restricted Cash

As of December 31, 2009 and 2008 we had $35.4 million of restricted cash, included in other assets, net, in the accompanying consolidated balance sheet, all of which related to the escrow funds for decommissioning liabilities associated with the South Marsh Island Block 130 (“SMI 130”) acquisition in 2002. Under the purchase agreement for this property, we are obligated to escrow 50% of production up to the first $20 million and 37.5% of production on the remaining

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balance up to $33 million in total. We had fully escrowed the requirement as of December 31, 2009 and 2008. We may use the restricted cash for decommissioning the related field.

Outlook

We anticipate capital expenditures in 2010 will total approximately $200 million. The estimates for these capital expenditures may increase or decrease based on various economic factors. However, we may reduce the level of our planned capital expenditures given a prolonged economic downturn or inability to execute sales transactions related to our non core business assets. We believe internally generated cash flow, cash from future sales of our non-core business assets, and borrowings under our existing credit facilities will provide the capital necessary to fund our 2010 initiatives.

Contractual Obligations and Commercial Commitments

The following table summarizes our contractual cash obligations as of December 31, 2009 and the scheduled years in which the obligation are contractually due (in thousands):

	Total (1)	Less Than 1 year	1-3 Years	3-5 Years	More Than 5 Years
Convertible Senior Notes(2)	$ 300,000	$	$	$	$ 300,000
Senior Unsecured Notes	550,000				550,000
Term Loan	414,766	4,326	8,652	401,788	
Revolving Loans					
MARAD debt	119,235	4,424	9,522	10,496	94,793
Loan note	3,674	3,674			
Interest related to long-term debt	563,436	79,924	155,906	140,008	187,598
Drilling and development costs	58,717	58,717			
Property and equipment(4)	14,854	14,854			
Operating leases(5)	99,110	43,781	51,611	2,922	796
Total cash obligations	$2,123,792	$ 209,700	$ 225,691	$ 555,214	$1,133,187

(1) Excludes unsecured letters of credit outstanding at December 31, 2009 totaling $49.2 million. These letters of credit primarily guarantee various contract bidding, insurance activities and shipyard commitments.

(2) Contractual maturity in 2025 (Notes can be redeemed by us or we may be required to purchase beginning in December 2012). Notes can be converted prior to stated maturity if the closing sale price of Helix's common stock for at least 20 days in the period of 30 consecutive trading days ending on the last trading

day of the preceding fiscal quarter exceeds 120% of the closing price on that 30th trading day (i.e. $38.56 per share) and under certain triggering events as specified in the indenture governing the Convertible Senior Notes. To the extent we do not have alternative long-term financing secured to cover the conversion, the Convertible Senior Notes would be classified as a current liability in the accompanying balance sheet. As of December 31, 2009, the conversion trigger was not met.

(3) Any future borrowing under our Revolver will mature on November 30, 2012.

(4) Costs incurred as of December 31, 2009 and additional property and equipment commitments (excluding capitalized interest) at December 31, 2009 consisted of the following (in thousands):

	Costs Incurred (a)	Costs Committed	Total Project Cost (a)
Caesar conversion	$ 264,777	$ 2,288	$ 290,000—300,000
Well Enhancer construction	232,612	486	250,000—260,000
Helix Producer I conversion(b)	269,449	12,080	360,000—370,000
Total	$ 766,838	$ 14,854	$ 900,000—930,000

(a) Includes capitalized interest.

(b) Represents 100% of the vessel conversion cost, of which we expect our portion to range between $318 million and $328 million.

(5) Operating leases include facility leases and vessel charter leases. Vessel charter lease commitments at December 31, 2009 were approximately $84.9 million.

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Contingencies

As disclosed in Notes 6 and 17, litigation involving the MMS claim that royalties were owed with respect to the oil and natural gas leases comprising our Gunnison deepwater field at Garden Banks Blocks 667, 668 and 669 was concluded in October 2009 with no change in our previous conclusion on the issue.

In January 2009, following the decision of the United States Court of Appeals for the Fifth Circuit Court to affirm the decision of the district court, we reversed our previously accrued royalties ($73.5 million) as oil and gas revenue in our first quarter 2009 results. Also effective in January 2009, we commenced recognizing oil and natural gas sales revenue associated with this previously disputed net revenue interest and we are no longer accruing any additional royalty reserves as we believe it is remote that we will be liable for such amounts.

A number of our longer term pipelay contracts have been adversely affected by delays in the completion and delivery of the Caesar. We believe two of our contracts qualify as loss contracts as defined under SOP 81-1 “Accounting for Performance of Construction-Type and Certain Production-Type Contracts”. Accordingly, we have estimated the future shortfall between our anticipated future revenues versus future costs. For one contract that was completed in May 2009, our loss was $0.8 million, all of which was provided with our estimated loss accrual at December 31, 2008. Under a second contract, which was terminated, we have a potential future liability of up to $25 million. As of December 31, 2008, we estimated the loss under this contract at $9.0 million. In the second quarter of 2009, services under this contract were substantially completed and we revised our estimated loss to approximately $15.8 million. To reflect this additional estimated loss we recorded an additional $6.8 million charge to cost of sales in the accompanying condensed consolidated statement of operations. We recently agreed to settle our obligation under this contract for $12.7 million. Accordingly we reversed $3.1 million of our previously accrued costs under this contract to reduce it from the estimated $15.8 million loss to $12.7 million at December 31, 2009. We have paid $7.2 million of the $12.7 million of estimated damages related to this terminated contact and expect to pay the remaining $5.5 million in the second quarter of 2010.

In March 2009, we were notified of a third party’s intention to terminate an international construction contract based on a claimed breach of that contract by one of our subsidiaries. As there are substantial defenses to this claimed breach, we cannot at this time determine if we have any exposure under the contract. In 2010, we will continue to assess our potential exposure to damages under this contract as the circumstances warrant. Under the terms of the contract, our potential liability is generally capped for actual damages at approximately $27 million Australian dollars (“AUD”) (approximately $24.3 million US dollars at December 31, 2009) and for liquidated damages at approximately $5 million AUD (approximately $4.5 million US dollars at December 31, 2009). At December 31, 2009, we have a $4.0 million AUD (approximately $3.6 million US dollars at December 31, 2009) receivable against our counterparty for work performed prior to the termination of the contract. We continue to pursue payment for this work and other claims against our counterparty. We have filed a counterclaim that in the aggregate approximates $12.0 million U.S. dollars. See Item 3. Legal Proceedings and Notes 6 and 17 for a detailed discussion of this contingency.

Convertible Preferred Stock

In January 2003, we completed the private placement of $25 million of a newly designated class of cumulative convertible stock (Series A-1 Cumulative Convertible Preferred Stock, par value $0.01 per share) convertible into 1,666,668 shares of our common stock at $15 per share. The preferred stock was issued to a private investment firm, Fletcher International, Ltd. (“Fletcher”). Subsequently on June 2004, Fletcher exercised an existing right to purchase an additional $30 million of cumulative convertible preferred stock (Series A-2 Cumulative Convertible Preferred Stock, par value $0.01 per share) convertible into 1,964,058 shares of our common stock at $15.27 per share. Pursuant to the agreement governing the preferred stock (the “Fletcher Agreement”), Fletcher was entitled to convert the preferred shares into common stock at any time, and to redeem the preferred shares into common stock at any time after December 31, 2004. In January 2009, Fletcher issued a redemption notice with respect to all its shares of the Series A-2 Cumulative Convertible Preferred Stock, and, pursuant to such redemption, we issued and delivered 5,938,776 shares of our common stock to Fletcher based on a redemption price of $5.05 per share as determined by the average closing price of our common stock on the three days starting on the third day prior to holder redeeming the shares of Series A-2 Cumulative Preferred Stock. Accordingly, in the first quarter of 2009 we recognized a $29.3 million charge to reflect the terms of this redemption, which was recorded as a reduction to our net income applicable to common shareholders. This beneficial conversion charge reflected the value associated with the additional 3,974,718 shares redeemed over the original

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1,964,058 shares that were contractually required to be issued upon conversion but was limited to the $29.3 million of net proceeds we received from the issuance of the Series A-2 Cumulative Convertible Preferred Stock.

The Fletcher Agreement provides that if the volume weighted average price of our common stock on any date is less than a certain minimum price (calculated at $2.767 subsequent to the above described redemption), then our right to pay Fletcher dividends in our common stock is extinguished, and we are required to deliver a notice to Fletcher that either (1) the conversion price will be reset to such minimum price (in which case Fletcher shall have no further right to cause the redemption of the preferred stock), or (2) in the event Fletcher exercises its redemption rights, we will satisfy our redemption obligations either in cash, or a combination of cash and common stock subject to a maximum number of shares (14,973,814) that can be delivered to Fletcher under the Fletcher Agreement. On February 25, 2009, the volume weighted average price of our common stock was below the minimum price, and on February 27, 2009 we provided notice to Fletcher that with respect to the Series A-1 Cumulative Convertible Preferred Stock the conversion price is reset to $2.767 as of that date and that Fletcher shall have no further rights to redeem the shares, and we have no further right to pay dividends in common stock. Subsequent to this election, the conversion price is not subject to any further adjustment or reset. As a result of the reset of the conversion price, Fletcher was entitled to receive an aggregate of 9,035,056 shares in future conversion(s) into our common stock based on the fixed $2.767 conversion price. In the event we elect to settle any future conversion in cash, Fletcher would receive cash in an amount approximately equal to the value of the shares it would receive upon a conversion, which could be substantially greater than the original face amount of the Series A-1 Cumulative Convertible Preferred Stock, and which would result in additional beneficial conversion charges in our statement of operations. Under the existing terms of our Senior Credit Facilities we are not permitted to deliver cash to the holder upon a conversion of the Convertible Preferred Stock.

In connection with the reset of the conversion price of the Series A-1 Cumulative Convertible Preferred Stock to $2.767, we were required to recognize a $24.1 million charge to reflect the value associated with the additional 7,368,388 shares that will be required to be delivered upon any future conversion(s) over the 1,666,668 shares that were to be delivered under the original contractual terms. This $24.1 million charge was recorded as a beneficial conversion charge reducing our net income applicable to common shareholders. Similar to the beneficial conversion charge associated with the redemption of Series A-2 Cumulative Convertible Preferred Stock, the beneficial conversion charge for the Series A-1 Cumulative Convertible Preferred Stock is limited to the $24.1 million of net proceeds received upon its issuance.

On July 23, 2009 and August 12, 2009, Fletcher provided a notice of conversion informing us of its election to convert 15,000 shares and 4,000 shares, respectively, of the Series A-1 Cumulative Convertible Preferred Stock into 5,421,033 shares and 1,445,608 shares, respectively, of our common stock. In connection with the closing of each of these conversions we also paid the accrued and unpaid dividends associated with these shares in cash, the amount of which was immaterial at the time of the conversion notice. The conversions were consummated on July 27, 2009 and August 14, 2009, respectively.

At December 31, 2009, we had 6,000 shares of convertible preferred stock outstanding, which are convertible into 2,168,413 shares of our common stock. The convertible preferred stock maintains its mezzanine presentation below liabilities but is not included as component of shareholders' equity, because we may, under certain instances, be required to settle any future conversions in cash.

Critical Accounting Estimates and Policies

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

Revenue Recognition

Contracting Services Revenues

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

Unbilled revenue represents revenue attributable to work completed prior to period end that has not yet been invoiced. All amounts included in unbilled revenue at December 31, 2009 and 2008 are expected to be billed and collected within one year.

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

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

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

Under the percentage-of-completion method, we recognize estimated contract revenue based on costs incurred to date as a percentage of total estimated costs. Changes in the expected cost of materials and labor, productivity, scheduling and other factors affect the total estimated costs. Additionally, external factors, including weather and other factors outside of our control, may also affect the progress and estimated cost of a project's completion and, therefore, the timing of income and revenue recognition. We routinely review estimates related to our contracts and reflect revisions to profitability in earnings on a current basis. If a current estimate of total contract cost indicates an ultimate loss on a contract, we recognize the projected loss in full when it is first determined. At December 31, 2008, we had two contracts that were deemed to be in loss status and we recorded an aggregate $9.8 million charge to cost of sales to estimate the expected loss to completion of the respective contracts (Note 2). We recognize additional contract revenue related to claims when the claim is probable and legally enforceable.

Oil and Gas Revenues

We record revenues from the sales of crude oil and natural gas when delivery to the customer has occurred, prices are fixed and determinable, collection is reasonably assured and title has transferred. This occurs when production has been delivered to a pipeline or a barge lifting has occurred. We may have an interest with other producers in certain properties. In this case, we use the entitlements method to account for sales of production. Under the entitlements method, we may receive more or less than our entitled share of production. If we receive more than our entitled share of production, the imbalance is treated as a liability. If we receive less than our entitled share, the imbalance is recorded as an asset. As of December 31, 2009, the net imbalance was a $2.5 million asset and was included in Other Current Assets ($7.6 million) and Accrued Liabilities ($5.1 million) in the accompanying consolidated balance sheet.

Goodwill and Other Intangible Assets

Under Codification or ("ASC") Topic No. 350 "Intangibles – Goodwill and Other", we are required to perform an annual impairment analysis of goodwill and intangible assets. We elected November 1 to be the annual impairment assessment date for goodwill and other intangible assets. However, we could be required to evaluate the recoverability of goodwill and other intangible assets prior to the required annual assessment date if we experience disruption to the business, unexpected significant declines in operating results, divestiture of a significant component of the business, emergence of unanticipated competition, loss of key personnel or a sustained decline in market capitalization. ASC 350 also requires testing of goodwill impairment to be at a reporting unit level and defines the reporting unit as an operating segment, as that term is used in ASC Topic No. 280 "Segment Reporting", or one level below the operating segment (referred to as a "component"), depending on whether certain criteria are met. At the time of our annual assessment of goodwill, we had six reporting units with goodwill and our impairment analysis was conducted at this level.

Goodwill impairment is determined using a two-step process that requires management to make judgments in determining what assumptions to use in the calculation. The first step is to identify if a potential impairment exists by comparing the fair value of the reporting unit with its carrying amount, including goodwill. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is not considered to have a potential impairment and the
second step of the impairment test is not necessary. However, if the carrying amount of a reporting unit exceeds its fair value, the second step is performed to determine if goodwill is impaired and to measure the amount of impairment loss to recognize, if any.

The second step compares the implied fair value of goodwill with the carrying amount of goodwill. If the implied fair value of goodwill exceeds the carrying amount, then goodwill is not considered impaired. However, if the carrying amount of goodwill exceeds the implied fair value, an impairment loss is recognized in an amount equal to that excess. The implied fair value of goodwill is determined in the same manner as the amount of goodwill recognized in a business combination (i.e., the fair value of the reporting unit is allocated to all the assets and liabilities, including any unrecognized intangible assets, as if the reporting unit had been acquired in a business combination).

We use both the income approach and market approach to estimate the fair value of our reporting units under the first step. Under the income approach, a discounted cash flow analysis is performed requiring us to make various judgmental assumptions about future revenue, operating margins, growth rates and discount rates. These judgmental assumptions are based on our budgets, long-term business plans, reserve reports, economic projections, anticipated future cash flows and market place data. Under the market approach, the fair value of each reporting unit is calculated by applying an average peer total invested capital EBITDA (defined as earnings before interest, income taxes and depreciation and amortization) multiple to the 2009 budgeted EBITDA for each reporting unit. Judgment is required when selecting peer companies that operate in the same or similar lines of business and are potentially subject to the same corresponding economic risks.

Based on the first step of the 2008 goodwill impairment analysis, the carrying amount of two of our reporting units exceeded its fair value as calculated under the first step, which required us to perform the second step of the impairment test. In the second step, the fair value of tangible and certain intangible assets was generally estimated using discounted cash flow analysis. The fair value of intangibles with indefinite lives, such as trademarks, was calculated using a royalty rate method. Based on our 2008 goodwill and indefinite-lived intangible impairment analysis, in the fourth quarter of 2008 we recorded a $704.3 million charge to write off the remaining goodwill of our

Oil and Gas segment. The impairment charges associated with our oil and gas segment are recorded as a component of operating loss in the accompanying consolidated statements of operations. We also recorded a $10.7 million charge in the fourth quarter of 2008 to write off the remaining goodwill and indefinite-lived intangible assets associated with our acquisition of Helix Energy Limited in 2005. Those impairment charges are reflected as components of income (loss) from discontinued operations in the accompanying consolidated statements of operations as a result of our sale of Helix Energy Limited in April 2009. These impairment charges did not have any current effect and will not have any future effect on cash flow or our results of operations.

While we believe we have made reasonable estimates and assumptions to calculate the fair value of the reporting units and other intangible assets, it is possible a material change could occur. We have $78.6 million of goodwill remaining

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at December 31, 2009. If our actual results are not consistent with our estimates and assumptions used to calculate fair value, our results of operations may be materially impacted as further impairments may occur.

Income Taxes

Deferred income taxes are based on the difference between financial reporting and tax bases of assets and liabilities. We utilize the liability method of computing deferred income taxes. The liability method is based on the amount of current and future taxes payable using tax rates and laws in effect at the balance sheet date. Income taxes have been provided based upon the tax laws and rates in the countries in which operations are conducted and income is earned. A valuation allowance for deferred tax assets is recorded when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized.

We consider the undistributed earnings of our principal non-U.S. subsidiaries to be permanently reinvested. At December 31, 2009, our principal non-U.S. subsidiaries had accumulated earnings and profits of approximately $58.0 million. We have not provided deferred U.S. income tax on the accumulated earnings and profits. The deconsolidation of CDI’s net income for tax return filing purposes after its initial public offering did not have a material impact on our consolidated results of operations; however, because of our inability to recover our tax basis in CDI tax free, a long term deferred tax liability is provided for any incremental increases to the book over tax basis.

It is our policy to provide for uncertain tax positions and the related interest and penalties based upon management’s assessment of whether a tax benefit is more likely than not to be sustained upon examination by tax authorities. At December 31, 2009, we believe we have appropriately accounted for any unrecognized tax benefits. To the extent we prevail in matters for which a liability for an unrecognized tax benefit is established or are required to pay amounts in excess of the liability, our effective tax rate in a given financial statement period may be affected.

See Note 11 for discussion of net operating loss carry forwards, deferred income taxes and uncertain tax positions taken by the Company.

Accounting for Oil and Gas Properties

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

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

We evaluate the impairment of our proved oil and gas properties on a field-by-field basis at least annually or whenever events or changes in circumstances indicate an asset’s carrying amount may not be recoverable. If an impairment is indicated, the cash flows are discounted at a rate approximate to our cost of capital and compared to the carrying value for determining the amount of the impairment loss to record. Estimated future cash flows are based on management's expectations for the future and include estimates of crude oil and natural gas reserves and future commodity prices, operating costs and future capital expenditures. Downward revisions in estimates of proved reserve quantities or expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future cash flows and could indicate a property impairment. We recorded property impairments totaling $120.6 million in 2009 ($55.9 million in the fourth quarter of 2009), $215.7 million in 2008 ($192.6 million in the fourth quarter of 2008) and approximately $64.1 million of property impairments in 2007, primarily related to downward reserve revisions, increased estimates of decommissioning costs and weak end of life well performance in some of our domestic properties.

We also periodically assess unproved properties for impairment based on exploration and drilling efforts to date on the individual prospects and lease expiration dates. Management's assessment of the results of exploration activities,

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availability of funds for future activities and the current and projected political climate in areas in which we operate also impact the amounts and timing of impairment provisions. We recorded a total of $20.1 million in 2009 and $8.9 million in 2008 of exploration expense to write off certain unproved oil and gas properties reflecting management's assessment that exploration activities would not commence prior to the respective lease expiration dates. During 2007, we recorded $9.9 million of exploration expense to impair certain unproved leasehold costs.

Exploratory Drilling Costs

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

At times, it may be determined that an exploratory well may have found hydrocarbons at the time drilling is completed, but it may not be possible to classify the reserves at that time. In this case, we may continue to capitalize the drilling costs as an uncompleted well beyond one year when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project, or the reserves are deemed to be proved. If reserves are not ultimately deemed proved or economically viable, the well is considered impaired and its costs, net of any salvage value, are charged to expense. At December 31, 2007, we had two wells that were deemed to be suspended wells under the criteria established by ASC Topic No. 932 "Extractive Activities – Oil and Gas" (ASC 932.35.18-20). Following the significant decrease in commodity prices in the second half of 2008 coupled with the December 2008 announcement of our intention to sell all or a part of our oil and gas business, we determined that further development of these wells was not probable. Accordingly, we recorded a total of $18.8 million to exploration expense to fully write off the capital costs associated with these two suspended wells. We recorded an additional $0.5 million to write off costs associated with suspended wells in 2009.

Occasionally, we may choose to salvage a portion of an unsuccessful exploratory well in order to continue exploratory drilling in an effort to reach the target geological structure/formation. In such cases, we charge only the unusable portion of the well bore to dry hole expense, and we continue to capitalize the costs associated with the salvageable portion of the well bore and add the costs to the new exploratory well. In certain situations, the well bore may be carried for more than one year beyond the date drilling in the original well bore was suspended. This may be due to the need to obtain and/or analyze the availability of equipment or crews or other activities necessary to pursue the targeted reserves or evaluate new or reprocessed seismic and geographic data. If, after we analyze the new information and conclude that we will not reuse the well bore or if the new exploratory well is determined to be unsuccessful after we complete drilling, we will charge the capitalized costs to dry hole expense. During the years ended December 31, 2009, 2008 and 2007, we incurred $21.4 million, $27.7 million and $20.2 million, respectively, of exploratory expenses, including the impairment of certain unproved leasehold costs as discussed above in "Accounting for Oil and Gas Properties" and in Note 6.

Estimated Proved Oil and Gas Reserves

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

Accounting for Decommissioning Liabilities

Our decommissioning liabilities consist of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. ACS Topic No. 410 “Asset Retirement and Environmental Obligations” requires oil and gas companies to reflect decommissioning liabilities on the face of the balance sheet at fair value on a discounted basis. Prior to the Remington acquisition, we historically purchased producing offshore oil and gas properties that were in the later stages of production. In conjunction with acquiring these properties, we assumed an obligation associated with decommissioning the property in accordance with regulations set by government agencies. The abandonment liability related to the acquisitions of these properties is determined through a series of management estimates.

Prior to an acquisition and as part of evaluating the economics of an acquisition, we will estimate the plug and abandonment liability. Our oil and gas operations personnel prepare detailed cost estimates to plug and abandon wells and remove necessary equipment in accordance with regulatory guidelines. We currently calculate the discounted value of the abandonment liability (based on an estimate of the year the abandonment will occur) and capitalize that portion as part of the basis acquired and record the related abandonment liability at fair value. The recognition of a decommissioning liability requires that management make numerous estimates, assumptions and judgments regarding factors such as the existence of a legal obligation for liability; estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. Decommissioning liabilities were $248.1 million and $225.8 million at December 31, 2009 and 2008, respectively.

On an ongoing basis, our oil and gas operations personnel monitor the status of wells, and as fields deplete and no longer produce, our personnel will monitor the timing requirements set forth by the MMS for plugging and abandoning the wells and commence abandonment operations when applicable. On an annual basis, management personnel reviews and updates the abandonment estimates and assumptions for changes, among other things, in market conditions, interest rates and historical experience.

Derivative Instruments and Hedging Activities

Our risk management activities involve the use of derivative financial instruments to hedge the impact of market price risk exposure primarily related to our oil and gas production, variable interest rate exposure and foreign currency exposure. To reduce the impact of these risks on earnings and increase the predictability of our cash flows, from time to time we have entered into certain derivative contracts, primarily collars and swaps, for a portion of our oil and gas production, interest rate swaps, and foreign currency forward contracts. Our oil and gas costless collars and swaps, interest rate swaps, and foreign currency forward exchange contracts are reflected in our balance sheet at fair value. Hedge accounting does not apply to our oil and gas forward sales contracts as these qualify for the normal purchase and sale scope exception under ASC Topic No. 815 “Derivatives and Hedging.”

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

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. Changes in the assumptions used could impact whether the fair value change in the hedged instrument is charged to earnings or accumulated other comprehensive income.

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

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

Property and Equipment

Property and equipment (excluding oil and gas properties and equipment), both owned and under capital leases, are recorded at cost. Depreciation expense is derived primarily using the straight-line method over the estimated useful lives of the assets (Note 2).

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

Assets are classified as held for sale when a formal plan to dispose of the assets exists and those assets meet the held for sale criteria. Assets held for sale are reviewed for potential loss on sale when the we commit to a plan to sell and thereafter while the asset is held for sale. Losses are measured as the difference between the fair value less costs to sell and the asset's carrying value. Estimates of anticipated sales prices are judgmental and subject to revisions in future periods, although initial estimates are typically based on sales prices for similar assets and other valuation data. We had no assets that met the criteria of being classified as assets held for sale at December 31, 2009.

Recertification Costs and Deferred Drydock Charges

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

As of December 31, 2009 and 2008, capitalized deferred drydock charges (Note 7) totaled \$12.0 million and \$38.6 million, respectively. During the years ended December 31, 2009, 2008 and 2007, drydock amortization expense was $16.4 million, $26.0 million and $23.0 million, respectively. We expect drydock amortization expense will decrease over the near term due to our deconsolidation of CDI which will be partially offset with our commissioning the vessels we have been constructing over the last three years.

Equity Investments

We periodically review our investments in Deepwater Gateway and Independence Hub for impairment. Under the equity method of accounting, an impairment loss would be recorded whenever a decline in value of an equity investment below its carrying amount is determined to be other than temporary. In judging “other than temporary,” we would consider

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the length of time and extent to which the fair value of the investment has been less than the carrying amount of the equity investment, the near-term and longer-term operating and financial prospects of the equity company and our longer-term intent of retaining the investment in the entity. During 2007, CDI determined that there was an other than temporary impairment in OTSL and the full value of CDI's investment in OTSL was impaired and CDI recognized equity losses of OTSL, inclusive of the impairment charge, of $10.8 million in 2007 (Note 8).

Worker's Compensation Claims

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

Recently Issued Accounting Principles

In June 2009, the Financial Accounting Standards Board (FASB) issued a new accounting standard which changes the consolidation rules as they relate to variable interest entities. Specifically, the new standard makes significant changes to the model for determining who should consolidate a variable interest entity, and also addresses how often this assessment should be performed. We adopted this standard in the first quarter of 2010 and the adoption did not have a material impact on our consolidated financial statements.

In August 2009, the FASB issued a new accounting standard which provides additional guidance on the measurement of liabilities at fair value. Specifically, when a quoted price in an active market for the identical liability is not available, the new standard requires that the fair value of a liability be measured using one or more of the valuation techniques that should maximize the use of relevant observable inputs and minimize the use of unobservable inputs. In addition, an entity is not required to include a separate input or adjustment to other inputs relating to the existence of a restriction that prevents the transfer of a liability. We adopted this standard in the fourth quarter of 2009 and the adoption did not have a material impact on our consolidated financial statements.

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

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

Interest Rate Risk. As of December 31, 2009, approximately 30% of our outstanding debt was based on floating rates. Changes based on the floating interest rates under our variable rate debt could result in an increase or decrease in our annual interest expense and related cash outlay. To reduce the impact of this market risk, in January 2010 we entered into various cash flow hedging interest rate swaps to stabilize cash flows relating to interest payments on $200 million of our Term Loan. The interest rate applicable to our variable rate debt may rise, increasing our interest expense. The impact of market risk is estimated using a hypothetical increase in interest rates by 100 basis points for our variable rate long-term debt that is not hedged. Based on this hypothetical assumption, we would have incurred an additional $3.9 million in interest expense for the year ended December 31, 2009.

Commodity Price Risk. We have utilized derivative financial instruments with respect to a portion of our 2010, 2009 and 2008 oil and gas production to achieve a more predictable cash flow. We do not enter into derivative or other financial instruments for trading purposes.

As of December 31, 2009, we have the following volumes under derivatives contracts related to our oil and gas producing activities totaling approximately 2.5 million barrels of oil and 25 Bcf of natural gas:

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Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:			(per barrel)
January 2010 — December 2010	Collar	100 MBbl	$62.50-$80.73
January 2010 — December 2010	Swap	77.1 MBbl	$76.99
January 2010 — June 2010	Swap	50 MBbl	$71.08
July 2010 — December 2010	Swap	15 MBbl	$74.07
Natural Gas:			(per Mcf)
January 2010 — December 2010	Swap	1,079.2 Mmcf	$5.82
January 2010 — December 2010	Collar	1,003.8 Mmcf	$6.00 — $6.70

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 with the change in NYMEX prices.

Foreign Currency Exchange Risk. Because we operate in various regions in the world, we conduct a portion of our business in currencies other than the U.S. dollar (primarily with respect to WOUK and WOSEA). The functional currency for WOUK is the applicable local currency (British Pound). The functional currency for WOSEA is the applicable local currency (Australian Dollar). Although 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.

Assets and liabilities of WOUK and WOSEA are translated using the exchange rates in effect at the balance sheet date, resulting in translation adjustments that are reflected in accumulated other comprehensive income in the shareholders' equity section of our balance sheet. Approximately 9% of our assets are impacted by changes in foreign currencies in relation to the U.S. dollar at December 31, 2009. We recorded unrealized gains (losses) of $30.6 million, $(71.1) million and $3.7 million to accumulated other comprehensive income (loss) for the years ended December 31, 2009, 2008 and 2007, respectively. Deferred taxes have not been provided on foreign currency translation adjustments since we consider our undistributed earnings (when applicable) of our non-U.S. subsidiaries to be permanently reinvested.

We also have subsidiaries with operations in the United Kingdom, Asia Pacific, Europe and Australia. These international subsidiaries conduct the majority of their operations in these regions in U.S. dollars which they consider the functional currency. When currencies other than the U.S. dollar are to be paid or received, the resulting transaction gain or loss is recognized in the statements of operations. These amounts resulted in a gain of $2.2 million for the year ended December 31, 2009 and a $10.0 million loss for the year ended December 31, 2008. The amounts for the year ended December 31, 2007 was not material to our results of operations or cash flows.

Our cash flows are subject to fluctuations resulting from changes in foreign currency exchange rates. Fluctuations in exchange rates are likely to impact our business and cash flow in the future. As a result, we entered into various foreign currency forward purchase contracts to stabilize expected cash outflows relating to certain vessel charters denominated in British pounds. The aggregate fair value of the foreign currency forwards as of December 31, 2009 and 2008 was a net asset (liability) of $2.1 million and $(0.9) million, respectively. In 2009, we recorded a $3.3 million gain compared to a $1.1 million loss in 2008 as a result of the change in fair value of our foreign currency forwards that did not qualify for hedge accounting (Note 22).

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Item 8. Financial Statements and Supplementary Data.

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

In making its assessment, management has utilized the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework. Based on this assessment, management has concluded that, as of December 31, 2009, the Company's internal control over financial reporting is effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

Ernst & Young LLP has issued an attestation report on the Company's internal control over financial reporting as of December 31, 2009, which is included herein.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Helix Energy Solutions Group, Inc. and Subsidiaries

We have audited Helix Energy Solutions Group, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2009, 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. and subsidiaries' management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

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

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.
Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Helix Energy Solutions Group, Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, 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, 2009 and 2008, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2009 of Helix Energy Solutions Group, Inc. and subsidiaries and our report dated February 26, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Houston, Texas
February 26, 2010

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Helix Energy Solutions Group, Inc. and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2009. 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, 2009 and 2008, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 2 to the consolidated financial statements, in 2009 the Company changed its method of accounting for non-controlling interests in the consolidated financial statements as a result of the adoption of a new accounting standard and changed its reserve estimates and required disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Helix Energy Solutions Group, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 26, 2010

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 270,673	$ 223,613
Accounts receivable —		
Trade, net of allowance for uncollectible accounts of $5,172 and $5,905	145,519	427,856
Unbilled revenue	17,854	42,889
Costs in excess of billing	9,305	74,361
Other current assets	121,331	172,089
Current assets of discontinued operations	878	19,215
Total current assets	565,560	960,023
Property and equipment	4,352,109	4,742,051
Less — Accumulated depreciation	(1,488,403)	(1,323,608)
	2,863,706	3,418,443
Other assets:		
Equity investments	189,411	196,660
Goodwill, net	78,643	366,218
Other assets, net	82,213	125,722
	$ 3,779,533	$ 5,067,066
LIABILITIES AND SHAREHOLDERS’ EQUITY		
Current liabilities:		
Accounts payable	$ 155,457	$ 344,807
Accrued liabilities	200,156	231,679
Current maturities of long-term debt	12,424	93,540
Current liabilities from discontinued operations	451	2,772
Total current liabilities	368,488	672,798
Long-term debt	1,348,315	1,933,686
Deferred income taxes	442,607	615,504
Decommissioning liabilities	182,399	194,665
Other long-term liabilities	4,262	81,637
Total liabilities	2,346,071	3,498,290
Convertible preferred stock	6,000	55,000
Commitments and contingencies		
Shareholders’ equity:		
Common stock, no par, 240,000 shares authorized, 104,281 and 91,972 shares issued	907,691	806,905
Retained earnings	519,807	417,940
Accumulated other comprehensive loss	(22,241)	(33,696)

Total controlling interest shareholders' equity	1,405,257	1,191,149
Noncontrolling interests	22,205	322,627
Total equity	1,427,462	1,513,776
	$ 3,779,533	$ 5,067,066

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

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2009	2008	2007
	(In thousands, except per share amounts)		
Net revenues:			
Contracting services	$ 1,076,349	$ 1,568,221	$ 1,147,857
Oil and gas	385,338	545,853	584,563
	1,461,687	2,114,074	1,732,420
Cost of sales:			
Contracting services	854,975	1,135,429	762,812
Oil and gas	218,617	357,853	372,904
Oil and gas property impairments	120,550	215,675	64,072
Exploration expense	24,383	32,926	26,725
	1,218,525	1,741,883	1,226,513
Gross profit	243,162	372,191	505,907
Goodwill and other indefinite-lived intangible impairments	—	704,311	—
Gain on oil and gas derivative commodity contracts	89,485	21,599	—
Gain on sale of assets, net	2,019	73,471	50,368
Selling and administrative expenses	130,851	177,172	144,996
Income (loss) from operations	203,815	(414,222)	411,279
Equity in earnings of investments	32,329	31,854	19,573
Gain on sale of Cal Dive common stock	77,343	—	151,696
Net interest expense and other	51,495	111,098	67,047
Income (loss) before income taxes	261,992	(493,466)	515,501
Provision for income taxes	(95,822)	(86,779)	(171,862)
Income (loss) from continuing operations	166,170	(580,245)	343,639
Income (loss) from discontinued operations, net of tax	9,581	(9,812)	1,347
Net income (loss), including noncontrolling interests	175,751	(590,057)	344,986
Net income applicable to noncontrolling interests	(19,697)	(45,873)	(29,288)
Net income (loss) applicable to Helix	156,054	(635,930)	315,698
Preferred stock dividends	(748)	(3,192)	(3,716)
Preferred stock beneficial conversion charges	(53,439)	—	—
Net income (loss) applicable to Helix common shareholders	$ 101,867	$ (639,122)	$ 311,982
Basic earnings (loss) per share of common stock:			
Continuing operations	$ 0.92	$ (6.94)	$ 3.40
Discontinued operations	0.09	(0.11)	0.02
Net income (loss) per common share	$ 1.01	$ (7.05)	$ 3.42
Diluted earnings (loss) per share of common stock:			

Continuing operations	$ 0.87	$ (6.94)	$ 3.25
Discontinued operations	0.09	(0.11)	0.01
Net income (loss) per common share	$ 0.96	$ (7.05)	$ 3.26
Weighted average common shares outstanding:			
Basic	99,136	90,650	90,086
Diluted	105,720	90,650	95,647

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

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(amounts in thousands)

	Helix Energy Solutions Shareholders' Equity						
	Common Stock						
	Shares	Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total controlling interest shareholders' equity	Non-controlling Interest	Total Equity
Balance, December 31, 2006	90,628	783,998	$ 745,080	$ 27,236	$ 1,556,314	$ 59,802	$ 1,616,116
Comprehensive income:							
Net income	—	—	315,698	—	315,698	29,288	344,986
Foreign currency translations adjustments	—	—	—	3,680	3,680	—	3,680
Unrealized loss on hedges, net	—	—	—	(9,654)	(9,654)	—	(9,654)
Comprehensive income					309,724	29,288	339,012
Reclass unamortized discount on convertible senior notes to reflect temporary equity status (Note 2)	—	(42,201)	—	—	(42,201)	—	(42,201)
Convertible preferred stock dividends	—	—	(3,716)	—	(3,716)	—	(3,716)
Stock compensation expense	—	14,607	—	—	14,607	—	14,607
Stock repurchase	(282)	(9,904)	—	—	(9,904)	—	(9,904)
Activity in company stock plans, net	1,039	4,547	—	—	4,547	—	4,547
Excess tax benefit from stock-based compensation	—	580	—	—	580	—	580
Investments in or dispositions of common stock of	—	—	—	—	—	174,836	174,836

consolidated subsidiaries in which Helix has a noncontrolling interest (Note 2)							
Balance, December 31, 2007	91,385	751,627	1,057,062	21,262	1,829,951	263,926	2,093,877
Comprehensive income (loss)							
Net income (loss)	—	—	(635,930)	—	(635,930)	45,873	(590,057)
Foreign currency translations adjustments	—	—	—	(71,134)	(71,134)	(93)	(71,227)
Unrealized loss (gain) on hedges, net	—	—	—	16,176	16,176	(480)	15,696
Comprehensive loss					(690,888)	45,300	(645,588)
Reclass unamortized discount on convertible senior notes to shareholders' equity (Note 2)	—	42,201	—	—	42,201	—	42,201
Convertible preferred stock dividends	—	—	(3,192)	—	(3,192)	—	(3,192)
Other	—	(3,952)	—	—	(3,952)	—	(3,952)
Stock compensation expense	—	15,506	—	—	15,506	—	15,506
Stock repurchase	(110)	(3,925)	—	—	(3,925)	—	(3,925)
Activity in company stock plans, net	697	4,113	—	—	4,113	—	4,113
Excess tax benefit from stock-based compensation	—	1,335	—	—	1,335	—	1,335
Investments in or dispositions of common stock of consolidated subsidiaries in which Helix has a noncontrolling interest (Note 2)	—	—	—	—	—	13,401	13,401

Balance, December 31, 2008	91,972	$ 806,905	$ 417,940	$ (33,696)	$ 1,191,149	$ 322,627	$ 1,513,776

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(Continued)
(amounts in thousands)

	Helix Energy Solutions Shareholders' Equity						
	Common Stock						
	Shares	Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total controlling interest shareholders' equity	Non-controlling Interest	Total Equity
Balance, December 31, 2008	91,972	$806,905	$ 417,940	$ (33,696)	$ 1,191,149	$ 322,627	$1,513,776
Comprehensive income (loss)							
Net income	—	—	156,054	—	156,054	19,697	175,751
Effect of deconsolidation of Cal Dive (Note 3)	—	—	—	—	—	(320,119)	(320,119)
Foreign currency translations adjustments	—	—	—	30,617	30,617	—	30,617
Unrealized loss (gain) on hedges, net	—	—	—	(18,275)	(18,275)	—	(18,275)
Unrealized loss on investment held for sale	—	—	—	(887)	(887)	—	(887)
Comprehensive loss					167,509	(300,422)	(132,913)
Convertible preferred stock dividends and preferred stock beneficial charges	—	—	(54,187)	—	(54,187)	—	(54,187)
Convertible preferred stock redemptions	12,805	102,502	—	—	102,502	—	102,502
Other	—	(319)	—	—	(319)	—	(319)
Stock compensation expense	—	9,530	—	—	9,530	—	9,530

Stock repurchase	(1,116)	(13,995)	—	—	(13,995)	—	(13,995)
Activity in company stock plans, net	620	2,173	—	—	2,173	—	2,173
Excess tax benefit from stock-based compensation	—	895	—	—	895	—	895
Balance, December 31, 2009	104,281	$907,691	$ 519,807	$ (22,241)	$ 1,405,257	$ 22,205	$1,427,462

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

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2009	2008	2007
		(In thousands)	
Cash flows from operating activities:			
Net income (loss), including noncontrolling interests	$ 175,751	$(590,057)	$ 344,986
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by operating activities —			
Depreciation and amortization	262,617	333,726	329,798
Asset impairment charges	121,855	215,675	64,072
Goodwill and other indefinite-lived intangible impairments	—	704,311	—
Exploratory drilling and related expenditures	21,367	27,703	20,187
Equity in (earnings) loss of investments, net of distributions	(6,321)	2,846	697
Equity in losses of OTSL, inclusive of impairment charge	—	—	10,841
Amortization of deferred financing costs	6,693	5,641	6,939
(Income) loss from discontinued operations	(9,581)	9,658	(1,345)
Stock compensation expense	11,992	21,412	17,302
Amortization of debt discount	7,880	7,385	6,920
Deferred income taxes	(64,926)	(5,402)	125,083
Excess tax benefit from stock-based compensation	(895)	(1,335)	(580)
Unrealized gain on derivative contracts	(5,237)	(1,669)	—
Gain on investment in Cal Dive common stock	(77,343)	—	(151,696)
Gain on sale of assets	(2,019)	(73,471)	(50,368)
Changes in operating assets and liabilities:			
Accounts receivable, net	52,245	(36,956)	(6,758)
Other current assets	49,028	(4,958)	(22,351)
Income tax payable	48,831	(12,937)	(153,804)
Accounts payable and accrued liabilities	(62,341)	(126,082)	(52,362)
Oil and gas decommissioning expenditures	(45,038)	(25,809)	(12,813)
Other noncurrent, net	(62,750)	(15,267)	(53,973)
Cash provided by operating activities	421,808	434,414	420,775
Cash provided by (used in) discontinued operations	(6,261)	3,305	(4,449)
Net cash provided by operating activities	415,547	437,719	416,326
Cash flows from investing activities:			
	(423,373)	(855,054)	(942,381)

Capital expenditures			
Acquisition of businesses, net of cash acquired	—	—	(147,498)
(Purchases) sale of short-term investments	—	—	285,395
Investments in equity investments	(1,657)	(846)	(17,459)
Distributions from equity investments, net	6,742	11,586	6,679
Proceeds from insurance reimbursement	—	13,200	—
Proceeds from sale of Cal Dive common stock	418,168	—	—
Reduction in cash from deconsolidation of Cal Dive	(112,995)	—	—
Proceeds from sales of property	23,717	274,230	78,073
Other, net	(6)	(614)	(1,248)
Cash used in investing activities	(89,404)	(557,498)	(738,439)
Cash provided by (used in) discontinued operations	20,872	(476)	(1,215)
Net cash used in investing activities	$ (68,532)	$ (557,974)	$ (739,654)

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Continued)

	Years Ended December 31,		
	2009	2008	2007
		(in thousands)	
Cash flows from financing activities:			
Repayment of Helix term loan	(4,326)	(4,326)	(405,408)
Borrowings on Helix Revolver	—	1,021,500	472,800
Repayments on Helix Revolver	(349,500)	(690,000)	(454,800)
Borrowings on unsecured senior debt	—	—	550,000
Repayment of MARAD borrowings	(4,214)	(4,014)	(3,823)
Borrowings on CDI Revolver	100,000	61,100	31,500
Repayments on CDI Revolver	—	(61,100)	(332,668)
Borrowings on CDI term loan	—	—	375,000
Repayments on CDI term loan	(20,000)	(60,000)	—
Borrowing under loan notes	—	—	5,000
Deferred financing costs	(6,970)	(1,796)	(17,165)
Capital lease payments	—	(1,505)	(2,519)
Preferred stock dividends paid	(645)	(3,192)	(3,716)
Repurchase of common stock	(13,995)	(3,925)	(9,904)
Excess tax benefit from stock-based compensation	895	1,335	580
Exercise of stock options, net	176	2,139	1,568
Net cash (used in) provided by financing activities	(298,579)	256,216	206,445
Effect of exchange rate changes on cash and cash equivalents	(1,376)	(1,903)	174
Net increase (decrease) in cash and cash equivalents	47,060	134,058	(116,709)
Cash and cash equivalents:			
Balance, beginning of year	223,613	89,555	206,264
	$ 270,673	$ 223,613	$ 89,555

Balance, end of year	

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

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 — Organization

Effective March 6, 2006, we changed our name from Cal Dive International, Inc. to Helix Energy Solutions Group, Inc. ("Helix" or the "Company"). Unless the context indicates otherwise, the terms "we," "us" and "our" in this report refer collectively to Helix and its subsidiaries. Until June 2009, Cal Dive International, Inc. (collectively with its subsidiaries referred to as "Cal Dive" or "CDI") was a majority-owned subsidiary of Helix. Helix sold substantially all its remaining ownership interests in Cal Dive during 2009 (Note 3). We are an international offshore energy company that provides development solutions and other contracting services to the energy market as well as to our own oil and gas properties. Our Contracting Services segment utilizes our vessels, offshore equipment and proprietary technologies to deliver services that may reduce finding and development costs and cover the complete lifecycle of an offshore oil and gas field. Our Contracting Services are located primarily in Gulf of Mexico, North Sea, Asia Pacific, and West Africa regions. Our Oil and Gas segment engages in prospect generation, exploration, development and production activities. Our oil and gas operations are almost exclusively located in the Gulf of Mexico.

Contracting Services Operations

We seek to provide services and methodologies which we believe are critical to finding and developing offshore reservoirs and maximizing production economics. Our "life of field" services are segregated into three disciplines: subsea construction, well operations and production facilities. We have disaggregated our contracting services operations into three reportable segments: Contracting Services; Shelf Contracting; and Production Facilities. Our Contracting Services business includes deepwater construction, well operations and drilling. Our former Shelf Contracting business represents the assets of CDI, of which we owned 57.2% at December 31, 2008. In 2009, we sold substantially all our remaining ownership of CDI through various transactions (Note 3). Our Production Facilities business includes our investments in Deepwater Gateway, L.L.C. ("Deepwater Gateway"), Independence Hub, LLC ("Independence Hub") and Kommandor LLC ("Kommandor").

Oil and Gas Operations

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

Discontinued Operations

In April 2009, we sold Helix Energy Limited ("HEL"), our former reservoir technology consulting business, to a subsidiary of Baker Hughes Incorporated for $25 million. As a result of the sale of HEL, which entity's operations were conducted by its wholly owned subsidiary, Helix RDS Limited ("Helix RDS"), we have presented the results of Helix RDS as discontinued operations in the accompanying consolidated financial statements. HEL and Helix RDS were previously components of our Contracting Services segment. We recognized an $8.3 million gain on the sale of HEL.

Economic Outlook

The economic downturn and weakness in the equity and credit capital markets continue to contribute to the uncertainty regarding the outlook of the global economy. This uncertainty, coupled with the negative near-term outlook for global demand for oil and natural gas, resulted in commodity price declines over the second half of 2008, with significant declines occurring in the fourth quarter of 2008. Natural gas prices continued to decline in 2009 with prices reaching near decade low levels. A decline in oil and natural gas prices negatively impacts our operating results and cash flows.   Our stock price also significantly declined over the second half of 2008. The declines in our stock price and the prices of oil and natural gas were considered in association with our required annual impairment assessment of goodwill and properties at year end 2008, which resulted in significant impairment charges (Note 2). Our stock price decreased further in the first quarter of 2009 resulting in our assessment of our goodwill amounts as of March 31, 2009; however, no further impairments were required. Our stock price subsequently increased and no further impairment of goodwill was required in 2009. At December 31, 2009 our remaining goodwill totaled $78.6 million, all of which is attributable to our Contracting Services segment.

Our Contracting Services segment may be negatively impacted by low commodity prices as some of our customers, primarily oil and gas companies, have announced their intention to reduce capital spending. With respect to our oil and gas operations, we hedged the price risk for a significant portion of our anticipated oil and gas production for 2010 when we entered into commodity hedges during 2009. These hedge contracts enable us to minimize our near-term cash flow risks related to declining commodity prices. See Note 22 for additional information regarding our oil and gas hedge contracts.

Note 2 — Summary of Significant Accounting Policies

Principles of Consolidation

Our consolidated financial statements include the accounts of majority-owned subsidiaries. The equity method is used to account for investments in affiliates in which we do not have majority ownership, but have the ability to exert significant influence. We consolidated our former subsidiary CDI until June 10, 2009, at which time our ownership in CDI was reduced to less than 50%. We recorded our proportional share of CDI’s results under the equity method of accounting until we sold substantially all our remaining ownership interests in CDI on September 23, 2009. We also account for our Deepwater Gateway and Independence Hub investments under the equity method of accounting. Minority interests represents the minority shareholders’ proportionate share of the equity in CDI, until we deconsolidated its results in June 2009, and Kommandor LLC. All material intercompany accounts and transactions have been eliminated. Certain reclassifications were made to previously reported amounts in the consolidated financial statements and notes thereto to make them consistent with the current presentation format, including the separate line disclosures of goodwill, oil and gas property impairment charges and exploration expense in the consolidated statements of operations reflecting the material amount of such charges, the adoption of certain recent accounting pronouncements that require retrospective application and the presentation of a former business unit as discontinued operations (Note 1). We have conducted our subsequent events review through February 26, 2010, the date our financial statements were filed with the Securities and Exchange Commission (“SEC”).

Use of Estimates

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

Cash and Cash Equivalents

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

Statement of Cash Flow Information

As of both December 31, 2009 and 2008, we had $35.4 million of restricted cash included in other assets (Note 7), all of which was related to funds required to be escrowed to cover decommissioning liabilities associated with the acquisition of the South Marsh Island Block 130 property in 2002. Under the purchase agreement for that property, we are obligated to escrow 50% of revenues on the first $20 million of production escrow and then 37.5% of revenues on production until a total of $33 million is escrowed. At December 31, 2009 the full escrow requirement under this agreement was met and is available for the future decommissioning of this field.

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

	Year Ended December 31, 2009	2008	2007
Interest paid, net of interest capitalized	$ 48,313	$ 53,000	$ 71,706
Income taxes paid	$ 106,480	$ 106,624	$ 203,873

Non-cash investing activities for the years ended December 31, 2009, 2008 and 2007 included $48.9 million, $78.5 million and $90.7 million, respectively, related to accruals of capital expenditures. The accruals have been reflected in the consolidated balance sheet as an increase in property and equipment and accounts payable.

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 amount of our net accounts receivable approximate fair value. We establish an allowance for uncollectible accounts receivable based on historical experience and any specific customer collection issues that we have identified. Uncollectible accounts receivable are written off when a settlement is reached for an amount that is less than the outstanding historical balance or when we have determined that the balance will not be collected (Note 19).

Inventories

We had inventory totaling $25.8 million at December 31, 2009 and $32.2 million at December 31, 2008. Our inventory primarily represents the cost of supplies to be used in our oil and gas drilling and development activities, primarily drilling pipe, tubulars and certain wellhead equipment, including two subsea trees. These costs will be partially reimbursed by third party participants in wells supplied with these materials. Our inventories are stated at the lower of cost or market value. For the year ended December 31, 2009, we recorded an aggregate of $1.8 million of charges to cost of sales to reduce our inventory to its lower of cost or market value at various times throughout the year, including $0.7 million at December 31, 2009. At December 31, 2008, we recorded $2.4 million of similar charges to reduce our inventory to its then estimated market value as of that date.

Property and Equipment

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

	Estimated Useful Life	2009	2008
Vessels	10 to 30 years	$ 1,542,403	$ 1,941,733
Oil and gas leases and related equipment	Units-of-Production	2,665,720	2,564,851
Machinery, equipment, buildings and leasehold improvement	5 to 30 years	143,986	235,467
Total property and equipment		$ 4,352,109	$ 4,742,051

The cost of repairs and maintenance is charged to expense as incurred, while the cost of improvements is capitalized. Total repair and maintenance expenses totaled $35.6 million, $72.4 million and $44.1 million for the years ended December 31, 2009, 2008 and 2007, respectively. Included in machinery, equipment, buildings and leasehold improvements were $19.5 million and $21.0 million of capitalized software costs at December 31, 2009 and 2008, respectively. Total amount charged to expense related to the amortization of these software costs was $2.6 million, $1.2 million and $0.3 million for the years ended December 31, 2009, 2008 and 2007, respectively.

For long-lived assets to be held and used, excluding goodwill, we base our evaluation of recoverability on impairment indicators such as the nature of the assets, the future economic benefit of the assets, any historical or future profitability measurements and other external market conditions or factors that may be present. If such impairment indicators are present or other factors exist that indicate the carrying amount of the asset may not be recoverable, we determine whether an impairment has occurred through the use of an undiscounted cash flow analysis of the asset at the lowest level for which identifiable cash flows exist. Our marine vessels are assessed on a vessel by vessel basis, while our ROVs are grouped and assessed by asset class. If an impairment has occurred, we recognize a loss for the difference between the carrying amount and the fair value of the asset. The fair value of the asset is measured using quoted market prices or, in the absence of quoted market prices, an estimate of discounted cash flows or a combination of the two. During the fourth quarter of 2009, we recorded an aggregate $1.3 million charge to reduce the carrying value of certain specific ROV equipment to its net realizable value. There were no such impairments related to our vessels during 2009, 2008 and 2007. See Note 6 for disclosure related to our oil and gas properties.

Assets are classified as held for sale when we have a formalized plan for disposal of certain assets and those assets meet the held for sale criteria. Assets classified as held for sale are included in other current assets. There were no assets meeting the requirements to be classified as assets held for sale at December 31, 2009 and 2008. As further discussed in Note 3, we own 500,000 shares of CDI common stock that we classify as an investment held for sale. Accordingly, we mark these shares to market at each period end based on the quoted stock price of CDI common stock on the NYSE, and record the change in the fair value of shares as a charge reflected within accumulated comprehensive income (loss) (Note 14).

Depreciation and Depletion. Depletion expense is determined on a field-by-field basis using the units-of-production method, with depletion rates for leasehold acquisition costs based on estimated total remaining proved reserves. Depletion rates for well and related facility costs are based on estimated total remaining proved developed reserves associated with each individual field. The depletion rates are changed whenever there is an indication of the need for a revision but, at a minimum, are evaluated annually. Any such revisions are accounted for prospectively as a change in accounting estimate.

Oil and Gas Properties. Almost all of our interests in oil and gas properties are located offshore in the Gulf of Mexico and located in waters regulated by the United States. We follow the successful efforts method of accounting for our natural gas and oil exploration and development activities. Under this method, the costs of successful wells and leases containing productive reserves are capitalized. Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized and are reflected as a reduction of investing cash flow in the accompanying consolidated statements of cash flow. Costs incurred relating to unsuccessful exploratory wells are expensed in the period when the drilling is determined to be unsuccessful and are included as a reconciling item to net income (loss) in operating activities in the accompanying consolidated statements of cash flow. See "— Exploratory Costs" below.

Proved Properties. We assess proved oil and gas properties for possible impairment at least annually or when events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. We recognize an impairment loss as a result of a triggering event and when the estimated undiscounted future cash flows from a property are less than the carrying value. If an impairment is indicated, the cash flows are discounted at a rate approximate to our cost of capital and compared to the carrying value for determining the amount of the impairment loss to record. In the discounted cash flow method, the estimated future cash flows are based on prices based on published forward commodity price curves as of the date of the estimate and management's estimates of future operating and development costs and a risk adjusted discount rate. Downward revisions in estimates of reserve quantities or expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future cash flows and could indicate a property impairment. We recorded approximately $120.6 million, $215.7 million and $64.1 million of property impairments in 2009, 2008 and 2007, respectively, primarily related to downward reserve revisions, weak end of life well performance in some of our domestic properties, fields lost as a result of Hurricanes Gustav and Ike, and the reassessment of the economics of some of our marginal fields in light of current oil and gas market conditions. These impairment charges included a total of $55.9 million in the fourth quarter of 2009 and $192.6 million in the fourth quarter of 2008.

Unproved Properties. We also periodically assess unproved properties for impairment based on exploration and drilling efforts to date on the individual prospects and lease expiration dates. Management's assessment of the results of exploration activities, availability of funds for future activities and the current and projected political climate in areas in which we operate also impact the amounts and timing of impairment provisions. We recorded impairments to unproved oil and gas properties totaling $20.1 million in 2009, $8.9 million in 2008 and $9.9 million in 2007. Such impairments were included in exploration expenses for our Oil and Gas segment.

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

Occasionally, we may choose to salvage a portion of an unsuccessful exploratory well in order to continue exploratory drilling in an effort to reach the target geological structure/formation. In such cases, we charge only the unusable portion of the well bore to dry hole exploration expense, and we continue to capitalize the costs associated with the salvageable portion of the well bore which increase the capital cost basis of the new exploratory well. In certain situations, the well bore may be carried for more than one year beyond the date drilling in the original well bore was suspended. This may reflect the need to obtain, and/or analyze the availability of, equipment or crews or other activities necessary to pursue the targeted reserves or evaluate new or reprocessed seismic and geographic data. If, after we analyze the new information and conclude that we will not reuse the well bore or if the new exploratory well is determined to be unsuccessful after we complete drilling, we will charge all the capitalized costs to dry hole exploration expense. During the year ended December 31, 2009, 2008 and 2007, we incurred $21.4 million, $27.7 million and $20.2 million, respectively, of exploratory expense; including $0.6 million, $18.8 million and $10.3 million of dry hole expense. See "— Note 6 — Oil and Gas Properties" for detailed discussion of our exploratory activities.

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

Properties Acquired from Business Combinations. Properties acquired through business combinations are recorded at their fair value. In determining the fair value of the proved and unproved properties, we prepare estimates of oil and gas reserves. We estimate future prices to apply to the estimated reserve quantities acquired and the estimated future operating and development costs to arrive at our estimates of future net revenues. For the fair value assigned to proved reserves, the future net revenues are discounted using a market-based weighted average cost of capital rate determined to be appropriate at the time of the acquisition. To compensate for inherent risks of estimating and valuing unproved reserves, probable and possible reserves are reduced by additional risk weighting factors. See Note 5 for a detailed discussion of our acquisition of Remington.

Capitalized Interest. Interest from external borrowings is capitalized on major projects until the assets are ready for their intended use. Capitalized interest is added to the cost of the underlying asset and is amortized over the useful lives of the asset in the same manner as the underlying asset. The total of our interest expense capitalized during each of the three years ended December 31, 2009, 2008 and 2007 was $48.1 million, $42.1 million and $31.8 million, respectively.

Equity Investments

We periodically review our investments in Deepwater Gateway and Independence Hub for impairment. Under the equity method of accounting, an impairment loss would be recorded whenever the fair value of an equity investment is determined to be below its carrying amount and the reduction is considered to be other than temporary. In judging "other than temporary," we would consider the length of time and extent to which the fair value of the investment has been less than the carrying amount of the equity investment, the near-term and long-term operating and financial prospects of the equity company and our longer-term intent of retaining the investment in the entity. During 2007, CDI determined that there was an other than temporary impairment in its investment of Offshore Technology Solutions Limited ("OTSL") and the full value of CDI's investment in OTSL was impaired and CDI recognized equity losses of OTSL, inclusive of the impairment charge, of $10.8 million in 2007 (Note 8).

Goodwill and Other Intangible Assets

Under FASB Codification ("ASC") Topic No. 350 "Intangibles – Goodwill and Other" we are required to perform an annual impairment analysis of goodwill and intangible assets. We elected November 1 to be the annual impairment assessment date for goodwill and other intangible assets. However, we could be required to evaluate the recoverability of goodwill and other intangible assets prior to the required annual assessment date if we experience disruption to the business, unexpected significant declines in operating results, divestiture of a significant component of the business, emergence of unanticipated competition, loss of key personnel or a sustained decline in market capitalization. Our goodwill impairment test involves a comparison of the fair value with our carrying amount. The fair value is determined using discounted cash flows and other market-related valuation models.

Goodwill impairment is determined using a two-step process. The first step is to identify if a potential impairment exists by comparing the fair value of the reporting unit with its carrying amount, including goodwill. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is not considered to have a potential impairment and the second step of the impairment test is not necessary. However, if the carrying amount of a reporting unit exceeds its fair value, the second step is performed to determine if goodwill is impaired and to measure the amount of impairment loss to recognize, if any.

The second step compares the implied fair value of goodwill with the carrying amount of goodwill. If the implied fair value of goodwill exceeds the carrying amount, then goodwill is not considered impaired. However, if the carrying amount of goodwill exceeds the implied fair value, an impairment loss is recognized in an amount equal to that excess. The implied fair value of goodwill is determined in the same manner as the amount of goodwill recognized in a business combination (i.e., the fair value of the reporting unit is allocated to all the assets and liabilities, including any unrecognized intangible assets, as if the reporting unit had been acquired in a business combination).

We use both the income approach and market approach to estimate the fair value of our reporting units under the first step. Under the income approach, a discounted cash flow analysis is performed requiring us to make various judgmental assumptions about future revenue, operating margins, growth rates and discount rates. These judgmental assumptions are based on our budgets, long-term business plans, reserve reports, economic projections, anticipated future cash flows and market place data. Under the market approach, the fair value of each reporting unit is calculated by applying an average peer total invested capital EBITDA (defined as earnings before interest, income taxes and depreciation and amortization) multiple to the upcoming fiscal year's budgeted EBITDA for each reporting unit. Judgment is required when selecting peer companies that operate in the same or similar lines of business and are potentially subject to the same corresponding economic risks.

The continued economic downturn and weakness in the equity and credit capital markets continues to lead to increased uncertainty regarding the outlook of the global economy. There were substantial commodity price declines over the second half of 2008, with significant declines occurring in the fourth quarter of 2008. Declines in oil and gas prices negatively impacts our operating results and cash flow. We believe that these events contributed to the significant decline in our stock price and corresponding market capitalization at that time. Based on the first step of the 2008 goodwill impairment analysis, the carrying amount of two of our reporting units exceeded their fair value as calculated under the first step, which required us to perform the second step of the impairment test. In the second step, the fair value of tangible and certain intangible assets was generally estimated using discounted cash flow analysis. The fair value of intangibles with indefinite lives such as trademark was calculated using a royalty rate method. Based on our 2008 goodwill impairment analysis, we recorded a $704.3 million charge to impairment expense in our Oil and Gas segment. In addition, we eliminated all the goodwill associated with Helix Energy Limited and its subsidiaries by recording an $8.3 million charge. We also recorded a $2.4 million charge related to a trade name used by Helix RDS. These charges related to Helix Energy Limited and its subsidiary, Helix RDS Limited, are reflected as a component of income (loss) from discontinued operations in the accompanying consolidated statements of operations. We did not record any impairment of goodwill in 2009 based on our evaluations conducted throughout the year. We primarily focused our goodwill evaluations on our Well Ops SEA Pty Ltd ("WOSEA") reporting unit's goodwill ($15.5 million at December 31, 2009) as its results were adversely affected by damages to their main revenue generating asset. The asset repairs are substantially complete and based on WOSEA's forecasted business activity no impairment of its goodwill was necessary during 2009.

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The changes in the carrying amount of goodwill are as follows (in thousands):

	Contracting Services	Shelf Contracting	Oil and Gas	Total
Balance at December 31, 2007	$ 82,179	$ 284,141	$712,392	$1,078,712
Impairment expense	—	—	(704,311)	(704,311)
Goodwill written off related to sale of business	—	—	(8,081)	(8,081)
Horizon acquisition (Note 5)	—	8,328	—	8,328
Well Ops SEA Pty Ltd. acquisition (Note 5)	1,029	—	—	1,029
Other adjustments(1)	(9,459)	—	—	(9,459)
Balance at December 31, 2008	73,749	292,469	—	366,218
Deconsolidation of Cal Dive (Note 3)	—	(292,469)	—	(292,469)
Other adjustments(1)	4,894	—	—	4,894
Balance at December 31, 2009	$ 78,643	$ —	$—	$78,643

(1) Reflects foreign currency adjustment for certain amount of our goodwill.

A summary of other intangible assets, net, is as follows (in thousands):

	As of December 31, 2009 Gross Amount	As of December 31, 2009 Accumulated Amortization	As of December 31, 2008 Gross Amount	As of December 31, 2008 Accumulated Amortization
Contract backlog	$ —	$ —	$ 2,960	$ (1,330)
Customer relationships	—	—	6,758	(2,294)
Non-compete agreements	1,800	(1,800)	4,800	(4,500)
Trade name	—	—	490	(74(1))
Intellectual property	1,617	(849)	1,458	(668)
Total	$ 3,417	$ (2,649)	$ 16,466	$ (8,866)

(1) Amortization amount reflects an impairment charge recorded to this indefinite-lived intangible assets in fourth quarter of 2008.

Total amortization expenses for intangible assets for the years ended December 31, 2009, 2008, and 2007 was $2.4 million, $5.8 million and $1.8 million, respectively. A summary of the estimated amortization expense for the next five years is as follows (in thousands):

Years Ended December 31,	
2010	$110
2011	$110
2012	$110
2013	$110

2014	$110

Recertification Costs and Deferred Drydock Charges

Our Contracting Services vessels are required by regulation to be recertified after certain periods of time. These recertification costs are incurred while the vessel is in drydock. In addition, routine repairs and maintenance are performed and, at times, major replacements and improvements are performed. We expense routine repairs and maintenance costs as they are incurred. We defer and amortize drydock and related recertification costs over the length of time for which we expect to receive benefits from the drydock and related recertification, which is generally 30 months but can be as long as 60 months if the appropriate permitting is obtained. Vessels are typically available to earn revenue for the period between drydock and related recertification processes. A drydock and related recertification process typically lasts one to two months, a period during which the vessel is not available to earn revenue. Major replacements and improvements, which extend the vessel's economic useful life or functional operating capability, are capitalized and depreciated over the vessel's remaining economic useful life. Inherent in this process are estimates we make regarding the specific cost incurred and the period that the incurred cost will benefit.

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As of December 31, 2009 and 2008, capitalized deferred drydock charges included within Other Assets in the accompanying consolidated balance sheet (Note 7) totaled $12.0 million and $38.6 million, respectively. During the years ended December 31, 2009, 2008 and 2007, drydock amortization expense was $16.4 million, $26.0 million and $23.0 million, respectively.

Accounting for Decommissioning Liabilities

We account for our decommissioning liabilities in accordance with ACS Topic No. 410 "Asset Retirement and Environmental Obligations" ("ACS 410"). This statement requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying cost of the asset. Our asset retirement obligations consist of estimated costs for dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. An asset retirement obligation and the related asset retirement cost are recorded when an asset is first constructed or purchased. The asset retirement cost is determined and discounted to present value using a credit-adjusted risk-free rate. After the initial recording, the liability is increased for the passage of time, with the increase being reflected as accretion expense in the statement of operations. Subsequent adjustment in the cost estimates are reflected in the liability and the amounts continue to be accreted over the useful life of the related long-lived asset.

ACS 410 calls for measurements of asset retirement obligations to include, as a component of expected costs, an estimate of the price that a third party would demand, and could expect to receive, for bearing the uncertainties and unforeseeable circumstances inherent in the obligations, sometimes referred to as a market-risk premium. To date, the oil and gas industry has no examples of credit-worthy third parties who are willing to assume this type of risk for a determinable price on major oil and gas production facilities and pipelines. Therefore, because determining such a market-risk premium would be an arbitrary process, we exclude it from our reclamation estimates.

The following table describes the changes in our asset retirement obligations for the year ended 2009 and 2008 (in thousands):

	2009	2008
Asset retirement obligation at January 1,	$ 225,781	$ 217,479
Liability incurred during the period	1,256	6,819
Liability settled during the period	(66,517)	(47,703)
Hurricane-related revisions in estimated cash flows	43,812	4,253
Other revisions in estimated cash flows	28,592	31,868
Accretion expense (included in depreciation and amortization)	15,204	13,065
Asset retirement obligations at December 31,	$ 248,128	$ 225,781

Revenue Recognition

Contracting Services Revenues

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

Unbilled revenue represents revenue attributable to work completed prior to period end that has not yet been invoiced. All amounts included in unbilled revenue at December 31, 2009 and 2008 are expected to be billed and collected within one year.

Dayrate Contracts. Revenues generated from specific time, materials and equipment contracts are generally earned on a dayrate basis and recognized as amounts are earned in accordance with contract terms. In connection with these contracts, we may receive revenues for mobilization of equipment and personnel. In connection with contracts, revenues related to mobilization are deferred and recognized over the period in which contracted services are performed using the straight-line method. Incremental costs incurred directly for mobilization of equipment and personnel to the contracted site, which typically consist of materials, supplies and transit costs, are also deferred and recognized over the period in which contracted services are performed using the straight-line method. Our policy to amortize the revenues and

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costs related to mobilization on a straight-line basis over the estimated contract service period is consistent with the general pace of activity, level of services being provided and dayrates being earned over the service period of the contract. Mobilization costs to move vessels when a contract does not exist are expensed as incurred.

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

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

Under the percentage-of-completion method, we recognize estimated contract revenue based on costs incurred to date as a percentage of total estimated costs. Changes in the expected cost of materials and labor, productivity, scheduling and other factors affect the total estimated costs. Additionally, external factors, including weather and other factors outside of our control, may also affect the progress and estimated cost of a project's completion and, therefore, the timing of income and revenue recognition. We routinely review estimates related to our contracts and reflect revisions to profitability in earnings on a current basis. If a current estimate of total contract cost indicates an ultimate loss on a contract, we recognize the projected loss in full when it is first determined. We recognize additional contract revenue related to claims when the claim is probable and legally enforceable. If dependable estimates of progress cannot be made or inherent hazards make such estimates doubtful, the completed contract method is used instead of percentage-of-completion method.

A number of our longer term pipelay contracts have been adversely affected by delays in the delivery of the Caesar. We believe two of our contracts qualified as loss contracts as defined under ACS Topic No. 605.35 "Revenue Recognition – Construction Type and Production Type Contracts". Accordingly, we estimate the future shortfall between our anticipated future revenues versus future costs whenever applicable. At December 31, 2008, we had one contract that was expected to be completed at an estimated loss of approximately $0.8 million. We recorded this estimated loss at December 31, 2008 and the project was completed in May 2009 at no additional loss. Under a second contract, which was terminated, we had a potential future liability of up to $25 million. As of December 31, 2008, we estimated the loss under this contract at $9.0 million. In the second quarter of 2009, services under this contract were substantially completed by a third party and we revised our estimated loss to approximately $15.8 million. To reflect this additional estimated loss we recorded an additional $6.8 million charge to cost of sales in the accompanying consolidated statement of operations. We recently agreed to settle our obligation under this contract for $12.7 million. Accordingly we reversed $3.1 million of our previously accrued loss under this contract to reduce it from the estimated $15.8 million loss to $12.7 million at December 31, 2009. We have paid $7.2 million of the $12.7 million of estimated the damages related to this terminated contact and expect to pay the remaining $5.5 million in the second quarter of 2010.

Oil and Gas Revenues

We record revenues from the sales of crude oil and natural gas when delivery to the customer has occurred, title has transferred, prices are fixed and determinable and collection is reasonably assured. This occurs when production has been delivered to a pipeline or a barge lifting has occurred. We may have an interest with other producers in certain properties. In this case, we use the entitlements method to account for sales of production. Under the entitlements method, we may receive more or less than our entitled share of production. If we receive more than our entitled share of production, the imbalance is treated as a liability. If we receive less than our entitled share, the imbalance is recorded as an asset. As of December 31, 2009, the net imbalance was a $2.5 million asset and was included in Other Current Assets ($7.6 million) and Accrued Liabilities ($5.1 million) in the accompanying consolidated balance sheet.

Income Taxes

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

It is our policy to provide for uncertain tax positions and the related interest and penalties based upon management's assessment of whether a tax benefit is more likely than not to be sustained upon examination by tax authorities. At December 31, 2009, we believe we have appropriately accounted for any unrecognized tax benefits. To the extent we prevail in matters for which a liability for an unrecognized tax benefit is established or are required to pay amounts in excess of the liability, our effective tax rate in a given financial statement period may be affected.

Foreign Currency

The functional currency for our foreign subsidiary, Helix Well Ops (U.K.) Limited is the applicable local currency (British Pound), and the functional currency of WOSEA. is its applicable local currency (Australian Dollar). Results of operations for these subsidiaries are translated into U.S. dollars using average exchange rates during the period. Assets and liabilities of these foreign subsidiaries are translated into U.S. dollars using the exchange rate in effect at December 31, 2009 and 2008 and the resulting translation adjustment, which was an unrealized (loss) gain of $30.6 million and $(71.1) million, respectively, is included in accumulated other comprehensive income, a component of shareholders' equity. All foreign currency transaction gains and losses are recognized currently in the statements of operations.

Canyon Offshore, Inc., our ROV subsidiary, has operations in the United Kingdom and Asia Pacific. 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 each of the years ended December 31, 2009, 2008 and 2007 were not material to our results of operations or cash flows.

Our foreign currency gains (losses) totaled $2.2 million in 2009, $(10.0) million in 2008 and $(0.5) million in 2007.

Derivative Instruments and Hedging Activities

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

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

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

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Commodity Price Risks

The fair value of derivative 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.

We have entered into various costless collar and swap contracts to stabilize cash flows relating to a portion of our expected oil and gas production. These contracts qualified for hedge accounting. However, due to disruptions in our production as a result of damages caused by the hurricanes in third quarter 2008, most of our 2009 natural gas financial contracts no longer qualified for hedge accounting as of March 31, 2009. At their inception, our forward sales contracts qualified for the normal purchases and sales scope exception but due to disruptions in our production as a result of damages caused by the 2008 hurricanes these contracts ceased to qualify for the scope exception.

The aggregate fair value of our commodity derivative instruments were a net asset (liability) of $(14.5) million and $22.3 million as of December 31, 2009 and 2008, respectively. For the years ended December 31, 2009, 2008 and 2007, we recorded unrealized gains (losses) of approximately $14.5 million, $14.9 million and $(8.1) million, net of tax expense (benefit) of $(5.1) million, $5.2 million and $(2.8) million, respectively, in accumulated other comprehensive income, a component of shareholders' equity. During 2009, 2008 and 2007, we reclassified approximately $17.0 million, $(23.4) million and $0.5 million, respectively, of gains (losses) from other comprehensive income to Oil and Gas revenues upon the sale of the related oil and gas production. In addition, during 2009 and 2008 we recorded a gains of approximately $89.5 million and $21.6 million, respectively, to reflect mark-to-market adjustments for changes in the fair values of our contracts that no longer qualified for hedge accounting. These gains are reported in the accompanying consolidated statements of operations in the line titled "Gain on oil and gas derivative commodity contracts". At the end of 2009 and 2007 all contracts qualified for hedge accounting.

As of December 31, 2009, we have the following volumes under derivatives and forward sales contracts related to our oil and gas producing activities totaling approximately 2.5 million barrels of oil and 25 Bcf of natural gas:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:			(per barrel)
January 2010 — December 2010	Collar	100 MBbl	$62.50-$80.73
January 2010 — December 2010	Swap	77.1 MBbl	$76.99
January 2010 — June 2010	Swap	50 MBbl	$71.08
July 2010 — December 2010	Swap	15 MBbl	$74.07
Natural Gas:			(per Mcf)
January 2010 — December 2010	Swap	1,079.2 Mmcf	$5.82
January 2010 — December 2010	Collar	1,003.8 Mmcf	$6.00 — $6.70

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 with the change in NYMEX prices.

Variable Interest Rate Risks

As the interest rates for some of our long-term debt are subject to market influences and will vary over the term of the debt, we entered into various interest rate swaps to stabilize cash flows relating to a portion of our interest payments on our variable interest rate debt. Changes in the interest rate swap fair value are deferred to the extent the swap is effective and are recorded as a component of accumulated other comprehensive income until the anticipated interest payments occur and are recognized in interest expense. The ineffective portion of the interest rate swap, if any, will be recognized immediately in earnings.

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In September 2006, we entered into various interest rate swaps to stabilize cash flows relating to a portion of our interest payments on our Term Loan (Note 10). These interest rate swaps qualified for hedge accounting. On December 21, 2007, we prepaid a portion of our Term Loan which reduced the notional amount of our interest rate swaps and caused our hedges to become ineffective. As a result, the interest rate swaps no longer qualified for hedge accounting treatment under SFAS No. 133. On January 31, 2008, we re-designated these swaps as cash flow hedges with respect to our outstanding LIBOR-based debt; however, at September 30, 2008, based on the hypothetical derivatives method, we assessed the hedges were not highly effective, and as such, no longer qualified for hedge accounting. During the year ended December 31, 2008 and 2007, we recognized $5.3 million and $0.6 million, respectively, of unrealized losses as other expense as a result of the change in fair value of our interest rate swaps. As of December 31, 2008 and December 31, 2007, the aggregate fair value of the derivative instruments was a net liability of $8.0 million and $4.7 million, respectively. During the year ended December 31, 2008 and 2007, we reclassified approximately $1.7 million and $(0.4) million of (gains) losses, respectively, from other accumulated comprehensive income (loss), a component of shareholders' equity, to interest expense. The last of the 2006 interest rate swaps were settled in October 2009.

In January 2010, we entered into $200 million, two year interest rate swaps to stabilize cash flows relating to a portion of our interest payments on our Term Loan (Note 10).

Foreign Currency Exchange Risks

Because we operate in various regions in the world, we conduct a portion of our business in currencies other than the U.S. dollar. We entered into various foreign currency forwards to stabilize expected cash outflows relating to certain shipyard contracts where the contractual payments are denominated in euros and expected cash outflows relating to certain vessel charters denominated in British pounds. The aggregate fair value of the foreign currency forwards as of December 31, 2009 and December 31, 2008 was a net asset (liability) of $2.1 million and $(0.9) million, respectively. For the year ended December 31, 2008 we recorded unrealized gains of approximately $0.1 million in accumulated other comprehensive income, a component of shareholders' equity, all of which were reclassified into earnings in 2009. All our remaining foreign exchange contracts are not accounted for as hedge contracts and changes in their fair value are being marked to market each reporting period. In 2009 we recorded gains totaled $3.3 million associated with foreign exchange contracts not qualifying for hedge accounting compared with a $1.1 million loss in 2008. See Note 22 for more information regarding our foreign currency contracts.

Earnings Per Share

Effective on January 1, 2009, ASC Topic No. 260 "Earnings Per Share" provided for the adoption of the requirements under the former FSP No. EITF 03-06-1, "Determining Whether Instruments Granted in Share Based Payment Transactions Are Participating Securities." We have shares of restricted stock issued and outstanding, some of which remain subject to certain vesting requirements. Holders of such shares of unvested restricted stock are entitled to the same liquidation and dividend rights as the holders of our outstanding common stock and are thus considered participating securities. Under this applicable accounting guidance, the undistributed earnings for each period are allocated based on the contractual participation rights of both the common shareholders and holders of any participating securities as if earnings for the respective periods had been distributed. Because both the liquidation and dividend rights are identical, the undistributed earnings are allocated on a proportionate basis. Further, we are required to compute EPS amounts under the two class method.

Basic earnings per share ("EPS") is computed by dividing the undistributed 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 basic and diluted per share amounts for the years ended December 31, 2009, 2008 and 2007 were as follows (in thousands):

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	Year Ended December 31,					
	2009		2008		2007	
	Income	Shares	Income	Shares	Income	Shares
Basic:						
Net income applicable to common shareholders	$101,867		$(639,122)		$311,982	
Less: Undistributed net income allocable to participating securities	(1,436)				(4,189)	
Undistributed net income applicable to common shareholders	100,431		(639,122)		307,793	
(Income) loss from discontinued operations	(9,581)		9,812		(1,347)	
Add: Undiscounted net income from discontinued operations allocable to participating securities	135				18	
Income (loss) per common share – continuing operations	$90,985	99,136	$(629,310)	90,650	$306,464	90,086

	Year Ended December 31,					
	2009		2008		2007	
	Income	Shares	Income	Shares	Income	Shares
Diluted:						
Net income per common share – continuing operations – Basic	$ 90,985	99,136	$(629,310)	90,650	$306,464	90,086
Effect of dilutive securities:						
Stock options		28				382
Undistributed earnings reallocated to participating securities	80				239	
Convertible Senior Notes						1,548
Convertible preferred stock	748	6,556			3,716	3,631
Income (loss) per common share continuing operations	91,813		(629,310)		310,419	
Income (loss) per common share discontinued operations	9,581		(9,812)		1,347	

Net income per common share	$101,394	105,720	$(639,122)	90,650	$311,766	95,647

The cumulative $53.4 million of beneficial conversion charges that were realized and recorded during the first quarter of 2009 following the transaction affecting our convertible preferred stock (Note 12) are not included as an addition to adjust earnings applicable to common stock for our diluted earnings per share calculation.

We had a net loss applicable to common shareholders in 2008. Accordingly, our diluted per share calculation for 2008 was equivalent to our basic loss per share calculation because it excluded any assumed exercise or conversion of common stock equivalents because they were deemed to be anti-dilutive, meaning their inclusion would have reduced the reported net loss per share for 2008. Shares that otherwise would have been included in the diluted per share amount included 0.3 million shares associated with stock options for which the exercise price was less than the average price of our common stock for 2008, 0.1 million shares associated with unvested restricted shares and 3.6 million equivalent shares of common stock from the assumed conversion of our convertible preferred stock. The diluted earnings (loss) per share calculation also excluded the consideration of adding back the $3.2 million of dividends and related costs associated with the convertible preferred stock that otherwise would have been added back to net income if assumed conversion of the shares was dilutive during 2008. There were no stock options outstanding for which the exercise price was greater than the average price of our common stock for each of the years ending December 31, 2008 and 2007.

Stock Based Compensation Plans

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

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business day prior to the grant date, and expense was recognized over the vesting period of each grant on a straight-line basis.

We did not grant any stock options during the three-year period ended December 31, 2009. The fair value of shares issued under the Employee Stock Purchase Plan was based on the 15% discount received by the employees. The estimated fair value of the options is amortized to expense over the vesting period. See "— Note 13 — Employee Benefit Plans" for discussion of our stock compensation.

Accounting for Sales of Stock by Subsidiary

We recognize a gain or loss upon the direct sale or issuance of equity by our subsidiaries if the sales price differs from our carrying amount, provided that the sale of such equity is not part of a broader corporate reorganization. See "— Note 3" for discussion of CDI's initial public offering and common stock issuance as part of the acquisition of Horizon Offshore, Inc. ("Horizon"). Effective January 1, 2009, we have changed our accounting policy of recognizing a gain or loss upon any future direct sale or issuance of equity by our subsidiaries if the sales price differs from our carrying amount to be in accordance with recently issued accounting requirements, in which a gain or loss will only be recognized when loss of control of a consolidated subsidiary occurs. See "New Accounting Standards" below and Note 3.

Consolidation of Variable Interest Entities

ASC Topic No. 810 "Consolidation" requires 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.

Fair Value of Financial Instruments

Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable and our long-term debt. The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to the highly liquid nature of these instruments. The carrying amount and estimated fair value of our debt, including current maturities as of December 31, 2009 and 2008 follow (amount in thousands):

	2009		2008	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Term Loan(1)	$414,766	$397,138	$419,093	$251,455
Revolving Credit Facility(2)			349,500	349,500
Cal Dive Term Loan(2), (3)			315,000	315,000
Convertible Senior Notes(1)	273,064	271,791	265,184	136,383
Senior Unsecured Notes(1)	550,000	563,750	550,000	261,250
MARAD Debt(4)	119,235	123,730	123,449	132,609
Loan Notes(5)	3,674	3,674	5,000	5,000
Total	$1,360,739	$1,360,083	$2,027,226	$1,451,197

(1) The fair values of these instruments were based on quoted market prices as of December 31, 2009 and 2008. The fair values were estimated using level 1 inputs using the market approach (see "Recently Issued Accounting Principles" below).

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

(3) We deconsolidated Cal Dive from our financial statements in June 2009 following the sale of a substantial amount of our remaining ownership interest in Cal Dive (Note 3).

(4) The fair value of the MARAD debt was determined by a third-party evaluation of the remaining average life and outstanding principal balance of the MARAD indebtedness as compared to other government guaranteed obligations in the market place with similar terms. The fair value of the MARAD debt was estimated using Level 2 fair value inputs using the cost approach (see "Recently Issued Accounting Principles" below).

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

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Major Customers and Concentration of Credit Risk

The market for our products and services is primarily the offshore oil and gas industry. Oil and gas companies spend capital on exploration, drilling and production operations expenditures, the amount of which is generally dependent on the prevailing view of future oil and gas prices that are subject to many external factors which may contribute to significant volatility in future prices. Our customers consist primarily of major oil and gas companies, well-established oil and pipeline companies and independent oil and gas producers and suppliers. We perform ongoing credit evaluations of our customers and provide allowances for probable credit losses when necessary. The percent of consolidated revenue of major customers, those whose total represented 10% or more of our consolidated revenues, was as follows: 2009 — Shell Offshore, Inc. (12%); 2008 — Louis Dreyfus Energy Services (10%) and Shell Offshore, Inc. (12%) and 2007 — Louis Dreyfus Energy Services (14%) and Shell Offshore, Inc. (10%). All of these customers were purchasers of our oil and gas production. We estimate that in 2009 we provided subsea services to over 200 customers.

New Accounting Standards

In September 2006, the FASB issued fair value accounting rules now included within ASC Codification Topic No. 820 “Fair Value Measurements and Disclosures” (ASC 820). We adopted the provisions of ASC 820 on January 1, 2008 for assets and liabilities not subject to the deferral and adopted this standard for all other assets and liabilities on January 1, 2009. The adoption of ASC 820 had an immaterial impact on our results of operations, financial condition and liquidity.

ASC 820, among other things, defines fair value, establishes a consistent framework for measuring fair value and expands disclosure for each major asset and liability category measured at fair value on either a recurring or nonrecurring basis. ASC 820 clarifies that fair value is an exit price, representing the amount that would be received to sell an asset, or paid to transfer a liability, in an orderly transaction between market participants. These fair value accounting rules establish a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value as follows:

- Level 1. Observable inputs such as quoted prices in active markets;
- Level 2. Inputs, other than the quoted prices in active markets, that are observable either directly or indirectly; and
- Level 3. Unobservable inputs for which there is little or no market data, which require the reporting entity to develop its own assumptions.

Assets and liabilities measured at fair value are based on one or more of three valuation techniques noted. The valuation techniques are as follows:

(a) Market Approach. Prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities.
(b) Cost Approach. Amount that would be required to replace the service capacity of an asset (replacement cost).
(c) Income Approach. Techniques to convert expected future cash flows to a single present amount based on market expectations (including present value techniques, option-pricing and excess earnings models).

The following table provides additional information related to assets and liabilities measured at fair value on a recurring basis at December 31, 2009 (in thousands):

	Level 1	Level 2	Level 3	Total	Valuation Technique

Assets:					
Oil and gas swaps and collars	$ –	$ 5,071	$ –	$ 5,071	(c)
Foreign currency forwards	–	2,074	–	2,074	(c)
Investment in Cal Dive (Note 3)	3,780	–	–	3,780	(a)
Liabilities:					
Oil and gas swaps and collars	–	19,536	–	19,536	(c)
Fair value of long term debt	1,236,353	123,730	–	1,360,083	(a),(b)
Total	$1,232,573	$136,121	$ –	$1,368,694	

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On June 30, 2009, we adopted the fair value standards within ASC Topic 820-10-65-4. These standards provide additional guidance for estimating fair value when the volume and level of activity for the asset or liability have significantly decreased and includes guidance for identifying circumstances that indicate a transaction is not orderly. This guidance is necessary to maintain the overall objective of fair value measurements, which is that fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date under current market conditions. The adoption of these standards had no impact on our results of operations, cash flows and financial condition.

On January 1, 2009, we adopted the revised standards for business combinations contained in ASC Topic 805 "Business Combinations." These standards now require the acquiring entity in a business combination to recognize all the assets acquired and liabilities assumed in the transaction, establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed, and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. It also requires that the costs incurred related to the acquisition be charged to expense as incurred, when previously these costs were capitalized as part of the acquisition cost of the asset or business. The adoption of these new standards had no impact on our results of operations, cash flows and financial condition.

On January 1, 2009 we adopted the financial requirements of ASC 810-10-65-1 "Consolidation Transition." These standards were enacted to improve the relevance, comparability, and transparency of financial information provided to investors by requiring all entities to report noncontrolling (minority) interests in subsidiaries as equity in the consolidated financial statements. These standards were required to be adopted prospectively, except the following provisions were required to be adopted retrospectively:

1. Reclassifying noncontrolling interest from the "mezzanine" to equity, separate from the parents' shareholders' equity, in the statement of financial position; and
2. Recasting consolidated net income to include net income attributable to both the controlling and noncontrolling interests. That is, retrospectively, the noncontrolling interests' share of a consolidated subsidiary's income should not be presented in the income statement as "minority interest."

Effective January 1, 2009, we changed our accounting policy of recognizing a gain or loss upon any future direct sale or issuance of equity by our subsidiaries if the sales price differs from our carrying amount, in which a gain or loss will only be recognized when loss of control of a consolidated subsidiary occurs. See Note 3 for disclosure of stock sales transactions that ultimately resulted in our loss of control of CDI.

On January 1, 2009 we adopted certain financial accounting standards included with ASC Topic No. 815 "Derivatives and Hedging." These standards apply to all derivative instruments and related hedged items and require that entities provide qualitative disclosures about the objectives and strategies for using derivatives, quantitative data about the fair value of and gains and losses on derivative contracts, and details of credit-risk-related contingent features in their hedged positions. Adoption of these standards had no impact on our results of operations, cash flows or financial condition. See Note 22 below for the required disclosures for our derivative instruments.

Effective January 1, 2009, we adopted accounting standards as required in ASC Topic No. 470-20 "Debt with Conversion and Other Options." These standards require retrospective application for all periods reported (with the cumulative effect of the change reported in retained earnings as of the beginning of the first period presented). These standards require the proceeds from the issuance of convertible debt instruments to be allocated between a liability component (issued at a discount) and an equity component. The resulting debt discount is amortized over the period the convertible debt is expected to be outstanding as additional non-cash interest expense. This standard affects the accounting treatment for our Convertible Senior Notes and increases our interest expense for our past and future reporting periods by recognizing accretion charges on the resulting debt discount.

Upon adoption, we recorded a discount of $60.2 million related to our Convertible Senior Notes. To arrive at this discount amount we estimated the fair value of the liability component of the Convertible Senior Notes as of the date of their issuance (March 30, 2005) using an income approach. To determine this estimated fair value, we used borrowing rates of similar market transactions involving comparable liabilities at the time of issuance and an expected life of 7.75 years. In selecting the expected life, we selected the earliest date that the holder could require us to repurchase all or a portion of the Convertible Senior Notes (December 15, 2012).

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On June 30, 2009, we adopted the general standards of accounting for and disclosures of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Specifically, ASC Topic No. 855 "Subsequent Events" sets forth the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements, the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements, and the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. The adoption of these standards had no impact on our results, cash flow or financial position as management already followed a similar approach prior to the adoption of this standard.

In December 2008, the SEC announced that it had approved revisions designed to modernize the oil and gas company reserve reporting requirements. In January 2010, the FASB issued Accounting Standards Update 2010-03 "Oil and Gas Reserve Estimation and Disclosures." For our reserve estimates at year end 2009, we have implemented the newly mandated authoritative guidance issued by the FASB on extractive activities for oil and gas reserves estimation and disclosures. The objective of the new guidance is to align the oil and gas reserve estimation and disclosure requirements with the requirements of the SEC. The most significant amendments to the requirements included the following.

- Commodity prices - estimates of proved reserves and related discounted cash flows now based on an average twelve month commodity price based on the price of oil and gas on the first day of each month for the year the reserve report relates;
- Disclosure of Unproved Reserves - Probable and Possible reserves may be disclosed separately from proved reserves on a voluntary basis. We elected not to disclose Probable and Possible reserves;
- Proved Undeveloped Reserve Guidelines – Reserves may be classified as proved undeveloped reserves if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years, unless specific circumstances justify a longer time;
- Reserves Estimation Using New Techniques – Reserves may be estimated through a use of reliable techniques in addition to traditional flow test and production history;
- Reserves Personnel and Estimation Process – Additional disclosure is required regarding the qualifications of the chief technical person who oversees the reserve estimation process and/or the independence of the preparer of our estimated proved reserves. We must also disclose our significant internal controls over the reserve estimation process;
- Disclosure by Geographic Area – Reserves in foreign countries must be presented separately if such reserves represent more than 15% of our total estimated oil and gas proved reserves; and
- Non Traditional Resources- The definition of oil and gas producing activities has been expanded to include other marketable products.

Note 3 — Ownership of Cal Dive International, Inc.

In December 2006, we contributed the assets of our Shelf Contracting segment into Cal Dive, our then wholly owned subsidiary. Cal Dive subsequently sold approximately 22.2 million shares of its common stock in an initial public offering and distributed the net proceeds of $264.4 million to us as a dividend. In December 2006, Cal Dive borrowed $201 million under its credit facility and distributed $200 million of the proceeds to us as a dividend. We recognized an after-tax gain of $96.5 million, net of taxes of $126.6 million as a result of these transactions. We used the proceeds for general corporate purposes. In connection with the offering, together with shares issued to CDI employees immediately after the offering, our ownership of CDI decreased to approximately 73.0% as of December 31, 2006. Our ownership in CDI was further reduced in December 2007 as a result of CDI's stock issuance related to the its acquisition of Horizon Offshore Inc. Our ownership in CDI as of December 31, 2008 was approximately 57.2%.

In January 2009, we sold approximately 13.6 million shares of Cal Dive common stock to Cal Dive for $86 million. This transaction constituted a single transaction and was not part of any planned set of transactions that would result in us having a noncontrolling interest in Cal Dive, and reduced our ownership in Cal Dive to approximately 51%. Because we retained control of CDI immediately after the transaction, the loss of approximately $2.9 million on this sale was treated as a reduction of our equity in the accompanying condensed consolidated balance sheet.

In June 2009, we sold 22.6 million shares of Cal Dive common stock held by us pursuant to a secondary public offering ("Offering"). Proceeds from the Offering totaled approximately $182.9 million, net of underwriting fees. Separately, pursuant to a Stock Repurchase Agreement with Cal Dive, simultaneously with the closing of the Offering, Cal Dive repurchased from us approximately 1.6 million shares of its common stock for net proceeds of $14 million at $8.50 per share, the Offering price. Following the closing of these two transactions, our ownership of Cal Dive common stock was reduced to approximately 26%.

Because these transactions reduced our ownership in Cal Dive to less than 50%, the $59.4 million gain resulting from the sale of these shares was reflected in "Gain on sale of Cal Dive common stock" in the accompanying consolidated statement of operations. The $59.4 million amount included an approximate $27.1 million gain associated with the re-measurement of our remaining 26% ownership interest in Cal Dive at its fair value on June 10, 2009, the date of the closing of the Offering, which represented the date of deconsolidation. Since we no longer held a controlling interest in Cal Dive, we ceased consolidating Cal Dive effective June 10, 2009, and subsequently accounted for our remaining ownership interest in Cal Dive under the equity method of accounting until September 23, 2009, as further discussed below.

On September 23, 2009, we sold 20.6 million shares of Cal Dive common stock held by us pursuant to a second secondary public offering ("Second Offering"). On September 24, 2009, the underwriters sold an additional 2.6 million shares of Cal Dive common stock held by us pursuant to their overallotment option under the terms of the Second Offering. The price for the Second Offering was $10 per share, with resulting proceeds totaling approximately $221.5 million, net of underwriting fees. We recorded an approximate $17.9 million gain associated with the Second Offering transactions.

Following the closing of the Second Offering transactions, we own 0.5 million shares of Cal Dive common stock, representing less than 1% of the total outstanding shares of Cal Dive. Accordingly we now classify our remaining interest in Cal Dive as an investment available for sale pursuant to ASC Topic No. 320 "Investment - Debt and Equity Securities." As an investment available for sale, the value of our remaining interest will be marked-to-market at each period end with the corresponding change in value being reported as a component of other comprehensive income (loss) in the accompanying consolidated balance sheet at December 31, 2009 (Note 14). We intend to sell our remaining shares of Cal Dive common stock over the near term. The value of our remaining investment in Cal Dive decreased by $1.3 million from the closing of the Second Offering to December 31, 2009.

Proceeds from our Cal Dive stock sale transaction were used for general corporate purposes.

Note 4 – Insurance Matters

In September 2008, we sustained damage to certain of our facilities resulting from Hurricane Ike. All of our segments were affected by the hurricane; however, the oil and gas segment suffered the substantial majority of our aggregate damages. While we sustained damage to our own production facilities from Hurricane Ike, the larger issue in terms of our production recovery involved damage to third party pipelines and onshore processing facilities. The timing of the repairs of these facilities was not subject to our control. One significant third party pipeline was not repaired and placed back into service until January 2010. Our insurance policy, which covered all of our operated and non-operated producing and non-producing properties, was subject to an approximate $6 million of aggregate deductibles. We met our aggregate deductible in September 2008. We record our hurricane-related repair costs as incurred in our oil and gas cost of sales. We record insurance reimbursements when the realization of the claim for recovery of a loss is deemed probable.

In June 2009, we reached a settlement with the underwriters of our insurance policies related to damages from Hurricane Ike. Insurance proceeds received in the second quarter of 2009 totaled $102.6 million. Previously, we had received approximately $25.6 million of reimbursements under previously submitted Ike-related insurance claims. In the second quarter of 2009, we recorded a $43.0 million net reduction in our cost of sales in the accompanying condensed consolidated statements of operations representing the amount our insurance recoveries exceeded our costs during the second quarter of 2009. The cost reduction reflected the net proceeds of $102.6 million partially offset by $8.1 million of hurricane-related expenses incurred in the second quarter of 2009 and $51.5 million of hurricane related impairment charges, including $43.8 million of additional estimated asset retirement costs ("ARO") resulting from additional work performed and/or further evaluation of facilities on properties that were classified as a "total loss" following the storm.

We are substantially complete with our hurricane repairs; however we are still incurring costs related to our accrued asset retirement obligations.

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The following table summarizes the claims and reimbursements by segment that affected our costs of sales accounts under various insurance claims resulting from damages sustained by Hurricane Ike, primarily those claims and reimbursements recently settled under our energy insurance policy (in thousands):

	Year Ended December 31, 2009	Since Inception in September 2008
Oil and gas:		
Hurricane repair costs	$ 25,788	$ 48,339
ARO liability adjustments	43,812	48,065
Hurricane-related impairments	7,699	37,597
Insurance recoveries (1)	(100,874)	(118,415)
Net (reimbursements) costs	$ (23,575)	$ 15,586
Contracting services:		
Hurricane repair costs	$ 776	$ 6,026
Insurance recoveries	(2,885)	(5,022)
Net (reimbursements) costs	(2,109)	1,004
Shelf Contracting (2):		
Hurricane repair costs	$ 613	$ 4,550
Insurance recoveries	(2,849)	(5,183)
Net reimbursements	$ (2,236)	(633)
Totals:		
Hurricane repair costs	$ 27,177	$ 58,915
ARO liability adjustments	43,812	48,065
Hurricane-related impairments	7,699	37,597
Insurance recoveries	(106,608)	(128,620)
Net (reimbursements) costs	$ (27,920)	$ 15,957

(1) Recoveries include reimbursements for capital items totaling $0.2 million in 2009 and $13.2 million in 2008.
(2) Includes amount prior to deconsolidation of Cal Dive in June 2009 (Note 3).

We renewed our energy and marine insurance for the period July 1, 2009 to June 30, 2010. However, this insurance renewal did not include wind storm coverage as the premium and deductibles would have been relatively substantial for the underlying coverage provided. In order to mitigate potential loss with respect to our most significant oil and gas properties from hurricanes in the Gulf of Mexico, we entered into a weather derivative (Catastrophic Bond). The Catastrophic Bond provides for payments of negotiated amounts should the eye of a Category 3 or greater hurricane pass within certain pre-defined areas encompassing our more prominent oil and gas producing fields. The premium for this Catastrophic Bond was approximately $13.1 million. The Catastrophic Bond is not considered a risk management instrument for accounting purposes. Accordingly, the premium associated with the Catastrophic Bond is not charged to expense on a straight line basis as customary with insurance premiums, but rather it is charged to expense on a basis to reflect the Catastrophic Bond’s intrinsic value at the end of the period. Because our Catastrophic Bond was underwritten to mitigate the risk of hurricanes in the Gulf of Mexico, substantially all of its intrinsic value is for the period associated with “hurricane season” (typically June 1 to November 30) with a substantial majority of the intrinsic value associated with the period July 1, 2009 to September 30, 2009. As a result, we charged to expense $10.4 million of our $13.1 premium in the third quarter of 2009 and $2.4 million of premium was charged to expense in the fourth quarter of 2009. The remaining $0.3 million will be charged to expense over first half of 2010. The expense associated with the Catastrophic Bond premium is recorded as a component of lease operating expense for our oil and gas operations.

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Note 5 — Acquisitions

Well Ops SEA Pty Ltd.

In October 2006, we acquired a 58% interest in Seatrac Pty Ltd. ("Seatrac") for total consideration of approximately $12.7 million (including $0.2 million of transaction costs), with approximately $9.1 million paid to existing Seatrac shareholders and $3.4 million for subscription of new Seatrac shares. We renamed this entity Well Ops SEA Pty Ltd. ("WOSEA"). WOSEA is a subsea well intervention and engineering services company located in Perth, Australia. On July 1, 2007, we exercised an option to purchase the remaining 42% of WOSEA for approximately $10.1 million. This purchase was accounted for as a business combination with the acquisition price allocated to the assets acquired and liabilities assumed based upon their estimated fair value, with the excess being recorded as goodwill. The following table summarizes the estimated fair values of the assets acquired and liabilities assumed at July 1, 2007 (in thousands):

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

Pro forma combined operating results for the years ended December 31, 2007 (adjusted to reflect the results of operations of WOSEA prior to its acquisition) are not provided because the pre-acquisition results related to WOSEA were not material to the historical results of the Company.

In February 2010, we announced the formation of a joint venture with Australian-based engineering and construction company, Clough Limited, to provide a range of subsea services to offshore operators in the Asia Pacific region. Services provided by the joint venture, named CloughHelix Pty Ltd., will include subsea well intervention and well abandonment, SURF (subsea infrastructure, umbilical, riser and flowline installation), saturation and air diving and subsea inspection, repair and maintenance services. The CloughHelix joint venture will integrate our well intervention equipment with Clough's new 12 man saturation diving system, to enable both to be deployed from the 118 meter long DP2 multiservice vessel, Normand Clough, outfitted with a 250 ton active heave compensated crane.

Note 6 — Oil and Gas Properties

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

At December 31, 2009, we had capitalized costs associated with ongoing exploration and/or appraisal activities totaling $3.1 million. In the fourth quarter of 2008, we charged the $18.6 million of costs associated with the Huey and Castleton exploration wells to dry hole exploration expense, when it became unlikely that we would pursue additional development of these wells. Other capitalized costs may be charged against earnings in future periods if management determines that commercial quantities of hydrocarbons have not been discovered or that future appraisal drilling or development activities are not likely to occur. The following table provides a detail of our capitalized exploratory project costs at December 31, 2009 and 2008 (in thousands):

	2009	2008
Wang (1)	$ 2,934	$ 1,545
Other	125	560
Total	$ 3,059	$ 2,105

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(1) Amounts include pre-engineering and limited capital items. Prospect is located in proximity of our Phoenix field, which is expected to commence production around mid-year 2010. Drilling of Wang is a discretionary capital item for 2010 but we expect exploration of this prospect will occur over the near term.

The following table reflects net changes in suspended exploratory well costs during the year ended December 31, 2009, 2008 and 2007 (in thousands):

	2009	2008	2007
Beginning balance at January 1,	$ 2,105	$ 19,096	$ 49,983
Additions pending the determination of proved reserves	36,208	2,305	213,699
Reclassifications to proved properties	(34,622)	(463)	(234,277)
Charged to dry hole expense	(632)	(18,833)	(10,309)
Ending balance at December 31,	$ 3,059	$ 2,105	$ 19,096

Further, the following table details the components of exploration expense for the years ended December 31, 2009, 2008 and 2007 (in thousands):

	Years Ended December 31,		
	2009	2008	2007
Delay rental and geological and geophysical costs	$ 3,016	$ 5,223	$ 6,538
Impairment of unproved properties	20,130	8,870	9,878
Dry hole expense	1,237	18,833	10,309
Total exploration expense	$ 24,383	$ 32,926	$ 26,725

Our oil and gas activities in the United States are regulated by the federal government and require significant third-party involvement, such as refinery processing and pipeline transportation. We record revenue from our offshore properties net of royalties paid to the MMS. Royalty fees paid totaled approximately $26.8 million, $66.3 million and $57.1 million for the years ended December 31, 2009, 2008 and 2007, respectively. In accordance with federal regulations that require operators in the Gulf of Mexico to post an area wide bond of $3 million, the MMS has allowed us to fulfill such bonding requirements through an insurance policy.

In August 2006, we acquired a 100% working interest in the Typhoon oil field (Green Canyon Blocks 236/237), the Boris oil field (Green Canyon Block 282) and the Little Burn oil field (Green Canyon Block 238) for assumption of certain decommissioning liabilities. We have received suspension of production (“SOP”) approval from the MMS. Following the acquisition of the Typhoon oil field and MMS approval, we renamed the field Phoenix. We expect to deploy a minimal floating production system in 2010 in the Phoenix field.

In December 2006, we acquired a 100% working interest in the Camelot gas field in the North Sea in exchange for the assumption of certain decommissioning liabilities estimated at approximately $7.6 million. In June 2007, we sold a 50% working interest in this property for approximately $1.8 million and the assumption by the purchaser of 50% of the decommissioning liability of approximately $4.0 million. We recognized a gain of approximately $1.6 million as a result of this sale. In February 2010, we acquired our joint interest partner and as a result we own a 100% interest in the Camelot field. We are now obligated to pay the entire abandonment obligation for the field (estimated to range between $10-$15 million). The acquired entity had secured its field abandonment obligations with a $10 million letter of credit which was fully collateralized with cash.

In 2007, we incurred $25.1 million of plug and abandonment overruns related to hurricanes Katrina and Rita, partially offset by insurance recoveries of $4.0 million. In addition, we increased our abandonment liability at December 31, 2007 for work yet to be done for certain properties damaged by the hurricanes totaling $9.6 million, partially offset by estimated insurance recoveries of $4.9 million.

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

In March and April 2008, we sold a total 30% working interest in the Bushwood discoveries (Garden Banks Blocks 463, 506 and 507) and other Outer Continental Shelf oil and gas properties (East Cameron Blocks 371 and 381), in two separate transactions to affiliates of a private independent oil and gas company for total cash consideration of approximately $183.4 million (which included the purchasers' share of incurred capital expenditures on these fields), and additional potential cash payments of up to $20 million based upon certain field production milestones. The new co-owners will also pay their pro rata share of all future capital expenditures related to the exploration and development of these fields. Decommissioning liabilities will be shared on a pro rata share basis between the new co-owners and us. Proceeds from the sale of these properties were used to pay down our outstanding revolving loans in April 2008. As a result of these sales, we recognized a pre-tax gain of $91.6 million in the first half of 2008.

In May 2008, we sold all our interests in our onshore proved and unproved oil and gas properties located in the states of Texas, Mississippi, Louisiana, New Mexico and Wyoming ("Onshore Properties") to an unrelated investor. We sold these Onshore Properties for cash proceeds of $47.3 million and recorded a related loss of $11.9 million in the second quarter of 2008. Proceeds from the sale of these properties were used to reduce amounts under our outstanding loans in May 2008. Included in the cost basis of the Onshore Properties was an $8.1 million allocation of goodwill from our Oil and Gas segment.

In December 2008, we announced the sale of all our interests in the Bass Lite field (Atwater Block 426), a 17.5% working interest, to our joint interest owners in the field for approximately $49 million. The sale had an effective date of November 1, 2008. Proceeds from the sale were used to fund our working capital requirements.

In 2009, we farmed-out our 100% leasehold interests in Green Canyon Block 490 located in the deepwater of the Gulf of Mexico. Our farm out agreement was structured such that the operator paid 100% of the drilling costs to evaluate the prospective reservoir. The operator has drilled the well and it was successful in finding commercial quantities of hydrocarbons. We have elected to participate for a 25 percent working interest in setting production casing and the right to participate in all subsequent operations. Well completion and development options are being evaluated for the new discovery.

Impairments

Proved property impairment charges are reflected as reductions in cost of sales in the accompanying consolidated statements of operations.

In 2007, we recorded impairment expense of approximately $64.1 million related to our proved oil and gas properties primarily as a result of downward reserve revisions and weak end of life well performance in some of our domestic properties. In addition, we recorded approximately $9.9 million of impairment expense related to our unproved properties primarily due to management's assessment that exploration activities would not commence prior to the respective lease expiration dates. Further, we expensed approximately $5.9 million of dry hole exploratory costs in fourth quarter of 2007 related to our South Marsh Island 123 #1 well drilled in 2007 due to management's decision not to execute previous development plans prior to the lease expiring. Lastly, 2007 depletion was impacted by certain producing properties that experienced significant proved reserve declines, thus causing a significant increase in the depletion rate for these properties.

As a result of our unsuccessful development well in January 2008 on Devil's Island (Garden Banks Block 344), we recognized impairment expense of $14.6 million in 2008 related to the cost incurred subsequent to December 31, 2007. The $20.9 million of the costs incurred related to this well through December 31, 2007, were charged to earnings in 2007.

In 2008, impairment expense totaled approximately $215.7 million ($192.6 million recorded in the fourth quarter of 2008) related to our proved oil and gas properties primarily as a result of downward reserve revisions reflecting lower oil and natural gas prices, weak end of life well performance for some of our domestic properties, fields lost as a result of Hurricanes Gustav and Ike and the reassessment of the economics of some of our marginal fields in light of our announced business strategy de-emphasis portions of our the oil and gas exploration and production business; we also recorded a $14.6 million asset impairment charge associated with the Devil’s Island Development well (Garden Banks Block 344) that was determined to be non-commercial in January 2008.

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In 2009, we recorded impairment expense totaling $120.6 million ($55.9 million in fourth quarter of 2009) related to reductions in our estimated proved reserves for twelve of our oil and gas fields at December 31, 2009 primarily reflecting mechanical and production issues at the related fields. In the second quarter of 2009, we recorded an aggregate of approximately $63.1 million of impairment charges. These charges primarily reflect the approximate $51.5 million of impairment-related charges recorded to properties that were severely damaged by Hurricane Ike (Note 4). Separately, we also recorded $11.5 million of impairment charges to reduce the asset carrying value of four fields following reductions in their estimated proved reserves as evaluated at June 30, 2009.

Note 7 — Details of Certain Accounts (in thousands)

Other current assets consisted of the following as of December 31, 2009 and 2008:

	2009	2008
Other receivables	$ 7,990	$ 22,977
Prepaid insurance	11,105	18,327
Other prepaids	21,819	23,956
Spare parts inventory	25,755	32,195
Current deferred tax assets	24,517	3,978
Hedging assets	6,214	26,800
Insurance claims to be reimbursed	—	7,880
Income tax receivable	8,492	23,485
Gas imbalance	7,655	7,550
Other	7,784	4,941
	$ 121,331	$ 172,089

Other assets, net, consisted of the following as of December 31, 2009 and 2008:

	2009	2008
Restricted cash	$ 35,409	$ 35,402
Deferred drydock costs, net	12,030	38,620
Deferred financing costs	30,061	33,431
Intangible assets with finite lives	768	7,600
Other	3,945	10,669
	$ 82,213	$ 125,722

Accrued liabilities consisted of the following as of December 31, 2009 and 2008:

	2009	2008
Accrued payroll and related benefits	$ 30,513	$ 46,224
Royalties payable	5,717	10,265
Current decommissioning liability	65,729	31,116
Unearned revenue	3,672	9,353
Billings in excess of costs	—	13,256
Insurance claims to be reimbursed	—	7,880
Accrued interest	27,830	34,299

Deposits	25,542	25,542
Hedging liability	19,536	7,687
Other	21,617	46,057
	$ 200,156	$ 231,679

Note 8 — Equity Investments

In June 2002, we formed Deepwater Gateway with Enterprise Products Partners, L.P., in which we each own a 50% interest, to design, construct, install, own and operate a tension leg platform ("TLP") production hub in deepwater of the Gulf of Mexico. Deepwater Gateway primarily services the Marco Polo field, which is owned and operated by Anadarko Petroleum Corporation. Our share of the Deepwater Gateway construction costs was approximately $120 million and our investment totaled $103.3 million and $106.3 million as of December 31, 2009 and 2008, respectively, and was included in our Production Facilities segment. The investment balance at December 31, 2009 and 2008 included approximately $1.5 million and $1.6 million, respectively, of capitalized interest and insurance paid by us.

In December 2004, we acquired a 20% interest in Independence Hub, an affiliate of Enterprise. Independence Hub owns the Independence Hub platform located in Mississippi Canyon Block 920 in a water depth of 8,000 feet. The platform reached mechanical completion in May 2007. First production began in July 2007. Our investment in Independence Hub was $86.1 million and $90.2 million as of December 31, 2009 and 2008, respectively (including capitalized interest of $5.6 million and $5.9 million at December 31, 2009 and 2008, respectively), and was included in our Production Facilities segment.

During 2007, CDI determined that there was an other than temporary impairment of its equity investment in OTSL and the full value of its investment was impaired. CDI recorded equity losses in OTSL of $10.8 million, inclusive of the impairment charge, and $0.5 million for the fiscal years ended December 31, 2007, and 2006, respectively. CDI sold its equity interest in OTSL to a third party in January 2009 for $0.4 million.

We made the following contributions to our equity investments during the years ended December 31, 2009, 2008 and 2007 (in thousands):

	Year Ended December 31,		
	2009	2008	2007
Independence Hub	$ —	$ —	$ 12,475
Other	1,657	846	4,984
Total	$ 1,657	$ 846	$ 17,459

We received the following distributions from our equity investments during the years ended December 31, 2009, 2008 and 2007 (in thousands):

	Year Ended December 31,		
	2009	2008	2007
Deepwater Gateway	$ 6,750	$ 23,500	$ 27,000
Independence Hub	26,000	25,000	10,800
Total	$ 32,750	$ 48,500	$ 37,800

Note 9 — Kommandor LLC

In October 2006, we partnered with Kommandor RØMØ, a Danish corporation, to form Kommandor LLC, a Delaware limited liability company, the purpose of which was to convert a ferry vessel into a ship-shaped dynamically-positioned floating production unit vessel. Upon completion of the conversion in April 2009, the vessel, (the Helix Producer I) was leased to us under a bareboat charter. We are performing additional capital modifications in order to utilize the vessel for future use as a floating production system servicing the Deepwater Gulf of Mexico, with initial service being provided for the Phoenix field, in which we hold an approximate 70% working interest. The initial investment for our 50% interest in Kommandor LLC was $15 million. We provided $98.9 million in interim construction financing to the joint venture and Kommandor provided a $5.0 million loan. During 2009, $58.8 million of this amount was converted to equity in our investment in Kommandor LLC. At December 31, 2009, Kommandor had $25.7 million of borrowings outstanding to us and $3.7 million to Kommandor RØMØ. These amounts were used to fund the conversion of the vessel. The vessel's conversion is to be completed in two phases. The first phase, the initial conversion, was completed in April 2009 at a total cost of approximately $170 million. We then charted the vessel from Kommandor LLC, and transported it from Greece to the Gulf of Mexico where it commenced installation of production facilities upgrades. The second phase is

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expected to be completed by mid year 2010. Estimated costs for the capital modifications to the vessel in the second phase, in which we expect to fund 100%, will range between $190 and $200 million.

The operating agreement with Kommandor RØMØ, provides that for a period of two months immediately following the fifth anniversary of the completion of the initial conversion (April 2014 – June 2014), we may purchase Kommandor RØMØ's membership interest at a value specified in the agreement ("Helix Option Period"). In addition, for a period of two months starting from 30 days after the Helix Option Period, Kommandor RØMØ can require us to purchase its share of the company at a value specified in the operating agreement. We estimate the cash outlay to Kommandor RØMØ for its interest in Kommandor LLC at the time the put or call is exercised to be approximately $28 million.

The consolidated results of Kommandor LLC are included in our Production Facilities segment. We own approximately 81% of Kommandor LLC at December 31, 2009. Kommandor LLC was a development stage enterprise since its inception in October 2006 to April 2009.

Note 10 — Long-Term Debt

Senior Unsecured Notes

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

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

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

Included in the Senior Unsecured Notes indenture are terms, conditions and covenants that are customary for this type of offering. The covenants include limitations on our and our subsidiaries' ability to incur additional indebtedness, pay dividends, repurchase our common stock, and sell or transfer assets. As of December 31, 2009, we were in compliance with these covenants.

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

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

Year	Redemption Price

2012	104.750%
2013	102.375%
2014 and thereafter	100.000%

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

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

Senior Credit Facilities

In July 2006, we entered into a credit agreement (the "Senior Credit Facilities") under which we borrowed $835 million in a term loan (the "Term Loan") and were initially able to borrow up to $300 million (the "Revolving Loans") under a revolving credit facility (the "Revolving Credit Facility"). The proceeds from the Term Loan were used to fund the cash portion of the Remington Oil and Gas Corporation acquisition. Total borrowing capacity under the Revolving Credit Facility at December 31, 2009 totaled $435 million. The full amount of the Revolving Credit Facility may be used for issuances of letters of credit. At December 31, 2009 we had no amounts drawn on the Revolving Credit Facility and our availability under the Facility totaled $385.8 million net of $49.2 million of unsecured letters of credit issued.

The Term Loan bears interest either at the one-, three- or six-month LIBOR at our current election plus a 2.00% margin (as amended in February 2010, the margin has been increased up to 2.50% depending on current leverage ratios, as defined) . Our average interest rate on the Term Loan for the years December 31, 2009 and 2008 was approximately 4.2% and 6.0%, respectively (including the effects of our interest rate swaps). The Revolving Loans bear interest based on one-, three- or six-month LIBOR rates or on Base Rates at our current election plus an applicable margin as discussed below. Margins on the Revolving Loans will fluctuate in relation to the consolidated leverage ratio as provided in the Credit Agreement. The average interest rate on the Revolving Loans was approximately 3.4% through date of their repayment in the second quarter of 2009. We have no amounts outstanding under the revolver at December 31, 2009.

In February 2010, we amended the Senior Credit Facility. This amendment:

- amends the consolidated leverage ratio that we are required to comply with. Through December 31, 2009, maximum permitted leverage was 3.50 to 1.00. Beginning with the quarter ending March 31, 2010, the ratio will be changed as follows:

  - March 31, 2010 – 5.00 to 1.00
  - June 30, 2010 – 5.50 to 1.00
  - September 30, 2010 – 5.00 to 1.00
  - December 31, 2010 – 4.50 to 1.00
  - March 31, 2011 and thereafter – 4.00 to 1.00

- adds a new Senior Credit Facility leverage ratio we are required to comply with beginning with the quarter ending March 31, 2010. The ratio will be as follows:

  - March 31 and June 30, 2010 – 2.50 to 1.00
  - September 30, 2010 – 2.25 to 1.00
  - December 31, 2010 and thereafter – 2.00 to 1.00

- increases the margin on Revolving Loans by 0.50% should the consolidated leverage ratio equal or exceed 4.50 to 1.00 and increases the margin on the Term Loan by 0.25% if consolidated leverage ratio is less than 4.50 to 1.00 and 0.50% if the consolidated leverage ratio is equal to or greater than 4.50 to 1.00.

In October 2009, we amended our Senior Credit Facility. Among other things, the amendment:

- extends the maturity of the revolving line of credit under the Credit Agreement from July 1, 2011 to November 30, 2012;

- permits the disposition of certain oil and gas properties without a limit as to value, provided that we use 60% of the proceeds from such sales to make certain mandatory prepayments of the Term Loan (40% of the proceeds can be reinvested into collateral);

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· relaxes limitations on our right to dispose of the Caesar vessel, by permitting the disposition of the Caesar provided that we use 60% of the proceeds from such sale to make certain mandatory prepayments of the Term Loan and permits us to contribute the Caesar to a joint venture or similar arrangement (40% of the proceeds can be reinvested into collateral);

· increases the maximum amount of all investments permitted in subsidiaries that are neither loan parties nor whose equity interests are pledged from $100 million to $150 million;

· increases the amount of restricted payments in the form of stock repurchases or redemptions such that we are permitted to repurchase or redeem up to $50 million of our common stock in the event we prepay an aggregate amount on the term loan greater than $200 million (up to $25 million if we prepay at least $100 million);

· amends the applicable margins under the revolving lines of credit under the Credit Agreement (ranging from 3.0% to 4.0% on LIBOR loans and 2.0% to 3.0% on Base Rate loans); and

· increases the accordion feature that allows Helix to increase the revolving line of credit by $100 million (to $550 million) at any time in future periods with lender approval.

We also completed an increase in the revolving line of credit from $420 million to $435 million (decreasing to $410 million beginning July 1, 2011 through November 30, 2012) utilizing the accordion feature included in the Credit Agreement through an increase in the commitments from existing and new lenders.

We may elect to prepay amounts outstanding under the Term Loan without prepayment penalty, but may not reborrow any amounts prepaid. We may prepay amounts outstanding under the Revolving Loans without prepayment penalty, and may reborrow amounts prepaid prior to maturity. In addition, upon the occurrence of certain dispositions or the issuance or incurrence of certain types of indebtedness, we may be required to prepay a portion of the Term Loan equal to the amount of proceeds received from such occurrences. Such prepayments will be applied first to the Term Loan, and any remaining excess will then be applied to the Revolving Loans.

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

If we or any of our subsidiaries do not pay any amounts owed to the Lenders under the Loan Documents when due, breach any other covenant to the Lenders or fail to pay other debt above a stated threshold, in each case, subject to applicable cure periods, then the Lenders have the right to stop making advances to us and to declare the Loans immediately due. The Credit Agreement includes other events of default that are customary for this type of transaction. As of December 31, 2009, we were in compliance with all debt covenants.

The Loans and our other obligations to the Lenders under the Loan Documents are guaranteed by all of our U.S. subsidiaries except Cal Dive I-Title XI, Inc., and are secured by a lien on substantially all of our assets and properties and all the assets and properties of our U.S. subsidiaries except Cal Dive I-Title XI, Inc. In addition, we have pledged a portion of the shares of our significant foreign subsidiaries to the lenders as additional security. The Senior Credit Facilities also contain provisions that limit our ability to incur certain types of additional indebtedness.

These provisions effectively prohibit us from incurring any additional secured indebtedness or indebtedness guaranteed by the Company. The Senior Credit Facilities do however permit us to incur certain unsecured indebtedness, and also provide for our subsidiaries to incur project financing indebtedness (such as our MARAD loans) secured by the underlying asset, provided that the indebtedness is not guaranteed by us.

As the rates for our Term Loan are subject to market influences and will vary over the term of the credit agreement, we entered into various cash flow hedging interest rate swaps to stabilize cash flows relating to a portion of our interest payments for our Term Loan. The interest rate swaps were effective October 3, 2006, and qualified for hedge accounting. On December 21, 2007, a prepayment made to a hedged portion of our Term Loan brought the balance of that portion below the amount hedged by interest rate swaps. As a result, the hedge instruments became ineffective and no longer qualify for hedge accounting as of that date. The final contracts settled in the fourth quarter of 2009. In January 2010, we entered into $200 million, two-year interest rate swaps to stabilize cash flows relating to a portion of our interest payments on our Term Loan.

Convertible Senior Notes

In March 2005, we issued $300 million of 3.25% Convertible Senior Notes due 2025 (“Convertible Senior Notes”) at 100% of the principal amount to certain qualified institutional buyers. The Convertible Senior Notes are convertible into cash and, if applicable, shares of our common stock based on the specified conversion rate, subject to adjustment. As a result of our two for one stock split in December 2005, the initial conversion rate of the Convertible Senior Notes of 15.56 shares of common stock per $1,000 principal amount of the Convertible Senior Notes, which was equivalent to a conversion price of approximately $64.27 per share of common stock, was changed to 31.12 shares of common stock per $1,000 principal amount of the Convertible Senior Notes which is equivalent to a conversion price of approximately $32.14 per share of common stock. We may redeem the Convertible Senior Notes on or after December 20, 2012. Beginning with the period commencing on December 20, 2012 to June 14, 2013 and for each six-month period thereafter, in addition to the stated interest rate of 3.25% per annum, we will pay contingent interest of 0.25% of the market value of the Convertible Senior Notes if, during specified testing periods, the average trading price of the Convertible Senior Notes exceeds 120% or more of the principal value. In addition, holders of the Convertible Senior Notes may require us to repurchase the notes at 100% of the principal amount on each of December 15, 2012, 2015, and 2020, and upon certain events, including a change of control (as defined) or the termination of trading of our common stock on a listed exchange. The effective interest rate for the Convertible Senior Notes was 6.6% following the adoption of ASC Topic No. 470-20 “Debt with Conversion and Other Options” (Note 2).

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

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

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

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

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

The conversion value means the product of (1) the conversion rate in effect (plus any applicable additional shares resulting from an adjustment to the conversion rate) or, if the Convertible Senior Notes are converted during a registration default, 103% of such conversion rate (and any such additional shares), and (2) the average of the last reported sale prices of our common stock for the trading days during the cash settlement period. At December 31, 2009, the conversion trigger was not met.

Our weighted average share price for 2009 was below the conversion price of $32.14 per share. The maximum number of shares of common stock which may be issued upon conversion of the Convertible Senior Notes is 13,303,770. We registered the 13,303,770 shares of common stock that may be issued upon conversion of the Convertible Senior Notes as well as 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.

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MARAD Debt

At December 31, 2009 and 2008, $119.2 million and $123.4 million, respectively, was outstanding on our long-term financing used for construction of the Q4000 (“MARAD Debt”). 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. The MARAD Debt is payable in equal semi-annual installments which began in August 2002 and matures 25 years from such date. The MARAD Debt is collateralized by the Q4000, with us guaranteeing 50% of the debt, and initially bore interest at a floating rate which approximated AAA Commercial Paper yields plus 20 basis points. As provided for in the MARAD Debt agreements, in September 2005, we fixed the interest rate on the debt through the issuance of a 4.93% fixed-rate note with the same maturity date (February 2027). In accordance with the MARAD Debt agreements, we are required to comply with certain covenants and restrictions, including the maintenance of minimum net worth, working capital and debt-to-equity requirements. At December 31, 2009, we are in compliance with these debt covenants.

Other

We paid financing costs associated with our debt totaling $7.1 million in 2009 and $2.2 million in 2008. Deferred financing costs of $30.1 million and $33.4 million at December 31, 2009 and 2008, respectively, are included within the caption “Other Assets, Net” in the accompanying consolidated balance sheets and are being amortized over the life of the respective agreements. In December 2007, as a result of prepaying $400 million of borrowing under our Term Loan, we charged $3.5 million to interest expense representing the proportionate share of the deferred financing cost related to the prepaid amount of the Term Loan.

Scheduled maturities of long-term debt and capital lease obligations outstanding as of December 31, 2009 were as follows (in thousands):

	Helix Term Loan	Helix Revolving Loans	Senior Unsecured Notes	Convertible Senior Notes(1)	MARAD Debt	Loan Note(2)	Total
Less than one year	$ 4,326	$	$	$	$ 4,424	$ 3,674	$ 12,424
One to two years	4,326				4,645	—	8,971
Two to three years	4,326				4,877	—	9,203
Three to four years	401,788				5,120	—	406,908
Four to five years					5,376	—	5,376
Over five years			550,000	300,000	94,793	—	944,793
Total debt	414,766		550,000	300,000	119,235	3,674	1,387,675
Current maturities	(4,326)				(4,424)	(3,674)	(12,424)
Long-term debt, less current maturities	410,440		550,000	300,000	114,811	—	1,375,251
Unamortized debt Discount (3)				(26,936)	—	—	(26,936)
Long-term debt	$410,440	$	$ 550,000	$ 273,064	$ 114,811	$ —	$ 1,348,315

(1) Beginning in December 2012, we may at our option repurchase notes or the holders may require repurchase of notes.

(2) Represents the balance of loan provided by Kommandor RØMØ to Kommandor LLC as of December 31, 2009.

(3) Reflects debt discount resulting from adoption of new provisions of ASC Topic No. 470-20 “Convertible Debt and Other Options” on January 1, 2009. The notes will increase to $300 million face amount through accretion of non-cash interest charges through 2012.

We had unsecured letters of credit outstanding at December 31, 2009 totaling approximately $49.2 million. These letters of credit primarily guarantee various contract bidding and insurance activities. The following table details our interest expense and capitalized interest for the years ended December 31, 2009, 2008 and 2007 (in thousands):

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	Year Ended December 31,		
	2009	2008	2007
Interest expense	$ 105,775	$ 136,989	$ 107,752
Interest income	(923)	(2,416)	(9,231)
Capitalized interest	(48,119)	(42,125)	(31,790)
Interest expense, net	$ 56,733	$ 92,448	$ 66,731

Note 11 — Income Taxes

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

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

	Year Ended December 31,		
	2009	2008	2007
Statutory rate	35.0%	35.0%	35.0%
Foreign provision	(1.1)	2.6	(1.4)
IRC Section 199 deduction	(1.2)	0.7	(0.2)
CDI equity pick up in excess of tax basis	3.0	(4.2)	
Nondeductible goodwill impairment (Note 2)		(50.0)	
Other	0.9	(1.7)	(0.1)
Effective rate	36.6%	(17.6)%	33.3%

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

	Year Ended December 31,		
	2009	2008	2007
Current	$ 160,829	$ 92,181	$ 46,780
Deferred	(65,007)	(5,402)	125,082
	$ 95,822	$ 86,779	$ 171,862

	Year Ended December 31,		
	2009	2008	2007
Domestic	$ 94,388	$ 42,780	$ 147,219
Foreign	1,434	43,999	24,643
	$ 95,822	$ 86,779	$ 171,862

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, 2009 and 2008 were as follows (in thousands):

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		2009		2008
Deferred tax liabilities:				
Depreciation and depletion	$	432,567	$	638,363
Subsidiary book basis in excess of tax		834		71,048
Equity investments in production facilities		54,122		41,839
Prepaid and other		48,312		57,230
Total deferred tax liabilities	$	535,835	$	808,480
Deferred tax assets:				
Net operating loss carryforward	$	(4,415)	$	(3,533)
Decommissioning liabilities		(84,572)		(150,337)
Reserves, accrued liabilities and other		(28,758)		(46,401)
Total deferred tax assets	$	(117,745)	$	(200,271)
Valuation allowance				3,317
Net deferred tax liability	$	418,090	$	611,526
Deferred income tax is presented as:				
Current deferred tax asset	$	(24,517)	$	(3,978)
Noncurrent deferred tax liabilities		442,607		615,504
Net deferred tax liability	$	418,090	$	611,526

We consider the undistributed earnings of our principal non-U.S. subsidiaries to be permanently reinvested. At December 31, 2009 and 2008, our principal non-U.S. subsidiaries had accumulated earnings and profits of approximately $58.0 million and $51.2 million, respectively. We have not provided deferred U.S. income tax on the accumulated earnings and profits. Alternatively, as a result of our inability to recover our tax basis in CDI tax free, we have provided a deferred tax liability on the incremental increases to the book over tax basis.

We have adopted the uncertain tax position provisions of ASC Topic No. 740 “Income Taxes.” We account for tax related interest in interest expense and tax penalties in operating expenses. During 2009, we recorded a $0.8 million long term liability for uncertain tax benefits, interest and penalty. At December 31, 2009, 2008, and 2007 there are $3.4 million, $5.2 million and $0.6 million of unrecognized tax benefits that if recognized would affect the annual effective rate. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows (in thousands):

	2009	2008	2007
Balance at January 1,	$ 5,183	$ 640	$
Additions based on tax positions related to current year		2,643	
Additions for tax positions of prior years	773	1,900	640
Reductions for tax positions of prior years	(2,539)		
Balance at December 31,	$ 3,417	$ 5,183	$ 640

We file tax returns in the U.S. and in various state, local and non-U.S. jurisdictions. We anticipate that any potential adjustments to our state, local and non-U.S. jurisdiction tax returns by tax authorities would not have a material impact on our financial position. The tax periods ending December 31, 2006, 2007, 2008 and 2009 remain subject to examination by the U.S. Internal Revenue Service ("IRS"). In addition, as we acquired Remington on July 1, 2006 we are exposed to any tax uncertainties related to Remington. For Remington, the tax period ending June 30, 2006 remains subject to examination by the IRS. In non-U.S. jurisdictions, the open tax periods primarily include 2007, 2008 and 2009.

In December 2006, we entered into the Tax Matters Agreement with CDI in connection with the CDI initial public offering. For the year ended December 31, 2009, this agreement did not have a material impact on our consolidated results of operations.

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Note 12 — Convertible Preferred Stock

In January 2003, we completed the private preferred 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) convertible into 1,666,668 shares of our common stock at $15 per share. The preferred stock was issued to a private investment firm, Fletcher International, Ltd. ("Fletcher"). Subsequently on June 2004, Fletcher exercised an existing right to purchase an additional $30 million of cumulative convertible preferred stock (Series A-2 Cumulative Convertible Preferred Stock, par value $0.01 per share) convertible into 1,964,058 shares of our common stock at $15.27 per share. Pursuant to the agreement governing the preferred stock (the "Fletcher Agreement"), Fletcher was entitled to convert the preferred shares into common stock at any time, and to redeem the preferred shares into common stock at any time after December 31, 2004. In January 2009, Fletcher issued a redemption notice with respect to all its shares of the Series A-2 Cumulative Convertible Preferred Stock, and, pursuant to such redemption, we issued and delivered 5,938,776 shares of our common stock to Fletcher based on a redemption price of $5.05 per share as determined by the average closing price of our common stock on the three days starting on the third day prior to holder redeeming the shares of Series A-2 Cumulative Preferred Stock. Accordingly, in the first quarter of 2009 we recognized a $29.3 million charge to reflect the terms of this redemption, which was recorded as a reduction to our net income applicable to common shareholders. This beneficial conversion charge reflected the value associated with the additional 3,974,718 shares delivered over the original 1,964,058 shares that were contractually required to be issued upon conversion but was limited to the $29.3 million of net proceeds we received from the issuance of the Series A-2 Cumulative Convertible Preferred Stock.

The Fletcher Agreement provides that if the volume weighted average price of our common stock on any date is less than a certain minimum price (calculated at $2.767 subsequent to the above described redemption), then our right to pay Fletcher dividends in our common stock is extinguished, and we are required to deliver a notice to Fletcher that either (1) the conversion price will be reset to such minimum price (in which case Fletcher shall have no further right to cause the redemption of the preferred stock), or (2) in the event Fletcher exercises its redemption rights, we will satisfy our redemption obligations either in cash, or a combination of cash and common stock subject to a maximum number of shares (14,973,814) that can be delivered to Fletcher under the Fletcher Agreement. On February 25, 2009, the volume weighted average price of our common stock was below the minimum price, and on February 27, 2009 we provided notice to Fletcher that with respect to the Series A-1 Cumulative Convertible Preferred Stock the conversion price is reset to $2.767 as of that date and that Fletcher shall have no further rights to redeem the shares, and we have no further right to pay dividends in common stock. Subsequent to this election, the conversion price is not subject to any further adjustment or reset. As a result of the reset of the conversion price, Fletcher was entitled to receive an aggregate of 9,035,056 shares in future conversion(s) into our common stock based on the fixed $2.767 conversion price. In the event we elect to settle any future conversion in cash, Fletcher would receive cash in an amount approximately equal to the value of the shares it would receive upon a conversion, which could be substantially greater than the original face amount of the Series A-1 Cumulative Convertible Preferred Stock, and which would result in additional beneficial conversion charges in our statement of operations. Under the existing terms of our Senior Credit Facilities we are not permitted to deliver cash to the holder upon a conversion of the Convertible Preferred Stock.

In connection with the reset of the conversion price of the Series A-1 Cumulative Convertible Preferred Stock to $2.767, we were required to recognize a $24.1 million charge to reflect the value associated with the additional 7,368,388 shares that will be required to be delivered upon any future conversion(s) over the 1,666,668 shares that were to be delivered under the original contractual terms. This $24.1 million charge was recorded as a beneficial conversion charge reducing our net income applicable to common shareholders. Similar to the beneficial conversion charge associated with the redemption of Series A-2 Cumulative Convertible Preferred Stock, the beneficial conversion charge for the Series A-1 Cumulative Convertible Preferred Stock is limited to the $24.1 million of net proceeds received upon its issuance.

On July 23, 2009 and August 12, 2009, Fletcher provided a notice of conversion informing us of its election to convert 15,000 shares and 4,000 shares, respectively, of the Series A-1 Cumulative Convertible Preferred Stock into 5,421,033 shares and 1,445,608 shares, respectively, of our common stock. In connection with the closing of each these conversions we also paid the accrued and unpaid dividends associated with these shares in cash, the amount of which was immaterial at the time of the conversion notice. The conversions were consummated on July 27, 2009 and August 14, 2009, respectively.

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At December 31, 2009, we had 6,000 shares of convertible preferred stock outstanding, which are convertible into 2,168,413 shares of our common stock, which represents the maximum number of shares that can be issued to Fletcher in future conversion transactions. The convertible preferred stock maintains its mezzanine presentation below liabilities but is not included as component of shareholders' equity, because we may, under certain instances, be required to settle any future conversions in cash.

The common shares issuable in connection with this convertible preferred stock outstanding are included in our diluted earnings per share computations using the "if converted" method based on the applicable conversion price of $2.767 per share, meaning that for almost all future reporting periods in which we have positive earnings and our average stock price exceeds $2.767 per share we will have an assumed conversion of convertible preferred stock and the applicable number of our shares (2,168,413 shares at December 31, 2009) will be included in our diluted shares outstanding amount.

The preferred stock has a minimum annual dividend rate of 4%, subject to adjustment, payable quarterly in cash. The dividend rate was 4% in 2009 and 2008 and 6.4% in 2007. At the time these dividends were paid we had the option to pay them in our common stock; we paid them in cash.

Note 13 — Employee Benefit Plans

Defined Contribution Plan

We sponsor a defined contribution 401(k) retirement plan covering substantially all of our employees. Our contributions are in the form of cash and are determined annually as 50 percent of each employee's contribution up to 5 percent of the employee's salary. Our costs related to deferred compensation plans totaled $1.5 million, $3.0 million and $2.8 million for the years ended December 31, 2009, 2008 and 2007, respectively. These amounts include $2.1 million and $1.4 million associated with CDI deferred compensation plans in 2008 and 2007, respectively.

Stock-Based Compensation Plans

We have three stock-based compensation plans: the 1995 Long-Term Incentive Plan, as amended (the "1995 Incentive Plan"), the 2005 Long-Term Incentive Plan (the "2005 Incentive Plan") and the 1998 Employee Stock Purchase Plan (the "ESPP"), which expired at end of 2008. As of December 31, 2009, there were approximately 1.7 million shares available for grant under our 2005 Incentive Plan.

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

We account for our stock-based compensation plans under ASC Topic No. 718 "Compensation – Stock Compensation". We continue to use the Black-Scholes option pricing model for valuing share-based payments relating to stock options and recognize compensation cost on a straight-line basis over the respective vesting period. No forfeitures were estimated for outstanding unvested options as historical forfeitures have been immaterial. Forfeitures on restricted stock totaled approximately 14% based on our historical forfeitures rate. Tax deduction benefits for an award in excess of recognized compensation cost is reported as a financing cash flow rather than as an operating cash flow. We did not grant any stock options in 2009, 2008 or 2007.

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Stock Options

The options outstanding at December 31, 2009, have exercise prices as follows: 139,000 shares at $8.57; 82,774 shares at $10.92; 30,400 shares at $10.94; 30,000 shares at $11.00; 127,680 shares at $12.18; 52,800 shares at $13.91; and 38,664 shares ranging from $8.14 to $10.59, and a weighted average remaining contractual life of 3.1 years.

Options outstanding are as follows:

	2009		2008		2007	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Options outstanding at beginning of year	521,654	$10.66	736,550	$10.55	883,070	$10.86
Exercised	(20,336)	$ 8.67	(214,896)	$10.28	(141,186)	$11.10
Terminated	—	—	—	—	(5,334)	$10.92
Options outstanding at end of year	501,318	$10.74	521,654	$10.66	736,550	$10.55
Options exercisable end of year	501,318	$10.74	473,054	$10.44	537,514	$10.28

For the years ended December 31, 2009, 2008 and 2007, $0.1 million, $1.1 million (of which $0.6 million of compensation expense was recognized in the first half of 2008 related to the acceleration of unvested options per the separation agreements between the Company and two of our former executive officers) and $1.0 million, respectively, was recognized as compensation expense related to stock options. The aggregate intrinsic value of the stock options exercised in 2009, 2008 and 2007 was approximately $0.1 million, $5.9 million and $4.1 million, respectively. The aggregate intrinsic value of options exercisable at December 31, 2009 was approximately $0.5 million. There was no aggregate intrinsic value of options exercisable at December 31, 2008 as the fair market value at year end was lower than the exercise price of the vested stock options. The aggregate intrinsic value of options exercisable at December 31, 2007 was $16.8 million.

Restricted Shares

We grant restricted shares to members of our board of directors, all executive officers and selected management employees. Compensation cost for each award is the product of grant date market value of each share and the number of shares granted. The following table summarizes information about our restricted shares during the years ended December 31, 2009, 2008 and 2007:

	2009		2008		2007	
	Shares	Grant Date Fair Value(1)	Shares	Grant Date Fair Value(1)	Shares	Grant Date Fair Value(1)
Restricted shares outstanding at beginning of year	1,206,526	$32.84	1,166,077	$32.19	729,212	$ 32.29
Granted	656,887	7.12	702,190	$34.01	702,297	$ 31.77

Vested	(327,777)	33.69	(386,963)	$31.19	(236,667)	$ 31.32
Forfeited	(92,371)	8.90	(274,778)	$35.40	(28,765)	$ 31.59
Restricted shares outstanding at end of year	1,443,265	22.47	1,206,526	$32.84	1,166,077	$ 32.19

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

For the years ended December 31, 2009, 2008 and 2007, $9.4 million, $18.5 million (of which $3.6 million was related to the accelerated vesting of restricted shares per the separation agreements between the Company and two of our former executive officers during the first half of 2008) and $11.7 million, respectively, was recognized as compensation expense related to restricted shares. In 2008 and 2007, compensation expense of $4.8 and $2.1 million, respectively, was related to the CDI Incentive Plan. Future compensation cost associated with unvested restricted stock awards at December 31, 2009 and 2008 totaled approximately $21.8 million and $53.3 million, respectively, of which $23.4 million related to the CDI Incentive Plan at December 31, 2008. The weighted average vesting period related to nonvested restricted stock awards at December 31, 2009 was approximately 3.2 years.

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In January 2010, we granted executive officers and select management employees 452,849 and 23,569 restricted shares and restricted stock units, respectively, under the 2005 Long-Term Incentive Plan. The shares and units vest 20% per year for a five-year period. The market value of the restricted stock is based on the quoted market price of the common stock on the business day prior to the grant date. The market value of the restricted shares was $11.75 per share or $5.6 million. We also granted certain of our outside directors 1,197 restricted shares. The shares vest on January 1, 2012. The market value of the restricted shares was $11.75 per share or $14,065.

Employee Stock Purchase Plan

In May 1998, we adopted a qualified, non-compensatory ESPP, which allows employees to acquire shares of common stock through payroll deductions over a six-month period. The purchase price is equal to 85% of the fair market value of the common stock on either the first or last day of the subscription period, whichever is lower. Purchases under the plan are limited to the lesser of 10% of an employee's base salary or $25,000 of our stock value. Shares of our common stock issued to our employees under the ESPP totaled 98,933 shares in 2008 and 222,984 in 2007. In 2007, we subsequently repurchased approximately the same number of shares of our common stock in the open market at a weighted average price of $35.04 per share and reduced the number of shares of our outstanding common stock. Under this plan 97,598 shares of common stock were purchased in the open market for our employees at a weighted-average share price of $33.12 during 2006. For the years ended December 31, 2008 and 2007, we recognized $1.8 million and $2.1, respectively, of compensation expense related to stock purchased under the ESPP and the CDI ESPP (of which $1.2 million and $0.6 million of expense for the years ended December 31, 2008 and 2007, respectively, was related to the CDI ESPP that became effective in the third quarter of 2007).

In January 2009, we issued 25,393 shares of our common stock to our employees under this plan to satisfy the employee purchase period from July 1, 2008 to December 31, 2008, which increased our common stock outstanding. There are no longer any shares available under this plan.

Stock Compensation Modifications

Under our 1995 Incentive Plan and our 2005 Long-Term Incentive Plan, upon a stock recipient's termination of employment, which is defined as employment with us and any of our majority-owned subsidiaries, any unvested restricted stock and stock options are forfeited immediately, and all unexercised vested options are forfeited as specified under the applicable plan or agreement. Ordinarily, once our beneficial ownership of CDI fell to 50% or below (the "Trigger Date"), the options and unvested shares granted to CDI employees would have been forfeited at such date under our current plans. As part of the Employee Matters Agreement between us and CDI, which was executed in December 2006, with respect to any employee who is a CDI employee as of the date of the IPO, we have agreed to extend the life of any vested and unexercised stock options to the earlier of (1) the expiration of the general term of the option or (2) the later of (i) December 31 of the calendar year in which the Trigger Date occurs, or (ii) the 15th day of the third month after the expiration of the 60-day period commencing on the Trigger Date (135 days). In addition, under the Employee Matters Agreement, restricted stock awards granted to employees of CDI as of the IPO closing date will continue under their present terms and the terms of the plans under which they were granted. The modification date for these restricted stock and options occurred at the date the Employee Matters Agreement was adopted.

Long-Term Incentive Cash Plan

In January 2009, we adopted the 2009 Long-Term Incentive Cash Plan (the "2009 LTI Plan") to provide certain long-term cash based compensation to eligible employees. Under terms of the 2009 LTI Plan, the majority of the cash awards, which vest over a five-year period of employment, are made in a fixed sum amount. Our Executive Officers and certain other members of senior management are granted cash awards. The amount of the payment on each applicable payment anniversary date will fluctuate based upon the Company's stock performance. The share-based cash awards are measured based on the performance of our stock price over the applicable award period compared to a base price determined by the Compensation Committee of the Board of Directors at the time of the award. The measurement period to determine the annual payment for the share-based cash awards is the last 20 trading days of the year (modified from the last 30 trading days as applied to the 2009 awards). Payment amounts are based on the calculated ratio of the average stock price during the annual measurement period over the original base price. The maximum amount payable under these share-based cash awards is twice the original targeted award and if the average price during the measurement period is less than 50% of the base price, no payout will be made at the applicable anniversary date. Payments under the 2009 LTI Plan are made each year on the anniversary date of the award. The share-based component of our 2009 LTI

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Plan is considered a liability plan under the guidance of ACS Topic No. 718 "Compensation – Stock Compensation" and as such will be re-measured to fair value each reporting period with corresponding changes be recorded as a charge to income as appropriate.

The total awards made under the 2009 LTI Plan totaled $14.7 million in 2009, including $8.1 million for our Executive Officers. For the year ended December 31, 2009, $3.7 million ($2.6 million related to Executive Officers) was recognized as compensation expense related to the 2009 LTI Plan and paid in January 2010. In January 2010, $10.1 million was awarded under the 2009 LTI Plan to eligible employees, including $6.0 million to our Executive Officers and other members of senior management.

Note 14 — Shareholders' Equity

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

The components of accumulated other comprehensive income (loss) as of December 31, 2009 and 2008 were as follows (in thousands):

	2009	2008
Cumulative foreign currency translation adjustment	$ (12,257)	$ (42,874)
Unrealized gain (loss) on hedges, net	(9,097)	9,178
Unrealized loss on investment available for sale	(887)	
Accumulated other comprehensive loss	$ (22,241)	$ (33,696)

Note 15 — Stock Buyback Program

In June 2009, we announced that we intend to purchase up to 1.5 million shares plus an amount equal to additional shares granted under the stock-based compensation plans (Note 13) of our common stock as permitted under our Senior Credit Facility. Our Board of Directors had previously granted us the authority to repurchase shares of our common stock in an amount equal to any equity grants made pursuant to our stock-based compensation plans. We may continue to make repurchases pursuant to this authority from time to time as additional equity grants are made under our stock based compensation plans based upon prevailing market conditions and other factors. All repurchases may be commenced or suspended at any time at the discretion of management. As of December 31, 2009, we had repurchased a total of 1,048,431 shares of our common stock for $13.4 million or an average of $12.80 per share. We retired all shares repurchased.

Note 16 — Related Party Transactions

Cal Dive International, Inc.

Subsequent to the initial public offering of Cal Dive from time to time, we have provided Cal Dive certain management and administrative services including: (i) accounting, treasury, payroll and other financial services; (ii) legal, insurance and claims services; (iii) information systems, network and communication services; (iv) employee benefit services (including direct third-party group insurance costs and 401(k) contribution matching costs discussed below); and (v) corporate facilities management services. Total allocated costs to Cal Dive for such services were $0.9 million for the period of January 1, 2009 through deconsolidation in June 2009. Total allocated services to Cal Dive totaled approximately $4.0 million and $3.6 million for the years ended December 31 2008 and 2007, respectively.

Included in these costs are costs related to the participation by CDI’s employees in our employee benefit plans through December 31, 2007, including employee medical insurance and a defined contribution 401(k) retirement plan. These costs were recorded as a component of operating expenses and were approximately $9.2 million for the year ended December 31, 2007. Our defined contribution 401(k) retirement plan is further disclosed in Note 13.

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

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

Pursuant to the Corporate Services Agreement, each party agreed to provide specified services to the other party, including administrative and support services for the time period specified therein. Generally once we ceased to own 50% or more of the total voting power of CDI common stock, all services may be terminated by either party upon 60 days notice, but a longer notice period is applicable for selected services. Each of the services were provided in exchange for a monthly charge as calculated for each service (based on relative revenues, number of users for a particular service, or other specified measure). In general, under the Corporate Services Agreement as originally entered into by the parties we provided CDI with services related to the tax, treasury, audit, insurance (including claims) and information technology functions; CDI provided us with services related to the human resources, training and orientation functions, and certain supply chain and environmental, health and safety services. However, the Corporate Services Agreement was amended effective January 1, 2008 and effective January 1, 2009 to reflect that CDI no longer provides us with these functions, and to reflect that we only provide CDI with certain information technology and insurance services. This Agreement was terminated in August 2009 upon mutual agreement between Cal Dive and us.

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

Pursuant to the Tax Matters Agreement, we are generally responsible for all federal, state, local and foreign income taxes that are attributable to CDI for all tax periods ending on the IPO; CDI is generally responsible for all such taxes beginning after the IPO. In addition, the agreement provides that for a period of up to ten years, CDI is required to make annual payments to us equal to 90% of tax benefits derived by CDI from tax basis adjustments resulting from the "Boot" gain recognized by us as a result of the distributions made to us as part of the IPO transaction. See Note 11 for more detailed disclosure of the Tax Matters Agreement.

Other

In April 2000, we acquired a 20% working interest in Gunnison, a Deepwater Gulf of Mexico prospect of Kerr-McGee. Financing for the exploratory costs of approximately $20 million was provided by an investment partnership (OKCD Investments, Ltd. or "OKCD"), the investors of which include current and former Helix senior management, in exchange for a revenue interest that is an overriding royalty interest of 25% of Helix's 20% working interest. Production from the Gunnison field commenced in December 2003. We have made payments to OKCD totaling $11.3 million, $21.6 million and $22.1 million in the years ended December 31, 2009, 2008 and 2007 respectively. Our Chief Executive Officer, Owen Kratz, through Class A limited partnership interests in OKCD, personally owns approximately 80.4% of the partnership. Martin Ferron, our former President and Chief Executive Officer, owns approximately 1.2% of the partnership and A. Wade Pursell, our former Executive Vice President and Chief Financial Officer, owns approximately 0.4% of the partnership. In 2000, OKCD also awarded Class B limited partnership interests to key Helix employees.

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During 2009, 2008 and 2007, we paid $3.3 million,$3.4 million and $12.3 million, respectively, to Weatherford International, Ltd. ("Weatherford"), an oil and gas industry company, for services provided to us. A member of our board of directors is part of the senior management team of Weatherford.

In 2009, we made $0.2 million in rental payments to Mine Maintenance Management whose partners include two current employees of our wholly owned WOSEA subsidiary. We currently lease from Mine Maintenance an office building and a fabrication facility both located in Perth, Australia.

Note 17 — Commitments and Contingencies

Lease Commitments

We lease several facilities, ROVs and vessels under noncancelable operating leases. Future minimum rentals under these leases are approximately $99.1 million at December 31, 2009 with $43.8 million due in 2010, $36.3 million in 2011, $15.3 million in 2012, $1.6 million in 2013, $1.3 million in 2014 and $0.8 million thereafter. Total rental expense under these operating leases was approximately $89.9 million, $59.6 million and $76.0 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Insurance

We carry Hull and Increased Value insurance which provides coverage for physical damage up to an agreed amount for each vessel. The deductibles are based on the value of the vessel with a maximum deductible of $1.0 million on the Q4000, Helix Producer I and Well Enhancer,$500,000 on the Intrepid, Seawell and Express and $375,000 on the Caesar. In addition to the primary deductibles the vessels are subject to an Annual Aggregate Deductible of $1.25 million. We also carry Protection and Indemnity ("P&I") insurance which covers liabilities arising from the operation of the vessels and General Liability insurance which covers liabilities arising from construction operations. The deductible on both the P&I and General Liability is $100,000 per occurrence. Onshore employees are covered by Workers' Compensation. Offshore employees, including divers and tenders and marine crews, are covered by Maritime Employers Liability insurance policy which covers Jones Act exposures and includes a deductible of $100,000 per occurrence plus a $1.0 million annual aggregate deductible. In addition to the liability policies named above, we currently carry various layers of Umbrella Liability for total limits of $500 million excess of primary limits. Our self-insured retention on our medical and health benefits program for employees is $250,000 per participant.

We incur workers' compensation and other insurance claims in the normal course of business, which management believes are covered by insurance. The Company analyzes each claim for potential exposure and estimates the ultimate liability of each claim. At December 31, 2009 we did not have any claims exceeding our deductible limits. At December 31, 2008, our liability above the applicable deductible limits was $7.9 million and we had a corresponding $7.9 million receivable from the insurance companies. These amounts are reflected in Accrued Liabilities and Other Current Assets in the consolidated balance sheet (Note 7). We have not incurred any significant losses as a result of claims denied by our insurance carriers. Our services are provided in hazardous environments where accidents involving catastrophic damage or loss of life could occur, and litigation arising from such an event may result in our being named a defendant in lawsuits asserting large claims. Although there can be no assurance the amount of insurance we carry is sufficient to protect us fully in all events, or that such insurance will continue to be available at current levels of cost or coverage, we believe that our insurance protection is adequate for our business operations. A successful liability claim for which we are underinsured or uninsured could have a material adverse effect on our business.

Litigation and Claims

On December 2, 2005, we received an order from the U.S. Department of the Interior Minerals Management Service ("MMS") that the price threshold for both oil and gas was exceeded for 2004 production and that royalties were due on such production notwithstanding the provisions of the Outer Continental Shelf Deep Water Royalty Relief Act of 2005 ("DWRRA"), which was intended to stimulate exploration and production of oil and natural gas in the deepwater Gulf of Mexico by providing relief from the obligation to pay royalty on certain federal leases up to certain specified production volumes. Our oil and gas leases affected by this dispute are Garden Banks Blocks 667, 668 and 669 ("Gunnison"). On May 2, 2006, the MMS issued another order that superseded the December 2005 order, and claimed that royalties on gas production are due for 2003 in addition to oil and gas production in 2004. The order also seeks interest on all royalties allegedly due. We filed a timely notice of appeal with respect to both the December 2005 Order and the May 2006 Order.

We received an additional order from the MMS dated September 30, 2008 stating that the price thresholds for oil and gas were exceeded for 2005, 2006 and 2007 production and that royalties and interest are payable, as well as an additional order from the MMS dated August 28, 2009 stating the price thresholds for oil and natural gas were exceeded for 2008 and that royalties and interest are payable. We appealed these orders on the same basis as the previous orders.

Other operators in the Deep Water Gulf of Mexico who have received notices similar to ours sought royalty relief under the DWRRA, including Kerr-McGee, the operator of Gunnison. In March of 2006, Kerr-McGee filed a lawsuit in federal district court challenging the enforceability of price thresholds in certain deepwater Gulf of Mexico leases, including ours. On October 30, 2007, the federal district court in the Kerr-McGee case entered judgment in favor of Kerr-McGee and held that the Department of the Interior exceeded its authority by including the price thresholds in the subject leases. The government appealed the district court's decision. On January 12, 2009, the United States Court of Appeals for the Fifth Circuit affirmed the decision of the district court in favor of Kerr-McGee, holding that the DWRRA unambiguously provides that royalty suspensions up to certain production volumes established by Congress apply to leases that qualify under the DWRRA. After the appellate court denied a request by the plaintiff for rehearing, the plaintiff subsequently petitioned the United States Supreme Court for a writ of certiorari for the Supreme Court to review the Fifth Circuit Court's decision. In October 2009, the United States Supreme Court announced its decision to deny the plaintiff's writ of certiorari, concluding the litigation in this dispute.

As a result of this dispute, we had been recording reserves for the disputed royalties (and any other royalties that may be claimed for production during 2005, 2006, 2007 and 2008) plus interest at 5% for our portion of the Gunnison related MMS claim. The result of accruing these reserves since 2005 had reduced our oil and gas revenues. Following the decision of the United States Court of Appeals for the Fifth Circuit Court, we reversed our previously accrued royalties ($73.5 million) to oil and gas revenues in the first quarter of 2009. Effective in January 2009, we commenced recognizing oil and natural gas sales revenue associated with this disputed net revenue interest and are no longer accruing any additional royalty reserves as we believed it was remote that we would be liable for such amounts in future. This belief was confirmed with the United States Supreme Court decision to deny the plaintiff's writ of certiorari in October 2009.

Contingencies

A number of our longer term pipelay contracts have been adversely affected by delays in the delivery of the Caesar. We believe two of our contracts qualify as loss contracts as defined under SOP 81-1 "Accounting for Performance of Construction-Type and Certain Production-Type Contracts." Accordingly, we have estimated the future shortfall between our anticipated future revenues versus future costs. For one contract that was completed in May 2009, our loss was $0.8 million, all of which was provided with our estimated loss accrual at December 31, 2008. Under a second contract, which was terminated, we had a potential future liability of up to $25 million. As of December 31, 2008, we estimated the loss under this contract at $9.0 million. In the second quarter of 2009, services under this contract were substantially completed and we revised our estimated loss to approximately $15.8 million. To reflect this additional estimated loss we recorded an additional $6.8 million charge to cost of sales in the accompanying condensed consolidated statement of operations. We recently agreed to settle our obligation under this contract for $12.7 million. Accordingly we reversed $3.1 million of our previously accrued costs under this contract to reduce it from the estimated $15.8 million loss to $12.7 million at December 31, 2009. We have paid $7.2 million of the $12.7 million of estimated damages related to this terminated contract and expect to pay the remaining $5.5 million in the second quarter of 2010.

In March 2009, we were notified of a third party's intention to terminate an international construction contract based on a claimed breach of that contract by one of our subsidiaries. As there are substantial defenses to this claimed breach, we cannot at this time determine if we have any exposure under the contract. In 2010, we will continue to assess our potential exposure to damages under this contract as the circumstances warrant. Under the terms of the contract, our potential liability is generally capped for actual damages at approximately $27 million Australian dollars ("AUD") (approximately $24.3 million US dollars at December 31, 2009) and for liquidated damages at approximately $5 million AUD (approximately $4.5 million US dollars at December 31, 2009). At December 31, 2009, we have a $4.0 million AUD (approximately $3.6 million US dollars at December 31, 2009) receivable against our counterparty for work performed prior to the termination of the contract. We continue to pursue payment for this work as well as other claims against our counterparty. We have asserted a counterclaim that in the aggregate approximates $12 million U.S. dollars.

Commitments

We are converting the Caesar (acquired in January 2006 for $27.5 million in cash) into a deepwater pipelay vessel. Total conversion costs are estimated to range between $290 million and $300 million (including capitalized interest of approximately $24 million), of which approximately $264.8 million had been incurred, with an additional $2.3 million committed, at December 31, 2009. We expect the Caesar to join our fleet in the first half of 2010.

Further, we, along with Kommandor Rømø, a Danish corporation, formed a joint venture company called Kommandor LLC and converted a ferry vessel into a floating production unit to be named the Helix Producer I. The total cost of the ferry and the conversion was approximately $170 million. We provided $98.9 million in interim construction financing to the joint venture. During 2009, $58.8 million of this amount was converted to equity in our investment in Kommandor LLC. Kommandor Rømø provided a $5.0 million loan to Kommandor LLC, the remaining balance of which was $3.7 million at December 31, 2009.

Total equity contributions and indebtedness guarantees provided by Kommandor Rømø are expected to total $42.5 million. The remaining costs to complete the project will be provided by Helix through equity contributions. Under the terms of the operating agreement of the joint venture, Kommandor Rømø elected not to make further contributions to the joint venture, thus the ownership interests in the joint venture were adjusted based on the relative contributions of each partner (including guarantees of indebtedness) to the total of all contributions and project financing guarantees.

Upon completion of the initial conversion, which occurred in April 2009, we chartered the Helix Producer I from Kommandor LLC., and are installing, at 100% our cost, processing facilities and a disconnectable fluid transfer system on the Helix Producer I for use on our Phoenix field. The cost of these additional facilities is estimated to range between $190 million and $200 million (including capitalized interest of $16 million) and the work is expected to be completed in the first half of 2010. As of December 31, 2009, approximately $269 million of costs related to the purchase of the Helix Producer I ($20 million), conversion of the Helix Producer I and construction of the additional facilities had been incurred, with an additional $12.1 million committed. The total estimated cost of the vessel, initial conversion and the additional facilities will range approximately between $360 million and $370 million. We have consolidated Kommandor LLC in all periods presented in the accompanying consolidated financial statements. The results of Kommandor LLC are included within our Production Facilities segment.

As of December 31, 2009, we planned to spend approximately $16 million for additional capital improvements to newly constructed Well Enhancer vessel and have committed to spend $58.7 million in additional capital expenditures for exploration, development and drilling costs related to our oil and gas properties.

Note 18 — Business Segment Information

Our operations are conducted through the following lines of business: contracting services operations and oil and gas operations. We have disaggregated our contracting services operations into three reportable segments in accordance with ASC Topic No 280 “Segment Reporting”: Contracting Services, Shelf Contracting and Production Facilities. As a result, our reportable segments consisted of the following: Contracting Services, Shelf Contracting, Oil and Gas and Production Facilities. Contracting Services operations include deepwater pipelay, well operations, robotics and drilling. Shelf Contracting operations consisted of CDI, which included all assets deployed primarily for diving-related activities and shallow water construction. On June 10, 2009, we ceased consolidating CDI when our remaining ownership interest decreased to below 50% following the sale of a portion of CDI common stock held by us (Note 3). We continued to disclose the results of Shelf Contracting business as a segment up to and through June 10,

2009. All material intercompany transactions between the segments have been eliminated.

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

The following summarizes certain financial data by business segment:

	Year Ended December 31,		
	2009	2008	2007
	(in thousands)		
Revenues			
Contracting Services	$ 796,158	$ 961,926	$ 673,808
Shelf Contracting	404,709	856,906	623,615
Oil and Gas	385,338	545,853	584,563
Production Facilities(2)	17,248	—	—
Intercompany elimination	(141,766)	(250,611)	(149,566)
Total	$1,461,687	$2,114,074	$1,732,420
Income (loss) from operations			
Contracting Services	$ 118,176	$ 181,983	$ 160,866
Shelf Contracting(1)	59,077	179,711	183,130
Oil and Gas	91,668	(709,966)	123,353
Production Facilities(2)	(3,918)	(719)	(847)
Corporate	(47,734)	(39,220)	(32,215)
Intercompany elimination	(13,454)	(26,011)	(23,008)
Total(4)	$ 203,815	$ (414,222)	$ 411,279
Net interest expense and other			
Contracting Services	$ (2,280)	$ 12,454	$ 4,707
Shelf Contracting	6,642	22,285	9,259
Oil and Gas	20,152	47,599	49,580
Production Facilities	2,011	386	331
Corporate and eliminations	24,970	28,374	3,170
Total	$ 51,495	$ 111,098	$ 67,047

Equity in losses of OTSL, inclusive of impairment	$ —	$ —	$ (10,841)
Equity in earnings of equity investments excluding OTSL	$ 32,329	$ 31,854	$ 30,414
Income (loss) before income taxes			
Contracting Services(3)	$ 120,456	$ 169,529	$ 156,159
Shelf Contracting(1)	52,435	157,426	163,030
Oil and Gas	71,516	(757,565)	73,773
Production Facilities(2)	18,300	30,749	29,236
Corporate and eliminations	(715)	(93,605)	93,303
Total	$ 261,992	$ (493,466)	$ 515,501

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	Year Ended December 31, 2009	2008	2007
	(in thousands)		
Provision (benefit) for income taxes			
Contracting Services	$ 43,334	$ 56,018	$ 51,091
Shelf Contracting	16,275	47,927	57,430
Oil and Gas	23,352	(15,092)	24,896
Production Facilities	6,198	12,569	10,509
Corporate and eliminations	6,663	(14,643)	27,936
Total	$ 95,822	$ 86,779	$ 171,862
Identifiable assets			
Contracting Services	$1,738,005	$1,572,618	$1,135,981
Shelf Contracting	—	1,309,608	1,274,050
Oil and Gas	1,541,153	1,708,428	2,634,238
Production Facilities	499,497	457,197	366,634
Discontinued operations	878	19,215	38,612
Total	$3,779,533	$5,067,066	$5,449,515
Capital expenditures			
Contracting Services	$ 204,228	$ 258,184	$ 286,362
Shelf Contracting	39,569	83,108	30,301
Oil and Gas	137,168	404,308	519,632
Production Facilities	44,065	110,300	123,545
Discontinued operations	—	476	1,215
Total	$ 425,030	$ 856,376	$ 961,055
Depreciation and amortization			
Contracting Services	$ 53,411	$ 44,489	$ 37,588
Shelf Contracting(1)	34,243	71,195	40,698
Oil and Gas	168,101	215,605	250,371

Production Facilities	3,295	—	—
Corporate and eliminations	3,567	2,437	1,141
Total	$ 262,617	$ 333,726	$ 329,798

(1) Includes $(10.8) million equity in (losses) earnings from CDI's investment in OTSL in 2007.

(2) In April 2009, Kommandor LLC commenced leasing the Helix Producer I to us under terms of a charter arrangement following the completion of the initial conversion of the vessel (Note 9). We are currently completing some capital upgrades to the vessel which are expected to be completed by mid year 2010. At that time the vessel will be used in our Phoenix field.

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

(4) Includes $704.3 million of goodwill impairment charges for year ending December 31, 2008 associated with our oil and gas segment. Also includes approximately $120.6 million, $215.7 million and $64.1 million of asset impairment charges for certain oil and gas properties for the years ended December 31, 2009, 2008 and 2007 respectively.

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Intercompany segment revenues during the years ended December 31, 2009, 2008 and 2007 were as follows (in thousands):

	Year Ended December 31,		
	2009	2008	2007
Contracting Services	$ 120,048	$ 195,207	$ 115,864
Shelf Contracting	7,865	55,404	33,702
Production Facilities	13,853	—	—
Total	$ 141,766	$ 250,611	$ 149,566

Intercompany segment profit (which only relates to intercompany capital projects) during the years ended December 31, 2009, 2008 and 2007 were as follows (in thousands):

	Year Ended December 31,		
	2009	2008	2007
Contracting Services	$ 13,205	$ 20,945	$ 10,026
Shelf Contracting	365	5,066	12,982
Production Facilities	(116)	—	—
Total	$ 13,454	$ 26,011	$ 23,008

Revenue by geographic region during the years ended December 31, 2009, 2008 and 2007 were as follows (in thousands):

	Year Ended December 31,		
	2009	2008	2007
United States	$ 923,481	$1,394,108	$1,261,844
United Kingdom	124,896	160,186	205,529
India	233,466	214,288	36,433
Other	179,844	345,492	228,614
Total	$1,461,687	$2,114,074	$1,732,420

We include the property and equipment, net in the geographic region in which it is legally owned. The following table provides our property and equipment, net of depreciation by geographic region (in thousands):

	Year Ended December 31,		
	2009	2008	2007
United States	$2,564,673	$3,170,866	$3,014,283
United Kingdom	284,637	206,009	187,551
Other	14,396	41,568	41,073
Total	$2,863,706	$3,418,443	$3,242,907

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Note 19 — Allowance Accounts

The following table sets forth the activity in our valuation accounts for each of the three years in the period ended December 31, 2009 (in thousands):

	Allowance for Uncollectible Accounts	Deferred Tax Asset Valuation Allowance
Balance, December 31, 2006	$ 965	$ —
Additions	5,122	2,967
Deductions	(3,213)	—
Balance, December 31, 2007	2,874	2,967
Additions	8,989	350
Deductions	(5,958)	—
Balance, December 31, 2008	5,905	3,317
Additions	9,220	—
Deductions (1)	(9,953)	(3,317)
Balance, December 31, 2009	$ 5,172	$ —

(1) Amounts include reductions of $5.9 million to the allowance for uncollectible accounts and $3.3 million to the deferred tax valuation allowance to reflect the deconsolidation of Cal Dive in June 2009 (Note 3).

See Note 2 for a detailed discussion regarding our accounting policy on Accounts Receivable and Allowance for Uncollectible Accounts and Note 11 for a detailed discussion of the valuation allowance related to our deferred tax assets.

Note 20 — Supplemental Oil and Gas Disclosures (Unaudited)

Recent Accounting Rules Activities

In December 2008, the SEC announced that it had approved revisions designed to modernize the oil and gas company reserve reporting requirements. In January 2010, the FASB issued Accounting Standards Update 2010-03 “Oil and Gas Reserve Estimation and Disclosures.” We adopted these rules on December 31, 2009 in conjunction with our year end 2009 proved reserve estimates and have implemented the newly mandated authoritative guidance issued by the FASB on extractive activities for oil and gas reserves estimation and disclosures (Note 2 – New Accounting Standards).

One effect of adoption of these rules included the application of lower prices at December 31, 2009 for both oil and natural gas than what would have been used under the previous rule (year end price). Generally, adoption of these new regulations had little effect on our estimates of reserves at December 31, 2009; however, the rule requiring development of proved undeveloped reserves within five years could significantly impact future estimates of our proved reserves (see “Proved Undeveloped Reserves” below).

The following information regarding our oil and gas producing activities is presented pursuant to ASC Topic No. 932-235-55 “Extractive Activities – Oil and Gas.”

Capitalized Costs

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

	2009	2008
Unproved oil and gas properties	$ 61,931	$ 101,892
Proved oil and gas properties	2,603,789	2,462,959
Total oil and gas properties	2,665,720	2,564,851
Accumulated depletion, depreciation and amortization	(1,272,797)	(1,023,493)
Net capitalized costs	$ 1,392,923	$ 1,541,358

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Included in capitalized costs of proved oil and gas properties being amortized is an estimate of our proportionate share of decommissioning liabilities assumed relating to these properties which are also reflected as decommissioning liabilities in the accompanying consolidated balance sheets. At December 31, 2009 and 2008, our oil and gas operations decommissioning liabilities were $248.1 million and $225.8 million, respectively.

Costs Incurred in Oil and Gas Producing Activities

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

	United States	United Kingdom	Total
Year Ended December 31, 2009—			
Property acquisition costs:			
Proved properties	$56	$—	$56
Unproved properties	1,829	—	1,829
Total property acquisition costs	1,885	—	1,885
Exploration costs	39,225	—	39,225
Development costs(1)	71,489	—	71,489
Asset retirement cost	66,468	2,644	69,112
Total costs incurred	$179,067	$2,644	$181,711
Year Ended December 31, 2008—			
Property acquisition costs:			
Proved properties	$2	$—	$2
Unproved properties	13,392	—	13,392
Total property acquisition costs	13,394	—	13,394
Exploration costs	7,528	—	7,528
Development costs(1)	421,335	—	421,335
Asset retirement cost	26,891	—	26,891
Total costs incurred	$469,148	$—	$469,148
Year Ended December 31, 2007—			
Property acquisition costs:			
Proved properties	$4,239	$—	$4,239
Unproved properties	16,347	—	16,347
Total property acquisition costs	20,586	—	20,586
Exploration costs	220,237	—	220,237
Development costs(1)	360,428	—	360,428
Asset retirement cost	58,082	—	58,082
Total costs incurred	$659,333	$—	$659,333

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

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Results of Operations for Oil and Gas Producing Activities

Amounts in thousands:

	United States	United Kingdom	Total
Year Ended December 31, 2009—			
Revenues	$384,375	$963	$385,338
Production (lifting) costs	117,565	2,271	119,836
Net hurricane reimbursement (Note 4)	(23,332)	—	(23,332)
Exploration expenses(2)	24,383	—	24,383
Depreciation, depletion, amortization and accretion	167,812	1,444	169,256
Proved property impairment charges	73,407	—	73,407
Gain on sale of oil and gas properties	(1,949)	—	(1,949)
Gain on oil and gas derivative contracts	(89,485)	—	(89,485)
Selling and administrative expenses	21,495	59	21,554
Pretax income (loss) from producing activities	94,479	(2,811)	91,668
Income tax expense (benefit)	24,280	(1,028)	23,252
Results of oil and gas producing activities(1)	$70,199	$(1,783)	$68,416
Year Ended December 31, 2008—			
Revenues	$541,983	$3,870	$545,853
Production (lifting) costs	122,106	2,448	124,554
Net hurricane costs (Note 4)	52,361	—	52,361
Exploration expenses(2)	32,926	—	32,926
Depreciation, depletion, amortization and accretion	198,144	959	199,103
Proved property and goodwill impairment charges	901,820	—	901,820
Gain on sale of oil and gas properties	(73,136)	(125)	(73,261)
Gain on oil and gas derivative contracts	(21,599)	—	(21,599)
Selling and administrative expenses	39,219	696	39,915
Pretax loss from producing activities	(709,858)	(108)	(709,966)

Income tax expense (benefit)	(16,242)	1,150	(15,092)
Results of oil and gas producing activities(1)	$(693,616)	$(1,258)	$(694,874)
Year Ended December 31, 2007—			
Revenues	$581,904	$2,659	$584,563
Production (lifting) costs	118,032	5,102	123,134
Exploration expenses(2)	26,725	—	26,725
Depreciation, depletion, amortization and accretion	228,083	615	228,698
Proved property impairment charges	85,145	—	85,145
Gain on sale of oil and gas properties	(42,566)	(1,717)	(44,283)
Selling and administrative	40,176	1,615	41,791
Pretax income (loss) from producing activities	126,309	(2,956)	123,353
Income tax expense (benefit)	26,240	(1,344)	24,896
Results of oil and gas producing activities(1)	$100,069	$(1,612)	$98,457

(1) Excludes net interest expense and other.

(2) See Note 6 for additional information related to the components of our exploration costs, including impairment charges for expiring unproved leases.

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Estimated Quantities of Proved Oil and Gas Reserves

We employ full-time experienced reserve engineers and geologists who are responsible for determining proved reserves in compliance with SEC guidelines. Our engineering reserve estimates were prepared based upon interpretation of production performance data and sub-surface information obtained from the drilling of existing wells. Our internal reservoir engineers and independent petroleum engineers analyzed 100% of our significant United States oil and gas fields on an annual basis (106 fields as of December 31, 2009). We consider any field with discounted future net revenues of 1% or greater of the total discounted future net revenues of all our fields to be significant.

At December 31, 2009 we engaged Huddleston & Co., Inc. ("Huddleston"), a independent reservoir engineering firm, to prepare a report to estimate our proved reserves at December 31, 2009. Their proved reserve estimates are included in this Form 10-K. Huddleston performed engineering audits of our estimates of proved reserves at December 31, 2008 and 2007. We prepared the proved reserve estimates associated with our one property in the United Kingdom for all periods presented in this Form 10-K.

An "engineering audit," as we use the term, is a process involving an independent petroleum engineering firm's extensive visits, collection and examination of all geologic, geophysical, engineering, production and economic data requested by the independent petroleum engineering firm. Our use of the term "engineering audit" is intended only to refer to the collective application of the procedures which Huddleston was engaged to perform and may be defined and used differently by other companies. The process for Huddleston to prepare their estimates of proved oil and natural gas reserves is substantially the same as during their audit of our internal reserves (discussed below). The primary difference between the audit and preparation of the reserve report is that in the culmination of the audit, Huddleston represented in its audit report that it believed our methodologies are consistent with the methodologies required by the SEC, Society of Petroleum Engineers ("SPE") and FASB while in the preparation of the 2009 reserve report we simply publish Huddleston's estimates of our proved oil and natural gas reserves.

The engineering audit of our estimated proved oil and natural gas reserves (applicable for 2008 and 2007) by the independent petroleum engineers involves their rigorous examination of our technical evaluation, interpretation and extrapolations of well information such as flow rates and reservoir pressure declines as well as other technical information and measurements. Our internal reservoir engineers interpret this data to determine the nature of the reservoir and ultimately the quantity of proved oil and gas reserves attributable to a specific property. Our proved reserves in this Form 10-K for the years ended December 31, 2008 and 2007 include only quantities that we expected to recover commercially using the then mandated year-end prices, costs, existing regulatory practices and technology. While we are reasonably certain that the proved reserves will be produced, the timing and ultimate recovery can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and changes in projections of long-term oil and gas prices. Revisions can include upward or downward changes in the previously estimated volumes of proved reserves for existing fields due to evaluation of (1) already available geologic, reservoir or production data or (2) new geologic or reservoir data obtained from wells. Revisions can also include changes associated with significant changes in development strategy, oil and gas prices, or the related production equipment/facility capacity. Huddleston also examined our estimates with respect to reserve categorization, using the definitions for proved reserves set forth in Regulation S-X Rule 4-10(a) and subsequent SEC staff interpretations and guidance.

In the conduct of the engineering audits in 2008 and 2007, Huddleston did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties or sales of production. However, if in the course of the examination something came to the attention of Huddleston which brought into question the validity or sufficiency of any such information or data, Huddleston did not rely on such information or data until it had satisfactorily resolved its questions relating thereto or had independently verified such information or data. Furthermore, in instances where decline curve analysis was not adequate in determining proved producing reserves, Huddleston evaluated our volumetric analysis, which included the analysis of production and pressure data. Each of the PUDs analyzed by Huddleston included volumetric analysis, which took into consideration recovery factors relative to the geology of the location and similar reservoirs. Where applicable, Huddleston examined data related to well spacing, including potential drainage from offsetting producing wells in evaluating proved reserves for un-drilled well locations.

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As previously mentioned, Huddleston prepared the proved reserve estimates for all of our U.S oil and gas properties at December 31, 2009. Huddleston's report on proved reserves is included herein as Exhibit 99.1 to this Form 10-K.

In 2008, the engineering audit by Huddleston included 100% of our producing properties together with essentially all of our non-producing and undeveloped properties in the U.S. Properties for analysis were selected by us and Huddleston based on discounted future net revenues. All of our significant properties were included in the engineering audit and such audited properties constituted approximately 97% of the total discounted future net revenues. Huddleston also analyzed the methods utilized by us in the preparation of all of the estimated reserves and revenues. Huddleston represented in its audit report that it believes our methodologies are consistent with the methodologies required by the SEC, Society of Petroleum Engineers ("SPE") and FASB. There were no limitations imposed, nor limitations encountered by us or Huddleston.

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

	United States	United(2) Kingdom	Total
Total proved reserves at December 31, 2006(1)	36,337	—	36,337
Revision of previous estimates	(473)	97	(376)
Production	(3,723)	—	(3,723)
Purchases of reserves in place	—	—	—
Sales of reserves in place	(1,858)	(49)	(1,907)
Extensions and discoveries	9,346	—	9,346
Total proved reserves at December 31, 2007	39,629	48	39,677
Revision of previous estimates	(250)	(47)	(297)
Production	(2,751)	(1)	(2,752)
Purchases of reserves in place	—	—	—
Sales of reserves in place	(5,277)	—	(5,277)
Extensions and discoveries	661	—	661
Total proved reserves at December 31, 2008	32,012	—	32,012
Revision of previous estimates	232	—	232
Production	(2,741)	—	(2,741)
Purchases of reserves in place	—	—	—
Sales of reserves in place	(1)	—	(1)
Extensions and discoveries	225	—	225
Total proved reserves at December 31, 2009	29,727	—	29,727

Total proved developed reserves as of :			
December 31, 2006	13,328	—	13,328
December 31, 2007	14,703	10	14,713
December 31, 2008	12,809	—	12,809
December 31, 2009	14,850	—	14,850

(1) Proved reserves at December 31, 2006 included approximately 17,573 MBbls acquired from the Remington acquisition.

(2) Reflects 50% ownership in the Camelot field's reserves in 2009, 2008 and 2007. In February 2010 we acquired the other 50% ownership interest in the Camelot field (Note 6).

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The following table presents our net ownership interest in proved gas reserves, including natural gas liquids (MMcf):

	United States	United(2) Kingdom	Total
Total proved reserves at December 31, 2006(1)	294,389	23,634	318,023
Revision of previous estimates	(12,209)	5,666	(6,543)
Production	(42,163)	(300)	(42,463)
Purchases of reserves in place	160	—	160
Sales of reserves in place	(2,932)	(14,700)	(17,632)
Extensions and discoveries	187,439	—	187,439
Total proved reserves at December 31, 2007	424,684	14,300	438,984
Revision of previous estimates	(32,098)	(1,017)	(33,115)
Production	(30,490)	(333)	(30,823)
Purchases of reserves in place	—	—	—
Sales of reserves in place (3)	(73,627)	—	(73,627)
Extensions and discoveries (4)	171,987	—	171,987
Total proved reserves at December 31, 2008	460,456	12,950	473,406
Revision of previous estimates (5)	(44,615)	(755)	(45,370)
Production	(27,139)	(195)	(27,334)
Purchases of reserves in place	—	—	—
Sales of reserves in place	(7,933)	—	(7,933)
Extensions and discoveries	6,546	—	6,546
Total proved reserves at December 31, 2009	387,315	12,000	399,315
Total proved developed reserves as of :			
December 31, 2006	156,251	—	156,251
December 31, 2007	134,047	1,500	135,547
December 31, 2008	256,794	950	257,744
December 31, 2009	124,763	—	124,763

(1)

Proved reserves at December 31, 2006 included approximately 159,338 MMcf acquired from the Remington acquisition.

(2) Reflects 50% ownership in the Camelot field's reserves in 2009, 2008 and 2007. In February 2010 we acquired the other 50% ownership interest in the Camelot field (Note 6).

(3) Amounts represent the sale of 30% of our working interest in Bushwood in March and April 2008, the sale of our entire portfolio of onshore properties in May 2008 and the sale of our Bass Lite field in December 2008 (Note 6).

(4) Includes additional discovery of proved reserves at the Bushwood field and formation of an area of mutual interest within the Bushwood field area.

(5) Includes a 38 Bcfe reduction of the proved reserves at Bushwood field reflecting certain reservoir issues for our Noonan Gas wells subsequent to their reestablishing sustained production in January 2009 and new geologic data collected throughout 2009.

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Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following table reflects the standardized measure of discounted future net cash flows relating to our interest in proved oil and gas reserves (in thousands):

	United States	United(1) Kingdom	Total
As of December 31, 2009—			
Future cash inflows	$3,166,306	$60,840	$3,227,146
Future costs:			
Production	(618,391)	(19,075)	(637,466)
Development and abandonment	(755,726)	(33,807)	(789,533)
Future net cash flows before income taxes	1,792,189	7,958	1,800,147
Future income tax expense	(417,042)	(1,560)	(418,602)
Future net cash flows	1,375,147	6,398	1,381,545
Discount at 10% annual rate	(387,036)	(3,449)	(390,485)
Standardized measure of discounted future net cash flows	$988,111	$2,949	$991,060
As of December 31, 2008—			
Future cash inflows	$4,011,788	$113,054	$4,124,842
Future costs:			
Production	(584,165)	(12,584)	(596,749)
Development and abandonment	(784,080)	(33,150)	(817,230)
Future net cash flows before income taxes	2,643,543	67,320	2,710,863
Future income tax expense	(777,736)	(53,626)	(831,362)
Future net cash flows	1,865,807	13,694	1,879,501
Discount at 10% annual rate	(562,354)	(4,992)	(567,346)
Standardized measure of discounted future net cash flows	$1,303,453	$8,702	$1,312,155
As of December 31, 2007—			
Future cash inflows	$6,769,106	$126,700	$6,895,806

Future costs:			
Production	(622,842)	(42,350)	(665,192)
Development and abandonment	(883,923)	(46,600)	(930,523)
Future net cash flows before income taxes	5,262,341	37,750	5,300,091
Future income tax expense	(1,617,709)	(18,850)	(1,636,559)
Future net cash flows	3,644,632	18,900	3,663,532
Discount at 10% annual rate	(831,705)	(4,313)	(836,018)
Standardized measure of discounted future net cash flows	$2,812,927	$14,587	$2,827,514

(1) Reflects 50% ownership in the Camelot field's reserves in 2009, 2008 and 2007. In February 2010 we acquired the other 50% ownership interest in the Camelot field (Note 6).

Future cash inflows are computed by applying the appropriate prices required by FASB at each year end, adjusted for location and quality differentials on a property-by-property basis, to year-end quantities of proved reserves, except in those instances where fixed and determinable price changes are provided by contractual arrangements at year-end. The discounted future cash flow estimates do not include the effects of our derivative instruments or forward sales agreements. See the following table for base prices used in determining the standardized measure:

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	United States	United Kingdom	Total
Year Ended December 31, 2009— (1)			
Oil price per Bbl	$58.05	$—	$58.05
Natural gas prices per Mcf	$3.72	$5.07	$3.76
Year Ended December 31, 2008—			
Oil price per Bbl	$42.76	$—	$42.76
Natural gas prices per Mcf	$5.74	$8.73	$5.83
Year Ended December 31, 2007—			
Oil price per Bbl	$93.98	$49.69	$93.92
Natural gas prices per Mcf	$7.17	$8.69	$7.22

(1) Year end price for December 31, 2009 represents the average trailing twelve month price for both oil and natural gas as now required under the new accounting standards. Previously proved reserve estimates were based on the price of oil and natural gas at December 31 of a given reporting period.

The future income tax expense was computed by applying the appropriate year-end statutory rates, with consideration of future tax rates already legislated, to the future pretax net cash flows less the tax basis of the associated properties. Future net cash flows are discounted at the prescribed rate of 10%. We caution that actual future net cash flows may vary considerably from these estimates. Although our estimates of total proved reserves, development costs and production rates were based on the best information available, the development and production of oil and gas reserves may not occur in the periods assumed. Actual prices realized, costs incurred and production quantities may vary significantly from those used. Therefore, such estimated future net cash flow computations should not be considered to represent our estimate of the expected revenues or the current value of existing proved reserves.

Changes in Standardized Measure of Discounted Future Net Cash Flows

Principal changes in the standardized measure of discounted future net cash flows attributable to our proved oil and gas reserves are as follows (in thousands):

	Year ended December 31,		
	2009	2008	2007
Standardized measure, beginning of year	$1,312,155	$ 2,827,514	$1,360,943
Changes during the year:			
Sales, net of production costs	(265,501)	(403,089)	(461,430)

Net change in prices and production costs	(245,883)	(1,713,458)	1,208,823
Changes in future development costs	(16,905)	(109,775)	(17,689)
Development costs incurred	74,133	403,653	351,964
Accretion of discount	161,254	338,582	261,931
Net change in income taxes	257,919	700,071	(665,750)
Purchases of reserves in place	—	—	(951)
Extensions and discoveries	10,457	335,643	1,285,499
Sales of reserves in place	(30,124)	(566,332)	(247,344)
Net change due to revision in quantity estimates	(85,450)	(96,096)	(80,865)
Changes in production rates (timing) and other	(180,995)	(404,558)	(167,617)
Total	(321,095)	(1,515,359)	1,466,571
Standardized measure, end of year	$ 991,060	$ 1,312,155	$2,827,514

Note 21 — Resignation of Executive Officers

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

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elected as President and Chief Executive Officer of Helix. In February 2008, we recognized approximately $5.4 million of compensation expense (inclusive of the expenses recorded for the acceleration of unvested stock options and restricted stock) related to the separation agreement between us and Mr. Ferron.

Wade Pursell resigned as our Chief Financial Officer effective June 25, 2008. Mr. Pursell remained employed by us through July 4, 2008, after which his employment terminated. Anthony Tripodo, who served as the chairman of our audit committee on our Board of Directors, was elected by our Board of Directors as the new Chief Financial Officer effective June 25, 2008, at which time he resigned from our Board of Directors. We recognized approximately $2.0 million of compensation expense (inclusive of the expenses recorded for the acceleration of unvested stock options and restricted stock) related to the separation agreement between us and Mr. Pursell.

Note 22 — Derivative Instruments and Hedging Activities

Derivatives designated as hedging instruments as defined in FASB Codification Topic No. 815 Derivatives and Hedging (in thousands):

	As of December 31, 2009		As of December 31, 2008	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Asset Derivatives:				
Oil contracts	Other current assets	$—	Other current assets	$7,468
Natural gas contracts	Other current assets	5,071	Other current assets	7,438
Foreign exchange forwards	Other current assets	—	Other current assets	506
		$5,071		$15,412

	As of December 31, 2009		As of December 31, 2008	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Liability Derivatives:				
Oil contracts	Accrued liabilities	$19,477	Accrued liabilities	$—
Natural gas contracts	Accrued liabilities	59	Accrued liabilities	—
Foreign exchange forwards	Accrued liabilities	—	Accrued liabilities	240
Interest rate swaps	Accrued liabilities	—	Accrued liabilities	1,378
Interest rate swaps	Other long-term liabilities	—	Other long-term liabilities	347
		$19,536		$1,965

Derivatives that were not designated as hedging instruments (in thousands):

As of December 31, 2009		As of December 31, 2008	
Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value

Asset Derivatives:				
Natural gas contracts	Other current assets	$—	Other current assets	$11,388
Foreign exchange forwards	Other current assets	1,143	Other current assets	—
Foreign exchange forwards	Other assets, net	931	Other assets, net	—
		$2,074		$11,388
Liability Derivatives:				
Foreign exchange forwards	Accrued liabilities	—	Accrued liabilities	1,205
Interest rate swaps	Accrued liabilities	—	Accrued liabilities	6,482
		$—		$7,687

The following tables present the impact that derivative instruments designated as cash flow hedges had on our consolidated statement of operations for the years ended December 31, 2009, 2008 and 2007 (in thousands):

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	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)		
	2009 (1)	2008	2007
Oil and natural gas commodity contracts	$ (19,092)	$ 14,977	$ (8,670)
Foreign exchange forwards	(538)	(72)	1,110
Interest rate swaps	712	1,911	(2,093)
	$ (18,918)	$ 16,816	$ (9,653)

(1) All unrealized gains (losses) related to our derivatives are expected to be reclassified into earnings by no later than December 31, 2010.

	Location of Gain (Loss) Reclassified from Accumulated OCI into Income	Gain (Loss) Reclassified from Accumulated OCI into Income Years Ended December 31, 2009	2008	2007
Oil and natural gas commodity contracts	Gain on oil and gas derivative contracts	$ 16,972	$ (23,423)	$ 462
Foreign exchange forwards	Net interest expense and other	—	—	—
Interest rate swaps	Net interest expense and other	(1,096)	(1,674)	—
		$ 15,876	$ (25,097)	$ 462

The following tables present the impact that derivative instruments not designated as hedges had on our consolidated statement of operations for the years ended December 31, 2009, 2008 and 2007 (in thousands):

	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives Years Ended December 31, 2009	2008	2007
Natural gas contracts	Gain on oil and gas derivative contracts	$ 89,485	$ 21,599	$ —
Foreign exchange forwards	Net interest expense and other	3,279	(1,115)	—
Interest rate swaps	Net interest expense and other	(468)	(5,285)	(618)
		$ 92,296	$ 15,199	$ (618)

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Note 23 — Quarterly Financial Information (Unaudited)

The offshore marine construction industry in the Gulf of Mexico is highly seasonal as a result of weather conditions and the timing of capital expenditures by oil and gas companies. Historically, a substantial portion of our services has been performed during the summer and fall months. As a result, historically a disproportionate portion of our revenues and net income is earned during such period. The following is a summary of consolidated quarterly financial information for 2009 and 2008 (in thousands, except per share data):

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31, (1)
2009				
Net revenues	$ 570,975	$ 494,639	$ 216,025	$ 180,048
Gross profit (loss)	161,210	135,756	2,617	(56,421)
Net income (loss)	107,202	100,469	4,020	(55,637)
Net income (loss) applicable to common shareholders	53,450	100,219	3,895	(55,697)
Basic earnings (loss) per common share	0.55	1.02	0.04	(0.53)
Diluted earnings (loss) per common share	0.50	0.94	0.04	(0.53)

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31 ,(2)
2008				
Net revenues	$ 441,769	$ 530,130	$ 607,736	$ 534,439
Gross profit (loss)	118,583	189,078	199,080	(134,550)
Net income (loss)	73,965	90,531	60,178	(860,604)
Net income (loss) applicable to common shareholders	73,084	89,651	59,297	(861,154)
Basic earnings (loss) per common share	0.80	0.98	0.65	(9.48)
Diluted earnings (loss) per common share	0.77	0.93	0.63	(9.48)

(1) Includes $55.9 million of impairment charges to reduce certain oil and gas properties to their estimated fair value at December 31, 2009 and an additional $20.1 million of impairment charges recorded to exploration expense related to offshore leases that will expire in 2010 without exploration capital being deployed, which is was not anticipated for these affected leases.

(2) Includes $907.6 million of impairment charges to reduce goodwill and other indefinite-lived intangible assets ($715 million) and certain oil and gas properties ($192.6 million) to their estimated fair value in fourth quarter of 2008.

Note 24 — Condensed Consolidated Guarantor and Non-Guarantor Financial Information

The payment of obligations under the Senior Unsecured Notes is guaranteed by all of our restricted domestic subsidiaries ("Subsidiary Guarantors") except for Cal Dive I-Title XI, Inc. Cal Dive and its subsidiaries were never guarantors of our Senior Unsecured Notes. Each of these Subsidiary Guarantors is included in our consolidated financial statements and has fully and unconditionally guaranteed the Senior Unsecured Notes on a joint and several basis. As a result of these guarantee arrangements, we are required to present the following condensed consolidating financial information. The accompanying guarantor financial information is presented on the equity method of accounting for all periods presented. Under this method, investments in subsidiaries are recorded at cost and adjusted for our share in the subsidiaries' cumulative results of operations, capital contributions and distributions and other changes in equity. Elimination entries relate primarily to the elimination of investments in subsidiaries and associated intercompany balances and transactions.

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HELIX ENERGY SOLUTIONS GROUP, INC.
CONDENSED CONSOLIDATING BALANCE SHEETS
(in thousands)

	As of December 31, 2009				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 258,742	$ 2,522	$ 9,409	$ —	$ 270,673
Accounts receivable, net	49,813	77,399	18,307	—	145,519
Unbilled revenue	9,425	480	17,254	—	27,159
Income taxes receivable	38,333	—	13,795	(43,636)	8,492
Other current assets	54,144	68,910	15,453	(25,668)	112,839
Current assets of discontinued operations	—	—	878	—	878
Total current assets	410,457	149,311	75,096	(69,304)	565,560
Intercompany	106,408	149,796	(190,729)	(65,475)	—
Property and equipment, net	220,408	1,919,412	729,131	(5,245)	2,863,706
Other assets:					
Equity investments in unconsolidated affiliates	—	—	189,411	—	189,411
Equity investments in affiliates	2,123,169	29,649	—	(2,152,818)	—
Goodwill, net	—	45,107	33,536	—	78,643
Other assets, net	48,822	41,669	22,919	(31,197)	82,213
Due from subsidiaries/parent	73,867	64,775	—	(138,642)	—
	$ 2,983,131	$ 2,399,719	$ 859,364	$ (2,462,681)	$ 3,779,533
LIABILITIES AND SHAREHOLDERS’ EQUITY					
Current liabilities:					
Accounts payable	$ 58,451	$ 79,128	$ 17,878	$ —	$ 155,457
Accrued liabilities	81,021	104,450	14,685	—	200,156
Income taxes payable	—	54,955	—	(54,955)	—
Current maturities of long-term debt	4,326	—	33,837	(25,739)	12,424
Current liabilities of discontinued operations	—	—	451	—	451
Total current liabilities	143,798	238,533	66,851	(80,694)	368,488

Long-term debt	1,233,504	—	114,811	—	1,348,315
Deferred income taxes	137,662	222,528	90,676	(8,259)	442,607
Decommissioning liabilities	—	176,657	5,742	—	182,399
Other long-term liabilities	924	2,495	766	77	4,262
Due to parent	—	—	99,352	(99,352)	—
Total liabilities	1,515,888	640,213	378,198	(188,228)	2,346,071
Convertible preferred stock	6,000	—	—	—	6,000
Total equity	1,461,243	1,759,506	481,166	(2,274,453)	1,427,462
	$ 2,983,131	$ 2,399,719	$ 859,364	$ (2,462,681)	$ 3,779,533

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HELIX ENERGY SOLUTIONS GROUP, INC.
CONDENSED CONSOLIDATING BALANCE SHEETS
(in thousands)

	As of December 31, 2008				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 148,704	$ 4,983	$ 69,926	$ —	$ 223,613
Accounts receivable, net	125,882	97,300	204,674	—	427,856
Unbilled revenue	43,888	1,080	72,282	—	117,250
Other current assets	120,320	79,202	41,031	(68,464)	172,089
Current assets of discontinued operations	—	—	19,215	—	19,215
Total current assets	438,794	182,565	407,128	(68,464)	960,023
Intercompany	78,395	100,662	(101,813)	(77,244)	—
Property and equipment, net	168,054	2,007,807	1,247,060	(4,478)	3,418,443
Other assets:					
Equity investments in unconsolidated affiliates	—	—	196,660	—	196,660
Equity investments in affiliates	2,331,924	31,374	—	(2,363,298)	—
Goodwill, net	—	45,107	321,111	—	366,218
Other assets, net	48,734	37,967	68,035	(29,014)	125,722
	$ 3,065,901	$ 2,405,482	$ 2,138,181	$ (2,542,498)	$ 5,067,066
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 99,197	$ 139,074	$ 107,856	$ (1,320)	$ 344,807
Accrued liabilities	87,712	65,090	83,233	(4,356)	231,679
Income taxes payable	(104,487)	82,859	9,149	12,479	—
Current maturities of long-term debt	4,326	—	173,947	(84,733)	93,540
Current liabilities of discontinued operations	—	—	2,772	—	2,772
Total current liabilities	86,748	287,023	376,957	(77,930)	672,798
Long-term debt	1,579,451	—	354,235	—	1,933,686
Deferred income taxes	184,543	242,967	191,773	(3,779)	615,504
Decommissioning liabilities	—	191,260	3,405	—	194,665

Other long-term liabilities	—	73,549	10,706	(2,618)	81,637
Due to parent	(100,528)	(3,741)	126,013	(21,744)	—
Total liabilities	1,750,214	791,058	1,063,089	(106,071)	3,498,290
Convertible preferred stock	55,000	—	—	—	55,000
Total equity	1,260,687	1,614,424	1,075,092	(2,436,427)	1,513,776
	$ 3,065,901	$ 2,405,482	$ 2,138,181	$ (2,542,498)	$ 5,067,066

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HELIX ENERGY SOLUTIONS GROUP, INC.
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(in thousands)

	Year Ended December 31, 2009				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$211,222	$ 701,706	$ 648,705	$ (99,946)	$ 1,461,687
Cost of sales	162,225	484,802	521,689	(95,124)	1,073,592
Oil and gas impairments	—	120,550	—	—	120,550
Exploration expense	—	24,383	—	—	24,383
Gross profit	48,997	71,971	127,016	(4,822)	243,162
Gain on oil and gas derivative commodity contracts	—	89,485	—	—	89,485
Gain on sale of assets, net	—	2,019	—	—	2,019
Selling and administrative expenses	(52,101)	(28,520)	(53,919)	3,689	(130,851)
Income (loss) from operations	(3,104)	134,955	73,097	(1,133)	203,815
Equity in earnings of unconsolidated affiliates	—	—	33,229	(900)	32,329
Equity in earnings (losses) of affiliates	145,340	(1,725)	—	(143,615)	—
Gain on sale of Cal Dive common stock	77,343	—	—	—	77,343
Net interest expense and other	(18,188)	(16,978)	(15,341)	988	(51,495)
Income before income taxes	201,391	116,252	90,985	(146,636)	261,992
Provision for income taxes	(43,417)	(39,855)	(13,571)	1,021	(95,822)
Income from continuing operations	157,974	76,397	77,414	(145,615)	166,170
Discontinued operations, net of tax	99	—	9,482	—	9,581
Net income, including noncontrolling interests	158,073	76,397	86,896	(145,615)	175,751
Net income applicable to noncontrolling interests	—	—	—	(19,697)	(19,697)
Net income applicable to Helix	158,073	76,397	86,896	(165,312)	156,054
Preferred stock dividends	(54,187)	—	—	—	(54,187)
Net income applicable to Helix common shareholders	$103,886	$ 76,397	$ 86,896	$ (165,312)	$ 101,867

	Year Ended December 31, 2008				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$ 404,591	$ 813,240	$ 1,170,707	$ (274,464)	$ 2,114,074
Cost of sales	347,433	554,628	837,685	(246,464)	1,493,282
Oil and gas impairments	—	215,675	—	—	215,675
Exploration expense	—	32,926	—	—	32,926
Gross profit	57,158	10,011	333,022	(28,000)	372,191
Goodwill and other intangible impairments	—	(704,311)	—	—	(704,311)
Gain on oil and gas derivative commodity contracts	—	21,599	—	—	21,599
Gain on sale of assets, net	—	73,136	335	—	73,471
Selling and administrative expenses	(42,194)	(47,372)	(91,974)	4,368	(177,172)
Income (loss) from operations	14,964	(646,937)	241,383	(23,632)	(414,222)
Equity in earnings of unconsolidated affiliates	—	—	31,854	—	31,854
Equity in earnings (losses) of affiliates	(584,299)	1,328	—	582,971	—
Net interest expense and other	(21,939)	(46,966)	(42,285)	92	(111,098)
Income (loss) before income taxes	(591,274)	(692,575)	230,952	559,431	(493,466)
(Provision) benefit for income taxes	(30,412)	(2,909)	(62,754)	9,296	(86,779)
Income (loss)from continuing operations	(621,686)	(695,484)	168,198	568,727	(580,245)
Discontinued operations, net of tax	—	—	(9,812)	—	(9,812)
Net income (loss), including noncontrolling interests	(621,686)	(695,484)	158,386	568,727	(590,057)
Net income (loss) applicable to noncontrolling interests	—	—	—	(45,873)	(45,873)
Net income (loss) applicable to Helix	(621,686)	(695,484)	158,386	522,854	(635,930)
Preferred stock dividends	(3,192)	—	—	—	(3,192)
Net income (loss) applicable to Helix common shareholders	$(624,878)	$ (695,484)	$ 158,386	$ 522,854	$ (639,122)

HELIX ENERGY SOLUTIONS GROUP, INC.
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(in thousands)

	Year Ended December 31, 2007				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$262,007	$ 769,648,	$ 874,324	$ (173,559)	$ 1,732,420
Cost of sales	201,001	514,653	568,480	(148,418)	1,135,716
Oil and gas impairments	—	64,072	—	—	64,072
Exploration expense	—	26,725	—	—	26,725
Gross profit	61,006	164,198	305,844	(25,141)	505,907
Gain on sale of assets, net	1,960	42,566	5,842	—	50,368
Selling and administrative expenses	(38,063)	(44,940)	(65,126)	3,133	(144,996)
Income from operations	24,903	161,824	246,560	(22,008)	411,279
Equity in earnings of unconsolidated affiliates	—	—	19,573	—	19,573
Equity in earnings (losses) of affiliates	219,280	15,140	—	(234,420)	—
Gain on sale of Cal Dive common stock	151,696	—	—	—	151,696
Net interest expense and other	7,539	(49,064)	(21,178)	(4,344)	(67,047)
Income before income taxes	403,418	127,900	244,955	(260,772)	515,501
Provision for income taxes	(70,592)	(39,871)	(70,623)	9,224	(171,862)
Income from continuing operations	332,826	88,029	174,332	(251,548)	343,639
Discontinued operations, net of tax	—	—	1,347	—	1,347
Net income, including noncontrolling interests	332,826	88,029	175,679	(251,548)	344,986
Net income applicable to noncontrolling interests	—	—	(113)	(29,175)	(29,288)
Net income applicable to Helix	332,826	88,029	175,566	(280,723)	315,698
Preferred stock dividends	(3,716)	—	—	—	(3,716)
Net income applicable to Helix common shareholders	$329,110	$ 88,029	$ 175,566	$ (280,723)	$ 311,982

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HELIX ENERGY SOLUTIONS GROUP, INC.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

	For the Year Ended December 31, 2009				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
			(in thousands)		
Cash flow from operating activities:					
Net income (loss), including noncontrolling interests	$ 158,073	$ 76,397	$ 86,896	$ (145,615)	$ 175,751
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:					
Equity in earnings of unconsolidated affiliates	—	—	(7,220)	899	(6,321)
Equity in earnings of affiliates	(145,340)	1,725	—	143,615	—
Other adjustments	26,633	163,451	80,281	(17,987)	252,378
Net cash provided by (used in) operating activities	39,366	241,573	159,957	(19,088)	421,808
Net cash provided by discontinued operations	—	—	(6,261)	—	(6,261)
Net cash provided by (used in) operating activities	39,366	241,573	153,696	(19,088)	415,547
Cash flows from investing activities:					
Capital expenditures	(35,657)	(245,354)	(142,362)	—	(423,373)
Acquisition of businesses, net of cash acquired	—	—	—	—	—
Investments in equity investments	—	—	(1,657)	—	(1,657)
Distributions from equity investments, net	—	—	6,742	—	6,742
Increases in restricted cash	—	(6)	—	—	(6)
Proceeds from sale of Cal Dive common stock	504,168	—	(112,995)	(86,000)	305,173
Proceeds from sales of property	—	23,717	—	—	23,717

Net cash provided by (used in) investing activities	468,511	(221,643)	(250,272)	(86,000)	(89,404)
Net cash provided by discontinued operations	—	—	20,872	—	20,872
Net cash provided by (used in) investing activities	468,511	(221,643)	(229,400)	(86,000)	(68,532)
Cash flows from financing activities:					
Borrowings on revolvers	—	—	100,000	—	100,000
Repayments on revolvers	(349,500)	—	—	—	(349,500)
Repayments of debt	(4,326)	—	(24,214)	—	(28,540)
Deferred financing costs	(6,970)	—	—	—	(6,970)
Preferred stock dividends paid	(645)	—	—	—	(645)
Repurchase of common stock	(13,995)	—	(86,000)	86,000	(13,995)
Excess tax benefit from stock-based compensation	895	—	—	—	895
Exercise of stock options, net	176	—	—	—	176
Intercompany financing	(23,474)	(22,391)	26,777	19,088	—
Net cash provided by (used in) financing activities	(397,839)	(22,391)	16,563	105,088	(298,579)
Effect of exchange rate changes on cash and cash equivalents	—	—	(1,376)	—	(1,376)
Net increase (decrease) in cash and cash equivalents	110,038	(2,461)	(60,517)	—	47,060
Cash and cash equivalents:					
Balance, beginning of year	148,704	4,983	69,926	—	223,613
Balance, end of year	$ 258,742	$ 2,522	$ 9,409	$ —	$ 270,673

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HELIX ENERGY SOLUTIONS GROUP, INC.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

	For the Year Ended December 31, 2008				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
	(in thousands)				
Cash flow from operating activities:					
Net income (loss), including noncontrolling interests	$ (621,686)	$ (695,484)	$ 158,386	$ 568,727	$ (590,057)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:					
Equity in earnings of unconsolidated affiliates	—	—	2,846	—	2,846
Equity in earnings of affiliates	584,299	(1,328)	—	(582,971)	—
Other adjustments	(48,995)	967,933	107,708	(5,021)	1,021,625
Net cash provided by (used in) operating activities	(86,382)	271,121	268,940	(19,265)	434,414
Net cash provided by discontinued operations	—	—	3,305	—	3,305
Net cash provided by (used in) operating activities	(86,382)	271,121	272,245	(19,265)	437,719
Cash flows from investing activities:					
Capital expenditures	(75,003)	(513,024)	(267,027)	—	(855,054)
Acquisition of businesses, net of cash acquired	—	—	—	—	—
Investments in equity investments	—	—	(846)	—	(846)
Distributions from equity investments, net	—	—	11,586	—	11,586
Increases in restricted cash	—	(614)	—	—	(614)
Proceeds from insurance	—	13,200	—	—	13,200
Proceeds from sales of property	—	271,758	2,472	—	274,230
Net cash used in investing activities	(75,003)	(228,680)	(253,815)	—	(557,498)

Net cash used in discontinued operations	—	—	(476)	—	(476)
Net cash used in investing activities	(75,003)	(228,680)	(254,291)	—	(557,974)
Cash flows from financing activities:					
Borrowings on revolvers	1,021,500	—	61,100	—	1,082,600
Repayments on revolvers	(690,000)	—	(61,100)	—	(751,100)
Repayments of debt	(4,326)	—	(64,014)	—	(68,340)
Deferred financing costs	(1,796)	—	—	—	(1,796)
Capital lease payments	—	—	(1,505)	—	(1,505)
Preferred stock dividends paid	(3,192)	—	—	—	(3,192)
Repurchase of common stock	(3,925)	—	—	—	(3,925)
Excess tax benefit from stock-based compensation	1,335	—	—	—	1,335
Exercise of stock options, net	2,139	—	—	—	2,139
Intercompany financing	(15,153)	(40,067)	35,955	19,265	—
Net cash provided by (used in) financing activities	306,582	(40,067)	(29,564)	19,265	256,216
Effect of exchange rate changes on cash and cash equivalents	—	—	(1,903)	—	(1,903)
Net increase (decrease) in cash and cash equivalents	145,197	2,374	(13,513)	—	134,058
Cash and cash equivalents:					
Balance, beginning of year	3,507	2,609	83,439	—	89,555
Balance, end of year	$ 148,704	$ 4,983	$ 69,926	$ —	$ 223,613

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HELIX ENERGY SOLUTIONS GROUP, INC.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

	For the Year Ended December 31, 2007				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
	(in thousands)				
Cash flow from operating activities:					
Net income (loss), including noncontrolling interests	$ 332,826	$ 88,029	$ 175,679	$ (251,548)	$ 344,986
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:					
Equity in earnings of unconsolidated affiliates	—	—	11,538	—	11,538
Equity in earnings of affiliates	(219,280)	(15,139)	—	234,419	—
Other adjustments	(268,156)	297,948	(135,511)	169,970	64,251
Net cash provided by (used in) operating activities	(154,610)	370,838	51,706	152,841	420,775
Net cash provided by discontinued operations	—	—	(4,449)	—	(4,449)
Net cash provided by (used in) operating activities	(154,610)	370,838	47,257	152,841	416,326
Cash flows from investing activities:					
Capital expenditures	(81,577)	(642,364)	(218,440)	—	(942,381)
Acquisition of businesses, net of cash acquired	—	—	(147,498)	—	(147,498)
Sale of short-term investments	285,395	—	—	—	285,395
Investments in equity investments	—	—	(17,459)	—	(17,459)
Distributions from equity investments, net	—	—	6,679	—	6,679
Increases in restricted cash	—	(1,112)	—	—	(1,112)
Proceeds from sales of property	—	53,547	24,526	—	78,073
Other, net	—	(136)	—	—	(136)
	203,818	(590,065)	(352,192)	—	(738,439)

Net cash used in investing activities					
Net cash used in discontinued operations	—	—	(1,215)	—	(1,215)
Net cash provided by (used in) investing activities	203,818	(590,065)	(353,407)	—	(739,654)
Cash flows from financing activities:					
Borrowings on revolvers	472,800	—	31,500	—	504,300
Repayments on revolvers	(454,800)	—	(332,668)	—	(787,468)
Borrowings under debt	550,000	—	380,000	—	930,000
Repayments of debt	(405,408)	—	(3,823)	—	(409,231)
Deferred financing costs	(11,377)	—	(5,788)	—	(17,165)
Capital lease payments	—	—	(2,519)	—	(2,519)
Preferred stock dividends paid	(3,716)	—	—	—	(3,716)
Repurchase of common stock	(9,904)	—	—	—	(9,904)
Excess tax benefit from stock-based compensation	580	—	—	—	580
Exercise of stock options, net	1,568	—	—	—	1,568
Intercompany financing	(327,933)	214,146	266,628	(152,841)	—
Net cash provided by (used in) financing activities	(188,190)	214,146	333,330	(152,841)	206,445
Effect of exchange rate changes on cash and cash equivalents	—	—	174	—	174
Net increase (decrease) in cash and cash equivalents	(138,982)	(5,081)	27,354	—	(116,709)
Cash and cash equivalents:					
Balance, beginning of year	142,489	7,690	56,085	—	206,264
Balance, end of year	$ 3,507	$ 2,609	$ 83,439	$ —	$ 89,555

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

None.

Item 9A. Controls and Procedures.

(a) Evaluation of disclosure controls and procedures. Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") as of the end of the fiscal year ended December 31, 2009. Based on this evaluation, the principal executive officer and the principal financial officer conclude that our disclosure controls and procedures were effective as of the end of the fiscal year ended December 31, 2009 to ensure that information that is required to be disclosed by us in the reports we file or submit under the Exchange Act is (i) identified, recorded, processed, summarized and reported, on a timely basis and (ii) accumulated and communicated to our management, as appropriate, to allow timely decisions regarding required disclosure.

(b) Changes in internal control over financial reporting. There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Securities Exchange Act, in the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

(c) Changes in Internal Control. There was not any change in our internal control over financial reporting that occurred during the fourth quarter of fiscal 2009 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting and the Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting thereon are set forth in Part II, Item 8 of this report on Form 10-K on page 74 and page 76, respectively.

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Except as set forth below, the information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with our 2010 Annual Meeting of Shareholders to be held on May 12, 2010. See also "Executive Officers of the Registrant" appearing in Part I of this Report.

Code of Ethics

We have adopted a Code of Business Conduct and Ethics for all directors, officers and employees as well as a Code of Ethics for Chief Executive Officer and Senior Financial Officers specific to those officers. Copies of these documents are available at our Website www.helixesg.com under Corporate Governance. Interested parties may also request a free copy of these documents from:

Helix Energy Solutions Group, Inc.

ATTN: Corporate Secretary
400 N. Sam Houston Parkway E., Suite 400
Houston, Texas 77060

Item 11. Executive Compensation.

The information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with our 2010 Annual Meeting of Shareholders to be held on May 12, 2010.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

The information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with our 2010 Annual Meeting of Shareholders to be held on May 12, 2010.

Item 13. Certain Relationships and Related Transactions.

The information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with our 2010 Annual Meeting of Shareholders to be held on May 12, 2010.

Item 14. Principal Accounting Fees and Services.

The information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection our 2010 Annual Meeting of Shareholders to be held on May 12, 2010.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

(1) Financial Statements.

The following financial statements included on pages 74 through 143 in this Annual Report are for the fiscal year ended December 31, 2009.

- 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, 2009 and 2008
- Consolidated Statements of Operations for the Years Ended December 31, 2009, 2008 and 2007
- Consolidated Statements of Shareholders’ Equity for the Years Ended December 31, 2009, 2008 and 2007
- Consolidated Statements of Cash Flows for the Years Ended December 31, 2009, 2008 and 2007
- 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. Reference is made to Exhibit listing beginning on page 147 hereof.

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SIGNATURES

Pursuant to the requirements of section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

HELIX ENERGY SOLUTIONS GROUP, INC.

By: /s/ ANTHONY TRIPODO
Anthony Tripodo
Executive Vice President and
Chief Financial Officer

February 26, 2010

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ OWEN KRATZ Owen Kratz	President, Chief Executive Officer and Director (principal executive officer)	February 26, 2010
/s/ ANTHONY TRIPODO Anthony Tripodo	Executive Vice President and Chief Financial Officer (principal financial officer)	February 26, 2010
/s/ LLOYD A. HAJDIK Lloyd A. Hajdik	Senior Vice President — Finance and Chief Accounting Officer (principal accounting officer)	February 26, 2010
/s/ GORDON F. AHALT Gordon F. Ahalt	Director	February 26, 2010
/s/ BERNARD J. DUROC-DANNER Bernard J. Duroc-Danner	Director	February 26, 2010
/s/ JOHN V. LOVOI John V. Lovoi	Director	February 26, 2010
/s/ T. WILLIAM PORTER T. William Porter	Director	February 26, 2010
/s/ NANCY K. QUINN Nancy K. Quinn	Director	February 26, 2010

/s/ WILLIAM L. TRANSIER William L. Transier	Director	February 26, 2010
/s/ JAMES A. WATT James A. Watt	Director	February 26, 2010

INDEX TO EXHIBITS

Exhibits	
2.1	Agreement and Plan of Merger dated January 22, 2006, among Cal Dive International, Inc. and Remington Oil and Gas Corporation, incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K/A, filed by the registrant with the Securities and Exchange Commission on January 25, 2006 (the "Form 8-K/A").
2.2	Amendment No. 1 to Agreement and Plan of Merger dated January 24, 2006, by and among, Cal Dive International, Inc., Cal Dive Merger — Delaware, Inc. and Remington Oil and Gas Corporation, incorporated by reference to Exhibit 2.2 to the Form 8-K/A.
3.1	2005 Amended and Restated Articles of Incorporation, as amended, of registrant, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by registrant with the Securities and Exchange Commission on March 1, 2006.
3.2	Second Amended and Restated By-Laws of Helix, as amended, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on September 28, 2006.
3.3	Certificate of Rights and Preferences for Series A-1 Cumulative Convertible Preferred Stock, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by registrant with the Securities and Exchange Commission on January 22, 2003 (the "2003 Form 8-K").
3.4	Certificate of Rights and Preferences for Series A-2 Cumulative Convertible Preferred Stock, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by registrant with the Securities and Exchange Commission on June 28, 2004 (the "2004 Form 8-K").
4.1	Credit Agreement dated July 3, 2006 by and among Helix Energy Solutions Group, Inc., and Bank of America, N.A., as administrative agent and as lender, together with the other lender parties thereto, incorporated by reference to Exhibit 4.1 to the registrant's Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on July 5, 2006.
4.2	Amendment No. 1 to Credit Agreement, dated as of November 29, 2007, by and among Helix, as borrower, Bank of America, N.A., as administrative agent, and the lenders named thereto incorporated by reference to Exhibit 10.3 to the December 2007 8-K.
4.3	Amendment No. 2 to Credit Agreement, dated as of October 9, 2009, by and among Helix, as borrower, Bank of America, N.A., as administrative agent, and the lenders named thereto, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on October 13, 2009.
4.4	Amendment No. 3 to Credit Agreement, dated as of February 19, 2010, by and among Helix, as borrower, Bank of America, N.A., as administrative agent, and the lenders named thereto. Incorporated by reference to Exhibit 10.1 to the registrant's Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on February 24, 2010.
4.5	Form of Common Stock certificate, incorporated by reference to Exhibit 4.7 to the Form 8-A filed by the Registrant with the Securities and Exchange Commission on June 30, 2006.
4.6	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.
4.7	Amendment No. 1 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of January 25, 2002, incorporated by reference to Exhibit 4.9 to the Form 10-K/A filed with the Securities and Exchange Commission on April 8, 2003.
4.8	

	Amendment No. 2 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of November 15, 2002, incorporated by reference to Exhibit 4.4 to the Form S-3 filed with the Securities and Exchange Commission on February 26, 2003.
4.9	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.
4.10	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 for the year ended December 31, 2004, filed by the registrant with the Securities Exchange Commission on March 16, 2005 (the “2004 10-K”).

4.11	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.
4.12	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”).
4.13	Form of 3.25% Convertible Senior Note due 2025 (filed as Exhibit A to Exhibit 4.15).
4.14	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.
4.15	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”).
4.16	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.
4.17	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.
4.18	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.
4.19	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.
4.20	Form of United States Government Guaranteed Ship Financing Bonds, Q4000 Series 4.93% Sinking Fund Bonds Due February 1, 2027 (filed as Exhibit A to Exhibit 4.21).
4.21	Form of Third Amended and Restated Promissory Note to United States of America, incorporated by reference to Exhibit 4.6 to the October 2005 8-K.
4.22	Term Loan Agreement by and among Kommandor LLC, Nordea Bank Norge ASA, as arranger and agent, Nordea Bank Finland Plc, as swap bank, together with the other lender parties thereto, effective as of June 13, 2007 incorporated by reference to Exhibit 4.7 to the registrants Quarterly Report on Form 10-Q for the fiscal quarter ended June 30, 2007, file by the registrant with the Securities and Exchange Commission on August 3, 2007.
4.23	Indenture, dated as of December 21, 2007, by and among Helix Energy Solutions Group, Inc., the Guarantors and Wells Fargo Bank, N.A. incorporated by reference to Exhibit 4.1 to the registrants Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on December 21, 2007 (the “December 2007 8-K”).
10.1	1995 Long Term Incentive Plan, as amended, incorporated by reference to Exhibit 10.3 to the Form S-1.
10.2	Amendment to 1995 Long Term Incentive Plan of Helix Energy Solutions Group, Inc.
10.3	2009 Long-Term Incentive Cash Plan of Helix Energy Solutions Group, Inc., 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 January 6, 2009 (the “January 2009 8-K”).
10.4	Form of Award Letter related to the 2009 Long-Term Incentive Cash Plan, incorporated by reference to Exhibit 10.2 to the January 2009 8-K.
10.5	Employment Agreement between Owen Kratz and Company dated February 28, 1999, incorporated by reference to Exhibit 10.5 to the Annual Report 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”).
10.6	Employment Agreement between Owen Kratz and Company dated November 17, 2008, 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 19, 2008 (the “November 2008 8-K”).
10.7	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.

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10.8	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.
10.9	Helix 2005 Long Term Incentive Plan, including the Form of Restricted Stock Award Agreement, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on May 12, 2005.
10.10	Amendment to 2005 Long Term Incentive Plan of Helix Energy Solutions Group, Inc.
10.11	Employment Agreement by and between Helix and Bart H. Heijermans, effective as of September 1, 2005, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on September 1, 2005.
10.12	Employment Agreement between Bart H. Heijermans and Company dated November 17, 2008, incorporated by reference to Exhibit 10.2 to the November 2008 8-K.
10.13	Employment Agreement between Alisa B. Johnson and Company dated September 18, 2006, incorporated by reference to Exhibit 10.2 to the 2006 Form 10-Q.
10.14	Employment Agreement between Alisa B. Johnson and Company dated November 17, 2008, incorporated by reference to Exhibit 10.3 to the November 2008 8-K.
10.15	Employment Letter from the Company to Robert P. Murphy dated December 21, 2006, incorporated by reference to Exhibit 10.9 to the 2006 Annual Report ("2006 Form 10-K").
10.16	Amendment to Employment Agreement between Robert P. Murphy and Company effective January 1, 2009, 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 December 12, 2008.
10.17	Master Agreement between the Company and Cal Dive International, Inc. dated December 8, 2006, incorporated by reference to Exhibit 10.10 to the 2006 Form 10-K.
10.18	Tax Agreement between the Company and Cal Dive International, Inc. dated December 14, 2006, incorporated by reference to Exhibit 10.11 to the 2006 Form 10-K.
10.19	Registration Rights Agreement dated as of December 21, 2007 by and among Helix Energy Solutions Group, Inc., the Guarantors named therein and Banc of America Securities LLC, as representative of the Initial Purchasers, incorporated by reference to Exhibit 10.1 to December 2007 8-K.
10.20	Purchase Agreement dated as of December 18, 2007 by and among Helix Energy Solutions Group, Inc., the Guarantors named therein and Banc of America Securities LLC, and the other Initial Purchasers named therein incorporated by reference to Exhibit 10.2 to the December 2007 8-K.
10.21	Letter Agreement by and between Helix Energy Solutions Group, Inc. and Martin R. Ferron dated February 8, 2008 incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on February 8, 2008 (the "February 2008 8-K").
10.22	Letter Agreement by and between Helix Energy Solutions Group, Inc. and Alan Wade Pursell dated June 25, 2008 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 June 30, 2008 (the "June 2008 8-K").
10.23	Employment Agreement between Anthony Tripodo and the Company dated June 25, 2008, incorporated by reference to Exhibit 10.2 to the June 2008 8-K.
10.24	First Amendment to Employment Agreement between Anthony Tripodo and the Company dated November 17, 2008, incorporated by reference to Exhibit 10.5 to the November 2008 8-K.
10.25	Consulting Agreement by and between A. Wade Pursell and the Company dated July 4, 2008, incorporated by reference to Exhibit 10.1 to the registrants Quarterly Report on Form 10-Q, filed by the registrant with the Securities and Exchange Commission on August 1, 2008.
10.26	Employment Agreement between Lloyd A. Hajdik and Company dated November 17, 2008, incorporated by reference to Exhibit 10.4 to the November 2008 8-K.
10.27	Stock Repurchase Agreement between Company and Cal Dive International, Inc. dated January 23, 2009, 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 January 28, 2009.
10.28	Stock Repurchase Agreement between Company and Cal Dive International, Inc., dated May 29, 2009 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 June 1, 2009.

14.1	Code of Ethics for Chief Executive Officer and Senior Financial Officers, incorporated by reference to Exhibit 14.1 to the Registrant's Current Report on Form 8-K, filed by Registrant with the Securities and Exchange Commission on December 7, 2009.
21.1*	List of Subsidiaries of the Company.
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of Huddleston & Co., Inc.
31.1*	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Owen Kratz, Chief Executive Officer.
31.2*	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Anthony Tripodo, Chief Financial Officer
32.1**	Certification of Helix's Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes — Oxley Act of 2002
99.1 *	Report of Huddleston & Co., Inc.

* Filed herewith.

** Furnished herewith.