HELIX ENERGY SOLUTIONS GROUP INC
Form 10-K
February 18, 2015

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

Form 10-K

R	ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
	For the fiscal year ended December 31, 2014
	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.)
3505 West Sam Houston Parkway North Suite 400 Houston, Texas (Address of principal executive offices)	77043 (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). R 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 £ (Do not check if a smaller reporting company)	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, 2014 was approximately $2.6 billion.

The number of shares of the registrant's Common Stock outstanding as of February 13, 2015 was 105,906,969.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement for the Annual Meeting of Shareholders to be held on May 7, 2015 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. 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,” “continue,” “may,” “potent and similar terms and phrases are forward-looking statements. Included in forward-looking statements are, among other things:

- statements regarding our business strategy or any other business plans, forecasts or objectives, any or all of which is subject to change;
- statements relating to the construction, upgrades or acquisition of vessels or equipment and any anticipated costs related thereto, including the construction of our Q5000 and Q7000 vessels and the construction of two chartered vessels to be used in connection with our contracts to provide well intervention services offshore Brazil (Note 11). For more information regarding our vessel construction activity, see Item 1. Business “— Our Operations”;
- 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 anticipated legislative, governmental, regulatory, administrative or other public body actions, requirements, permits or decisions;
- statements regarding the collectability of our trade receivables;
- 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.

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 domestic and global economic conditions and the future impact of such conditions on the oil and gas industry and the demand for our services;
- unexpected delays in the delivery or chartering of new vessels for our well intervention and robotics fleet, including the Q5000, the Q7000, the Grand Canyon II and the Grand Canyon III and the two newbuild chartered vessels to be used to perform contracted well intervention work in Brazil;
- unexpected future capital expenditures (including the amount and nature thereof);

- the effectiveness and timing of completion of our vessel upgrades and major maintenance items;
- the results of our continuing efforts to control costs and improve performance;
- the success of our risk management activities;
- the effects of competition;
- 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 effectiveness of our current and future hedging activities;
- the long-term availability (or lack thereof) of capital (including any financing) to fund our business strategy and/or operations;
- the effects of our indebtedness;
- the potential impact of a loss of one or more key employees; and
- the impact of general, market, industry or business conditions.

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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 15 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. (together with its subsidiaries, unless context requires otherwise, "Helix", the "Company", "we," "us" or "our") was incorporated in the state of Minnesota in 1979. We are an international offshore energy services company that provides specialty services to the offshore energy industry, with a focus on well intervention and robotics operations. We seek to provide services and methodologies that we believe are critical to developing offshore reservoirs and maximizing production economics. Our "life of field" services are segregated into four disciplines: well intervention, robotics, production facilities and subsea construction. We primarily conduct operations in the Gulf of Mexico, North Sea, Asia Pacific and West Africa regions. For additional information regarding our strategy and business operations, see sections titled "Our Strategy" and "Our Operations" included elsewhere within Item 1. Business of this Annual Report.

Our principal executive offices are located at 3505 West Sam Houston Parkway North, Suite 400, Houston, Texas 77043; our phone number is 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 May 2014. 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 Annual Report.

Please refer to the subsection "— Certain Definitions" on page 13 for definitions of additional terms commonly used in this Annual Report. Unless otherwise indicated any reference to Notes herein refers to Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data located elsewhere in this Annual Report.

OUR STRATEGY

Our focus is on growing our well intervention and robotics businesses. We believe that focusing on these services will deliver quality long-term financial returns. We are making strategic investments that expand our service capabilities or add capacity to existing services in our key operating regions. The size of our well intervention fleet has increased with the addition of the Helix 534, which was placed in service in February 2014. Our well intervention fleet will further expand following the completion of the two newbuild semi-submersible vessels currently under construction, the Q5000 and the Q7000, and the expected delivery in 2016 of two newbuild monohull vessels which we will charter in connection with the well intervention service agreements that we entered into with Petróleo Brasileiro S.A. ("Petrobras") in February 2014. In addition, we are expanding our robotics operations by acquiring additional remotely operated vehicles ("ROVs") as well as chartering two newbuild ROV support vessels, the Grand Canyon II and the Grand Canyon III, both of which are scheduled for delivery in the first half of 2015.

On January 5, 2015, Helix, OneSubsea LLC, OneSubsea B.V., Schlumberger Technology Corporation, Schlumberger B.V. and Schlumberger Oilfield Holdings Ltd. (collectively, the "Parties") entered into a Strategic Alliance Agreement and related agreements for the Parties' strategic alliance to design, develop, manufacture, promote, market and sell on a global basis integrated equipment and services for subsea well intervention. The alliance is expected to leverage the Parties' capabilities to provide a unique, fully integrated offering to clients, combining marine support with well access and control technologies.

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OUR OPERATIONS

We have four reportable business segments: Well Intervention, Robotics, Production Facilities and Subsea Construction. We provide a full range of services primarily in deepwater in the Gulf of Mexico, North Sea, Asia Pacific and West Africa regions. Our Well Intervention segment includes our vessels and equipment used to perform well intervention services primarily in the Gulf of Mexico and North Sea regions. Our well intervention vessels include the Q4000, the Helix 534, the Seawell, the Well Enhancer and the Skandi Constructor, which is a chartered vessel. Our Robotics segment currently operates four chartered vessels, and also includes ROVs, trenchers and ROVDrills designed to complement offshore subsea construction and well intervention services. Our Production Facilities segment includes the Helix Producer I (the "HP I"), a dynamically positioned floating production vessel (which we now own 100% after acquiring in February 2014 our former minority partner's noncontrolling interests in the entity that owns the vessel for $20.1 million), our equity investments in Deepwater Gateway, L.L.C. ("Deepwater Gateway") and Independence Hub, LLC ("Independence Hub"), and the Helix Fast Response System (the "HFRS"). All of our production facilities activities are located in the Gulf of Mexico. Our Subsea Construction results have diminished following the sale of essentially all of our assets related to this reportable segment, including the sale in January 2014 of our spoolbase located in Ingleside, Texas. See Note 12 for financial results associated with our business segments. Previously, we had an additional business segment, Oil and Gas, which was sold in February 2013 (see "Discontinued Operations" below). Our current services include:

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

- Reclamation. Reclamation and remediation services; well plugging and abandonment services; pipeline abandonment services; and site inspections.

- Development. Installation of subsea pipelines, flowlines, control umbilicals, manifold assemblies and risers; burial of pipelines; installation and tie-in of riser and manifold assembly; commissioning, testing and inspection; and cable and umbilical lay and connection. We have experienced increased demand for our services from the alternative energy industry. Some of the services we provide to these alternative energy businesses include subsea power cable installation, trenching and burial, along with seabed coring and preparation for construction of wind turbine foundations.

- Production facilities. Provision of oil and natural gas processing services to oil and gas companies, primarily those operating in the deepwater of the Gulf of Mexico, using our HP I vessel. Currently, the HP I is being utilized to process production from the Phoenix field (Note 5). In addition to the services provided by our HP I vessel, we maintain equity investments in two production hub facilities in the Gulf of Mexico.

- Fast Response System. Provision of the HFRS as a response resource that can be identified in permit applications to federal and state agencies and called out in the event of a well control incident.

Demand for our services 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. The performance of our business is also largely dependent on the prevailing market prices for oil and natural gas, which are impacted by global economic conditions, hydrocarbon production and capacity, geopolitical issues, weather, and several other 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;
- regional conflicts and 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 exploration and production of shale oil and natural gas;
- the cost of offshore exploration for and production and transportation of oil and natural gas;
- the ability of oil and 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
- domestic and international tax laws, regulations and policies.

Notwithstanding the recent sharp decline in oil and gas prices, 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 emphasizing the need for continual production and the replacement thereof; (2) mature global production rates for offshore and subsea wells; (3) globalization of the natural gas market; (4) an increasing number of mature and small reservoirs; (5) increasing offshore activity, particularly in deepwater; and (6) an increasing number of subsea developments.

Well Intervention

We engineer, manage and conduct well construction, intervention and abandonment operations in water depths ranging from 200 to 10,000 feet. 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 intervention to troubleshoot or enhance production, shift sleeves, log wells or perform recompletions. Our vessels serve as work platforms for well intervention services at costs that are typically significantly less than offshore drilling rigs. Competitive advantages of our vessels are derived from their lower operating costs, together with an ability to mobilize quickly and to maximize operational 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 reservoirs. We expect long-term demand for well intervention services to increase due to the growing number of subsea tree installations and the efficiency gains from specialized intervention assets and equipment.

In the Gulf of Mexico, our multi-service semi-submersible vessel, the Q4000, has set a series of well intervention “firsts” in increasingly deeper water without the use of a traditional drilling rig. In 2010, the Q4000 served as a significant component in the Macondo well control and containment efforts. The Q4000 also serves an important role in the HFRS that was established in 2011. In August 2012, we acquired a drillship and subsequently performed upgrades and modifications to render it suitable for use as a well intervention vessel. We renamed the vessel the Helix 534 and it commenced well intervention operations in February 2014.

In the North Sea, the Seawell has provided well intervention and abandonment services for hundreds of North Sea subsea wells since 1987. The vessel is currently undergoing both its normal regulatory dry dock and certain capital upgrades that are intended to extend its useful economic life, and is scheduled to return to service in April 2015. The Well Enhancer has performed well intervention, abandonment and coil tubing services since it joined our fleet in the North Sea region in 2009. In April 2013, we chartered the Skandi Constructor for use in our North Sea operations. The vessel was subsequently configured to perform well intervention operations and it commenced service in that capacity in September 2013. The initial term of the charter will expire in March 2016.

In March 2012, we executed a contract with a shipyard in Singapore for the construction of a newbuild semi-submersible well intervention vessel, the Q5000. This shipyard contract fixed the majority of the construction costs for the Q5000. The costs incurred under this contract are paid at contractually scheduled intervals, with the last remaining payment coming due when the vessel is delivered, which is expected to occur in the second quarter of 2015. We currently anticipate the Q5000 being available to perform well intervention services in the second half of 2015. In September 2014, a credit agreement for a term loan in an amount of up to $250 million was entered into to partially finance the construction of the Q5000 and other future capital projects. The term loan will be funded at or near the time of the delivery of the Q5000.

In September 2013, we executed a second contract with the same shipyard in Singapore that is currently constructing the Q5000. This contract provides for the construction of a newbuild semi-submersible well intervention vessel, the Q7000, which will be built to North Sea standards. This shipyard contract fixed the majority of the expected costs associated with the construction of the Q7000. Pursuant to the terms of this contract, 20% of the contract price was paid upon the signing of the contract and the remaining 80% will be paid upon the delivery of the vessel, which is expected to occur in 2016.

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In February 2014, we entered into agreements with Petrobras to provide well intervention services offshore Brazil. The initial term of the agreements with Petrobras is for four years with options to extend. In connection with the Petrobras agreements, we entered into charter agreements with Siem Offshore AS for two newbuild monohull vessels, both of which are expected to be in service for Petrobras in 2016.

Robotics

We have been actively engaged in robotics for approximately 30 years. We operate ROVs, trenchers and ROVDrills designed for offshore construction, maintenance and well intervention services. As global marine construction support moves to deeper waters, the use of ROV systems has increased and the scope of ROV services is becoming even more significant. Our chartered 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 their subsea activities worldwide. Our robotics assets include 50 ROVs, five trenching systems and two ROVDrills. Our robotics business unit primarily operates in the Gulf of Mexico, North Sea, West Africa and Asia Pacific regions. We currently charter vessels on a long-term basis to support our robotics operations and we have historically engaged spot vessels on short-term charter agreements as needed. Vessels currently under long-term charter agreements include the Deep Cygnus, the Olympic Canyon, the Rem Installer and the Grand Canyon. We also have entered into long-term charter agreements for the Grand Canyon II and the Grand Canyon III, which are scheduled for delivery in the first half of 2015.

Over the last decade there has been a dramatic increase in offshore activity associated with the growing alternative (renewable) energy industry. Specifically there has been a large increase in services performed for the offshore wind farm industry. As the level of activity for offshore alternative energy projects has increased, so has the need for reliable services and related equipment. Historically, this work was performed with the use of barges and other similar vessels, but these types of services are now being contracted to vessels such as our Deep Cygnus and Grand Canyon chartered vessels that are suitable for harsh weather conditions which can occur offshore, especially in northern Europe where offshore wind farming is currently concentrated. In 2014, revenues derived from offshore renewables contracts accounted for 13% of our global robotics revenues. Looking ahead to 2015, we believe that our robotics business unit is positioned to continue the services it provides to a range of clients in the alternative energy business. This is expected to include the use of our chartered vessels, ROVs and trenchers to provide burial services relating to subsea power cable installations on key wind farm developments.

Production Facilities

We own the HP I, a ship-shaped dynamically positioning floating production unit capable of processing up to 45,000 barrels of oil and 80 million cubic feet (“MMcf”) of natural gas per day. The HP I is currently being used to process production from the Phoenix field. Our existing contract for service to the Phoenix field will not expire until at least December 31, 2016.

We own a 50% interest in Deepwater Gateway which owns the Marco Polo TLP 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 (“Bcf”) of natural gas production per day from multiple ultra-deepwater fields in the eastern Gulf of Mexico. These two over-sized production facilities allow oil and gas operators to tie back less economically viable discoveries. Ownership of production facilities enables us to earn a transmission company type return through tariff charges.

We developed the HFRS as a culmination of our experience as a responder in the Macondo well control and containment efforts. The HFRS centers on two vessels, the HP I and the Q4000, both of which played a key role in the Macondo well control and containment efforts and are currently operating in the Gulf of Mexico. In 2011, we signed an agreement with Clean Gulf Associates ("CGA"), a non-profit industry group, allowing, in exchange for a retainer fee, the HFRS to be named as a response resource in permit applications to federal and state agencies and making the HFRS available to certain CGA participants who executed utilization agreements with us that specified the day rates to be charged should the HFRS be deployed in connection with a well control incident. The original set of agreements expired on March 31, 2013, and we entered into a new set of substantially similar agreements with the operators who formed HWCG LLC, a Delaware limited liability company comprised of some of the original CGA members as well as other industry participants, to perform the same functions as CGA with respect to the HFRS. These agreements became effective April 1, 2013, and have a four-year term.

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Subsea Construction

Our subsea construction operations included the use of umbilical lay and pipelay vessels and ROVs to develop fields in the deepwater. We sold our remaining pipelay vessels, the Caesar and the Express, in mid-year 2013 and our spoolbase property located in Ingleside, Texas in January 2014. The offshore construction industry (i.e., Subsea Construction) represents a substantial component of our Robotics segment revenue base as we provide ROV and trencher support and services to complement and directly support the Subsea Construction operations.

DISCONTINUED OPERATIONS

Our former Oil and Gas segment was engaged in prospect generation, exploration, development and production activities. We exited our oil and gas business in February 2013 upon the sale of our former domestic oil and gas subsidiary, Energy Resource Technology GOM, Inc. ("ERT"), for $624 million plus additional consideration in the form of overriding royalty interests in ERT's Wang well and certain exploration prospects.

GEOGRAPHIC AREAS

We primarily operate in the U.S. Gulf of Mexico, North Sea, Asia Pacific and West Africa regions. See Note 12 for revenues as well as property and equipment, net of accumulated depreciation, by geographic areas.

CUSTOMERS

Our customers include major and independent oil and gas producers and suppliers, pipeline transmission companies, alternative (renewable) energy companies and offshore engineering and construction firms. The level of services required by any particular customer depends, in part, on the size of that customer's capital expenditure budget in a particular year. Consequently, customers that account for a significant portion of revenues in one fiscal year may represent an immaterial portion of revenues in subsequent fiscal years. The percent of consolidated revenues from major customers, those whose total represented 10% or more of our consolidated revenues is as follows: 2014 — Anadarko (13%), 2013 — Shell (14%) and 2012 — Shell (12%). We provided services to over 60 customers in 2014.

COMPETITION

The oilfield services industry is highly competitive. While price is a factor, the ability to access specialized vessels, attract and retain skilled personnel, and demonstrate a good safety record is also important. Our principal competitors include Oceaneering International, Inc., FTO Services, Fugro N.V., DOF ASA, Aker Solutions ASA, Island Offshore, Edison Chouest Offshore Companies and DeepOcean Group. Our competitors in the well intervention business also include international drilling contractors. Our competitors may have significantly more financial, personnel, technological and other resources available to them.

TRAINING, SAFETY, ENVIRONMENT AND QUALITY ASSURANCE

Our corporate goal, based on the belief that all accidents can be prevented, is to provide an incident-free workplace by focusing on risk management and safe behavior. We have established a corporate culture in which QHSE has equal priority to our other business objectives. Should QHSE be in conflict with business objectives, then QHSE will take priority. Everyone at Helix has the authority and the duty to "STOP WORK" which they believe is unsafe.

Our QHSE management systems and training programs were developed by management personnel based on common industry work practices and by employees with on-site experience who understand the risk and physical challenges of the ocean work site. As a result, management believes that our QHSE programs are among the best in the industry. We maintain a company-wide effort to continuously improve our control of QHSE risks and the behavior of our people.

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The process includes the assessment of risk through the use of selected risk analysis tools, control of work through management system procedures, job risk assessment of all routine and non-routine tasks, documentation of all daily observations, collection of data and data treatment to provide the mechanism for understanding our QHSE risks and at-risk behaviors. In addition, we schedule hazard hunts by management on each vessel, and regularly audit QHSE management systems, both are completed with assigned responsibilities and action due dates.

The management systems of our well intervention and robotics business units have been independently assessed and registered compliant to ISO 9001 (Quality Management Systems) and ISO 14001 (Environmental Management Systems).

GOVERNMENT REGULATION

Many aspects of the offshore marine construction industry are subject to extensive governmental regulations. We are subject to the jurisdiction of the U.S. Coast Guard (the "Coast Guard"), the U.S. Environmental Protection Agency (the "EPA"), three divisions of the U.S. Department of the Interior, the Bureau of Ocean Energy Management (the "BOEM"), the Bureau of Safety and Environmental Enforcement (the "BSEE") and the Office of Natural Resource Revenue (the "ONRR") and the U.S. Customs Service, as well as private industry organizations such as the American Bureau of Shipping (the "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.

The development and operation of oil and gas properties located on the Outer Continental Shelf ("OCS") of the United States is regulated primarily by the BOEM and BSEE. Among other requirements, the BOEM 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. As a service company, we are not subject to these regulations, but do 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 in general.

In April 2010, the Deepwater Horizon drilling rig experienced an explosion and fire, and later sank into the Gulf of Mexico. The complete destruction of the Deepwater Horizon rig also resulted in a significant release of crude oil into the Gulf. As a result of this explosion and oil spill, a moratorium was placed on offshore deepwater drilling in the United States, which was subsequently lifted in October 2010 and replaced with enhanced safety standards for offshore deepwater drilling. Operators whose deepwater operations were suspended as a result of the moratorium and who wish to resume deepwater drilling, as well as all operators initiating new deepwater drilling projects, must demonstrate compliance with these enhanced standards. The applicable standards now include Notice to Lessees (NTL), NTL 2010-N06 (Environmental NTL), NTL 2010-N10 (Compliance and Evaluation NTL), NTL 2013-N02 (Significant Change to Oil Spill Response Plan Worst Case Scenario), the Final Drilling Safety Rule, and a rule regarding Production Measurement Documents. Inspections will be conducted of each deepwater drilling operation for compliance with BOEM and BSEE regulations, including but not limited to the testing of blowout preventers, before drilling resumes. Deepwater operators also need to comply with the Safety and Environmental Management System (“SEMS”) Rule within the deadlines specified by the regulation. Each operator must demonstrate that it has enforceable obligations that ensure that containment resources are available promptly in the event of a deepwater blowout, regardless of the company or operator involved. During 2011, the Department of the Interior established a mechanism relating to the availability of blowout containment resources, including our HFRS system, and the BOEM and BSSE are now regulating these resources. It is also expected that the BOEM and BSEE will issue further regulations regarding deepwater offshore drilling.

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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.

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 $854,400 or $1,000 per gross ton for vessels other than tank vessels. Liability limits are higher for other types of facilities and could apply if our operations resulted in Responsible Party status for a spill from such a facility. 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.

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 natural 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.

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OCSLA provides the federal government with broad discretion in regulating the production of offshore resources of oil and natural 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. Equally important, since August 2012, the BSSE has implemented policy guidelines (IPD No. 12-07) under which the agency will issue incidents of noncompliance directly to contractors for serious violations of BSEE regulations. As of this date, we believe that we are not the subject of any civil or criminal enforcement actions under OCSLA.

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

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

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 emissions of carbon dioxide, methane and other greenhouse gases. For example, the U.S. Congress has from time to time considered legislation to reduce greenhouse gas emissions, and almost one-half of the states already have taken legal measures to reduce greenhouse gas emissions, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs.

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 EPA issued an “endangerment and cause or contribute finding” for greenhouse gases under the Federal Clean Air Act, which allowed the EPA to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Since 2009, the EPA has issued regulations that, among other things, require a reduction in emissions of greenhouse gases from motor vehicles and that impose greenhouse gas emission limitations in Clean Air Act permits for certain stationary sources. The EPA has received petitions to regulate greenhouse gas emissions from marine vessels, but we are currently unaware of any rulemaking projects initiated pursuant to the petitions.

Additionally, in October 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas sources in the United States on an annual basis, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA expanded its greenhouse reporting rule to include onshore petroleum and natural gas production, offshore petroleum and natural gas production, onshore natural gas processing, natural gas transmission, underground natural gas storage, liquefied natural gas storage, liquefied natural gas import and export, and natural gas distribution facilities. Under these rules, reporting of greenhouse gas emissions from such facilities is required on an annual basis.

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We believe 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.

INSURANCE MATTERS

Our businesses involve 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 the suspension of operations. Damages 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 our financial condition, results of operations and cash flows.

As discussed below, we maintain insurance policies to cover some of our risk of loss associated with our operations. We maintain the amount of insurance we believe is prudent based on our estimated loss potential. However, not all of our business activities can be insured at the levels we desire because of either limited market availability or unfavorable economics (limited coverage for the underlying cost).

Our insurance is renewed annually on July 1 and covers a twelve-month period from July 1 to June 30.

We maintain Hull and Increased Value insurance, which provides coverage for physical damage up to an agreed amount for each vessel. The deductibles are $1.0 million on the Q4000, the HP I and the Well Enhancer, and $500,000 on the Seawell and the Helix 534. In addition to the primary deductibles, the vessels are subject to an annual aggregate deductible of $5 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 and marine crews are covered by a Maritime Employers Liability ("MEL") 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 described above, we currently carry various layers of Umbrella Liability for total limits of $500 million in excess of primary limits. Our self-insured retention on our medical and health benefits program for employees is $250,000 per participant.

We also maintain Operator Extra Expense coverage that provides up to $150 million of coverage per each loss occurrence for a well control issue. Separately, we also maintain $500 million of liability insurance and $150 million of oil pollution insurance. For any given oil spill event we have up to $650 million of insurance coverage.

We customarily have reciprocal agreements with our customers and vendors in which each contracting party is responsible for its respective personnel. Under these agreements we are indemnified against third party claims related to the injury or death of our customers' or vendors' personnel. With respect to well work contracted to us, the customer is generally contractually responsible for pollution emanating from the well. We separately maintain additional coverage for an amount up to $100 million that would cover us under certain circumstances against any such third party claims associated with well control events.

We incur workers' compensation, MEL, and other insurance claims in the normal course of business, which management believes are covered by insurance. We analyze each claim for potential exposure and estimate the ultimate liability of each claim. At December 31, 2014, we did not have any claims exceeding our deductible limits. 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.

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EMPLOYEES

As of December 31, 2014, we had approximately 1,800 employees, of which approximately 830 were salaried personnel. As of December 31, 2014, we also contracted with third parties to utilize 25 non-U.S. citizens to crew our foreign flagged vessels. Our employees do not belong to a union nor are they employed pursuant to any collective bargaining agreement or any similar arrangement. We believe that 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. From time to time, we also provide information about Helix on Twitter (@Helix ESG) and LinkedIn (www.linkedin.com). Copies of this Annual Report for the year ended December 31, 2014, and previous and subsequent copies of our Quarterly Reports on Form 10-Q and any Current Reports on Form 8-K, and any amendments thereto, are or will be available free of charge at our website as soon as reasonably practicable after they are filed with, or furnished to, the Securities and Exchange Commission ("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.

We intend to satisfy the requirement under Item 5.05 of Form 8-K to disclose any amendments to our Code of Conduct and Business Ethics and our Code of Ethics for Chief Executive Officer and Senior Financial Officers and any waiver from any provision of those codes by posting such information in the Investor Relations section of our website at www.HelixESG.com.

CERTAIN DEFINITIONS

Defined below are certain terms helpful to understanding our business that are located through this Annual Report:

BOEM: The Bureau of Ocean Energy Management ("BOEM") is responsible for managing environmentally and economically responsible development of the U.S. offshore resources. Its functions include offshore leasing, resource evaluation, review and administration of oil and gas exploration and development plans, renewable energy development, National Environmental Policy Act analysis and environmental studies.

BSEE: The Bureau of Safety and Environmental Enforcement ("BSEE") is responsible for safety and environmental oversight of offshore oil and gas operations, including permitting and inspections of offshore oil and gas operations. Its functions include the development and enforcement of safety and environmental regulations, permitting offshore exploration, development and production, inspections, offshore regulatory programs, oil spill response and newly formed training and environmental compliance programs.

Deepwater: Water depths exceeding 1,000 feet.

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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 a vessel to maintain its position without the use of anchors.

DP2: Two DP systems on a single vessel providing the redundancy that allows the vessel to maintain position even with the failure of one DP system.

DP3: Triple-redundant DP control system comprising a triple-redundant dynamic positioning system controller unit and three identical operator stations. The system has to withstand fire or flood in any one compartment without the system failing. Loss of position should not occur from any single failure, including a completely burnt fire subdivision or flooded watertight compartment.

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.

QHSE: Quality, Health, Safety and Environmental programs to protect the environment, safeguard employee health and avoid 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 3,000 meters. 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.

Spot Vessels: Vessels not owned or under long-term charter but contracted on a short-term basis by us to perform specific projects.

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

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

Well Intervention Services: Activities related to well maintenance and production management/enhancement services. Our well intervention operations include the utilization of slickline and electric line services, pumping services, specialized tooling and coiled tubing services.

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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.

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:

- 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;
- general global economic and business conditions, as well as certain potential geopolitical developments, that affect demand for and/or prices of oil and natural gas and, in turn, our business;
- technological advances that increase the efficiency of oil and gas production or result in new means of oil and gas production that affect supplies of oil and natural gas and, in turn, our business;
- our ability to manage risks related to our business and operations;
- our ability to manage shipyard construction, and upgrades and modifications of our vessels;
- 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; and
- consolidation by our customers, which could result in loss of a customer.

Economic downturn could negatively impact our business, and in a continued downturn with a negative effect on the price of oil and natural gas, our customers may seek to cancel, renegotiate or defer work under our service contracts.

Our operations are affected by local, national and worldwide economic conditions and the condition of the oil and gas industry. Certain economic data indicates that the global economy faces an uncertain outlook. The consequences of a prolonged period of little or no economic growth will likely result in a lower level of activity and increased uncertainty regarding the direction of oil and gas prices and capital markets, which will likely contribute to decreased offshore exploration and drilling. A lower level of offshore exploration and drilling activity could have a material adverse effect on the demand for our services. In addition, a general decline in economic conditions and demand for energy would also result in lower oil and gas prices, which may also adversely affect demand for and revenues from our services. Likewise, a lower level of offshore activity by oil and gas operators could lead to a surplus of available vessels and therefore downward pressure on the rates we can charge in the market for our services. The extent of the impact of these factors on our results of operations and cash flows depends on the length and severity of the decreased demand for our services and lower oil and gas prices.

In the short term, our customers could react to negative market conditions, and may seek to renegotiate their contracts with us or cancel earlier work and shift it to later years, or to cancel their contracts with us even if cancellation involves their paying a cancellation fee. Continued market deterioration could also jeopardize the ability to perform 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 oil and gas prices could lead to changes in a counterparty's liquidity and increase our exposure to credit risk and bad debts, and in particular, our robotics business unit tends to do business with smaller customers who may not be capitalized to the same extent as larger operators which may lead to more frequent collection issues. In such events, our financial results could be adversely affected and we could incur losses and our liquidity could be negatively impacted.

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Our business is adversely affected by low oil and gas prices in a cyclical oil and gas industry.

Conditions in the oil and gas industry are subject to factors beyond our control. Our services 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 natural gas, including, but not limited to:

- worldwide economic activity;
- demand for oil and natural gas, especially in the United States, Europe, China and India;
- regional conflicts and economic and political conditions in the Middle East and other oil-producing regions;
- actions taken by OPEC;
- the availability and discovery rate of new oil and natural gas reserves in offshore areas;
- the exploration and production of shale oil and natural gas;
- the cost of offshore exploration for and production and transportation of oil and natural gas;
- the ability of oil and 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 low oil and gas prices will likely have a material adverse effect on our financial position, cash flows and results of operations.

Our current backlog for our services may not be ultimately realized, and our contracts may be terminated early.

As of December 31, 2014, backlog for our services supported by written agreements or contracts totaled $2.3 billion, of which $591.6 million is expected to be performed in 2015. Although historically our service contracts were of relatively short duration, over the last several years we have been entering into longer term contracts, specifically the BP contract in the Gulf of Mexico and more recently, the Petrobras contract for offshore Brazil. As a consequence, we incur capital costs which we expect to recover over the term of the contracts, we charter vessels over the terms of and for the purpose of performing contracts, and/or we forego other contracting opportunities for the term of these contracts. We may not be able to perform under these contracts due to events beyond our control. In addition, our customers may seek to cancel, terminate, suspend or renegotiate our contracts in the event of our customers' diminished demand for our services due to market conditions, some of which contracts provide for a cancellation fee that is substantially less than the expected rates from the contracts. For example, we had two contracts canceled during the second half of 2014, which reduced our backlog for both 2014 and 2015. In addition, some of our customers could experience liquidity issues or could otherwise be unable or unwilling to perform under the contract, which could lead a customer to seek to repudiate, cancel or renegotiate a contract. Our inability or the inability of our customers to perform under our or their contractual obligations, or the early cancellation or termination of our contracts by our customers, could have a material adverse effect on our financial position, results of operations and cash flows.

Vessel upgrade, repair and construction projects are subject to risks, including delays, cost overruns, and failure to secure drilling contracts.

We are constructing two newbuild semi-submersible well intervention vessels, the Q5000 and the Q7000. We also construct additional ROVs and trenchers from time to time. We may also commence the construction of additional vessels for our fleet in the future without first obtaining service contracts covering any such vessels. Our failure to secure service contracts for vessels or other assets under construction could adversely affect our financial position, results of operations and cash flows.

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Depending on available opportunities, we may construct additional vessels for our fleet in the future. In addition, we incur significant upgrade, refurbishment and repair expenditures on our fleet from time to time. Some of these expenditures are unplanned. These projects are subject to risks of delay or cost overruns inherent in any large construction project resulting from numerous factors, including the following:

- shortages of equipment, materials or skilled labor;
- unscheduled delays in the delivery of ordered materials and equipment;
- unanticipated increases in the cost of equipment, labor and raw materials, particularly steel;
- weather interferences;
- difficulties in obtaining necessary permits or in meeting permit conditions;
- design and engineering problems;
- political, social and economic instability, war and civil disturbances;
- delays in customs clearance of critical parts or equipment;
- financial or other difficulties or failures at shipyards and suppliers;
- disputes with shipyards and suppliers; and
- work stoppages and other labor disputes.

Delays in the delivery of vessels being constructed or undergoing upgrades, refurbishment or repair may result in delay in contract commencement, resulting in a loss of revenue and cash flow to us, and may cause our customers to seek to terminate or shorten the terms of their contract, and/or seek delay damages, under applicable late delivery clauses, if any. For example, the contracts for our chartered vessels in Brazil have significant penalty provisions for late delivery to Petrobras of the vessels which escalate with further delay, and if the vessels are late in delivery to Petrobras beyond a certain date, the contracts also may be terminated. In the event of termination of these and other contracts, we may not be able to secure a replacement contract on favorable terms, if at all. Moreover, if the contract with Petrobras were to be canceled, we would still be responsible for the charter costs of the two monohull vessels we have contracted to perform this work in Brazil.

The estimated capital expenditures for vessels, upgrades, refurbishments and construction projects could materially exceed our planned capital expenditures. Moreover, our vessels undergoing upgrades, refurbishment and repair may not earn a day rate during the period they are out of service. Additionally, as vessels age, they are more likely to be subject to higher maintenance and repair activities and thus suffer lower levels of utilization. Any significant period of unplanned maintenance and repairs related to our vessels could materially affect our results of operations and cash flows.

Time chartering of our ROV support vessels requires us to make payments regardless of utilization and revenue generation, which could adversely affect our operations.

Most of our ROV support vessels are under long-term time charter contracts. Should we not have work for those vessels, we are still required to make time charter payments, and making those payments absent revenue generation could have an adverse effect on our financial position, results of operations and cash flows.

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 may 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.

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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 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 service 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.

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 liability claim for which we are not fully insured could have a material adverse effect on our business. Moreover, we cannot assure you that we will be able to maintain adequate insurance in the future at rates that we consider reasonable. 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. The current insurance on our vessels is in amounts approximating 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 revenue, increased costs and other liabilities, and therefore, the loss of any of our large vessels could have a material adverse effect on us.

Our customers may be unable or unwilling to indemnify us.

Consistent with standard industry practice, we typically obtain contractual indemnification from our customers whereby they agree to protect and indemnify us for liabilities resulting from various hazards associated with the drilling industry. We can provide no assurance, however, that our customers will be willing or financially able to meet these indemnification obligations. Also, we may choose not to enforce these indemnities because of business reasons.

Enhanced regulations for deepwater drilling offshore may reduce the need for our services.

Exploration and development activities and the production and sale of oil and natural gas are subject to extensive federal, state, local and international regulations. In the U.S. Gulf of Mexico, under enhanced safety standards, in order for an operator to conduct deepwater drilling, it is required to comply with existing and newly developed regulations and standards. The BSEE conducts many inspections of deepwater drilling operations for compliance with its regulations, including but not limited to the testing of blowout preventers, before drilling may commence. Operators also need to comply with the Safety and Environmental Management System (SEMS Rule) within the deadlines specified by the regulation, and ensure that their contractors have SEMS compliant safety and environmental policies. Additionally, each operator must demonstrate that it has containment resources that are available promptly in the event of a deepwater blowout, regardless of the company or operator involved. It is expected that the BOEM and BSEE will continue to issue further regulations regarding deepwater offshore drilling. Our contracting services business, a significant portion of which is in the Gulf of Mexico, provides development services to newly drilled wells, and therefore relies heavily on the industry’s drilling of new oil and gas wells. If the issuance of permits is significantly delayed, or if demand for our services is decreased or delayed because other oil and gas operations are delayed or reduced due to increased costs, demand for our services in the Gulf of Mexico may also decline. Moreover, if our vessels are not redeployed to other locations where we can provide our services at a profitable rate, our business, financial condition and results of operations would be materially affected.

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We cannot predict with any certainty the substance or effect of any new or additional regulations in the United States or in other areas around the world including the increase in costs or delays associated with such regulations. If the United States or other countries where we operate enact stricter restrictions on offshore drilling or further regulate offshore drilling and increase costs for our customers, our business, financial condition and results of operations could be materially affected.

Government Regulation, including recent legislative initiatives, may affect our business operations.

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, and could include regulations pertaining to contracting service operators such as ourselves. 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 natural 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. For example, the U.S. Congress has from time to time considered legislation to reduce greenhouse gas emissions, and almost one-half of the states already have taken legal measures to reduce greenhouse gas emissions, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs.

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 EPA issued an "endangerment and cause or contribute finding" for greenhouse gases under the federal Clean Air Act, which allowed the EPA to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Since 2009, the EPA has issued regulations that, among other things, require a reduction of emissions of greenhouse gases from motor vehicles and that impose greenhouse gas emission limitations in Clean Air Act permits for certain stationary sources. The EPA has received petitions to regulate greenhouse gas emissions from marine vessels, but we are currently unaware of any rulemaking projects initiated pursuant to the petitions.

Additionally, in October 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas sources in the United States on an annual basis, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA expanded its greenhouse reporting rule to include onshore petroleum natural gas production, offshore petroleum and natural gas production, onshore natural gas processing, natural gas transmission, underground natural gas storage, liquefied natural gas storage, liquefied natural gas import and export, and natural gas distribution facilities. Under these rules, reporting of greenhouse gas emissions from such facilities is required on an annual basis.

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These regulatory developments and legislative initiatives may curtail production and demand for fossil fuels such as oil and natural gas in areas of the world where our customers operate and thus adversely affect future demand for our 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.

The application of the Jones Act (which regulates the kind of vessels that can carry goods between ports of the US) to offshore oil and gas work in the US is interpreted in large part by letter rulings of the U.S. Customs and Border Protection Agency ("CBP"). The cumulative effect of these letter rulings has been to establish a framework for offshore operators to understand when an operation can be carried out by a foreign flag vessel and when it must be carried out by a coastwise qualified US flag vessel. In early 2010, CBP and its parent agency, the Department of Homeland Security ("DHS"), initiated a proposed rulemaking that would have been subject to public comment following publication in the Federal Register. The proposed rulemaking would have largely reversed the holdings of years of letter rulings from the CBP regarding the application of the Jones Act to offshore oil and gas work. The agencies subsequently withdrew the proposed rulemaking before it was published in the Federal Register. If DHS or CBP re-proposes a change to the application of the Jones Act similar to that originally proposed by CBP, and such proposal is adopted, or if CBP issues one or more letter rulings that interprets the Jones Act as being more restrictive to the operation of foreign flag vessels, such a 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 our offshore services in the US.

Failure to comply with the U.S. Foreign Corrupt Practices Act or foreign anti-bribery legislation could have an adverse impact on our business.

The U.S. Foreign Corrupt Practices Act (the "FCPA") and similar anti-bribery laws in other jurisdictions, including the United Kingdom Bribery Act 2010 and the Brazilian Clean Company Act, generally prohibit companies and their intermediaries from making improper payments to foreign officials for the purpose of obtaining or retaining business. We operate in many parts of the world that have experienced governmental corruption to some degree and, in certain circumstances, strict compliance with anti-bribery laws may conflict with local customs and practices and impact our business. Although we have programs in place covering compliance with anti-bribery legislation, any failure to comply with the FCPA or other anti-bribery legislation could subject us to civil and criminal penalties or other sanctions, which could have a material adverse effect on our business, financial position, results of operations and cash flows, and cause certain reputational damage. We could also face fines, sanctions and other penalties from authorities in the relevant foreign jurisdictions, including prohibition of our participating in or curtailment of business operations in those jurisdictions and the seizure of rigs or other assets.

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, including changes in customs, assessments and procedures, and changes in similar laws and regulations that may

affect our ability to move our assets in and out of foreign jurisdictions;
- 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.

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

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

The oilfield services business in which we operate is 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, Asia Pacific or West Africa regions, levels of competition may increase and our business could be adversely affected.

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.

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

Access to financing may be limited and uncertain, especially in times of economic weakness. If capital and credit markets are limited, we may incur increased costs associated with any additional financing we may require for future operations. Additionally, if capital and credit markets are limited, this could potentially result in our customers curtailing 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 capital markets as needed to fund their 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 non-core business assets.

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.

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

As of December 31, 2014, we had $551.4 million of consolidated indebtedness outstanding. The 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 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 flows 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 flows to service debt obligations;

- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- limiting our ability to expand our business through capital expenditures or pursuit of acquisition opportunities due to negative covenants in senior secured credit facilities that place annual and aggregate limitations on the types and amounts of investments that we may make, and limit our ability to use proceeds from asset sales for purposes other than debt repayment (except in certain circumstances where proceeds may be reinvested under criteria set forth in our credit agreements).

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A prolonged 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 may be affected by the 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 against our collateral.

Our consolidated financial results are reported in U.S. dollars while certain assets and other reported items are denominated in the currencies of other countries, creating currency translation risk.

The reporting currency for our consolidated financial statements is the U.S. dollar. Certain of our assets, liabilities, revenues and expenses are denominated in other countries' currencies. Those assets, liabilities, revenues and expenses are translated into U.S. dollars at the applicable exchange rates to prepare our consolidated financial statements. Therefore, increases or decreases in exchange rates between the U.S. dollar and those other currencies affect the value of those items as reflected in our consolidated financial statements, even if their value remains unchanged in their original currency. For instance, we conduct much of our North Sea operations using the British pound, which has recently experienced a sharp decline in its value against the U.S. dollar. Substantial fluctuations in exchange rates could have a significant impact on our results.

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 its cyclical nature, which is attributable, among other reasons, to the volatility in oil and gas prices. Our continued success depends on the active participation of our key employees. The loss of our key people could adversely affect our operations.

The delivery of our services also requires 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, in particular for our expanded well intervention fleet, including meeting any applicable local content requirements that apply when we work in international waters. 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 strategy, our results of operations could be harmed.

Our current strategy is to expand our well intervention and robotics businesses. We must plan and manage our growth effectively to achieve increased revenue and maintain profitability in our evolving market. If we fail to effectively manage current and future growth, our results of operations could be adversely affected. In the past, 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 planned expansion of our services.

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Cybersecurity breaches or business system disruptions may adversely affect our business.

We rely on our information technology infrastructure and management information systems to operate and record aspects of our business. Although we take measures to protect against cybersecurity risks, including unauthorized access to our confidential and proprietary information, our security measures may not be able to detect or prevent every attempted breach. Similar to other companies, we may be subject to cybersecurity breaches caused by, among other things, illegal hacking, computer viruses, or acts of vandalism or terrorism. A breach could result in an interruption in our operations, unauthorized publication of our confidential business or proprietary information, unauthorized release of customer or employee data, violation of privacy or other laws, and exposure to litigation. Any such breach could materially harm our business and operating results.

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

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.

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 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.

Item 2. Properties

OUR VESSELS

We own a fleet of five vessels and 50 ROVs, five trenchers, and two ROVDrills. We also charter five vessels. Currently all of our vessels, both owned and chartered, have DP capabilities specifically designed to meet the needs of deepwater market participants. Our Seawell and Well Enhancer vessels have built-in saturation diving systems.

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Listing of Vessels and Robotics Assets Related to Operations (1)

	Flag State	Placed in Service (2)	Length (Feet)	Berths	SAT Diving	DP	Crane Capacity (tons)
Floating Production Unit —							
Helix Producer I (3)	Bahamas	4/2009	528	95	—	DP2	26 and 26
Well Intervention —							
Q4000 (4)	U.S.	4/2002	312	135	—	DP3	160 and 360; 600 Derrick
Seawell	U.K.	7/2002	368	129	Capable	DP2	65 and 130; 80 Derrick
Well Enhancer	U.K.	10/2009	432	120	Capable	DP2	100; 150 Derrick
Skandi Constructor (6)	Bahamas	4/2013	395	100	—	DP3	150; 140 Derrick
Helix 534	Bahamas	2/2014	534	156	—	DP2	600 Derrick
Robotics —							
50 ROVs, 5 Trenchers and 2 ROVDrills (3), (5)	—	Various	—	—	—	—	—
Olympic Canyon (6)	Norway	4/2006	304	87	—	DP2	150
Deep Cygnus (6)	Panama	4/2010	400	92	—	DP2	150 and 25
Grand Canyon (6)	Panama	10/2012	419	104	—	DP3	250
Rem Installer (6)	Norway	7/2013	353	110	—	DP2	250

(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. 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) Serve as security for our Credit Agreement described in Note 6.

(4) Subject to vessel mortgage securing our MARAD debt described in Note 6.

(5) Average age of our fleet of ROVs, trenchers and ROVDrills is approximately 6.6 years.

(6) Chartered vessel.

We incur routine dry dock, inspection, maintenance and repair costs pursuant to applicable statutory 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 other vessels on a short-term basis, such as tugboats, cargo barges, utility boats and additional robotics support vessels. The Seawell, the Q4000 and the H534 all are scheduled to be in dry dock during 2015.

PRODUCTION FACILITIES

We own a 50% interest in Deepwater Gateway which owns the Marco Polo TLP located in the Gulf of Mexico. We also own a 20% interest in Independence Hub, which owns the Independence Hub platform that serves as a regional hub located in the eastern Gulf of Mexico. For more information regarding our production facilities, see Item 1. Business "— Our Operations."

FACILITIES

Our corporate headquarters are located at 3505 West Sam Houston Parkway North, Suite 400, Houston, Texas. We own the Aberdeen (Dyce), Scotland facility and lease our other facilities. The list of our facilities as of January 31, 2015 is as follows:

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Location	Function	Size
Houston, Texas	Helix Energy Solutions Group, Inc. Corporate Headquarters, Project Management, and Sales Office	118,630 square feet (including 30,104 square feet subject to three years remaining under a sub-lease agreement)
	Helix Well Ops, Inc. Corporate Headquarters, Project Management and Sales Office	
	Canyon Offshore, Inc. Corporate, Management and Sales Office	
	Helix Subsea Construction, Inc. Corporate Headquarters	
	Kommandor LLC Corporate Headquarters	
Houston, Texas	Helix Energy Solutions Group, Inc. Canyon Offshore, Inc. Warehouse and Storage Facility	5.5 acres (Building: 90,640 square feet)
Houston, Texas	Canyon Offshore, Inc. Warehouse and Storage Facility	3.7 acres (Building: 22,000 square feet)
Aberdeen, Scotland	Helix Well Ops (U.K.) Limited Corporate Offices and Operations	27,000 square feet
	Energy Resource Technology (U.K). Limited Corporate Offices	
Aberdeen, Scotland	Helix Well Ops (U.K.) Limited Warehouse and Storage Facility	14,124 square feet
Aberdeen (Dyce), Scotland	Canyon Offshore Limited Corporate Offices, Operations and Sales Office	3.9 acres (Building: 42,463 square feet, including 7,000 square feet subject to two years remaining under a sub-lease agreement)
Singapore	Canyon Offshore International Corp Corporate, Operations and Sales Office	22,486 square feet
	Helix Offshore Crewing Service Pte. Ltd. Corporate Headquarters	
Luxembourg	Helix Offshore International S.à r.l. and subsidiaries Corporate Offices and Operations	161 square feet
Brazil	Helix do Brasil Serviços de Petróleo Ltda Corporate, Operations and Sales Office	1,447 square feet

Item 3. Legal Proceedings

We are, from time to time, party to litigation arising in the normal course of our business. We believe that there are currently no legal proceedings, the outcome of which would have a material adverse effect on our financial position, results of operations or cash flows.

Item 4. Mine Safety Disclosures

Not applicable.

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Executive Officers of the Company

The executive officers of Helix are as follows:

Name	Age	Position
Owen Kratz	60	President and Chief Executive Officer and Director
Anthony Tripodo	62	Executive Vice President and Chief Financial Officer
Clifford V. Chamblee	55	Executive Vice President and Chief Operating Officer
Alisa B. Johnson	57	Executive Vice President, General Counsel and Corporate Secretary

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 his former position of President and Chief Executive Officer. He was appointed Chairman in May 1998 and served as Helix'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. From February 2006 to December 2011, Mr. Kratz was a member of the Board of Directors of Cal Dive International, Inc., a publicly-traded company, which was formerly a subsidiary of Helix. Mr. Kratz has a Bachelor of Science degree from State University of New York (SUNY).

Anthony Tripodo was named as Executive Vice President and Chief Financial Officer of Helix on June 25, 2008. Mr. Tripodo oversees the finance, treasury, accounting, tax, information technology 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 1997 to 2003, Mr. Tripodo was Executive Vice President of Veritas DGC, Inc., an international oilfield service company specializing in geophysical services, including serving as Executive Vice President, Chief Financial Officer and Treasurer of Veritas from 1997 to 2001. 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 also has served as a director of three publicly-traded companies in the oilfield services industry in addition to his prior service as a director of Helix. He graduated Summa Cum Laude with a Bachelor of Arts degree from St. Thomas University (Miami).

Clifford V. Chamblee was named Executive Vice President and Chief Operating Officer of Helix in February 2013. He served as Executive Vice President-Contracting Services of Helix from May 2011 until February 2013. He joined Helix's robotics subsidiary, Canyon Offshore, Inc. (Canyon), in 1997. Mr. Chamblee served as President of Canyon from 2006 until 2011. Prior to becoming President of Canyon, Mr. Chamblee held several positions with increasing responsibilities at Canyon managing the operations of the company including as Senior Vice President and Vice President Operations from 1997 until 2006. Mr. Chamblee has been involved in the robotics industry for over 33 years. From 1988 to 1997, Mr. Chamblee held various positions with Sonsub International, Inc., including Vice President Remote Systems, Marketing Manager and Operations Manager. From 1986 until 1988, he was Operations Manager and Superintendent for Helix (then known as Cal Dive). From 1981 until 1986, Mr. Chamblee held various positions for Oceaneering International/Jered, including ROV Superintendent and ROV Supervisor. Prior to 1981, he was an ROV Technician for Martech International.

Alisa B. Johnson joined Helix 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 oversees the legal, human resources and contracts and insurance functions. Ms. Johnson has been involved with the energy industry for over 24 years. Prior to joining Helix, Ms. Johnson worked for Dynegy Inc. for nine years, at which company she held various legal positions of increasing responsibility, including Senior Vice President and Group General Counsel — Generation. From 1990 to 1997, Ms. Johnson held various legal positions at Destec Entergy, Inc. Prior to that Ms. Johnson was in private law practice. Ms. Johnson received her Bachelor of Arts degree Cum Laude from Rice University and her law degree Cum Laude from the University of Houston.

PART II

Item 5. Market for the Registrant's Common Equity, Related Stockholder 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
2013		
First Quarter	$25.49	$20.59
Second Quarter	$25.99	$20.33
Third Quarter	$27.58	$23.12
Fourth Quarter	$25.85	$21.33
2014		
First Quarter	$24.16	$19.44
Second Quarter	$26.41	$21.59
Third Quarter	$28.00	$21.91
Fourth Quarter	$27.70	$19.48
2015		
First Quarter (1)	$21.99	$17.14

(1) Through February 13, 2015

On February 13, 2015, the closing sale price of our common stock on the NYSE was $19.08 per share. As of February 13, 2015, there were 327 registered shareholders and approximately 25,500 beneficial shareholders of our common stock.

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

Shareholder Return Performance Graph

The following graph compares the cumulative total shareholder return on our common stock for the period since December 31, 2009 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 (the "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: Atwood Oceanics, Inc., Dril-Quip, Inc., GulfMark Offshore, Inc., Hercules Offshore, Inc., Hornbeck Offshore Services, Inc., McDermott International, Inc., Oceaneering International, Inc., Oil States International, Inc., Rowan Companies plc, Superior Energy Services, Inc., TETRA Technologies, Inc., and Tidewater 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, 2014 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, 2009 in our common stock at the closing price on that date price and on December 31, 2009 in the three indices presented. We paid no cash dividends during the period presented. The cumulative total percentage returns for the period presented are as follows: our stock — 84.7%; the Peer Group — (12.3)%; the OSX — 8.2%; and S&P 500 — 105.1%. These results are not necessarily indicative of future performance.

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

	As of December 31,					
	2009	2010	2011	2012	2013	2014
Helix	$ 100.0	$ 103.3	$ 134.5	$ 175.7	$ 197.3	$ 184.7
Peer Group Index	$ 100.0	$ 120.1	$ 112.7	$ 112.3	$ 145.6	$ 87.7
Oil Service Index	$ 100.0	$ 125.8	$ 111.0	$ 113.0	$ 144.2	$ 108.2
S&P 500	$ 100.0	$ 115.1	$ 117.5	$ 136.3	$ 180.4	$ 205.1

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	(d) Maximum number of shares that may yet be purchased under the program (1) (2)
October 1 to October 31, 2014	—	$ —	—	—
November 1 to November 30, 2014	—	—	—	—
December 1 to December 31, 2014	—	—	—	55,674
	—	$ —	—	55,674

(1) Under the terms of our stock repurchase program, the issuance of shares to members of our Board of Directors and to certain employees, including shares issued to our employees under the Employee Stock Purchase Plan (the "ESPP") (Note 8), increases the number of shares available for repurchase. For additional information regarding our stock repurchase program, see Note 10.

(2) In January 2015, we issued approximately 0.3 million shares of restricted stock to our executive officers, selected management employees and certain members of our Board of Directors who have elected to take their quarterly fees in stock in lieu of cash. We also issued approximately 0.1 million shares of our common stock to our employees under the ESPP. These issuances will increase the number of shares available for repurchase by a corresponding amount (Note 8).

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Item 6. Selected Financial Data.

The financial data presented below for each of the five years ended December 31, 2014 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. In February 2013, we sold ERT and as a result, the assets and liabilities included in the sale of ERT and the historical operating results of our former Oil and Gas segment are presented as discontinued operations in this Annual Report.

	Year Ended December 31,				
	2014	2013	2012	2011	2010
	(in thousands, except per share amounts)				
Net revenues	$1,107,156	$876,561	$846,109	$702,000	$774,469
Gross profit	344,036	260,685	49,915	149,683	164,817
Income (loss) from operations (1)	261,756	179,034	(68,483)	63,040	51,079
Equity in earnings of investments	879	2,965	8,434	22,215	19,469
Net income (loss) from continuing operations	195,550	111,976	(66,840)	37,816	(17,496)
Income (loss) from discontinued operations, net of tax (2)	—	1,073	23,684	95,221	(106,657)
Net income (loss), including noncontrolling interests	195,550	113,049	(43,156)	133,037	(124,153)
Net income applicable to noncontrolling interests	(503)	(3,127)	(3,178)	(3,098)	(2,835)
Net income (loss) applicable to Helix	195,047	109,922	(46,334)	129,939	(126,988)
Adjusted EBITDA from continuing operations (3)	378,010	268,311	233,612	178,953	160,250
Basic earnings (loss) per share of common stock:					
Continuing operations	$1.85	$1.03	$(0.67)	$0.33	$(0.19)
Discontinued operations	—	0.01	0.23	0.90	(1.03)
Net income (loss) per common share	$1.85	$1.04	$(0.44)	$1.23	$(1.22)
Diluted earnings (loss) per share of common stock:					
Continuing operations	$1.85	$1.03	$(0.67)	$0.33	$(0.19)
Discontinued operations	—	0.01	0.23	0.90	(1.03)
Net income (loss) per common share	$1.85	$1.04	$(0.44)	$1.23	$(1.22)
Weighted average common shares outstanding:					
Basic	105,029	105,032	104,449	104,528	103,857
Diluted	105,045	105,184	104,449	104,953	103,857

(1) Amount in 2012 includes impairment charges of approximately $177.1 million, including $14.6 million for the Intrepid, $157.8 million for the Caesar and related mobile pipelay equipment, and $4.6 million for well intervention assets associated with our former operations in Australia. See Note 2 for additional information regarding these impairment charges.

(2) Oil and gas property impairment charges and asset retirement obligation overruns totaled $144.3 million in 2012, including the $138.6 million charge to reduce the value of ERT's properties to their estimated fair value in connection with the announcement of the sale of ERT in December 2012, $112.6 million in 2011 and $176.1 million in 2010. Also includes exploration expenses totaling $3.5 million in 2013, $3.3 million in 2012, $10.9 million in 2011 and $8.3 million in 2010.

(3) This is a non-GAAP financial measure. See "Non-GAAP Financial Measures" below for an explanation of the definition and use of such measure as well as a reconciliation of these amounts to each year's respective reported net income (loss) from continuing operations.

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	December 31,				
	2014	2013	2012	2011	2010
	(in thousands)				
Working capital	$468,660	$553,427	$351,061	$548,066	$373,057
Total assets (1)	2,700,698	2,544,280	3,386,580	3,582,347	3,592,020
Long-term debt (including current maturities)	551,372	566,152	1,019,228	1,155,321	1,357,932
Convertible preferred stock (2)	—	—	—	1,000	1,000
Total controlling interest shareholders' equity	1,653,474	1,499,051	1,393,385	1,421,403	1,260,604
Noncontrolling interests	—	25,059	26,029	28,138	25,040
Total equity	1,653,474	1,524,110	1,419,414	1,449,541	1,285,644

(1) Amounts at December 31, 2012, 2011 and 2010 included assets of discontinued oil and gas operations.

(2) In 2012, the holder of our convertible preferred stock converted the remaining $1 million of the convertible preferred stock into 0.4 million shares of our common stock (Note 2). In 2010, the holder of our convertible preferred stock converted $5 million of the convertible preferred stock into 1.8 million shares of our common stock.

Non-GAAP Financial Measures

A non-GAAP financial measure is generally defined by the SEC as a numerical measure of a company's historical or future performance, financial position, or cash flows that includes or excludes amounts from the most directly comparable measure under U.S. generally accepted accounting principles ("GAAP"). We measure our operating performance based on EBITDA, a non-GAAP financial measure that is commonly used but is not a recognized accounting term under GAAP. We use EBITDA to monitor and facilitate the internal evaluation of the performance of our business operations, to facilitate external comparison of our business results to those of others in our industry, to analyze and evaluate financial and strategic planning decisions regarding future investments and acquisitions, to plan and evaluate operating budgets, and in certain cases, to report our results to the holders of our debt as required by our debt covenants. We believe our measure of EBITDA provides useful information to the public regarding our ability to service debt and fund capital expenditures and may help our investors understand our operating performance and compare our results to other companies that have different financing, capital and tax structures.

We define EBITDA as net income (loss) from continuing operations plus income taxes, depreciation and amortization expense, and net interest expense and other. We separately disclose our non-cash asset impairment charges, which, if not material, would be reflected as a component of our depreciation and amortization expense. Because such impairment charges are material for most of the periods presented, we have reported them as a separate line item in the accompanying consolidated statements of operations. Non-cash impairment charges related to goodwill are also added back if applicable. Loss on early extinguishment of long-term debt is considered equivalent to additional interest expense and thus is added back to net income (loss) from continuing operations.

In the following reconciliation, we provide amounts as reflected in our accompanying consolidated financial statements unless otherwise footnoted. This means that these amounts are recorded at 100% even if we do not own 100% of all of our subsidiaries. Accordingly, to arrive at our measure of Adjusted EBITDA from continuing operations, when applicable, we deduct the noncontrolling interests related to the adjustment components of EBITDA and the gain or loss on disposition of assets from continuing operations.

Other companies may calculate their measures of EBITDA and Adjusted EBITDA differently than we do, which may limit their usefulness as comparative measures. Because EBITDA is not a financial measure calculated in accordance with GAAP, it should not be considered in isolation or as a substitute for net income (loss) attributable to common shareholders or cash flows from operations, but used as a supplement to these GAAP financial measures. The reconciliation of our net income (loss) from continuing operations to EBITDA from continuing operations and Adjusted EBITDA from continuing operations is as follows:

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	Year Ended December 31,				
	2014	2013	2012	2011	2010
Net income (loss) from continuing operations	$195,550	$111,976	$(66,840)	$37,816	$(17,496)
Adjustments:					
Income tax provision (benefit)	66,971	31,612	(59,158)	(36,806)	19,166
Net interest expense and other	17,045	32,892	48,822	71,328	66,638
Loss on early extinguishment of long-term debt	—	12,100	17,127	2,354	—
Depreciation and amortization	109,345	98,535	97,201	91,188	81,878
Asset impairment charges (1)	—	—	177,135	17,127	23,060
EBITDA from continuing operations	388,911	287,115	214,287	183,007	173,246
Adjustments:					
Noncontrolling interests	(661)	(4,077)	(4,128)	(4,060)	(3,878)
Unrealized loss on commodity derivative contracts	—	—	9,977	—	—
(Gain) loss on disposition of assets, net	(10,240)	(14,727)	13,476	6	(9,118)
ADJUSTED EBITDA from continuing operations	$378,010	$268,311	$233,612	$178,953	$160,250

(1) Amount in 2012 includes impairment charges of $14.6 million for the Intrepid, $157.8 million for the Caesar and related mobile pipelay equipment, and $4.6 million for well intervention assets associated with our former operations in Australia. Amount in 2011 includes a $6.6 million impairment charge related to our well intervention equipment in Australia and a $10.6 million other than temporary impairment loss on our former equity investment in an Australian joint venture. Amount in 2010 includes $16.7 million related to goodwill impairment of our Australian well intervention subsidiary.

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

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 Annual 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 Annual 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 Annual Report.

Executive Summary

Our Strategy

We are an international offshore energy services company that provides specialty services to the offshore energy industry, with a focus on well intervention and robotics operations. Our focus is on growing our well intervention and robotics businesses. We believe that focusing on these services will deliver quality long-term financial returns. We are making strategic investments that expand our service capabilities or add capacity to existing services in our key operating regions. The size of our well intervention fleet has increased with the addition of the Helix 534, which was placed in service in February 2014. Our well intervention fleet will further expand following the completion of the two newbuild semi-submersible vessels currently under construction, the Q5000 and the Q7000, and the expected delivery in 2016 of two newbuild monohull vessels which we will charter in connection with the well intervention service agreements that we entered into with Petrobras in February 2014. In addition, we are expanding our robotics operations by acquiring additional ROVs as well as chartering two newbuild ROV support vessels, the Grand Canyon II and the Grand Canyon III, both of which are scheduled for delivery in the first half of 2015.

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On January 5, 2015, Helix, OneSubsea LLC, OneSubsea B.V., Schlumberger Technology Corporation, Schlumberger B.V. and Schlumberger Oilfield Holdings Ltd. (collectively, the "Parties") entered into a Strategic Alliance Agreement and related agreements for the Parties' strategic alliance to design, develop, manufacture, promote, market and sell on a global basis integrated equipment and services for subsea well intervention. The alliance is expected to leverage the Parties' capabilities to provide a unique, fully integrated offering to clients, combining marine support with well access and control technologies.

Economic Outlook and Industry Influences

Demand for our services 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. The performance of our business is also largely dependent on the prevailing market prices for oil and natural gas, which are impacted by global economic conditions, hydrocarbon production and capacity, geopolitical issues, weather, and several other 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;
- regional conflicts and economic and political conditions in the Middle East and other oil-producing regions;
- actions taken by OPEC;
- the availability and discovery rate of new oil and natural gas reserves in offshore areas;
- the exploration and production of shale oil and natural gas;
- the cost of offshore exploration for and production and transportation of oil and natural gas;
- the ability of oil and 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
- domestic and international tax laws, regulations and policies.

Global prices for oil and natural gas have declined significantly in the fourth quarter of 2014 and early portion of 2015 based on concerns over excess supply coupled with a slowing global economic outlook. The trading price for crude oil on the New York Mercantile Exchange dropped substantially since July 2014 and fell below $45 per barrel in January 2015 for the first time since 2009. Many analysts currently predict that prices for oil and natural gas may decrease further and remain low through 2015. The decrease in oil and gas prices is attributable to a global supply and demand imbalance which reflects both increased production in certain countries primarily in the United States and a general weakening of the global economy that has primarily affected both Europe and Asia. In light of the recent sharp decline in oil and gas prices, many oil and gas companies have announced reductions in capital spending for 2015. Any additional news suggesting weak or declining economic data could affect global equity and the oil and gas markets, which could affect normal business activities. Weaker global equity and oil and gas markets could potentially reduce investment in offshore oil and gas capital projects, which may affect rates that drilling rig contractors can charge for their services. We believe that capital would be less likely to be expended on the beginning of offshore projects, for example for exploration drilling projects, than on projects that span the life of an oil and gas field's production. However, during periods of sustained low oil and gas prices, no one in the industry is immune to the effect of any near term planned capital spending reductions, including us. Our Well Intervention and Robotics operations are intended to service the life span of an oil and gas field as well as to provide abandonment services at the end of the life of a field as required by governmental regulations. Thus over the longer term, we believe that fundamentals for our business remain favorable as the need for continual oil and gas production is the primary driver of demand for our services.

In addition, 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 emphasizing the need for continual production and the replacement thereof; (2) mature global production rates for offshore and subsea wells; (3) globalization of the natural gas market; (4) an increasing number of mature and small reservoirs; (5) increasing offshore activity, particularly in deepwater; and (6) an increasing number of subsea developments.

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At December 31, 2014, we had cash on hand of $476.5 million and $583.6 million available for borrowing under our Revolving Credit Facility. Our capital expenditures for 2015 are currently anticipated to total approximately $400 million. If we successfully implement our business plan, we believe that we have sufficient liquidity without incurring additional indebtedness beyond the existing capacity under the Revolving Credit Facility and the Nordea Credit Agreement (Note 6).

Business Activity Summary

We have enhanced our financial position and strengthened our balance sheet with proceeds from the sale of certain non-core business assets, which, together with our increased liquidity under our credit agreements, allow us to strategically focus on our core well intervention and robotics businesses. Since 2009, we have generated approximately $1.5 billion in pre-tax proceeds from asset sale transactions. These dispositions include approximately $55 million from the sale of individual oil and gas properties, over $500 million from the sale of our stockholdings in Cal Dive International Inc., $25 million from the sale of our former reservoir consulting business, approximately $238 million from the sale of our two remaining pipelay vessels, the Caesar and the Express, and $624 million from the sale of ERT.

In January 2014, we sold our spoolbase property located in Ingleside, Texas for $45 million. In connection with this sale, we received $15 million in cash and a $30 million secured promissory note. Interest on the note is payable quarterly at a rate of 6% per annum. We received $2.5 million and $7.5 million of principal payments on this note in December 2014 and January 2015, respectively. Under the terms of the note, the remaining $20 million principal balance is required to be paid with a $10 million payment on each December 31 of 2015 and 2016. The sale of our Ingleside spoolbase resulted in a $10.5 million gain in 2014.

In February 2014, we acquired our former minority partner's noncontrolling interests in the entity that owns the HP I for $20.1 million. We now own 100% of the vessel.

RESULTS OF OPERATIONS

We have four reportable business segments: Well Intervention, Robotics, Production Facilities and Subsea Construction. Our Subsea Construction results have diminished following the sale of essentially all of our assets related to this reportable segment, including the sale of our Ingleside spoolbase in January 2014. Previously, we had an additional business segment, Oil and Gas. In February 2013, we completed the sale of ERT (Notes 1 and 13). Accordingly, the results of ERT are presented as discontinued operations for all periods presented in this Annual Report.

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

We seek to provide services and methodologies that we believe are critical to developing offshore reservoirs and maximizing production economics. We operate primarily in deepwater in the Gulf of Mexico, North Sea, Asia Pacific and West Africa regions, with services that cover the lifecycle of an offshore oil or gas field. In addition, our Robotics operations are often contracted for the development of renewable energy projects (wind farms). As of December 31, 2014, our consolidated backlog that is supported by written agreements or contracts totaled $2.3 billion, of which $591.6 million is expected to be performed in 2015. The substantial majority of our backlog is associated with our Well Intervention business segment. As of December 31, 2014, our well intervention backlog was $2.0 billion, including $418.3 million expected to be performed in 2015. Representing approximately 67% of our total backlog are a five-year contract with BP to provide well intervention services with our Q5000 semi-submersible vessel and four-year agreements with Petrobras to provide well intervention services offshore Brazil with two chartered newbuild monohull vessels (both expected to be placed in service in 2016). At December 31, 2013, the total backlog associated with our operations was $2.0 billion. Backlog contracts are cancelable sometimes without penalties. For example, we recently had two such backlog contracts canceled and although in these instances we are entitled to some cancellation fees, the amount of those fees is substantially less than the rates we would have generated if our services were performed in accordance with the terms of the contracts. Accordingly, backlog is not necessarily a reliable indicator of total annual revenues for our services as contracts may be added, deferred, suspended, canceled and in many cases modified while in progress.

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Comparison of Years Ended December 31, 2014 and 2013

The following table details various financial and operational highlights for the periods presented (dollars in thousands):

	Year Ended December 31, 2014	2013	Increase/ (Decrease)
Net revenues —			
Well Intervention	$667,849	$452,452	$215,397
Robotics	420,224	333,246	86,978
Production Facilities	93,175	88,149	5,026
Subsea Construction	358	71,321	(70,963)
Intercompany elimination	(74,450)	(68,607)	(5,843)
	$1,107,156	$876,561	$230,595
Gross profit —			
Well Intervention	$219,554	$142,762	$76,792
Robotics	86,419	57,035	29,384
Production Facilities	41,762	50,619	(8,857)
Subsea Construction	461	18,302	(17,841)
Corporate and other	(3,239)	(4,673)	1,434
Intercompany elimination	(921)	(3,360)	2,439
	$344,036	$260,685	$83,351
Gross margin —			
Well Intervention	33 %	32 %	
Robotics	21 %	17 %	
Production Facilities	45 %	57 %	
Total company	31 %	30 %	
Number of vessels or ROV assets (1) / Utilization (2)			
Well Intervention vessels	5/88 %	4/92 %	
ROV assets	57/78 %	57/63 %	
Robotics vessels	4/85 %	5/88 %	

(1) Represents number of vessels or ROV assets as of the end of 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.

(2) Average vessel utilization rate is calculated by dividing the total number of days the vessels or ROV assets generated revenues by the total number of calendar days in the applicable period.

Intercompany segment amounts are derived primarily from equipment and services provided to other business segments at rates consistent with those charged to third parties. Intercompany segment revenues during the years ended December 31, 2014 and 2013 are as follows (in thousands):

	Year Ended December 31, 2014	2013	Increase/ (Decrease)

Well Intervention	$29,875	$22,448	$7,427
Robotics	44,575	41,169	3,406
Production Facilities	—	4,673	(4,673)
Subsea Construction	—	317	(317)
	$74,450	$68,607	$5,843

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Intercompany segment profit (loss) during the years ended December 31, 2014 and 2013 is as follows (in thousands):

	Year Ended December 31, 2014	2013	Increase/ (Decrease)
Well Intervention	$(323)	$(141)	$(182)
Robotics	1,419	3,518	(2,099)
Production Facilities	(175)	(175)	—
Subsea Construction	—	158	(158)
	$921	$3,360	$(2,439)

In reviewing the discussion below of our results of operations, please refer to the tables above and Note 12 for supplemental information regarding our business segment results. This discussion specifically refers to our Well Intervention, Robotics and Production Facilities segments. We sold our remaining Subsea Construction pipelay vessels in mid-year 2013 (Note 2).

Revenues. Our total net revenues increased by 26% in 2014 as compared to 2013. Net revenues for our business segments increased year over year, reflecting the addition of vessels in our Well Intervention business (see below), the increased asset utilization within our Robotics segment, and the slightly higher revenues for the HP I reflecting the variable production component of the fee arrangement in the Phoenix field. Our Subsea Construction revenues decreased reflecting the sale of our pipelay vessels in mid-year 2013 (Note 2).

Our Well Intervention revenues increased by 48% in 2014 as compared to 2013 primarily reflecting the addition of two vessels, the chartered Skandi Constructor in April 2013 and the Helix 534 in February 2014, as well as higher demand for our services. Our vessels had high utilization (88%) during 2014 despite three vessels being in regulatory dry dock in 2014: the Well Enhancer (24 days), the Skandi Constructor (29 days) and the Seawell (25 days). The Seawell is currently undergoing both its normal regulatory dry dock and certain capital upgrades and is scheduled to return to service in April 2015. The upgrades to the Seawell are intended to extend the vessel's useful economic life. Separately, a supply boat collided into the Q4000 in November 2014, which caused some damage to the vessel. The Q4000 was on reduced rates for 17 days during collision inspection and repairs. In addition, the H534 was idle for 53 days during the fourth quarter of 2014, including 14 days for required annual inspections and 39 days following the cancellation of a contract.

Our Robotics revenues increased by 26% in 2014 as compared to 2013. The increase primarily reflects the higher utilization of our ROVs and trenchers, and 259 additional days of spot vessel utilization. Our trenching activities, primarily conducted in the North Sea region, have significantly increased during 2014 as compared to the unusually weak market that was experienced in 2013.

Our Production Facilities revenues increased by 6% in 2014 as compared to 2013, which reflects an increase in our total revenues under our fee arrangement for the HP I, including the variable portion of the fee for throughput processed by the HP I. The quarterly HFRS retainer fees also increased effective April 1, 2013 as a result of new four-year agreements.

Gross Profit. Our gross profit increased by 32% in 2014 as compared to 2013. The gross profit related to our Well Intervention segment increased by 54% in 2014 as compared to 2013 reflecting the addition of two vessels to our fleet since March 31, 2013.

The gross profit associated with our Robotics segment increased by 52% in 2014 as compared to 2013 reflecting increased utilization for our ROVs and trenching assets and related support vessels. Utilization for our trenching assets increased significantly reflecting the resumption of trenching projects in the North Sea region following an unusually weak year for that work in 2013.

The gross profit related to our Production Facilities segment decreased by 17% in 2014 as compared to 2013. The decrease primarily reflects the amortization of the HP I's initial regulatory dry dock costs that were incurred during the fourth quarter of 2013.

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Loss on Commodity Derivative Contracts. In December 2012, following the announcement of the sale of ERT, we de-designated our oil and gas commodity derivative contracts and interest rate swap contracts as hedging instruments (Note 15). The $14.1 million loss on commodity derivative contracts reflects the net loss on our oil and gas commodity derivative contracts during the first quarter of 2013. In February 2013, we paid approximately $22.5 million to settle our remaining open commodity derivative contracts.

Gain on Disposition of Assets, Net. The $10.2 million net gain on disposition of assets in 2014 primarily reflects a $10.5 million gain associated with the sale of our Ingleside spoolbase in January 2014 (Note 2). The $14.7 million gain on disposition of assets in 2013 primarily reflects a $1.1 million loss on the sale of the Caesar in June 2013 and a $15.6 million gain on the sale of the Express in July 2013.

Selling, General and Administrative Expenses. Our selling, general and administrative expenses increased by $10.3 million in 2014 as compared to 2013. The increase primarily reflects $5.3 million of charges associated with the provision for uncertain collection of a portion of our existing trade receivables (Note 14), certain costs associated with start-up activities in Brazil, and costs to support the growth of both our well intervention and robotics businesses. However, our selling, general and administrative expenses as a percentage of net revenues decreased from 9.4% in 2013 to 8.4% in 2014.

Equity in Earnings of Investments. Equity in earnings of investments decreased by $2.1 million in 2014 as compared to 2013. The decrease primarily reflects lower revenues for both Deepwater Gateway and Independence Hub due to lower production at the fields being processed at each facility. Additionally, Deepwater Gateway's operations were affected by a fire at the facility in early May 2014 that shut in production at the platform for most of the second quarter. Production was restored to the facility in July 2014.

Net Interest Expense. Our net interest expense totaled $17.9 million in 2014 as compared to $32.9 million in 2013. The decrease consists of both a reduction in interest expense and an increase in interest income. The decrease in interest expense reflects the substantial reduction in our indebtedness, including the $318.4 million repayment of debt in February 2013 following the sale of ERT and our redemption in July 2013 of the remaining $275 million of our Senior Unsecured Notes then outstanding. Interest income totaled $4.8 million for 2014 as compared to $1.2 million for 2013. The amount of interest income for 2014 includes $2.1 million related to a U.S. Internal Revenue Service ("IRS") income tax refund (Note 7) and $1.8 million on the promissory note held in connection with the sale of our Ingleside spoolbase (Note 2). Capitalized interest remained consistent year over year.

Loss on Early Extinguishment of Long-term Debt. The $12.1 million loss in 2013 included the $8.6 million loss in connection with our redemption in July 2013 of the remaining $275 million Senior Unsecured Notes then outstanding and the acceleration of the remaining $3.5 million of deferred financing fees related to the term loan component of our former credit agreement following the repayment of that indebtedness.

Other Income, Net. We reported net other income of $0.8 million for 2014 primarily reflecting foreign exchange fluctuations in our non-U.S. dollar functional currencies. Included in this amount was $1.7 million of losses related to ineffectiveness associated with our foreign currency hedge with respect to the Grand Canyon II charter payments (Note 15).

Other Income – Oil and Gas. The $16.9 million income for 2014 included a $7.2 million insurance reimbursement related to asset retirement work previously performed. The majority of the remaining oil and gas income is associated with our overriding royalty interests in ERT's Wang well, which commenced production in late April 2013. The $6.6 million income for 2013 primarily represents cash payments related to services we provided to ERT following its sale to a third party and the initial proceeds associated with our overriding royalty interests in ERT's Wang well.

Income Tax Provision. Income taxes reflected expenses of $67.0 million in 2014 as compared to $31.6 million in 2013. The variance primarily reflects increased profitability in the current year period. The effective tax rate of 25.5% for 2014 was higher than the 22.0% effective tax rate for 2013 as a result of increased profitability in certain jurisdictions with higher tax rates.

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Comparison of Years Ended December 31, 2013 and 2012

The following table details various financial and operational highlights for the periods presented (dollars in thousands):

	Year Ended December 31, 2013	2012	Increase/ (Decrease)
Net revenues —			
Well Intervention	$452,452	$378,546	$73,906
Robotics	333,246	328,726	4,520
Production Facilities	88,149	80,091	8,058
Subsea Construction	71,321	192,521	(121,200)
Intercompany elimination	(68,607)	(133,775)	65,168
	$876,561	$846,109	$30,452
Gross profit —			
Well Intervention	$142,762	$100,656	$42,106
Robotics	57,035	66,005	(8,970)
Production Facilities	50,619	40,645	9,974
Subsea Construction	18,302	(130,139)	148,441
Corporate and other	(4,673)	(19,374)	14,701
Intercompany elimination	(3,360)	(7,878)	4,518
	$260,685	$49,915	$210,770
Gross margin —			
Well Intervention	32%	27%	
Robotics	17%	20%	
Production Facilities	57%	51%	
Subsea Construction	26%	(68)%	
Total company	30%	6%	
Number of vessels or ROV assets (1) / Utilization (2)			
Well Intervention vessels	4/92%	3/82%	
ROV assets	57/63%	55/67%	
Robotics vessels	5/88%	4/92%	
Subsea Construction vessels	0/92%	2/84%	

(1) Represents number of vessels or ROV assets as of the end of 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.

(2) Average vessel utilization rate is calculated by dividing the total number of days the vessels or ROV assets generated revenues by the total number of calendar days in the applicable period. Utilization statistics for construction vessels only include the time each vessel was in service prior to its eventual sale.

Intercompany segment revenues during the years ended December 31, 2013 and 2012 are as follows (in thousands):

	Year Ended December 31, 2013	2012	Increase/ (Decrease)

Well Intervention	$22,448	$36,781	$(14,333)
Robotics	41,169	46,465	(5,296)
Production Facilities	4,673	46,057	(41,384)
Subsea Construction	317	4,472	(4,155)
	$68,607	$133,775	$(65,168)

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Intercompany segment profit (loss) during the years ended December 31, 2013 and 2012 are as follows (in thousands):

	Year Ended December 31, 2013	2012	Increase/ (Decrease)
Well Intervention	$(141)	$6,203	$(6,344)
Robotics	3,518	180	3,338
Production Facilities	(175)	(175)	—
Subsea Construction	158	1,670	(1,512)
	$3,360	$7,878	$(4,518)

In reviewing the discussion below of our results of operations, please refer to the tables above and Note 12 for supplemental information regarding our business segment results.

Revenues. Our total net revenues increased by 4% in 2013 as compared to 2012 reflecting year-over-year revenue increases in each of our Well Intervention, Robotics and Production Facilities segments, offset in part by the substantial decrease in our Subsea Construction revenues as a result of the sale of our two remaining subsea construction pipelay vessels in mid-2013 (Note 2).

Our Well Intervention revenues increased by 20% in 2013 as compared to 2012 primarily reflecting the addition of a chartered vessel, the Skandi Constructor, to our North Sea fleet, and increased utilization of our three other well intervention vessels. The higher utilization rates in 2013 primarily reflected fewer idle days associated with regulatory dry docks in 2013 (the Well Enhancer for 24 days) as compared to 2012 (the Q4000 for 70 days, the Seawell for 52 days and the Well Enhancer for 52 days). In December 2013, the Well Enhancer commenced an additional regulatory dry dock, which has been completed and the vessel returned to service in late January 2014.

Our Robotics revenues increased by 1% in 2013 as compared to 2012 primarily reflecting the greater number of ROVs owned and higher ROVDrill revenues. However, Robotics revenues were adversely affected by a decrease in the number of spot vessel opportunities in 2013 as compared to those in 2012, a reduction in utilization rates resulting from greater than usual seasonal declines in the North Sea in early 2013 and lower year-over-year trenching activities associated with the deferral of many previously anticipated 2013 trenching projects in the North Sea region to 2014 and beyond.

Our Production Facilities revenues increased by 10% in 2013 as compared to 2012, which reflected a substantial increase in our total revenues under the fee arrangement with ERT for the use of the HP I to process production from the Phoenix field, which was revised following our sale of ERT in February 2013. Revenues generated by the HP I were eliminated in consolidation prior to the sale of ERT. The quarterly HFRS retainer fee also increased effective April 1, 2013 as a result of a new set of four-year agreements.

Our Subsea Construction revenues decreased by 63% in 2013 as compared to 2012 reflecting the sale of both the Caesar and the Express in mid-2013.

Gross Profit. Our gross profit increased significantly in 2013 as compared to 2012. In 2012, we recorded asset impairment charges of $177.1 million, including $157.8 million for the Caesar and related mobile pipelay equipment, $14.6 million for the Intrepid, and $4.6 million for well intervention assets associated with our former operations in Australia (Note 2). Absent the effect of the impairment charges, our gross profit increased by 15% in 2013 as compared to 2012.

Our Well Intervention gross profit increased by 42% in 2013 as compared to 2012 primarily reflecting revenue increases as a result of the addition of the Skandi Constructor and improved utilization rates in 2013.

Our Robotics gross profit decreased by 14% in 2013 as compared to 2012 reflecting a high volume of lower gross margin work in 2013 in an effort to reduce the idle time of our robotics assets. The increased pressure of this business reflected a tight market in the North Sea region in early 2013 and a light trenching market throughout 2013 following a good year of such activity in 2012.

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Our Production Facilities gross profit increased by 25% in 2013 as compared to 2012. The positive variance reflected both the increased processing fees under the revised contract with ERT following the completion of its sale in February 2013, and the higher retainer fee under the new HFRS agreements that went into effect in April 2013.

The increase in Subsea Construction gross profit in 2013 as compared to 2012 primarily reflected the $172.4 million of impairment charges we recorded in 2012, offset in part by our pipelay vessels only being in operation for the first half of 2013 prior to their sale as compared to a full year of operations in 2012.

Loss on Commodity Derivative Contracts. In December 2012, following the announcement of the sale of ERT, we de-designated our oil and gas commodity derivative contracts and interest rate swap contracts as hedging instruments (Note 15). The $14.1 million loss on commodity derivative contracts in 2013 reflected the net loss on our oil and gas commodity derivative contracts during the first quarter of 2013. In February 2013, we paid approximately $22.5 million to settle our remaining open commodity derivative contracts. The $10.5 million loss on commodity derivative contracts in 2012 reflected the amount of mark-to-market loss of unsettled oil and gas commodity derivative contracts associated with de-designation of these contracts as hedging instruments.

Gain (Loss) on Disposition of Assets, Net. The $14.7 million net gain on disposition of assets for 2013 primarily reflected a $1.1 million loss on the sale of the Caesar in June 2013 and a $15.6 million gain on the sale of the Express in July 2013 (Note 2). The $13.5 million loss on the disposition of assets in 2012 reflected the sale of the Intrepid in September 2012.

Selling, General and Administrative Expenses. Our selling, general and administrative expenses decreased by $12.2 million in 2013 as compared to 2012. The decrease reflected the reduction in the size of our organization following the sales of ERT, the Caesar and the Express, and the related effect of these transactions on the level of our corporate staffing. This decrease in our selling, general and administrative expenses was partially offset by approximately $1.9 million of severance related costs and $2.2 million associated with the provision for uncertain collection of a portion of our existing trade receivables in 2013 (Note 14). Additionally, the 2012 amount included approximately $3.5 million of severance and other closure costs associated with our decision to sell our remaining pipelay assets, to cease our Australian well intervention operations and to terminate the remaining lease term and other related closure costs associated with our former office in Rotterdam, The Netherlands. Lastly, our 2012 amount also included $2.6 million drawn against a letter of credit related to an international well abandonment project that was completed in 2011, of which amount $2.3 million (net of certain costs associated with the recovery) was recovered in 2014.

Equity in Earnings of Investments. Equity in earnings of investments decreased by $5.5 million in 2013 as compared to 2012. The decrease was primarily due to Independence Hub receiving lower fees from major customers of the facility following the expiration of a five-year supplemental monthly demand fee in March 2012 and lower throughput at both the Deepwater Gateway and Independence Hub facilities.

Net Interest Expense. Our net interest expense totaled $32.9 million in 2013 as compared to $48.2 million in 2012. The decrease consisted of both a reduction in interest expense and increases in capitalized interest and interest income. The decrease in interest expense reflected the substantial reduction in our indebtedness, including the $318.4 million repayment of debt in February 2013 following the sale of ERT, the early redemption of $200 million of our Senior Unsecured Notes in March 2012 and our redemption in July 2013 of the remaining $275 million of the Senior Unsecured Notes then outstanding. Capitalized interest totaled $10.4 million for 2013 as compared to $4.9 million for 2012. Interest income totaled $1.2 million for 2013 as compared to $0.5 million for 2012, reflecting our increased average cash on hand during 2013.

Loss on Early Extinguishment of Long-term Debt. The $12.1 million loss in 2013 included the $8.6 million loss on our redemption in July 2013 of the remaining $275 million Senior Unsecured Notes outstanding and the acceleration of the remaining deferred financing fees related to the term loan component of our former credit agreement following the repayment of that indebtedness. The charges of $17.1 million in 2012 were associated with the early extinguishment of portions of our debt, including $11.5 million related to our redemption of $200 million of our Senior Unsecured Notes and $5.6 million related to our repurchase of $142.2 million of our 2025 Notes. See Note 6 for information regarding our debt repayments.

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Other Income – Oil and Gas. The $6.6 million income for 2013 reflected the proceeds associated with our overriding royalty interests in ERT's Wang well, which commenced production in late April 2013, and cash payments related to services we provided to ERT following its sale in February 2013.

Income Tax Provision (Benefit). Income taxes reflected an expense of $31.6 million in 2013 as compared to a benefit of $59.2 million in 2012. The variance primarily reflected increased profitability in 2013 as compared to 2012. The effective tax rate for 2013 was a 22.0% expense. The effective tax rate for 2012 was a 47.0% benefit. The variance was primarily attributable to increased profitability of operations located within the United States.

Oil and Gas

All of our oil and gas assets sold in February 2013 were located in the U.S. Gulf of Mexico. The operating results of our discontinued oil and gas operations during 2012 and 2013 are presented in Note 13. Our continuing operations include one oil and gas property located offshore of the United Kingdom ("U.K."). We completed the reclamation activities of this offshore property in 2013 in accordance with the applicable U.K. regulations (Note 13). We had no revenues associated with our U.K. oil and gas property during the three-year period ended December 31, 2014. There were no operating costs associated with this U.K. property in 2013 and 2014. Operating costs for 2012 totaled $0.7 million.

LIQUIDITY AND CAPITAL RESOURCES

Overview

The following table presents certain information useful in the analysis of our financial condition and liquidity as of December 31, 2014 and 2013 (in thousands):

	2014	2013
Net working capital	$468,660	$553,427
Long-term debt (1)	$523,228	$545,776
Liquidity (2)	$1,060,092	$1,062,413

(1) Long-term debt does not include the current maturities portion of the long-term debt as that amount is included in net working capital. It is also net of the unamortized debt discount on the 2032 Notes. See Note 6 for information related to our existing debt.

(2) Liquidity, as defined by us, is equal to cash and cash equivalents plus available capacity under our Revolving Credit Facility, which capacity is reduced by letters of credit drawn against the facility. Our liquidity at December 31, 2014 included cash and cash equivalents of $476.5 million and $583.6 million of available borrowing capacity under our Revolving Credit Facility (Note 6). Our liquidity at December 31, 2013 included cash and cash equivalents of $478.2 million and $584.2 million of available borrowing capacity under our Revolving Credit Facility.

The carrying amount of our long-term debt, including current maturities, as of December 31, 2014 and 2013 is as follows (in thousands):

	2014	2013
Term Loan (matures June 2018)	$ 277,500	$ 292,500

2032 Notes (mature March 2032) (1)		179,080		173,484
MARAD Debt (matures February 2027)		94,792		100,168
Total debt	$	551,372	$	566,152

(1) These amounts are net of the unamortized debt discount of $20.9 million and $26.5 million, respectively. The 2032 Notes will increase to their $200 million face amount through accretion of non-cash interest charges through March 15, 2018, which is the first date on which the holders of the notes may require us to repurchase the notes.

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The following table provides summary data from our consolidated statements of cash flows (in thousands):

	Year Ended December 31,		
	2014	2013	2012
Cash provided by (used in):			
Operating activities	$359,485	$104,861	$176,068
Investing activities	$(335,512)	$(126,077)	$(295,712)
Financing activities	$(30,071)	$(487,421)	$(145,232)
Discontinued operations (1)	$—	$552,462	$156,373

(1) Represents total cash flows associated with the operations of ERT. ERT was sold in February 2013. Proceeds from the sale of ERT totaled $614.8 million, net of transaction costs. Other cash flows in the table above reflect our continuing operations.

Our current requirements for cash primarily reflect the need to fund capital expenditures for our current lines of business and to service our debt. Historically, we have funded our capital program with cash flows from operations, borrowings under credit facilities and use of project financing along with other debt and equity alternatives.

As a further response to the recent announcements regarding industry-wide reductions in capital spending, we remain even more focused on maintaining a strong balance sheet and adequate liquidity. Over the near term, we may seek to reduce, defer or cancel certain planned capital expenditures. We believe that internally-generated cash flows, available borrowing capacity under our Revolving Credit Facility and the Nordea Credit Agreement will be sufficient to fund our operations over at least the next twelve months.

In accordance with our Credit Agreement, the 2032 Notes, the MARAD Debt agreements, and the Nordea Credit Agreement, we are required to comply with certain covenants, including certain financial ratios such as a consolidated interest coverage ratio and consolidated leverage ratio, as well as the maintenance of minimum net worth, working capital and debt-to-equity requirements. Our Credit Agreement also contains 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 us. The Credit Agreement does permit us to incur certain unsecured indebtedness, and also provides for our subsidiaries to incur project financing indebtedness (such as our MARAD Debt and our Nordea Credit Agreement indebtedness) secured by the underlying asset, provided that such indebtedness is not guaranteed by us. The Credit Agreement also permits our Unrestricted Subsidiaries to incur indebtedness provided that it is not guaranteed by us or any of our Restricted Subsidiaries. As of December 31, 2014 and 2013, we were in compliance with all of our debt covenants.

A prolonged period of weak economic activity may make it difficult to comply with our covenants and other restrictions in agreements governing our debt. Furthermore, during any period of sustained weak economic activity, our ability to access the full available commitment of $600 million under our revolving credit facility may be impacted. Our ability to comply with these covenants and other restrictions is affected by economic conditions and other events beyond our control. If we fail to comply with these covenants and other restrictions, such failure could lead to an event of default, the possible acceleration of our repayment of outstanding debt and the exercise of certain remedies by our lenders, including foreclosure against our collateral.

In July 2013, we borrowed $300 million under our Term Loan in connection with our early redemption of the remaining $275 million Senior Unsecured Notes then outstanding. We may borrow and/or obtain letters of credit up to $600 million under our Revolving Credit Facility. Subject to customary conditions, we may request that aggregate commitments with respect to the Revolving Credit Facility be increased by, or additional term loans be made of, or a combination thereof, up to $200 million. See Note 6 for additional information relating to our long-term debt, including more information regarding our current and former credit agreements, including covenants and collateral.

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The 2032 Notes can be converted to our common stock prior to their stated maturity upon certain triggering events specified in the Indenture governing the notes. Beginning in March 15, 2018, the holders of the 2032 Notes may require us to repurchase these notes or we may at our own option elect to repurchase them. To the extent we do not have cash on hand or long-term financing secured to cover the conversion, the 2032 Notes would be classified as current liabilities in our consolidated balance sheet. No conversion triggers were met during the years ended December 31, 2014 and 2013.

Operating Cash Flows

Total cash flows from operating activities increased by $285.1 million in 2014 as compared to 2013 primarily reflecting increases in income from operations, changes in working capital, and a $35.2 million income tax refund we received in September 2014 from the IRS. Operating cash flows for 2013 also included $30.5 million of net cash used in discontinued operations related to ERT, which we sold in February 2013.

Total cash flows from operating activities decreased by $378.1 million in 2013 as compared to 2012 primarily reflecting the sales of ERT and our remaining pipelay vessels, payment of taxes associated with the sales, and the related settlement of our oil and gas commodity derivatives.

Investing Activities

Capital expenditures have consisted principally of the purchase or construction of dynamically positioned vessels, improvements and modifications to existing assets, and investments in our production facilities. Significant sources (uses) of cash associated with investing activities for the years ended December 31, 2014, 2013 and 2012 are as follows (in thousands):

	Year Ended December 31,		
	2014	2013	2012
Capital expenditures:			
Well Intervention	$(283,635)	$(283,132)	$(274,451)
Robotics	(51,348)	(39,655)	(44,500)
Production Facilities	(869)	(1,252)	(823)
Other	(1,060)	(387)	(3,265)
Distributions from equity investments, net (1)	7,911	9,295	7,797
Proceeds from sale of assets (2)	13,574	189,054	19,530
Acquisition of noncontrolling interests (3)	(20,085)	—	—
Net cash used in investing activities – continuing operations	(335,512)	(126,077)	(295,712)
Oil and Gas capital expenditures	—	(31,855)	(125,423)
Proceeds from sale of ERT, net of transaction costs	—	614,820	—
Other	—	—	5,366
Net cash provided by (used in) investing activities – discontinued operations	—	582,965	(120,057)
Net cash provided by (used in) investing activities	$(335,512)	$456,888	$(415,769)

(1) Distributions from equity investments are net of undistributed equity earnings from our equity investments. Gross distributions from our equity investments for the years ended December 31, 2014, 2013 and 2012 were $8.8 million, $12.3 million and $16.2 million, respectively (Note 4).

(2) Primarily reflects cash received from the sale of our Ingleside spoolbase in early 2014, the sale of both the Caesar and the Express in mid-year 2013, and the sale of the Intrepid and certain equipment associated with our former Australian well intervention operations in 2012.

(3) Relates to the acquisition in February 2014 of our former minority partner's noncontrolling interests in Kommandor LLC, the entity that owns the HP I (Notes 2 and 5).

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Capital expenditures associated with our business primarily include payments associated with the construction of our Q5000 and Q7000 vessels (see below), payments in connection with the acquisition and subsequent upgrades and modifications of the Helix 534 (see below), the investment in the topside well intervention equipment for the two newbuild monohull vessels that are expected to be used in service for Petrobras (see below) and the costs incurred in the acquisition of additional ROVs and trenchers for our robotics business.

In March 2012, we executed a contract with a shipyard in Singapore for the construction of a newbuild semi-submersible well intervention vessel, the Q5000. This $386.5 million shipyard contract represents the majority of the expected costs associated with the construction of the Q5000. Pursuant to the terms of this contract, payments are made in a fixed percentage of the contract price, together with any variations, on contractually scheduled dates. At December 31, 2014, our total investment in the Q5000 was $342.4 million, including $289.4 million of scheduled payments made to the shipyard. We plan to incur approximately $155 million on the Q5000 in 2015, including the last remaining shipyard payment of $97.1 million. We currently anticipate the vessel being available to perform well intervention services in the second half of 2015. In September 2014, we entered into the Nordea Credit Agreement to partially finance the construction of the Q5000 and other future capital projects (Note 6). The Nordea Term Loan will be funded at or near the time of the delivery of the Q5000, which is expected to occur in the second quarter of 2015.

In September 2013, we executed a second contract with the same shipyard in Singapore that is currently constructing the Q5000. This contract provides for the construction of a newbuild semi-submersible well intervention vessel, the Q7000, which will be built to North Sea standards. This $346.0 million shipyard contract represents the majority of the expected costs associated with the construction of the Q7000. Pursuant to the terms of this contract, 20% of the contract price was paid upon the signing of the contract and the remaining 80% will be paid upon the delivery of the vessel, which is expected to occur in 2016. At December 31, 2014, our total investment in the Q7000 was $91.8 million, including $69.2 million paid to the shipyard upon signing the contract. In 2015, we plan to incur approximately $40 million of costs related to the construction of the Q7000.

In February 2014, we entered into agreements with Petrobras to provide well intervention services offshore Brazil. The initial term of the agreements with Petrobras is for four years with options to extend. In connection with the Petrobras agreements, we entered into charter agreements with Siem Offshore AS for two newbuild monohull vessels, both of which are expected to be in service for Petrobras in 2016. Our total investment in the topside equipment for both vessels is expected to be approximately $260 million. We have invested $52.0 million as of December 31, 2014 and plan to invest approximately $65 million in the topside equipment in 2015.

Net cash used in discontinued operations relates to capital expenditures associated with ERT. Oil and Gas capital expenditures for the first quarter of 2013 included costs associated with the exploration and development activities primarily related to the Wang well within the Phoenix field at Green Canyon Block 237.

Outlook

We anticipate that our capital expenditures in 2015 will total approximately $400 million. This estimate may increase or decrease based on various economic factors and/or the existence of additional investment opportunities. However, we may reduce the level of our planned future capital expenditures given any prolonged economic downturn. We believe that our cash on hand, internally-generated cash flows, and availability under our current credit facility will provide the capital necessary to continue funding our 2015 initiatives.

Contractual Obligations and Commercial Commitments

The following table summarizes our contractual cash obligations as of December 31, 2014 and the scheduled years in which the obligations are contractually due (in thousands):

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	Total (1)	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
2032 Notes (2)	$200,000	$ —	$ —	$ —	$200,000
Term Loan (3)	277,500	22,500	60,000	195,000	—
MARAD debt	94,792	5,644	12,148	13,390	63,610
Interest related to debt (4)	184,031	24,475	42,743	24,380	92,433
Property and equipment (5)	505,393	199,646	305,747	—	—
Operating leases (6)	1,030,094	139,983	328,728	257,790	303,593
Total cash obligations	$2,291,810	$392,248	$749,366	$490,560	$659,636

(1) Excludes unsecured letters of credit outstanding at December 31, 2014 totaling $16.4 million. These letters of credit guarantee items such as various contractual obligations, customs duties, contract bidding and insurance activities.

(2) Notes mature in 2032. The 2032 Notes can be converted prior to their stated maturity if the closing price of our 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 130% of their issuance price on that 30th trading day (i.e., $32.53 per share). At December 31, 2014, the conversion trigger was not met. The first date that the holders of these notes may require us to repurchase the notes is March 15, 2018. See Note 6 for additional information.

(3) Amount reflects borrowings made in July 2013. The Term Loan will mature on June 19, 2018.

(4) Interest payment obligations were calculated using stated coupon rates for fixed rate debt and interest rates applicable at December 31, 2014 for variable rate debt.

(5) Primarily reflects the costs associated with our well intervention assets currently under construction, including our new semi-submersible well intervention vessels, the Q5000 and the Q7000, and the topside equipment for the two newbuild monohull vessels that we plan to charter (Note 11).

(6) Operating leases include vessel charters and facility leases. At December 31, 2014, our vessel charter and ROV lease commitments totaled approximately $1.0 billion, including four vessels that will not be delivered to us until 2015 and 2016.

Contingencies

We believe that there are currently no contingencies which would have a material effect on our financial position, results of operations or cash flows.

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

Our results of operations and financial condition, as reflected in the accompanying consolidated 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 that 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. See Note 2 for a detailed discussion on the application of our accounting policies.

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Revenue Recognition

Revenues from our services are derived from contracts, which are both short-term and long-term in duration. Our long-term contracts are contracts that 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.

Revenue on significant turnkey contracts is recognized under the percentage-of-completion method based on the ratio of costs incurred to total estimated costs at completion. 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 affect the progress and estimated cost of a project's completion and, therefore, the timing of 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. As of December 31, 2014, contract revenues subject to estimation were immaterial to our total consolidated revenues.

Goodwill and Other Intangible Assets

We are required to perform an annual impairment analysis of goodwill. We elected November 1 to be our annual impairment assessment date for goodwill. However, we could be required to evaluate the recoverability of goodwill prior to the 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.

As allowed under the guidance, we first assess qualitative factors in order to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount, including goodwill. Some of the qualitative factors evaluated include, among other things, the results of the most recent impairment test, the most recent operating results of the reporting unit, the current outlook for the reporting unit, and the current conditions of the market in which the reporting unit operates. If the qualitative assessment indicates a potential impairment, we perform the first step of the goodwill impairment test as described below. Our policy is to bypass the qualitative assessment at least once every three years and perform the first step of the goodwill impairment test, with the latest such test occurring on November 1, 2013.

We use both the income approach and the market approach to estimate the fair value of our reporting units under the first step of our goodwill impairment assessment. 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, economic projections, anticipated future cash flows and market place data. These assumptions could ultimately be materially different from our future actual results. 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 forecasted 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 economic risks.

Our goodwill at December 31, 2014, 2013 and 2012 was associated with our Well Intervention and Robotics segments. In our 2013 goodwill impairment test, the fair value of both of our reporting units with goodwill exceeded their respective carrying amounts. We performed the qualitative assessment as described above in both 2012 and 2014. Based on those assessments, we concluded that there was no indication of goodwill impairment and we did not perform step one of the impairment test in either year. We did not record any amount of goodwill impairment at December 31, 2014, 2013 or 2012.

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Income Taxes

Deferred income taxes are based on the differences between the 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, 2014, our principal non-U.S. subsidiaries had accumulated earnings and profits of approximately $338.0 million. We have not provided deferred U.S. income tax on the accumulated earnings and profits as we consider them permanently reinvested.

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, 2014, we believe that 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 7 for discussion of net operating loss carry forwards, deferred income taxes and uncertain tax positions taken by us.

Derivative Instruments and Hedging Activities

Our risk management activities involve the use of derivative financial instruments to hedge the impact of market risk exposure. Historically, we have used derivative instruments to reduce our market risk exposure related to oil and gas prices (prior to the sale of ERT), variable interest rates and foreign currency exchange rates. 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, including costless collars and swaps for a portion of our oil and gas production, interest rate swaps, and foreign currency exchange contracts. All derivative contracts are reflected in our balance sheet at fair value, unless otherwise noted.

We formally document all relationships between hedging instruments and the related 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 designated as hedges 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 (loss) (a component of shareholders' equity).

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 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. The fair value of our oil and gas derivative contracts reflected our best estimate and was based upon exchange or over-the-counter quotations whenever they are available. Quoted valuations may not have been available due to location differences or terms that extend beyond the period for which quotations are available. Where quotes were not available, we utilized other valuation techniques or models to estimate market values.

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.

See Notes 2 and 15 for additional information regarding our derivative contracts.

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Property and Equipment

Property and equipment is recorded at cost. Depreciation expense is derived primarily using the straight-line method over the estimated useful lives of the assets (Note 2).

Assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate that the carrying amount of the asset or asset group is not recoverable and exceeds its fair value. Our marine vessels are assessed on a vessel by vessel basis, while our ROVs are grouped and assessed by asset class. The expected future cash flows used for the assessment of recoverability are based on judgmental assessments of operating costs, project margins and capital project decisions, considering all available information at the date of review. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants or based on a multiple of operating cash flows validated with historical market transactions of similar assets where possible. If an impairment has occurred, we recognize a loss for the difference between the carrying amount and the fair value of the asset.

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 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 amount. Estimates of anticipated sales prices are judgmental and subject to revision in future periods, although initial estimates are typically based on sales prices for similar assets and other valuation data.

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 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 entity and our longer-term intent of retaining the investment in the entity.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

As of December 31, 2014, we were exposed to market risk in two areas: interest rates and foreign currency exchange rates.

Interest Rate Risk. As of December 31, 2014, $277.5 million of our outstanding debt was subject to floating rates. The interest rate applicable to our variable rate debt may rise, increasing our interest expense and related cash outlay. To reduce the impact of this market risk, in September 2013 we entered into interest rate swap contracts to fix the interest rate on $148.1 million of our Term Loan debt. These swap contracts, which are settled monthly, began in October 2013 and extend through October 2016. 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 $1.5 million in interest expense for the year ended December 31, 2014.

Foreign Currency Exchange Rate 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 our North Sea operations). As such, our earnings are subject to movements in foreign currency exchange rates when transactions are denominated in (i) currencies other than the U.S. dollar, which is our functional currency, or (ii) the functional currency of our subsidiaries, which is not necessarily the U.S. dollar. In order to mitigate the effects of exchange rate risk in areas outside the United States, we generally pay a portion of our expenses in local currencies and a substantial portion of our contracts provide for collections from customers in U.S. dollars.

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Assets and liabilities of our subsidiaries that do not have the U.S. dollar as their functional currency are translated using the exchange rates in effect at the balance sheet date, resulting in translation adjustments that are reflected in "Accumulated other comprehensive loss" ("Accumulated OCI") in the shareholders' equity section of our consolidated balance sheets. At December 31, 2014, approximately 15% of our assets are impacted by changes in foreign currencies in relation to the U.S. dollar. We recorded foreign currency translation unrealized gains (losses) of $(19.5) million, $5.0 million and $7.3 million to Accumulated OCI for the years ended December 31, 2014, 2013 and 2012, 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 other subsidiaries with operations in the United Kingdom, Asia Pacific and Europe. These subsidiaries conduct the majority of their operations in these regions in U.S. dollars which is their functional currency. When currencies other than the U.S. dollar are to be paid or received, the resulting transaction gain or loss is recognized in the consolidated statements of operations as a component of "Other income (expense), net." For the years ended December 31, 2014, 2013 and 2012, these amounts resulted in gains (losses) of $2.5 million, $0.7 million and $(0.5) million, respectively.

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 flows in 2015 and in the future. As a result, we entered into various foreign currency exchange contracts to stabilize expected cash outflows relating to certain vessel charters denominated in British pounds and Norwegian kroners. In January 2013, we entered into foreign currency exchange contracts to hedge through September 2017 the foreign currency exposure associated with the Grand Canyon charter payments ($104.6 million) denominated in Norwegian kroner (NOK591.3 million). In February 2013, we entered into similar foreign currency exchange contracts for the Grand Canyon II and the Grand Canyon III charter payments ($100.4 million and $98.8 million) denominated in Norwegian kroner (NOK594.7 million and NOK595.0 million), through July 2019 and February 2020, respectively. These contracts currently qualify for hedge accounting treatment. All of our remaining foreign exchange contracts that were not accounted for as hedge contracts have been settled and changes in their fair value were marked-to-market in earnings in each reporting period. At December 31, 2014 and 2013, the aggregate fair value of the foreign currency exchange contracts was a net liability of $50.4 million and $15.0 million, respectively. For the year ended December 31, 2014, we recorded losses totaling $1.7 million as a component of "Other income (expense), net" in the consolidated statement of operations. These losses were related to ineffectiveness associated with our foreign currency hedges with respect to the Grand Canyon II charter payments. For the years ended December 31, 2013 and 2012, the gains (losses) resulting from changes in the fair value of our foreign exchange contracts that were not designated for hedge accounting (Note 15) totaled $(0.6) million and $0.4 million, respectively.

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Item 8. Financial Statements and Supplementary Data.

Report of Independent Registered Public Accounting Firm

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, 2014 and 2013, and the related consolidated statements of operations, comprehensive income (loss), shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2014. 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 did not audit the financial statements of Deepwater Gateway, L.L.C. (a corporation in which the Company has a 50% interest) and Independence Hub, LLC (a corporation in which the Company has a 20% interest) for the year ended December 31, 2012. In the consolidated financial statements, the Company’s equity in earnings of investments includes approximately $8 million for the year ended December 31, 2012 from Deepwater Gateway, L.L.C. and Independence Hub, LLC combined. Those statements were audited by other auditors whose reports have been furnished to us, and our opinion, insofar as it relates to the amounts included for Deepwater Gateway, L.L.C. and Independence Hub, LLC, for the year ended December 31, 2012, is based solely on the reports of the other auditors.

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 and the reports of other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the reports of other auditors, 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, 2014 and 2013, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Helix Energy Solutions Group, Inc. and subsidiaries’ internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 18, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 18, 2015

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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, 2014, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (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, 2014, 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, 2014 and 2013, and the related consolidated statements of operations, comprehensive income (loss), shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2014 and our report dated February 18, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 18, 2015

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Management Committee of
Deepwater Gateway, L.L.C.
Houston, Texas

We have audited the balance sheet of Deepwater Gateway, L.L.C. (the "Company") as of December 31, 2012, and the related statements of operations, cash flows and members' equity for the year ended December 31, 2012 (not separately included herein). 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 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 the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2012, and the results of its operations and its cash flows for the year ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Houston, Texas
February 15, 2013

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Management Committee of
Independence Hub, LLC
Houston, Texas

We have audited the balance sheet of Independence Hub, LLC (the “Company”) as of December 31, 2012, and the related statements of operations, cash flows, and members' equity for the year ended December 31, 2012 (not separately included herein). 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 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 the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2012, and the results of its operations and its cash flows for the year ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Houston, Texas
February 15, 2013

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands)

	December 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 476,492	$ 478,200
Accounts receivable:		
Trade, net of allowance for uncollectible accounts of $4,735 and $2,234, respectively	104,724	156,925
Unbilled revenue	28,542	25,732
Costs in excess of billing	2,034	1,508
Current deferred tax assets	31,180	51,573
Other current assets	51,301	29,709
Total current assets	694,273	743,647
Property and equipment	2,241,444	1,963,706
Less accumulated depreciation	(506,060)	(431,489)
Property and equipment, net	1,735,384	1,532,217
Other assets:		
Equity investments	149,623	157,919
Goodwill	62,146	63,230
Other assets, net	59,272	47,267
Total assets	$ 2,700,698	$ 2,544,280
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 83,403	$ 72,602
Accrued liabilities	104,923	96,482
Income tax payable	9,143	760
Current maturities of long-term debt	28,144	20,376
Total current liabilities	225,613	190,220
Long-term debt	523,228	545,776
Deferred tax liabilities	260,275	265,879
Other non-current liabilities	38,108	18,295
Total liabilities	1,047,224	1,020,170
Commitments and contingencies		
Shareholders' equity:		
Common stock, no par, 240,000 shares authorized, 105,586 and 105,640 shares issued, respectively	934,447	933,507
Retained earnings	781,279	586,232
Accumulated other comprehensive loss	(62,252)	(20,688)
Total controlling interest shareholders' equity	1,653,474	1,499,051
Noncontrolling interests	—	25,059
Total equity	1,653,474	1,524,110
Total liabilities and shareholders' equity	$ 2,700,698	$ 2,544,280

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
(in thousands, except per share amounts)

	Year Ended December 31,		
	2014	2013	2012
Net revenues	$1,107,156	$876,561	$846,109
Cost of sales:			
Cost of sales	763,120	615,876	619,059
Asset impairment charges	—	—	177,135
Total cost of sales	763,120	615,876	796,194
Gross profit	344,036	260,685	49,915
Loss on commodity derivative contracts	—	(14,113)	(10,507)
Gain (loss) on disposition of assets, net	10,240	14,727	(13,476)
Selling, general and administrative expenses	(92,520)	(82,265)	(94,415)
Income (loss) from operations	261,756	179,034	(68,483)
Equity in earnings of investments	879	2,965	8,434
Net interest expense	(17,859)	(32,898)	(48,160)
Loss on early extinguishment of long-term debt	—	(12,100)	(17,127)
Other income (expense), net	814	6	(662)
Other income – oil and gas	16,931	6,581	—
Income (loss) before income taxes	262,521	143,588	(125,998)
Income tax provision (benefit)	66,971	31,612	(59,158)
Net income (loss) from continuing operations	195,550	111,976	(66,840)
Income from discontinued operations, net of tax	—	1,073	23,684
Net income (loss), including noncontrolling interests	195,550	113,049	(43,156)
Less net income applicable to noncontrolling interests	(503)	(3,127)	(3,178)
Net income (loss) applicable to Helix	$195,047	$109,922	$(46,334)
Basic earnings (loss) per share of common stock:			
Continuing operations	$1.85	$1.03	$(0.67)
Discontinued operations	—	0.01	0.23
Net income (loss) per common share	$1.85	$1.04	$(0.44)
Diluted earnings (loss) per share of common stock:			
Continuing operations	$1.85	$1.03	$(0.67)
Discontinued operations	—	0.01	0.23
Net income (loss) per common share	$1.85	$1.04	$(0.44)
Weighted average common shares outstanding:			
Basic	105,029	105,032	104,449
Diluted	105,045	105,184	104,449

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 COMPREHENSIVE INCOME (LOSS)
(in thousands)

	Year Ended December 31, 2014	2013	2012
Net income (loss), including noncontrolling interests	$195,550	$113,049	$(43,156)
Other comprehensive loss, net of tax:			
Unrealized loss on hedges arising during the period	(37,364)	(16,847)	(22,773)
Reclassification adjustments for loss included in net income	3,365	1,476	(2,661)
Reclassification adjustments for loss from derivatives de-designated as cash flow hedges included in net income	—	—	5,524
Income taxes on unrealized loss on hedges	11,899	5,380	6,969
Unrealized loss on hedges, net of tax	(22,100)	(9,991)	(12,941)
Foreign currency translation gain (loss)	(19,464)	4,970	7,291
Other comprehensive loss, net of tax	(41,564)	(5,021)	(5,650)
Comprehensive income (loss)	153,986	108,028	(48,806)
Less comprehensive income applicable to noncontrolling interests	(503)	(3,127)	(3,178)
Comprehensive income (loss) applicable to Helix	$153,483	$104,901	$(51,984)

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
(in thousands)

	Helix Energy Solutions Group 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, 2011	105,530	$ 908,776	$ 522,644	$ (10,017)	$ 1,421,403	$ 28,138	$ 1,449,541
Net income (loss)	—	—	(46,334)	—	(46,334)	3,178	(43,156)
Foreign currency translation adjustments	—	—	—	7,291	7,291	—	7,291
Unrealized loss on hedges, net	—	—	—	(12,941)	(12,941)	—	(12,941)
Distributions to noncontrolling interests	—	—	—	—	—	(5,287)	(5,287)
Equity component of debt discount on Convertible Senior Notes due 2032	—	22,419	—	—	22,419	—	22,419
Convertible preferred stock conversion	362	1,000	—	—	1,000	—	1,000
Stock compensation expense	—	7,361	—	—	7,361	—	7,361
Stock repurchases	(405)	(6,415)	—	—	(6,415)	—	(6,415)
Activity in company stock plans, net and other	276	787	—	—	787	—	787
Excess tax from stock-based compensation	—	(1,186)	—	—	(1,186)	—	(1,186)
Balance, December 31, 2012	105,763	$ 932,742	$ 476,310	$ (15,667)	$ 1,393,385	$ 26,029	$ 1,419,414
Net income	—	—	109,922	—	109,922	3,127	113,049
	—	—	—	4,970	4,970	—	4,970

Foreign currency translation adjustments							
Unrealized loss on hedges, net	—	—	—	(9,991)	(9,991)	—	(9,991)
Distributions to noncontrolling interests	—	—	—	—	—	(4,097)	(4,097)
Equity component of debt discount on Convertible Senior Notes due 2032	—	49	—	—	49	—	49
Stock compensation expense	—	7,510	—	—	7,510	—	7,510
Stock repurchases	(390)	(8,855)	—	—	(8,855)	—	(8,855)
Activity in company stock plans, net and other	267	1,842	—	—	1,842	—	1,842
Excess tax from stock-based compensation	—	219	—	—	219	—	219
Balance, December 31, 2013	105,640	$ 933,507	$ 586,232	$ (20,688)	$ 1,499,051	$ 25,059	$ 1,524,110
Net income	—	—	195,047	—	195,047	503	195,550
Foreign currency translation adjustments	—	—	—	(19,464)	(19,464)	—	(19,464)
Unrealized loss on hedges, net	—	—	—	(22,100)	(22,100)	—	(22,100)
Distributions to noncontrolling interests	—	—	—	—	—	(1,018)	(1,018)
Acquisition of noncontrolling interests	—	2,898	—	—	2,898	(24,544)	(21,646)
Stock compensation expense	—	2,176	—	—	2,176	—	2,176
Stock repurchases	(321)	(7,698)	—	—	(7,698)	—	(7,698)
Activity in company stock plans, net and other	267	3,496	—	—	3,496	—	3,496
Excess tax from stock-based compensation	—	68	—	—	68	—	68
	105,586	$ 934,447	$ 781,279	$ (62,252)	$ 1,653,474	$ —	$ 1,653,474

Balance,
December 31,
2014

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
(in thousands)

	Year Ended December 31, 2014	2013	2012
Cash flows from operating activities:			
Net income (loss), including noncontrolling interests	$195,550	$113,049	$(43,156)
Adjustments to reconcile net income (loss), including noncontrolling interests, to net cash provided by operating activities:			
Income from discontinued operations, net of tax	—	(1,073)	(23,684)
Depreciation and amortization	109,345	98,535	97,201
Asset impairment charges	—	—	177,135
Amortization of deferred financing costs	4,870	5,187	9,086
Stock-based compensation expense	3,133	8,307	7,627
Amortization of debt discount	5,596	5,172	9,729
Deferred income taxes	23,154	(24,937)	(69,584)
Excess tax from stock-based compensation	(68)	(219)	1,186
(Gain) loss on disposition of assets, net	(10,240)	(14,727)	13,476
Loss on early extinguishment of debt	—	12,100	17,127
Unrealized (gain) loss and ineffectiveness on derivative contracts, net	1,320	77	(250)
Changes in operating assets and liabilities:			
Accounts receivable, net	43,963	(3,320)	(3,652)
Other current assets	(6,461)	14,277	(10,434)
Income tax payable	9,088	(56,164)	(16,812)
Accounts payable and accrued liabilities	12,841	(32,045)	73,448
Oil and gas asset retirement costs	(1,024)	(10,334)	(37,970)
Other noncurrent, net	(31,582)	(9,024)	(24,405)
Net cash provided by operating activities	359,485	104,861	176,068
Net cash provided by (used in) discontinued operations	—	(30,503)	276,430
Net cash provided by operating activities	359,485	74,358	452,498
Cash flows from investing activities:			
Capital expenditures	(336,912)	(324,426)	(323,039)
Distributions from equity investments, net	7,911	9,295	7,797
Proceeds from sale of assets	13,574	189,054	19,530
Acquisition of noncontrolling interests	(20,085)	—	—
Net cash used in investing activities	(335,512)	(126,077)	(295,712)
Net cash provided by (used in) discontinued operations	-	582,965	(120,057)
Net cash provided by (used in) investing activities	(335,512)	456,888	(415,769)
Cash flows from financing activities:			
Early extinguishment of Senior Unsecured Notes	—	(281,490)	(209,500)
Borrowings under revolving credit facility	—	47,617	100,000
Repayment of revolving credit facility	—	(147,617)	—
Issuance of Convertible Senior Notes due 2032	—	—	200,000
Repurchase of Convertible Senior Notes due 2025	—	(3,487)	(298,288)
Proceeds from term loans	—	300,000	100,000
Repayment of term loans	(15,000)	(374,681)	(12,569)

Repayment of MARAD borrowings	(5,376)	(5,120)	(4,877)
Deferred financing costs	(3,586)	(10,954)	(7,580)
Distributions to noncontrolling interests	(1,018)	(4,097)	(5,287)
Repurchases of common stock	(8,382)	(11,256)	(7,197)
Excess tax from stock-based compensation	68	219	(1,186)
Exercise of stock options, net and other	—	734	1,252
Proceeds from issuance of ESPP shares	3,223	2,711	—
Net cash used in financing activities	(30,071)	(487,421)	(145,232)
Effect of exchange rate changes on cash and cash equivalents	4,390	(2,725)	(860)
Net increase (decrease) in cash and cash equivalents	(1,708)	41,100	(109,363)
Cash and cash equivalents:			
Balance, beginning of year	478,200	437,100	546,463
Balance, end of year	$476,492	$478,200	437,100

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

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 — Organization

Unless the context indicates otherwise, the terms “we,” “us” and “our” in this Annual Report refer collectively to Helix Energy Solutions Group, Inc. and its subsidiaries (“Helix” or the “Company”). We are an international offshore energy services company that provides specialty services to the offshore energy industry, with a focus on well intervention and robotics operations. We conduct operations primarily in deepwater in the Gulf of Mexico, North Sea, Asia Pacific and West Africa regions.

Our Operations

We seek to provide services and methodologies that we believe are critical to developing offshore reservoirs and maximizing production economics. Our “life of field” services are segregated into four business segments: Well Intervention, Robotics, Production Facilities and Subsea Construction (Note 12). Our Well Intervention segment includes our vessels and equipment used to perform well intervention services primarily in the Gulf of Mexico and North Sea regions. Our well intervention vessels include the Q4000, the Helix 534, the Seawell, the Well Enhancer and the Skandi Constructor, which is a chartered vessel. Our Robotics segment currently operates four chartered vessels, and also includes ROVs, trenchers and ROVDrills designed to complement offshore construction and well intervention services. Our Production Facilities segment includes the Helix Producer I (the “HP I”) vessel (Note 5), our equity investments in Deepwater Gateway, L.L.C. (“Deepwater Gateway”) and Independence Hub, LLC (“Independence Hub”) (Note 4), and the Helix Fast Response System (the “HFRS”) which provides certain operators access to our Q4000 and HP I vessels in the event of a well control incident in the Gulf of Mexico.

Discontinued Operations

In December 2012, we announced a definitive agreement for the sale of Energy Resource Technology GOM, Inc. (“ERT”), a former wholly-owned U.S. subsidiary that conducted our oil and gas operations in the Gulf of Mexico. In February 2013, we sold ERT for $624 million plus additional consideration in the form of overriding royalty interests in ERT’s Wang well and certain exploration prospects. As a result, we have presented the historical operating results of our former Oil and Gas segment as discontinued operations in the accompanying consolidated financial statements. See Note 13 for additional information regarding our discontinued oil and gas operations and Note 6 regarding the use of a portion of the sale proceeds to reduce our indebtedness under our former credit agreement.

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 account for our Deepwater Gateway and Independence Hub investments under the equity method of accounting. Noncontrolling interests represent the minority shareholders’ proportionate share of the equity in Kommandor LLC (Note 5). All material intercompany accounts and transactions have been eliminated. Certain reclassifications were made to previously-reported amounts in the consolidated financial statements and notes thereto to make them consistent with the current presentation format.

Use of Estimates

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

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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

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

	Year Ended December 31,		
	2014	2013	2012
Interest paid, net of interest capitalized	$11,628	$39,040	$68,735
Income taxes paid	$70,509	$113,331	$43,111

Our non-cash investing activities include accruals for property and equipment capital expenditures. As of December 31, 2014 and 2013, these non-cash investing accruals totaled $14.1 million and $9.5 million, respectively. Additionally, $27.5 million of our non-cash investing activities relates to the promissory note we received in connection with the sale of our Ingleside spoolbase in January 2014.

Accounts and Notes Receivable and Allowance for Uncollectible Accounts

Accounts and notes receivable are stated at the historical carrying amount net of write-offs and allowance for uncollectible accounts. The amount of our net accounts receivable and our note receivable approximates fair value. We establish an allowance for uncollectible accounts based on historical experience and any specific collection issues that we have identified. Uncollectible receivables 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 14).

Property and Equipment

Overview. Property and equipment is recorded at cost. Property and equipment is depreciated on a straight line basis over the estimated useful life of each asset. The following is a summary of the gross components of property and equipment (dollars in thousands):

	Estimated Useful Life	2014	2013
Vessels	15 to 30 years	$1,657,448	$1,403,573
ROVs, trenchers and ROVDrills	10 years	310,841	271,801
Machinery, equipment, buildings and leasehold improvements	5 to 30 years	273,155	288,332
Total property and equipment		$2,241,444	$1,963,706

The cost of repairs and maintenance is charged to expense as incurred, while the cost of improvements is capitalized. For the years ended December 31, 2014, 2013 and 2012, repair and maintenance expense totaled $44.6 million, $31.5 million and $39.3 million, respectively. Included in machinery, equipment, buildings and leasehold improvements were $17.4 million and $17.5 million of capitalized software costs ($3.9 million and $4.8 million, net of accumulated amortization) at December 31, 2014 and 2013, respectively. For the years ended December 31, 2014, 2013 and 2012, the total amount charged to expense related to the amortization of these software costs was $1.3

million, $1.8 million and $2.6 million, respectively.

Assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate that the carrying amount of the asset or asset group is not recoverable and exceeds the asset's or asset group's fair value. If, upon review, the sum of the undiscounted future cash flows expected to be generated by the asset or asset group is less than its carrying amount, an impairment is recorded. The amount of the impairment recorded is calculated as the difference between the carrying amount of the asset or asset group and its estimated fair value. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely

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independent of the cash flows of other groups of assets. Our marine vessels are assessed on a vessel by vessel basis, while our remotely operated vehicles (“ROVs”) are grouped and assessed by asset class. The expected future cash flows used for impairment reviews and related fair value calculations are based on assessments of operating costs, project margins and capital project decisions, considering all available information at the date of review. The fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants or based on a multiple of operating cash flows validated with historical market transactions of similar assets where possible. These fair value measurements fall within Level 3 of the fair value hierarchy.

In 2012, we decided to cease our well intervention operations in Australia. We recorded a $4.6 million impairment charge to reduce our well intervention assets in Australia to their fair value of $5.0 million. In 2012, as a result of diminished work opportunities for the Intrepid, we placed the subsea construction vessel in cold-stack mode and recorded an impairment of $14.6 million to reduce its carrying amount to its fair value of $28.0 million. We later sold the vessel for $14.5 million in cash, which resulted in an additional loss on disposal of $13.5 million.

Also in 2012, we entered into an agreement to sell our two remaining subsea construction pipelay vessels, the Caesar and the Express, and related pipelay equipment for a total sales price of $238.3 million. In connection with the announcement of the sale of our remaining subsea construction pipelay vessels and related equipment, we recorded an impairment of $157.8 million to reduce the carrying amount of the Caesar and related pipelay equipment to their respective fair values of $138.3 million, which reflects the consideration we expected to receive at the time of the sale. In June 2013, we completed the sale of the Caesar and related equipment and recorded an additional loss on disposal of $1.1 million. In July 2013, we completed the sale of the Express for $100 million, which resulted in a gain on disposal of $15.6 million.

In January 2014, we sold our spoolbase located in Ingleside, Texas for $45 million. In connection with this sale, we received $15 million in cash, including a $5 million deposit we received at the time the agreement was signed in December 2013. The remainder was paid to us with a $30 million secured promissory note. Interest on the note is payable quarterly at a rate of 6% per annum. We received $2.5 million and $7.5 million of principal payments on this note in December 2014 and January 2015, respectively. Under the terms of the note, the remaining $20 million principal balance is required to be paid with a $10 million payment on each December 31 of 2015 and 2016. See Note 13 for disclosure related to the impairment charges associated with certain of our former oil and gas properties.

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 life of the asset in the same manner as the underlying asset. The total of our interest expense capitalized during the years ended December 31, 2014, 2013 and 2012 was $10.4 million, $10.4 million and $4.9 million, respectively.

Equity Investments

We periodically review our equity 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 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 entity and our longer-term intent of retaining the investment in the entity.

Goodwill

We are required to perform an annual impairment analysis of goodwill. We elected November 1 to be our annual impairment assessment date for goodwill. However, we could be required to evaluate the recoverability of goodwill prior to the 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. At the time of our annual assessment of goodwill on November 1, 2014, we had two reporting units with goodwill.

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As allowed under the guidance, we first assess qualitative factors in order to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount, including goodwill. Some of the qualitative factors evaluated include, among other things, the results of the most recent impairment test, the most recent operating results of the reporting unit, the current outlook for the reporting unit, and the current conditions of the market in which the reporting unit operates. If the qualitative assessment indicates a potential impairment, we perform the first step of the goodwill impairment test as described below. Our policy is to bypass the qualitative assessment at least once every three years and perform the first step of the goodwill impairment test, with the latest such test occurring on November 1, 2013.

The goodwill impairment test is 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 were acquired in a business combination).

We use both the income approach and the market approach to estimate the fair value of our reporting units under the first step of our goodwill impairment assessment. 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, 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 forecasted 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 economic risks.

Our goodwill at December 31, 2014, 2013 and 2012 was associated with our Well Intervention and Robotics segments. In our 2013 goodwill impairment test, the fair value of both of our reporting units with goodwill exceeded their respective carrying amounts. We performed the qualitative assessment as described above in both 2012 and 2014. Based on those assessments, we concluded that there was no indication of goodwill impairment and we did not perform step one of the impairment test in either year. We did not record any amount of goodwill impairment at December 31, 2014, 2013 or 2012.

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

	Well Intervention	Robotics	Total
Balance at December 31, 2012	$ 17,828	$ 45,107	$ 62,935
Other adjustments (1)	295	—	295
Balance at December 31, 2013	18,123	45,107	63,230
Other adjustments (1)	(1,084)	—	(1,084)

Balance at December 31, 2014	$ 17,039	$ 45,107	$ 62,146

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

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Recertification Costs and Deferred Dry Dock Charges

Our vessels are required by regulation to be recertified after certain periods of time. Recertification costs are incurred while a vessel is in dry dock. 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 dry dock and related recertification costs over the length of time for which we expect to receive benefits from the dry dock and related recertification, which is generally 30 months but can be as long as 60 months if the appropriate permitting is obtained. A dry dock and related recertification process typically lasts one to two months, a period during which the vessel is idle and generally not available to earn revenue. Major replacements and improvements that extend the vessel's economic useful life or functional operating capability are capitalized and depreciated over the vessel's remaining economic useful life.

As of December 31, 2014 and 2013, capitalized deferred dry dock charges included within "Other assets, net" in the accompanying consolidated balance sheets (Note 3) totaled \$11.6 million and \$20.8 million (net of accumulated amortization of \$7.5 million and \$14.5 million), respectively. During the years ended December 31, 2014, 2013 and 2012, dry dock amortization expense was \$14.1 million, \$14.8 million and \$8.6 million, respectively.

Revenue Recognition

Revenues from our services are derived from contracts, which are both short-term and long-term in duration. Our long-term services contracts are contracts that 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, 2014 and 2013 are expected to be billed and collected within one year. However, we also monitor the collectability of our outstanding trade receivables on a continual basis in connection with our evaluation of allowance for doubtful accounts.

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. 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 using the same 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 under 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 provision of services;
- we can reasonably estimate our progress towards completion and our costs;
- the contract includes provisions for 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.

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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 affect the progress and estimated cost of a project's completion and, therefore, the timing of 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.

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.

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, 2014, we believe that 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

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 Helix Well Ops (U.K.) Limited ("WOUK")). The functional currency for WOUK is the applicable local currency (British Pound). Results of operations for these subsidiaries are translated into U.S. dollars using average exchange rates during the period. Assets and liabilities of these foreign subsidiaries are translated into U.S. dollars using the exchange rate in effect at December 31, 2014 and 2013 and the resulting translation adjustments, which were unrealized gains (losses) of $(19.5) million and $5.0 million, respectively, are included in "Accumulated other comprehensive loss" ("Accumulated OCI"), a component of shareholders' equity.

For the years ended December 31, 2014, 2013 and 2012, our foreign currency transaction gains (losses) totaled $2.5 million, $0.7 million and $(0.5) million, respectively. These realized amounts are exclusive of any gains or losses from our foreign currency exchange derivative contracts. All foreign currency transaction gains and losses are recognized currently in the consolidated statements of operations.

Derivative Instruments and Hedging Activities

Our operations are exposed to market risks associated with interest rates and foreign currency exchange rates. Our risk management activities involve the use of derivative financial instruments to hedge the impact of market risk exposure related to variable interest rates and foreign currency exchange rates. All derivatives are reflected in the accompanying consolidated balance sheets at fair value.

We formally document all relationships between hedging instruments and the related 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 designated as hedges 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 because it is probable the hedged transaction will not occur, deferred gains or losses on the hedging instruments are recognized in earnings immediately.

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If the forecasted transaction continues to be probable of occurring, any deferred gains or losses in accumulated other comprehensive income (loss) (a component of shareholders' equity) are amortized to earnings over the remaining period of the original forecasted transaction.

We engage solely 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 fair value of derivatives that are designated as cash flow hedges are deferred to the extent that the hedges are effective. These fair value changes are recorded as a component of Accumulated OCI until the hedged transactions occur and are recognized in earnings. The ineffective portion of changes in the fair value of cash flow hedges 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.

Interest Rate Risk

From time to time, we enter into interest rate swaps to stabilize cash flows related to our long-term debt subject to variable interest rates. Changes in the fair value of an interest rate swap are deferred to the extent the swap is effective. These changes are recorded as a component of Accumulated OCI until the anticipated interest payments occur and are recognized in interest expense. The ineffective portion of the interest rate swap, if any, is recognized immediately in earnings within the line titled "Net interest expense." The amount of ineffectiveness associated with our interest rate swap contracts was immaterial for all periods presented.

Foreign Currency Exchange Rate 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. We entered into various foreign currency exchange contracts to stabilize expected cash outflows relating to certain vessel charters that are denominated in British pounds and Norwegian kroner. At December 31, 2014 and 2013, the aggregate fair value of the foreign exchange contracts was a net liability of $50.4 million and $15.0 million, respectively.

See Note 15 for more information regarding the accounting for our derivative contracts including our oil and gas commodity contracts associated with ERT.

Earnings Per Share

The presentation of basic EPS amounts on the face of the accompanying consolidated statements of operations is computed by dividing the net income applicable to our common shareholders by the weighted average shares of our 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. We have shares of restricted stock issued and outstanding, which currently are unvested. Holders of such shares of unvested restricted stock are entitled to the same liquidation and dividend rights as the holders of our outstanding unrestricted common stock and the shares are thus considered participating securities. Under applicable accounting guidance, the undistributed earnings for each period are allocated based on the 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 earnings per share ("EPS") amounts under the two class method in periods in which we have earnings from continuing operations. For periods in which we have a net loss, we do not use the two class method as holders of our restricted shares are not contractually obligated to share in such losses.

The computations of the numerator (income) and denominator (shares) to derive the basic and diluted EPS amounts presented on the face of the accompanying consolidated statements of operations for the years ended December 31, 2014, 2013 and 2012 are as follows (in thousands):

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	Year Ended December 31,					
	2014		2013		2012	
	Income	Shares	Income	Shares	Income	Shares
Basic:						
Continuing operations:						
Net income applicable to Helix	$ 195,047		$ 109,922		$ (46,334)	
Less: Income from discontinued operations, net of tax	—		(1,073)		(23,684)	
Net income from continuing operations	195,047		108,849		(70,018)	
Less: Undistributed income allocable to participating securities – continuing operations	(1,018)		(801)		—	
Net income applicable to common shareholders – continuing operations	$ 194,029	105,029	$ 108,048	105,032	$ (70,018)	104,449
Discontinued operations:						
Income from discontinued operations, net of tax	$ —		$ 1,073		$ 23,684	
Less: Undistributed income allocable to participating securities – discontinued operations	—		(8)		—	
Net income applicable to common shareholders – discontinued operations	$ —	105,029	$ 1,065	105,032	$ 23,684	104,449
Diluted:						
Continuing operations:						
Net income applicable to common shareholders – continuing operations	$ 194,029	105,029	$ 108,048	105,032	$ (70,018)	104,449
Effect of dilutive securities:						
Share-based awards other than participating securities	—	16	—	152	—	—
Undistributed income reallocated to participating securities	—	—	1	—	—	—
Net income applicable to common shareholders – continuing operations	$ 194,029	105,045	$ 108,049	105,184	$ (70,018)	104,449
Discontinued operations:						
Income from discontinued operations, net of tax	$ —	105,045	$ 1,073	105,184	$ 23,684	104,449

We had net losses from continuing operations for the year ended December 31, 2012. Accordingly, our diluted EPS calculation for 2012 was equivalent to our basic EPS 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 in those respective years. Shares that otherwise would have been included in the diluted per share calculations for the year ended December 31, 2012, assuming we had earnings from continuing operations, are as follows (in thousands):

	2012
Diluted shares (as reported)	104,449
Share-based awards	382
Convertible preferred stock	334
Total	105,165

In addition, approximately 8.0 million of potentially dilutive shares related to our Convertible Senior Notes Due 2032 (the “2032 Notes”) were excluded from the diluted EPS calculation for the years ended December 31, 2014 and 2013 because we have the right and the intention to settle any such future conversions in cash (Note 6). Approximately 9.3 million of potentially dilutive shares related to our Convertible Senior Notes Due 2025 (the “2025 Notes”) then outstanding were excluded for the year ended December 31, 2012 as the conversion trigger of $38.57 per share was not met.

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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, 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. Our customers consist primarily of major and independent oil and gas producers and suppliers, pipeline transmission companies, alternative (renewable) energy companies and offshore engineering and construction firms. We perform ongoing credit evaluations of our customers and provide allowances for probable credit losses when necessary. The percent of consolidated revenue from major customers (those representing 10% or more of our consolidated revenues) is as follows: 2014 — Anadarko (13%); 2013 — Shell (14%) and 2012 — Shell (12%). Most of the revenues from Shell were generated by our Well Intervention segment.

Fair Value Measurements

Fair value is defined as 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. The 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 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).

Our financial instruments include cash and cash equivalents, accounts receivable, accounts payable, long-term debt and various derivative instruments. 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 following tables provide additional information related to other financial instruments measured at fair value on a recurring basis (in thousands):

	Fair Value Measurements at December 31, 2014 Using				
	Level 1	Level 2 (1)	Level 3	Total	Valuation Technique
Assets:					
Interest rate swaps	$ —	$ 369	$ —	$ 369	(c)
Liabilities:					
Fair value of long-term debt (2)	222,900	375,393	—	598,293	(a)
Foreign exchange contracts	—	50,428	—	50,428	(c)
Interest rate swaps	—	561	—	561	(c)
Total net liability	$ 222,900	$ 426,013	$ —	$ 648,913	

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	Fair Value Measurements at December 31, 2013 Using				
	Level 1	Level 2 (1)	Level 3	Total	Valuation Technique
Assets:					
Foreign exchange contracts	$ —	$ 69	$ —	$ 69	(c)
Interest rate swaps	—	446	—	446	(c)
Liabilities:					
Fair value of long-term debt (2)	242,250	403,437	—	645,687	(a)
Foreign exchange contracts	—	15,071	—	15,071	(c)
Interest rate swaps	—	746	—	746	(c)
Total net liability	$ 242,250	$ 418,739	$ —	$ 660,989	

(1) Unless otherwise indicated, the fair value of our Level 2 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 based on market data. Our actual results may differ from our estimates, and these differences could be positive or negative. See Note 15 for further discussion on fair value of our derivative instruments.

(2) See Note 6 for additional information regarding our long-term debt. The value of our long-term debt at December 31, 2014 and 2013 is as follows (in thousands):

	2014		2013	
	Carrying Amount	Fair Value (b)	Carrying Amount	Fair Value (b)
Term Loan (matures June 2018)	$277,500	$270,563	$292,500	$293,963
2032 Notes (mature March 2032) (a)	200,000	222,900	200,000	242,250
MARAD Debt (matures February 2027)	94,792	104,830	100,168	109,474
Total debt	$572,292	$598,293	$592,668	$645,687

(a) Carrying amount excludes the related unamortized debt discount of $20.9 million and $26.5 million at December 31, 2014 and 2013, respectively.

(b) The estimated fair value of the 2032 Notes was determined using Level 1 inputs under the market approach. The fair value of the Term Loan and the MARAD Debt was estimated using Level 2 fair value inputs under the market approach. The fair value of the Term Loan and the MARAD debt was determined using a third party evaluation of the remaining average life and outstanding principal balance of the indebtedness as compared to other obligations in the marketplace with similar terms.

Debt Discount

In connection with the issuance of the 2032 Notes, we recorded a discount of $35.4 million under existing accounting requirements. To arrive at this discount amount, we estimated the fair value of the liability component of the 2032 Notes as of the date of their issuance (March 12, 2012) 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 6.0 years. In selecting the expected life, we selected the earliest date that the holders could require us to repurchase all or a portion of the 2032 Notes (March 15, 2018). The remaining unamortized amount of the discount of the 2032 Notes was $20.9 million and $26.5 million at December 31, 2014 and 2013, respectively (Note 6).

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Convertible Preferred Stock

In December 2012, the holder of the remaining $1 million of Convertible Preferred Stock converted it into 361,402 shares of our common stock. Our Convertible Preferred Stock was assessed for inclusion in our diluted earnings per share calculation using the if converted method (see "Earnings Per Share") above.

Related Party Transactions

Our Chief Executive Officer, Owen Kratz, through Class A limited partnership interests in OKCD Investments, Ltd. ("OKCD"), personally owns approximately 85% of the partnership. OKCD receives a royalty from ERT, which was a wholly owned subsidiary of Helix until ERT was sold in February 2013. Payments to OKCD during the period in which Helix owned ERT totaled $0.6 million in 2013.

New Accounting Standards

In May 2014, the Financial Accounting Standards Board issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)." This ASU provides a single five-step approach to account for revenue arising from contracts with customers. The ASU requires entities to recognize revenue in a way that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This guidance is effective prospectively for annual reporting periods beginning after December 15, 2016, including interim periods. Early adoption is not permitted. The guidance permits companies to either apply the requirements retrospectively to all prior periods presented, or apply the requirements in the year of adoption through a cumulative adjustment. We are currently evaluating which transition approach to use and the potential impact the adoption of this new standard may have on our consolidated financial statements.

We do not expect any other recent accounting standards to have a material impact on our financial position, results of operations or cash flows.

Note 3 — Details of Certain Accounts

Other current assets consisted of the following as of December 31, 2014 and 2013 (in thousands):

	2014	2013
Note receivable (1)	$17,500	$ —
Other receivables	423	785
Prepaid insurance	6,582	7,038
Other prepaids	15,541	12,999
Spare parts inventory	1,857	1,038
Value added tax receivable	9,326	7,589
Other	72	260
Total other current assets	$51,301	$29,709

Other assets, net, consisted of the following as of December 31, 2014 and 2013 (in thousands):

	2014	2013
Note receivable (1)	$10,000	$ —
Deferred dry dock expenses, net (Note 2)	11,631	20,833

Deferred financing costs, net (Note 6)	23,399	24,297
Intangible assets with finite lives, net	696	622
Charter fee deposit (Note 11)	12,544	—
Other	1,002	1,515
Total other assets, net	$59,272	$47,267

(1) Relates to the remaining balance of the promissory note we received in connection with the sale of our Ingleside spoolbase in January 2014 (Note 2).

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Accrued liabilities consisted of the following as of December 31, 2014 and 2013 (in thousands):

	2014	2013
Accrued payroll and related benefits	$61,246	$50,527
Current asset retirement obligations	575	2,024
Unearned revenue	11,461	19,608
Billing in excess of cost	—	1,677
Accrued interest	4,221	4,187
Derivative liability (Note 15)	13,222	2,651
Taxes payable excluding income tax payable	6,236	4,811
Pipelay assets sale deposit	—	5,000
Other	7,962	5,997
Total accrued liabilities	$104,923	$96,482

Note 4 — Equity Investments

As of December 31, 2014, we had two investments that we account for using the equity method of accounting: Deepwater Gateway and Independence Hub, both of which are included in our Production Facilities segment.

Deepwater Gateway, L.L.C. In June 2002, we, along with Enterprise Products Partners L.P. (”Enterprise”), formed Deepwater Gateway, each with a 50% interest, to design, construct, install, own and operate a tension leg platform production hub primarily for Anadarko Petroleum Corporation's Marco Polo field in the Deepwater Gulf of Mexico. As of December 31, 2014 and 2013, our investment in Deepwater Gateway totaled $80.9 million and $85.8 million (including net capitalized interest of $1.2 million and $1.3 million), respectively.

Independence Hub, LLC. 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. As of December 31, 2014 and 2013, our investment in Independence Hub was $68.8 million and $72.1 million (including net capitalized interest of $3.9 million and $4.3 million), respectively.

We received the following distributions from our equity method investments during the years ended December 31, 2014, 2013 and 2012 (in thousands):

	Year Ended December 31,		
	2014	2013	2012
Deepwater Gateway	$6,150	$7,600	$8,157
Independence Hub	2,640	4,660	8,073
Total	$8,790	$12,260	$16,230

Note 5 — 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 HP I) was leased to us under a bareboat charter. We subsequently installed topside oil and gas processing equipment, at 100% our cost, that allows the HP I to serve as a floating production system primarily servicing fields in the Deepwater of the Gulf of Mexico. In June 2010, the HP I was certified for use as a floating production unit by the

U.S. Coast Guard. The HP I initially participated in the Macondo well control and containment efforts. Subsequently, the HP I mobilized to the Phoenix field where production commenced in October 2010. The HP I is under contract with ERT to service the Phoenix field through at least December 31, 2016.

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The consolidated results of Kommandor LLC are included in our Production Facilities segment. We owned approximately 81% of Kommandor LLC at December 31, 2013. In February 2014, we acquired Kommandor RØMØ's noncontrolling interest (approximately 19%) in Kommandor LLC for $20.1 million.

Note 6 — Long-Term Debt

Long-term debt consisted of the following as of December 31, 2014 and 2013 (in thousands):

	2014	2013
Term Loan (matures June 2018)	$277,500	$292,500
2032 Notes (mature March 2032)	200,000	200,000
MARAD Debt (matures February 2027)	94,792	100,168
Unamoritized debt discount	(20,920)	(26,516)
Total debt	551,372	566,152
Less current maturities	(28,144)	(20,376)
Long-term debt	$523,228	$545,776

Credit Agreement

In June 2013, we entered into a Credit Agreement (the "Credit Agreement") with a group of lenders pursuant to which we borrowed $300 million under the Credit Agreement's term loan (the "Term Loan") component and may borrow revolving loans (the "Revolving Loans") and/or obtain letters of credit under a revolving credit facility up to an outstanding amount of $600 million (the "Revolving Credit Facility"). Subject to customary conditions, we may request an increase of up to $200 million in aggregate commitments with respect to the Revolving Credit Facility, additional term loans or a combination thereof. The $300 million we borrowed under the Term Loan in 2013 was in connection with our early redemption of the remaining $275 million Senior Unsecured Notes outstanding in July 2013 (see "Senior Unsecured Notes" below). At December 31, 2014, our availability under the Revolving Credit Facility totaled $583.6 million, net of $16.4 million of letters of credit issued.

The Term Loan and the Revolving Loans (together, the "Loans") will bear interest, at our election, in relation to either the base rate established by Bank of America N.A. or to a LIBOR rate, provided that all Swing Line Loans (as defined in the Credit Agreement) will be base rate loans.

The Loans or portions thereof bearing interest at the base rate will bear interest at a per annum rate equal to the base rate plus a margin ranging from 1.00% to 2.00%. The Loans or portions thereof bearing interest at a LIBOR rate will bear interest at the LIBOR rate selected by us plus a margin ranging from 2.00% to 3.00%. A letter of credit fee is payable by us equal to our applicable margin for LIBOR rate Loans multiplied by the daily amount available to be drawn under outstanding letters of credit. Margins on the Loans will vary in relation to the consolidated coverage ratio, as provided by the Credit Agreement. We currently also pay a fixed commitment fee of 0.375% on the unused portion of our Revolving Credit Facility. The Term Loan currently bears interest at the one-month LIBOR rate plus 2.25%. In September 2013, we entered into various interest rate swap contracts to fix the one-month LIBOR rate on $148.1 million of the Term Loan (Note 15). The fixed LIBOR rates were between 74 and 75 basis points.

The Term Loan is repayable in scheduled principal installments of 5% in each of the initial two loan years ($15 million per year), and 10% in each of the remaining three loan years ($30 million per year), payable quarterly, with a balloon payment of $180 million at maturity. These installment amounts are subject to adjustment for any prepayments on the Term Loan. We may elect to prepay amounts outstanding under the Term Loan without premium or penalty, but may not reborrow any amounts prepaid. We may prepay amounts outstanding under the Revolving

Loans without premium or penalty, and may reborrow any amounts paid up to the amount of the Revolving Credit Facility. The Loans mature on June 19, 2018. In certain circumstances, we will be required to prepay the Loans.

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The Credit Agreement and the other documents entered into in connection with the Credit Agreement (together, the "Loan Documents") include terms and conditions, including covenants, which we consider customary for this type of transaction. The covenants include restrictions on our and our subsidiaries' ability to grant liens, incur indebtedness, make investments, merge or consolidate, sell or transfer assets, pay dividends and incur capital expenditures. In addition, the Credit Agreement obligates us to meet certain financial ratios, including the Consolidated Interest Coverage Ratio and the Consolidated Leverage Ratio (as defined in the Credit Agreement). We have designated five of our foreign subsidiaries, and may designate any newly established foreign subsidiaries, as subsidiaries that are not generally subject to the covenants in the Credit Agreement (the "Unrestricted Subsidiaries"), provided we meet certain liquidity requirements, in which case EBITDA of the Unrestricted Subsidiaries is not included in the calculations with respect to our financial covenants. Our obligations under the Credit Agreement are guaranteed by our wholly-owned domestic subsidiaries (except Cal Dive I – Title XI, Inc.) and Canyon Offshore Limited. Our obligations under the Credit Agreement, and of the guarantors under their guaranty, are secured by most of our assets and assets of the guarantors and Canyon Offshore Limited, plus pledges of up to two-thirds of the shares of certain foreign subsidiaries.

Convertible Senior Notes Due 2032

In March 2012, we completed a public offering and sale of $200.0 million in aggregate principal amount of 3.25% Convertible Senior Notes due 2032. The net proceeds from the issuance of the 2032 Notes were $195.0 million, after deducting the underwriter's discounts and commissions and offering expenses. We used the net proceeds to repurchase and retire $142.2 million of aggregate principal amount of the 2025 Notes (see below) in separate, privately negotiated transactions. The remaining net proceeds were used for other general corporate purposes, including the repayment of other indebtedness.

The 2032 Notes bear interest at a rate of 3.25% per annum, and are payable semi-annually in arrears on March 15 and September 15 of each year, beginning on September 15, 2012. The 2032 Notes will mature on March 15, 2032 unless earlier converted, redeemed or repurchased. The 2032 Notes are convertible in certain circumstances and during certain periods at an initial conversion rate of 39.9752 shares of common stock per $1,000 principal amount (which represents an initial conversion price of approximately $25.02 per share of common stock), subject to adjustment in certain circumstances as set forth in the Indenture governing the 2032 Notes. We have the right and the intention to settle any such future conversions in cash.

Prior to March 20, 2018, the 2032 Notes are not redeemable. On or after March 20, 2018, we, at our option, may redeem some or all of the 2032 Notes in cash, at any time upon at least 30 days' notice, at a price equal to 100% of the principal amount plus accrued and unpaid interest (including contingent interest, if any) up to but excluding the redemption date. In addition, the holders of the 2032 Notes may require us to purchase in cash some or all of their 2032 Notes at a repurchase price equal to 100% of the principal amount of the 2032 Notes, plus accrued and unpaid interest (including contingent interest, if any) up to but excluding the applicable repurchase date, on March 15, 2018, March 15, 2022 and March 15, 2027, or, subject to specified exceptions, at any time prior to the 2032 Notes' maturity following a fundamental change (as defined in the Indenture governing the 2032 Notes).

In connection with the issuance of the 2032 Notes, we recorded a discount of $35.4 million as required under existing accounting rules. To arrive at this discount amount, we estimated the fair value of the liability component of the 2032 Notes as of the date of their issuance (March 12, 2012) 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 6.0 years. In selecting the expected life, we selected the earliest date upon which the holders could require us to repurchase all or a portion of the 2032 Notes (March 15, 2018). The effective interest rate for the 2032 Notes is 6.9% after considering the effect of the accretion of the related debt discount that represented the equity component of the 2032 Notes at their inception. As of December 31, 2014, the carrying amount of the equity component of the 2032 Notes was $22.5 million.

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MARAD Debt

This U.S. government guaranteed financing (the "MARAD Debt") is pursuant to Title XI of the Merchant Marine Act of 1936 administered by the Maritime Administration, and was used to finance the construction of the Q4000. The MARAD Debt is payable in equal semi-annual installments beginning in August 2002 and matures in February 2027. The MARAD Debt is collateralized by the Q4000, is guaranteed 50% by us, and initially bore interest at a floating rate that 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.

Nordea Credit Agreement

In September 2014, our wholly-owned subsidiary, Helix Q5000 Holdings S.à r.l. ("Q5000 Holdings"), a Luxembourg entity, entered into a Credit Agreement (the "Nordea Credit Agreement") with a syndicated bank lending group for a term loan (the "Nordea Term Loan") in an amount of up to $250 million. The Nordea Term Loan will be funded at or near the time of the delivery of the Q5000, which is currently estimated in the second quarter of 2015. The parent company of Q5000 Holdings, Helix Vessel Finance S.à r.l., has guaranteed the Nordea Term Loan. The loan will be secured by the Q5000 and its charter earnings as well as by a pledge of the shares of Q5000 Holdings. This indebtedness is nonrecourse to Helix.

The Nordea Term Loan will bear interest at a LIBOR rate plus a margin of 2.5%, with an undrawn fee of 0.875%. The Nordea Term Loan matures five years after funding and is repayable in scheduled principal installments of $8.9 million, payable quarterly, with a balloon payment of $80.4 million at maturity. Installment amounts are subject to adjustment for any prepayments on this debt. Q5000 Holdings may elect to prepay amounts outstanding under the Nordea Term Loan without premium or penalty, but may not reborrow any amounts prepaid. In certain circumstances, Q5000 Holdings will be required to prepay the loan.

The Nordea Credit Agreement and the other related loan documents include terms and conditions, including covenants that are considered customary for this type of transaction. The covenants include restrictions on Q5000 Holdings's ability to grant liens, incur indebtedness, make investments, merge or consolidate, sell or transfer assets, and pay dividends. In addition, the Nordea Credit Agreement obligates Q5000 Holdings to meet minimum financial requirements, including liquidity, consolidated debt service coverage and collateral maintenance.

Former Credit Facility

Similar to our current Credit Agreement, our former credit facility contained both term loan and revolving loan components. This indebtedness was scheduled to mature on July 1, 2015. In February 2013, we repaid $318.4 million of borrowings outstanding under this former credit facility with the proceeds from the sale of ERT. We fully repaid the remaining indebtedness outstanding under this credit facility in June 2013. In connection with the repayments of this debt, we recorded charges totaling $3.5 million to accelerate a pro rata portion of the deferred financing costs associated with our former term loan debt. This charge is reflected as a component of "Loss on early extinguishment of long-term debt" in the accompanying consolidated statements of operations.

Senior Unsecured Notes

In December 2007, we issued $550 million of 9.5% Senior Unsecured Notes due 2016 (the "Senior Unsecured Notes"). In March 2012, we purchased $200.0 million of the balance then outstanding of the Senior Unsecured Notes. For this purchase, we paid a total of $213.5 million, including $200.0 million in principal, a $9.5 million call premium and $4.0 million of accrued and unpaid interest. This purchase resulted in a loss on early extinguishment of debt totaling $11.5 million, which reflects the $9.5 million call premium and a $2.0 million charge to accelerate a pro rata portion of the deferred financing costs associated with the issuance of the Senior Unsecured Notes. The loss on this early extinguishment of these notes is reflected as a component of “Loss on early extinguishment of long-term debt” in the accompanying consolidated statements of operations.

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We had $275.0 million of the Senior Unsecured Notes outstanding at the beginning of 2013. In July 2013, we paid $282.0 million to fully redeem the remaining Senior Unsecured Notes, including $275.0 million with respect to the principal amount outstanding, $6.5 million of call premium and $0.5 million in accrued and unpaid interest. Our 2013 results of operations include a loss on early extinguishment of debt totaling $8.6 million, which reflects the $6.5 million call premium and a $2.1 million charge to accelerate the remaining deferred financing costs associated with the original issuance of the Senior Unsecured Notes.

Convertible Senior Notes Due 2025

In March 2005, we issued $300 million of 3.25% Convertible Senior Notes due 2025 at 100% of the principal amount to certain qualified institutional buyers. The effective interest rate for the 2025 Notes was 6.6% after considering the effect of the accretion of the related debt discount that represented the equity component of the 2025 Notes at their inception.

In connection with the issuance of additional Convertible Senior Notes (see "Convertible Senior Notes Due 2032" above) in March 2012, we repurchased $142.2 million in aggregate principal of the 2025 Notes. In these repurchase transactions, we paid an aggregate amount of $145.1 million, representing principal plus $1.8 million of premium and $1.1 million of accrued interest. The loss on this early extinguishment of the 2025 Notes totaled $5.6 million and is reflected as a component of "Loss on early extinguishment of long-term debt" in the accompanying consolidated statements of operations. The loss includes the acceleration of $3.5 million of unamortized discount associated with the 2025 Notes, the $1.8 million premium paid in connection with the repurchase of a portion of the 2025 Notes and a $0.3 million charge to accelerate a pro rata portion of the deferred financing costs associated with the original issuance of the 2025 Notes. The remainder of the 2025 Notes was extinguished when the holders exercised their option for us to repurchase their notes in December 2012 ($154.3 million) and in February 2013 when we repurchased the remaining $3.5 million of the 2025 Notes that were not put to us in December 2012.

Other

In accordance with our Credit Agreement, the 2032 Notes, the MARAD Debt agreements, and the Nordea Credit Agreement, we are required to comply with certain covenants, including certain financial ratios such as a consolidated interest coverage ratio and consolidated leverage ratio, as well as the maintenance of minimum net worth, working capital and debt-to-equity requirements. As of December 31, 2014, we were in compliance with these covenants.

We paid financing costs associated with our debt totaling $3.6 million in 2014 and $11.0 million in 2013. Unamortized deferred financing costs are included in "Other assets, net" in the accompanying consolidated balance sheets and are amortized over the life of the respective debt agreements. The following table reflects the components of our deferred financing costs for the years ended December 31, 2014 and 2013 (in thousands):

	December 31, 2014			December 31, 2013		
	Gross Carrying Amount	Accumulated Amortization	Net	Gross Carrying Amount	Accumulated Amortization	Net
Term Loan (matures June 2018) (1)	$ 3,638	$ (1,091)	$ 2,547	$ 3,638	$ (364)	$ 3,274
Revolving Credit Facility (matures June 2018) (1)	13,275	(3,982)	9,293	13,275	(1,327)	11,948
2032 Notes (mature March 2032)	3,759	(1,763)	1,996	3,759	(1,148)	2,611

MARAD Debt (matures February 2027)	12,200	(6,223)	5,977	12,200	(5,736)	6,464
Nordea Term Loan	3,586	—	3,586	—	—	—
Total deferred financing costs	$ 36,458	$ (13,059)	$ 23,399	$ 32,872	$ (8,575)	$ 24,297

(1) Relates to amounts allocated to the existing Term Loan and Revolving Credit Facility, which became effective in June 2013.

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Scheduled maturities of long-term debt outstanding as of December 31, 2014 are as follows (in thousands):

	Term Loan	MARAD Debt	2032 Notes (1)	Total
Less than one year	$22,500	$5,644	$ —	$28,144
One to two years	30,000	5,926	—	35,926
Two to three years	30,000	6,222	—	36,222
Three to four years	195,000	6,532	—	201,532
Four to five years	—	6,858	—	6,858
Over five years	—	63,610	200,000	263,610
Total debt	277,500	94,792	200,000	572,292
Current maturities	(22,500)	(5,644)	—	(28,144)
Long-term debt, less current maturities	255,000	89,148	200,000	544,148
Unamortized debt discount (2)	—	—	(20,920)	(20,920)
Long-term debt	$255,000	$89,148	$179,080	$523,228

(1) Beginning in March 2018, the holders of the 2032 Notes may require us to repurchase these notes or we may at our option elect to repurchase these notes. The notes will mature in March 2032.

(2) The 2032 Notes will increase to their face amount through accretion of non-cash interest charges through March 2018.

The following table details the components of our net interest expense for the years ended December 31, 2014, 2013 and 2012 (in thousands):

	Year Ended December 31, 2014	2013	2012
Interest expense (1)	$33,064	$44,484	$53,601
Interest income	(4,786)	(1,167)	(548)
Capitalized interest	(10,419)	(10,419)	(4,893)
Net interest expense	$17,859	$32,898	$48,160

(1) Interest expense of $2.8 million and $28.6 million was allocated to ERT during the years ended December 31, 2013 and 2012, respectively, and is included in discontinued operations. Following the sale of ERT in February 2013, we ceased allocation of interest expense to ERT, which then constituted a discontinued operation.

Note 7 — Income Taxes

We and our subsidiaries file a consolidated U.S. federal income tax return. We believe that our recorded assets and liabilities are reasonable; however, tax laws and regulations are subject to interpretation and tax litigation is inherently uncertain, and therefore our assessments can involve a series of complex judgments about future events and rely heavily on estimates and assumptions.

Components of income tax provision (benefit) on continuing operations reflected in the consolidated statements of operations consisted of the following (in thousands):

Year Ended December 31,

	2014	2013	2012
Current	$43,817	$57,128	$6,572
Deferred	23,154	(25,516)	(65,730)
	$66,971	$31,612	$(59,158)

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	Year Ended December 31,		
	2014	2013	2012
Domestic	$29,613	$11,615	$(78,211)
Foreign	37,358	19,997	19,053
	$66,971	$31,612	$(59,158)

Components of income (loss) before income taxes are as follows (in thousands):

	Year Ended December 31,		
	2014	2013	2012
Domestic	$73,700	$36,176	$(256,859)
Foreign	188,821	107,412	130,861
	$262,521	$143,588	$(125,998)

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 that 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 from continuing operations are as follows:

	Year Ended December 31,		
	2014	2013	2012
Statutory rate	35.0 %	35.0 %	35.0 %
Foreign provision	(9.1)	(11.6)	11.2
Other	(0.4)	(1.4)	0.8
Effective rate	25.5 %	22.0 %	47.0 %

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, 2014 and 2013 are as follows (in thousands):

	2014	2013
Deferred tax liabilities:		
Depreciation	$211,903	$169,404
Original Issue Discount on 2032 Notes	16,269	14,720
Equity investments in production facilities	50,685	84,870
Prepaid and other	4,211	7,556
Total deferred tax liabilities	$283,068	$276,550
Deferred tax assets:		
Net operating losses	$(23,076)	$(40,105)
Reserves, accrued liabilities and other	(53,973)	(44,999)
Total deferred tax assets	(77,049)	(85,104)
Valuation allowance	23,076	22,860
Net deferred tax liabilities	$229,095	$214,306
Deferred income tax is presented as:		

Current deferred tax assets	(31,180)	(51,573)
Noncurrent deferred tax liabilities	260,275	265,879
Net deferred tax liabilities	$229,095	$214,306

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At December 31, 2014, we had a $23.1 million valuation allowance related to certain non-U.S. deferred tax assets, primarily net operating losses generated in Australia, as management believes it is more likely than not that we will not be able to utilize the tax benefit. Additional valuation allowances may be made in the future if in management's opinion it is more likely than not that the tax benefit will not be utilized.

We consider the undistributed earnings of our principal non-U.S. subsidiaries to be permanently reinvested. At December 31, 2014 and 2013, our principal non-U.S. subsidiaries had accumulated earnings and profits of approximately $338.0 million and $202.6 million, respectively. We have not provided deferred U.S. income tax on the accumulated earnings and profits as we consider them permanently reinvested.

We had no uncertain tax positions as of December 31, 2014. We account for tax-related interest in interest expense and tax penalties in selling, general and administrative expenses. We accrued $0.2 million for interest in each of 2012 and 2013, which brought our total liabilities for interest and penalties to $1.3 million in the accompanying consolidated balance sheet at December 31, 2013. At both December 31, 2013 and 2012, we had $3.4 million of unrecognized tax benefits that if recognized would have affected the annual effective rate. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows (in thousands):

	2014	2013	2012
Balance at January 1,	$4,723	$4,506	$7,085
Additions for tax positions of prior years	—	217	206
Reductions for tax positions of prior years	(4,723)	—	(2,785)
Balance at December 31,	$ —	$4,723	$4,506

In 2012, we reversed a $2.8 million long-term liability originally recorded in 2011 related to an uncertain tax position that we ultimately did not take when the 2011 tax return was filed. In 2014, we recognized a $3.4 million tax benefit as a result of the completion of examination procedures for the 2006 through 2010 audit period by the U.S. Internal Revenue Service ("IRS") (see below). In connection with the recognition of that benefit, we reversed approximately $1.3 million of accrued interest and penalties.

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. In June 2014, the IRS and the Joint Committee on Taxation completed the examination procedures including all appeals and administrative reviews that the taxing authorities are required and expected to perform for the 2006 through 2010 audit period, and in September 2014, we received an income tax refund in the amount of $35.2 million. The refund was primarily attributable to the utilization of a net operating loss carryback from 2010. The tax periods from 2006 through 2014 remain open to review and examination by the IRS. In non-U.S. jurisdictions, the open tax periods include 2009 through 2014.

Note 8 — 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, prior to 2014, consisted of a 50% match of each employee's contribution up to 5% of the employee's salary. Beginning in 2014, our matching contributions increased to 75% of the first 5% of the employee's salary. For the years ended December 31, 2014, 2013 and 2012, our costs related to the 401(k) plan totaled $2.2 million, $1.7 million and $1.6 million, respectively.

Employee Stock Purchase Plan

We have an employee stock purchase plan (the "ESPP"). The ESPP has 1.5 million shares authorized for issuance, of which 1.2 million shares were available for issuance as of December 31, 2014. Eligible employees who participate in the ESPP may purchase shares of our common stock through payroll deductions on an after-tax basis over a four-month period beginning on January 1, May 1, and September 1 of each year during the term of the ESPP, subject to certain restrictions and limitations established by the Compensation Committee of our Board of Directors and Section 423 of the Internal Revenue Code. The per

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share price of common stock purchased under the ESPP is equal to 85% of the lesser of (i) its fair market value on the first trading day of the purchase period or (ii) its fair market value on the last trading day of the purchase period. The total value of the ESPP awards is calculated using the component approach where each award is computed as the sum of 15% of a share of non-vested stock, a call option on 85% of a share of non-vested stock, and a put option on 15% of a share of non-vested stock. For the years ended December 31, 2014 and 2013, share-based compensation expense with respect to the ESPP was $1.0 million and $0.8 million, respectively.

Long-Term Incentive Stock-Based Plan

We currently have one active long-term incentive stock-based plan, the 2005 Long-Term Incentive Plan, as amended and restated effective May 9, 2012 (the "2005 Incentive Plan"). In May 2012, the shareholders approved an amendment to and restatement of the 2005 Incentive Plan to: (i) authorize 4.3 million additional shares for issuance pursuant to our equity incentive compensation strategy, (ii) authorize incentive stock options, stock appreciation rights, cash awards and performance awards to be made pursuant to the 2005 Incentive Plan, and (iii) include performance criteria for awards that may be made contingent upon the achievement of one or more performance measures, as well as limits on individual awards, in accordance with the requirements for performance-based compensation under Section 162(m) of the Internal Revenue Code. As of December 31, 2014, there were 6.2 million shares available for issuance under the 2005 Incentive Plan, which includes a maximum of 2.0 million shares that may be granted as incentive stock options.

The 2005 Incentive Plan is administered by the Compensation Committee of Helix's Board of Directors. The Compensation Committee also 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 Compensation Committee may grant stock options, restricted stock, restricted stock units ("RSUs"), performance share units ("PSUs") and cash awards. Prior to 2012, awards granted to employees under the incentive plans vested 20% per year over a five-year period. Commencing in 2012, awards granted under the 2005 Incentive Plan have a vesting period of three years (or 33% per year).

The following grants of share-based awards were made in 2014 under the 2005 Incentive Plan:

Date of Grant	Shares	Grant Date Fair Value Per Share	Vesting Period
January 2, 2014 (1)	73,609	$ 23.18	33% per year over three years
January 2, 2014 (2)	73,609	$ 26.79	100% on January 1, 2017
January 2, 2014 (3)	2,724	$ 23.18	100% on January 1, 2016
April 1, 2014 (3)	4,051	$ 22.98	100% on January 1, 2016
July 1, 2014 (3)	3,397	$ 26.31	100% on January 1, 2016
October 1, 2014 (3)	3,882	$ 22.06	100% on January 1, 2016
December 4, 2014 (4)	51,792	$ 23.17	33% per year over three years

(1) Reflects the grant of restricted stock to our executive officers.

(2) Reflects the grant of PSUs to our executive officers.

(3) Reflects the grant of restricted stock to certain members of our Board of Directors who have made an election to take their quarterly fees in stock in lieu of cash.

(4) Reflects annual equity grants to each independent member of our Board of Directors.

In January 2015, we granted our executive officers and selected management employees 293,029 shares of restricted stock under the 2005 Incentive Plan. The market value of the restricted shares was $21.67 per share or $6.3 million and the shares vest 33% per year for a three-year period. Separately, we issued our executive officers and selected management employees 293,029 PSUs under the 2005 Incentive Plan.

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Compensation cost for restricted stock is the product of grant date fair value of each share and the number of shares granted and is recognized over the respective vesting periods on a straight-line basis. Forfeitures on restricted stock totaled approximately 8% based on our most recent five-year average of historical forfeiture rates. 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. Stock-based compensation that is based solely on service conditions is recognized on a straight-line basis over the vesting period of the related shares.

For the years ended December 31, 2014, 2013 and 2012, $10.4 million, $8.8 million, $7.7 million, respectively, was recognized as stock-based compensation expense related to restricted stock, PSUs and RSUs.

Restricted Stock

We grant restricted stock to members of our Board of Directors, executive officers and selected management employees. The following table summarizes information about our restricted stock during the years ended December 31, 2014, 2013 and 2012:

	2014		2013		2012	
	Shares	Grant Date Fair Value (1)	Shares	Grant Date Fair Value (1)	Shares	Grant Date Fair Value (1)
Awards outstanding at beginning of year	771,942	$13.62	1,191,402	$14.14	1,263,218	$14.80
Granted	139,455	23.22	168,468	21.63	349,430	16.30
Vested (2) (3)	(356,437)	11.27	(502,022)	17.50	(400,180)	18.07
Forfeited	—	—	(85,906)	13.79	(21,066)	15.00
Awards outstanding at end of year (3)	554,960	$17.54	771,942	$13.62	1,191,402	$14.14

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

(2) Total fair value of restricted stock and RSUs that vested during the years ended December 31, 2014, 2013 and 2012 was $8.2 million, $11.0 million and $6.7 million, respectively.

(3) The vested and year-end amounts in 2014 each include 33,760 shares of RSUs with the grant date fair value of $15.80 per share. In December 2013, management elected to pay out the January 2014 vesting of these RSUs in cash. As a result, we recorded a $1.3 million liability associated with these RSUs at December 31, 2013 and an additional liability of $0.2 million during 2014. We paid $0.8 million of this liability in January 2014 and $0.7 million in January 2015.

Future compensation expense associated with unvested restricted stock and RSUs at December 31, 2014, 2013, and 2012 totaled approximately $5.7 million, $7.5 million and $11.2 million, respectively. The weighted average vesting period related to unvested restricted stock and RSUs at December 31, 2014 was approximately 1.2 years.

Performance Stock Units

Since 2012, we have issued PSUs to our executive officers. We also issued PSUs to selected management employees in January 2015. The PSUs provide for an award based on the performance of our common stock over a three-year period with the maximum amount of the award being 200% of the original awarded PSUs and the minimum amount being zero. The PSUs vest 100% on the three-year anniversary date of the grant. The vested PSUs may be settled in either cash or shares of our common stock at the discretion of the Compensation Committee of our Board of Directors.

We issued 73,609 PSUs in 2014 with a grant date fair value of $26.79 per unit, 89,329 PSUs in 2013 with a grant date fair value of $27.50 per unit and 132,910 PSUs in 2012 with a grant date fair value of $23.68 per unit. The estimated fair value of the PSUs on grant date was determined using a Monte Carlo simulation model. Until December 2014, the PSUs were being treated as an equity award. Accordingly, compensation expense associated with the PSUs was fixed, as represented by the number of PSUs multiplied by their respective grant date fair value. The fixed amount was being amortized on a straight-line basis over the three-year vesting period. In connection with the vesting of the 2012 PSU awards (which occurred in early January 2015), the decision was made by the Compensation Committee of Helix's Board of

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Directors to settle these PSUs with a cash payment rather than an equivalent number of shares of our common stock, which was the default provision of the PSU awards. Accordingly, PSUs are now accounted for as a liability plan. In connection with this determination, we recorded a $7.9 million liability and an additional $3.3 million compensation charge to reflect the estimated fair value of unvested PSUs as of December 31, 2014. We paid $4.5 million of this liability to cash settle the 2012 grant of PSUs when they vested in January 2015.

Stock Options

There have been no stock options granted since 2004. At December 31, 2011, we had 192,800 stock options outstanding at a weighted average exercise price of $10.52 per share. During 2012, 140,000 of these awards were exercised at a weighted average exercise price of $9.24 per share. The remaining 52,800 stock options were exercised in 2013 at a weighted average price of $13.91 per share. There were no stock option awards remaining at December 31, 2013. The aggregate intrinsic value of the stock options exercised during the years ended December 31, 2013 and 2012 was approximately $0.5 million and $1.3 million, respectively. The aggregate intrinsic value of options exercisable at December 31, 2012 was approximately $0.4 million.

Long-Term Incentive Cash Plans

We also have certain long-term incentive cash plans (the “LTI Cash Plans”) that provide long-term cash-based compensation to eligible employees. Cash awards historically have been both fixed sum amounts payable (for non-executive management only) as well as cash awards indexed to our common stock with the payment amount at each vesting date fluctuating based on the performance of our common stock (for both executive and non-executive management). Payment amounts are measured based on the calculated ratio of the average stock price during the applicable measurement period over the original base price determined by the Compensation Committee of our Board of Directors at the time of the award. 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 75% of the base price, no payout will be made at the applicable anniversary date. Cash payments under the LTI Cash Plans are made each year on the anniversary date of the award. Cash awards granted since 2012 have a vesting period of three years while those granted prior to 2012 have a vesting period of five years. The LTI Cash Plans are considered liability plans and as such are re-measured to fair value each reporting period with corresponding changes in the liability amount being reflected in our results of operations.

The cash awards granted under the LTI Cash Plans to our executive officers and selected management employees totaled $8.9 million in 2014, $8.4 million in 2013 and $4.2 million in 2012. Total compensation expense associated with the cash awards issued pursuant to the LTI Cash Plans was $7.2 million ($3.6 million related to our executive officers), $9.1 million ($5.3 million related to our executive officers) and $8.7 million ($7.3 million related to our executive officers), respectively, for the years ended December 31, 2014, 2013 and 2012. The liability balance for the cash awards issued under the LTI Cash Plans was $12.8 million at December 31, 2014 and $14.8 million at December 31, 2013, including $7.9 million at December 31, 2014 and $11.1 million at December 31, 2013 associated with the cash awards issued to our executive officers under the LTI Cash Plans. During 2014, 2013 and 2012, we paid $9.2 million, $7.1 million and $5.5 million of the liability associated with the LTI Cash Plans. In January 2015, we paid $8.9 million of the liability balance as of December 31, 2014. No long-term incentive cash awards were granted in January 2015.

Note 9 — 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.

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The components of Accumulated OCI as of December 31, 2014 and 2013 are as follows (in thousands):

	2014	2013
Cumulative foreign currency translation adjustment	$(30,161)	$(10,697)
Unrealized loss on hedges, net (1)	(32,091)	(9,991)
Accumulated other comprehensive loss	$(62,252)	$(20,688)

(1) Amounts relate to foreign currency hedges for the Grand Canyon, the Grand Canyon II and the Grand Canyon III charters as well as interest rate swap contracts for the Term Loan, and are net of deferred income taxes totaling $17.3 million and $5.4 million as of December 31, 2014 and 2013, respectively (Note 15).

Note 10 — Stock Buyback Program

In June 2009, we announced that we intended to purchase up to 1.5 million shares of our common stock plus an amount equal to additional shares of our common stock granted under our stock-based compensation plans (Note 8) as permitted under our Credit Agreement (Note 6). Our Board of Directors had previously granted us the authority to repurchase shares of our common stock in an amount equal to any equity issued to our employees, officers and directors under our stock-based compensation plans, including share-based awards issued under our existing long-term incentive plans and shares issued to our employees under our employee stock purchase plans (Note 8). We may continue to make repurchases pursuant to this authority from time to time as additional equity is issued under our stock based plans depending on prevailing market conditions and other factors. As described in an announced plan, all repurchases may be commenced or suspended at any time as determined by management. During 2014, we purchased 320,911 shares as then available under this program for $7.7 million or an average of $23.99 per share. As of December 31, 2014, we had repurchased a total of 3,589,425 shares of our common stock for $53.5 million or an average of $14.90 per share. We had 55,674 shares of our common stock available for repurchase under the program at December 31, 2014.

Note 11 — Commitments and Contingencies and Other Matters

Commitments

Commitments Related to Expansion of Our Fleet

In March 2012, we executed a contract with a shipyard in Singapore for the construction of a newbuild semi-submersible well intervention vessel, the Q5000. This $386.5 million shipyard contract represents the majority of the expected costs associated with the construction of the Q5000. Pursuant to the terms of this contract, payments are made in a fixed percentage of the contract price, together with any variations, on contractually scheduled dates. The vessel is expected to be completed and placed in service in the third quarter of 2015. In September 2014, we entered into the Nordea Credit Agreement to partially finance the construction of the Q5000 and other future capital projects. The Nordea Term Loan will be funded at or near the time of the delivery of the Q5000 (Note 6). At December 31, 2014, our total investment in the Q5000 was $342.4 million, including $289.4 million of scheduled payments made to the shipyard.

In February 2013, we contracted to charter the Grand Canyon II and the Grand Canyon III for use in our robotics operations. The terms of the charters will be five years from the respective delivery dates, both of which are scheduled to be in the first half of 2015.

In September 2013, we executed a second contract with the same shipyard in Singapore that is currently constructing the Q5000. This contract provides for the construction of a newbuild semi-submersible well intervention vessel, the Q7000, which will be built to North Sea standards. This $346.0 million shipyard contract represents the majority of the expected costs associated with the construction of the Q7000. Pursuant to the terms of this contract, 20% of the contract price was paid upon the signing of the contract and the remaining 80% will be paid upon the delivery of the vessel, which is expected to occur in 2016. At December 31, 2014, our total investment in the Q7000 was $91.8 million, including the $69.2 million paid to the shipyard upon signing the contract.

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In February 2014, we entered into agreements with Petróleo Brasileiro S.A. ("Petrobras") to provide well intervention services offshore Brazil. The initial term of the agreements with Petrobras is for four years with options to extend. In connection with the Petrobras agreements, we entered into charter agreements with Siem Offshore AS for two newbuild monohull vessels, both of which are expected to be in service for Petrobras in 2016. At December 31, 2014, our total investment in the topside equipment for the two vessels was $52.0 million. In addition, we paid a charter fee deposit of $12.5 million in November 2014.

Lease Commitments

We lease facilities and charter vessels under non-cancelable operating leases and vessel charters expiring at various dates through 2025. Future minimum rentals at December 31, 2014 are as follows (in thousands):

	Vessels	Facilities and Other	Total
2015	$134,964	$5,019	$139,983
2016	159,334	4,570	163,904
2017	160,433	4,391	164,824
2018	126,890	4,418	131,308
2019	122,004	4,478	126,482
Thereafter	282,879	20,714	303,593
Total lease commitments	$986,504	$43,590	$1,030,094

For the years ended December 31, 2014, 2013 and 2012, total rental expense was approximately $147.2 million, $102.1 million and $85.0 million, respectively.

We sublease some of our facilities under non-cancelable sublease agreements. For the years ended December 31, 2014 and 2013, total rental income was $0.8 million and $0.4 million, respectively. As of December 31, 2014, the minimum rentals to be received in the future totaled $2.0 million.

Contingencies and Claims

We believe that there are currently no contingencies which would have a material effect on our financial position, results of operations or cash flows.

Litigation

We are involved in various legal proceedings, primarily involving claims for personal injury under the General Maritime Laws of the United States and the Jones Act based on alleged negligence. In addition, from time to time we incur other claims, such as contract disputes, in the normal course of business.

Note 12 — Business Segment Information

We have four reportable business segments: Well Intervention, Robotics, Production Facilities and Subsea Construction. Our Well Intervention segment includes our vessels and equipment used to perform well intervention services primarily in the Gulf of Mexico and North Sea regions. Our well intervention vessels include the Q4000, the Helix 534, the Seawell, the Well Enhancer and the Skandi Constructor, which is a chartered vessel. We are currently constructing two additional well intervention vessels, the Q5000 and the Q7000. We have also contracted to charter two newbuild vessels, which are expected to be delivered in 2016 and used in connection with our contracts to provide well intervention services offshore Brazil. Our Robotics segment currently operates four chartered vessels, and also includes ROVs, trenchers and ROVDrills designed to complement offshore subsea construction and well intervention services. The Production Facilities segment includes the HP I as well as our investments in Deepwater Gateway and Independence Hub that are accounted for under the equity method. Over the past several years, we have sold essentially all of the assets associated with our Subsea Construction business, including the sale in January 2014 of our spoolbase located in Ingleside, Texas (Note 2). As mentioned above, our robotics business provides significant direct services to complement the offshore subsea construction industry, and

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will continue to do so. All material intercompany transactions between the segments have been eliminated. In February 2013, we sold ERT and as a result, the assets and liabilities included in the sale of ERT and the historical operating results of our former Oil and Gas segment are presented as discontinued operations in the accompanying consolidated financial statements. See Note 13 for additional information regarding our discontinued operations.

We evaluate our performance based on operating income and income before income taxes of each segment. Segment assets are comprised of all assets attributable to each reportable segment. Corporate and other includes all assets not directly identifiable with our business segments. Certain financial data by reportable segment are summarized as follows (in thousands):

	Year Ended December 31,		
	2014	2013	2012
Net revenues —			
Well Intervention	$667,849	$452,452	$378,546
Robotics	420,224	333,246	328,726
Production Facilities	93,175	88,149	80,091
Subsea Construction	358	71,321	192,521
Intercompany elimination	(74,450)	(68,607)	(133,775)
Total	$1,107,156	$876,561	$846,109
Income (loss) from operations —			
Well Intervention	$204,810	$131,840	$85,482
Robotics	68,329	44,132	55,678
Production Facilities	41,138	49,778	40,082
Subsea Construction (1)	10,923	33,685	(148,862)
Corporate and other	(62,523)	(77,041)	(92,985)
Intercompany elimination	(921)	(3,360)	(7,878)
Total	$261,756	$179,034	$(68,483)
Net interest expense and other —			
Well Intervention	$(6,915)	$(217)	$2,152
Robotics	7,304	(210)	(1,203)
Production Facilities	384	380	365
Subsea Construction	(278)	480	(247)
Corporate and eliminations (2)	(381)	37,978	64,882
Total	$114	$38,411	$65,949
Equity in earnings of equity investments	$879	$2,965	$8,434
Income (loss) before income taxes —			
Well Intervention	$211,725	$132,057	$83,205
Robotics	61,025	44,342	56,881
Production Facilities	41,633	52,363	48,276
Subsea Construction	11,201	33,205	(148,615)
Corporate and eliminations	(63,063)	(118,379)	(165,745)
Total	$262,521	$143,588	$(125,998)
Income tax provision (benefit) —			
Well Intervention	$50,102	$26,718	$15,400

Robotics	21,612	15,530	20,222
Production Facilities	14,395	17,233	15,784
Subsea Construction	3,881	11,655	(51,329)
Corporate and eliminations	(23,019)	(39,524)	(59,235)
Total	$66,971	$31,612	$(59,158)

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	Year Ended December 31,		
	2014	2013	2012
Identifiable assets —			
Well Intervention	$1,470,349	$1,245,229	$936,926
Robotics	299,701	282,373	258,117
Production Facilities	459,427	495,829	504,828
Subsea Construction	27,547	38,054	303,479
Corporate and other	443,674	482,795	483,003
Discontinued operations	—	—	900,227
Total	$2,700,698	$2,544,280	$3,386,580
Capital expenditures —			
Well Intervention	$283,635	$283,132	$274,451
Robotics	51,348	39,655	44,500
Production Facilities	869	1,252	823
Corporate and other	1,060	387	3,265
Total	$336,912	$324,426	$323,039
Depreciation and amortization —			
Well Intervention	$57,570	$44,619	$37,736
Robotics	24,478	22,263	19,933
Production Facilities	21,278	17,193	16,828
Subsea Construction	—	8,651	19,773
Corporate and eliminations	6,019	5,809	2,931
Total	$109,345	$98,535	$97,201

(1) Amount in 2014 includes the $10.5 million gain on the sale of our Ingleside spoolbase in January 2014. Amount in 2013 includes the $1.1 million loss on the sale of the Caesar in June 2013 and the $15.6 million gain on the sale of the Express in July 2013. Amount in 2012 includes impairment charges of $157.8 million for the Caesar and $14.6 million for the Intrepid (Note 2).

(2) Amount in 2014 includes $16.9 million of income with $7.2 million from an insurance reimbursement related to asset retirement work previously performed and the remaining income associated with our overriding royalty interests in ERT's Wang well, which commenced production in late April 2013.

Intercompany segment amounts are derived primarily from equipment and services provided to other business segments at rates consistent with those charged to third parties. Intercompany segment revenues during the years ended December 31, 2014, 2013 and 2012 are as follows (in thousands):

	Year Ended December 31,		
	2014	2013	2012
Well Intervention	$29,875	$22,448	$36,781
Robotics	44,575	41,169	46,465
Production Facilities	—	4,673	46,057
Subsea Construction	—	317	4,472
Total	$74,450	$68,607	$133,775

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Intercompany segment profits (losses) (which only relate to intercompany capital projects) during the years ended December 31, 2014, 2013 and 2012 are as follows (in thousands):

	Year Ended December 31,		
	2014	2013	2012
Well Intervention	$(323)	$(141)	$6,203
Robotics	1,419	3,518	180
Production Facilities	(175)	(175)	(175)
Subsea Construction	—	158	1,670
Total	$921	$3,360	$7,878

Revenues by individually significant region during the years ended December 31, 2014, 2013 and 2012 are as follows (in thousands):

	Year Ended December 31,		
	2014	2013	2012
United States	$403,994	$345,525	$281,308
North Sea (1)	504,016	403,816	345,074
Other	199,146	127,220	219,727
Total	$1,107,156	$876,561	$846,109

(1) Includes revenues of $362.7 million, $327.1 million and $283.1 million, respectively, which were from the United Kingdom during years ended December 31, 2014, 2013 and 2012.

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

	Year Ended December 31,		
	2014	2013	2012
United States	$913,422	$1,119,075	$1,180,586
United Kingdom	355,996	336,317	304,062
Luxembourg	465,875	76,749	—
Other	91	76	1,227
Total	$1,735,384	$1,532,217	$1,485,875

Note 13 — Oil and Gas Properties

Results of Discontinued Operations

In February 2013, we sold ERT for $624 million plus additional consideration in the form of overriding royalty interests in ERT's Wang well and certain exploration prospects. As a result, we have presented the historical operating results of our former Oil and Gas segment as discontinued operations in the accompanying consolidated financial statements.

The following summarized financial information relates to ERT, which is reported as “Income (loss) from discontinued operations, net of tax” in the accompanying consolidated statements of operations (in thousands):

	Year Ended December 31,	
	2013 (1)	2012
Revenues	$48,847	$557,231
Costs:		
Production (lifting) costs	16,017	164,663
Hurricane repair expense	—	662
Exploration expenses	3,514	3,295
Depreciation, depletion, amortization and accretion	1,226	158,284
Proved property impairment and abandonment (2)	(152)	151,045
Loss on sale of oil and gas properties	—	1,714
Hedge ineffectiveness and non-hedge gain on commodity derivative contracts	—	(5,550)
Selling, general and administrative expenses	1,229	17,823
Net interest expense and other (3)	2,732	28,191
Total costs	24,566	520,127
Pretax income from discontinued operations	24,281	37,104
Income tax provision	8,499	13,420
Income from operations of discontinued operations	15,782	23,684
Loss on sale of business, net of tax	(14,709)	—
Income from discontinued operations, net of tax	$1,073	$23,684

(1) Results for 2013 reflect the operating results from January 1, 2013 through February 6, 2013 when ERT was sold. There were no material results of operations for our former oil and gas segment subsequent to the sale of ERT.

(2) Results for 2012 include a charge of $138.6 million to reduce our carrying amount of ERT to its estimated fair value less costs to sell.

(3) Net interest expense of $2.7 million and $27.7 million, respectively, for the years ended December 31, 2013 and 2012 was allocated to ERT and primarily consisted of interest associated with indebtedness directly attributed to the substantial oil and gas acquisition made in 2006. This includes interest related to debt required to be repaid upon the disposition of ERT.

Revenue Recognition for Royalty Interests

Revenues from royalty interests are recognized according to monthly oil and gas production on an entitlement basis. Revenues for royalty interests are reflected in "Other income – oil and gas" in the accompanying consolidated statements of operations.

United Kingdom Property

Since 2006, we have maintained an ownership interest in the Camelot field, located offshore in the North Sea. This property was not included in the sale of ERT. Modifications to U.K. regulations governing such operations required us to reassess our existing abandonment plan and cost estimates in 2011. The results of this review concluded that the scope of work to be performed in the abandoning of the wells in the field would be significantly expanded and as a result our cost estimates significantly increased. Based on our abandonment plan in accordance with applicable regulations in the United Kingdom, we recorded $15.5 million of additional charges to expense in 2012 to reflect increases in our estimated costs to complete our abandonment activities at Camelot, including the removal of certain environmentally sensitive materials. At December 31, 2012, the recorded asset retirement obligation for the Camelot field was $2.9 million.

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During 2013, we recorded a $1.6 million charge reflecting the estimated final costs to complete the abandonment of Camelot. We completed our reclamation activities for this offshore property in 2013, including removing and appropriately disposing of all the related structures, and the plugging and abandoning of all the wells associated with the property. At December 31, 2014 and 2013, the remaining asset retirement obligation related to the regulatory compliance process was $0.6 million and $1.1 million, respectively.

The operating results and financial position associated with our U.K. property did not qualify for discontinued operations accounting treatment as this property was not classified as held for sale, and thus are reflected as continuing operations in our consolidated financial statements for all periods presented. Other than the impairment charges and asset retirement costs described above, the operating results associated with the Camelot field were immaterial for all periods presented in this Annual Report.

Separately, we retained the reclamation obligations associated with one property located in the Gulf of Mexico pursuant to the terms of the ERT sale transaction. During 2013, we paid $5.2 million for our pro-rata share of the costs to complete the reclamation of this property. For the year ended December 31, 2014, we recorded a $7.2 million insurance reimbursement related to asset retirement work previously performed on this property.

Note 14 — 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, 2014 (in thousands):

	Allowance for Uncollectible Accounts	Deferred Tax Asset Valuation Allowance
Balance at December 31, 2011	$ 4,000	$14,310
Additions (1)	1,257	2,081
Deductions	(105)	—
Balance at December 31, 2012	5,152	16,391
Additions (2)	2,236	6,469
Deductions (3)	(5,154)	—
Balance at December 31, 2013	$ 2,234	$22,860
Additions (4)	5,331	216
Deductions (5)	(2,830)	—
Balance at December 31, 2014	$ 4,735	$23,076

(1) The increase in valuation allowance includes $2.0 million related to our net operating losses generated in Australia and $0.1 million to our oil and gas operations in the United Kingdom. Our Australia deferred tax asset balance has a full valuation allowance against it in all periods presented.

(2) The increase in valuation allowance includes $6.5 million related to our net operating losses generated in Australia.

(3) The decrease primarily reflects the reversal of a $4 million allowance against our trade receivables for work performed offshore India in 2007 as we collected the previously adjusted receivable balance pursuant to a settlement agreement.

(4)

The increase in allowance for uncollectible accounts reflects charges associated with the provision for uncertain collection of a portion of our existing trade receivables related to our Robotics segment.

(5) The decrease reflects the write-offs of trade receivables deemed uncollectible.

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See Note 2 for a detailed discussion regarding our accounting policy on accounts receivable and allowance for uncollectible accounts and Note 7 for a detailed discussion of the valuation allowance related to our deferred tax assets.

Note 15 — Derivative Instruments and Hedging Activities

Derivatives designated as hedging instruments are as follows (in thousands):

	As of December 31, 2014			As of December 31, 2013		
	Balance Sheet Location		Fair Value	Balance Sheet Location		Fair Value
Asset Derivatives:						
Interest rate swaps	Other assets, net	$	369	Other assets, net	$	446
		$	369		$	446
Liability Derivatives:						
Foreign exchange contracts	Accrued liabilities	$	12,661	Accrued liabilities	$	1,905
Interest rate swaps	Accrued liabilities		561	Accrued liabilities		746
Foreign exchange contracts	Other non-current liabilities		37,767	Other non-current liabilities		13,166
		$	50,989		$	15,817

Derivatives that were not designated as hedging instruments are as follows (in thousands):

	As of December 31, 2014			As of December 31, 2013	
	Balance Sheet Location		Fair Value	Balance Sheet Location	Fair Value
Asset Derivatives:					
Foreign exchange contracts	Other current assets	$	—	Other current assets	$69
		$	—		$69

As a result of the announcement in December 2012 of the sale of ERT, we de-designated all of our then remaining oil and gas derivative contracts as hedging instruments. In addition, under the terms of our former credit facility (Note 6), we were required to use a portion of the proceeds from the sale of ERT as well as from the sale of the Caesar and Express vessels, to make payments to reduce our indebtedness. Because of the probability that the former term loan debt would be totally repaid before the expiration of our then existing interest rate swaps, we also concluded in December 2012 that those swaps no longer qualified as cash flow hedges. In connection with the de-designation of these derivative contracts as hedging instruments, we were required to recognize amounts previously recorded in Accumulated OCI and related deferred taxes into earnings. The mark-to-market adjustments related to our oil and gas commodity derivative contracts and interest rate swaps are reflected in "Loss on commodity derivative contracts" and "Other income (expense), net", respectively, in the accompanying consolidated statements of operations. In February 2013, we settled all of our then remaining commodity derivative contracts and then existing interest rate swap contracts for payments of approximately $22.5 million and $0.6 million, respectively.

In January 2013, we entered into foreign currency exchange contracts to hedge through September 2017 the foreign currency exposure associated with the Grand Canyon charter payments ($104.6 million) denominated in Norwegian kroner (NOK591.3 million). In February 2013, we entered into similar foreign currency exchange contracts to hedge our foreign currency exposure with respect to the Grand Canyon II and Grand Canyon III charter payments ($100.4

million and $98.8 million, respectively) denominated in Norwegian kroner (NOK594.7 million and NOK595.0 million, respectively), through July 2019 and February 2020, respectively. These contracts currently qualify for hedge accounting treatment. All of our remaining foreign exchange contracts that were not accounted for as hedge contracts have been settled. We had no foreign currency exchange contracts for vessel charters denominated in British pounds as of December 31, 2014.

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In September 2013, we entered into various interest rate swap contracts to fix the interest rate on $148.1 million of our Term Loan debt (Note 6). These monthly contracts began in October 2013 and extend through October 2016. These contracts are accounted for under hedge accounting.

For the year ended December 31, 2014, we recorded losses totaling $1.7 million in "Other income (expense), net" in the accompanying consolidated statement of operations related to ineffectiveness associated with our foreign currency hedges with respect to the Grand Canyon II charter payments. Ineffectiveness associated with our cash flow hedges was immaterial for the years ended December 31, 2013 and 2012. The following tables present the impact that derivative instruments designated as cash flow hedges had on our Accumulated OCI (net of tax) and our consolidated statements of operations for the years ended December 31, 2014, 2013 and 2012 (in thousands). We estimate that as of December 31, 2014, $7.8 million of losses in Accumulated OCI associated with our derivatives is expected to be reclassified into earnings within the next 12 months.

	Gain (Loss) Recognized in OCI on Derivatives, Net of Tax (Effective Portion) Year Ended December 31,		
	2014	2013	2012
Foreign exchange contracts	$(22,170)	$(9,796)	$ —
Oil and gas commodity contracts	—	—	(12,860)
Interest rate swaps	70	(195)	(81)
	$(22,100)	$(9,991)	$(12,941)

	Location of Gain (Loss) Reclassified from Accumulated OCI into Earnings (Effective Portion)	Gain (Loss) Reclassified from Accumulated OCI into Earnings (Effective Portion) Year Ended December 31,		
		2014	2013	2012
Oil and gas commodity contracts	Income from discontinued operations, net of tax	$ —	$ —	$3,184
Interest rate swaps	Net interest expense	(858)	(152)	(523)
Foreign exchange contracts	Cost of sales	(2,507)	(1,324)	—
		$(3,365)	$(1,476)	$2,661

The following table presents the impact that derivative instruments not designated as hedges had on our consolidated statement of operations for the years ended December 31, 2014, 2013 and 2012 (in thousands):

	Location of Gain (Loss) Recognized in Earnings on Derivatives	Gain (Loss) Recognized in Earnings on Derivatives Year Ended December 31,		
		2014	2013	2012
Oil and gas commodity contracts	Income from discontinued operations, net of tax	$ —	$ —	$5,550
Oil and gas commodity contracts	Loss on commodity derivative contracts	—	(14,113)	(10,507)
Interest rate swaps	Other expense, net	—	(86)	(567)

Foreign exchange contracts	Other expense, net	7	(630)	411
		$7	$(14,829)	$(5,113)

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Note 16 — Quarterly Financial Information (Unaudited)

Offshore marine construction activities may fluctuate 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 2014 and 2013 (in thousands, except per share amounts):

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
2014				
Net revenues	$ 253,572	$ 305,587	$ 340,837	$ 207,160
Gross profit	$ 75,846	$ 109,138	$ 126,247	$ 32,805
Net income applicable to Helix	$ 53,719	$ 57,782	$ 75,586	$ 7,960
Basic earnings per common share	$ 0.51	$ 0.55	$ 0.72	$ 0.08
Diluted earnings per common share	$ 0.51	$ 0.55	$ 0.71	$ 0.08

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
2013				
Net revenues (1)	$ 197,429	$ 232,178	$ 220,117	$ 226,837
Gross profit (2)	52,567	67,497	69,457	71,164
Net income applicable to Helix:				
Income from continuing operations	$ 557	$ 27,240	$ 44,549	$ 36,503
Income (loss) from discontinued operations	1,058	(29)	44	—
Net income applicable to Helix	$ 1,615	$ 27,211	$ 44,593	$ 36,503
Basic earnings per common share:				
Income from continuing operations	$ 0.01	$ 0.26	$ 0.42	$ 0.35
Income from discontinued operations	0.01	—	—	—
Basic earnings per common share	$ 0.02	$ 0.26	$ 0.42	$ 0.35
Diluted earnings per common share:				
Income from continuing operations	$ 0.01	$ 0.26	$ 0.42	$ 0.35
Income from discontinued operations	0.01	—	—	—
Diluted earnings per common share	$ 0.02	$ 0.26	$ 0.42	$ 0.35

(1) Excludes revenues from discontinued operations of $48.8 million for the quarter ended March 31, 2013.

(2) Excludes gross profit from discontinued operations of $28.2 million for the quarter ended March 31, 2013.

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

None.

Item 9A. Controls and Procedures

(a) Disclosure Controls and Procedures. We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the design and operation of our disclosure controls and procedures, as such term is defined in

Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Based on this evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2014 to provide reasonable assurance that information required to be disclosed in our reports under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms; and (ii) accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

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(b) Management's Report on Internal Control over Financial Reporting. Our 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. 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 U.S. generally accepted accounting principles. This process includes policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) 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.

Our management assessed the effectiveness of our internal control over financial reporting at December 31, 2014. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework (2013 framework). Based on this assessment, management concluded that, as of December 31, 2014, our internal control over financial reporting was effective based on those criteria.

The effectiveness of our internal control over financial reporting as of December 31, 2014 has been audited by Ernst & Young LLP, our independent registered public accounting firm, as stated in its report which appears in Item 8 of this Annual Report on Form 10-K.

(c) Changes in Internal Control over Financial Reporting. There were no changes in our internal control over financial reporting during the fourth quarter of fiscal 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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 Exchange Act of 1934 in connection with our 2015 Annual Meeting of Shareholders to be held on May 7, 2015. 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
3505 W. Sam Houston Parkway N., Suite 400
Houston, Texas 77043

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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 Exchange Act of 1934 in connection with our 2015 Annual Meeting of Shareholders to be held on May 7, 2015.

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 Exchange Act of 1934 in connection with our 2015 Annual Meeting of Shareholders to be held on May 7, 2015.

Item 13. Certain Relationships and Related Transactions, and Director Independence

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 Exchange Act of 1934 in connection with our 2015 Annual Meeting of Shareholders to be held on May 7, 2015.

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 Exchange Act of 1934 in connection with our 2015 Annual Meeting of Shareholders to be held on May 7, 2015.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(1)Financial Statements

The following financial statements included on pages 49 through 89 in this Annual Report are for the fiscal year ended December 31, 2014.

- 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, 2014 and 2013
- Consolidated Statements of Operations for the Years Ended December 31, 2014, 2013 and 2012
- Consolidated Statements of Comprehensive Income (Loss) for the Years Ended December 31, 2014, 2013 and 2012
- Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2014, 2013 and 2012
- Consolidated Statements of Cash Flows for the Years Ended December 31, 2014, 2013 and 2012
- 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 93 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 18, 2015

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	President, Chief Executive Officer and	February 18, 2015
Owen Kratz	Director (principal executive officer)	
/s/ ANTHONY TRIPODO	Executive Vice President and Chief	February 18, 2015
Anthony Tripodo	Financial Officer (principal financial officer)	
/s/ JAMES M. HALL	Chief Accounting Officer	February 18, 2015
James M. Hall	(principal accounting officer)	
/s/ JOHN V. LOVOI	Director	February 18, 2015
John V. Lovoi		
/s/ T. WILLIAM PORTER	Director	February 18, 2015
T. William Porter		
/s/ NANCY K. QUINN	Director	February 18, 2015
Nancy K. Quinn		
/s/ JAN A. RASK	Director	February 18, 2015
Jan A. Rask		

/s/ WILLIAM L. TRANSIER William L. Transier	Director	February 18, 2015
/s/ JAMES A. WATT James A. Watt	Director	February 18, 2015

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INDEX TO EXHIBITS

Exhibits	Description	Filed or Furnished Herewith or Incorporated by Reference from the Following Documents (Registration or File Number)
3.1	2005 Amended and Restated Articles of Incorporation, as amended, of registrant.	Exhibit 3.1 to the Current Report on Form 8-K filed on March 1, 2006 (000-22739)
3.2	Second Amended and Restated By-Laws of Helix, as amended.	Exhibit 3.1 to the Current Report on Form 8-K filed on September 28, 2006 (001-32936)
4.1	Form of Common Stock certificate.	Exhibit 4.7 to the Form 8-A filed on June 30, 2006 (001-32936)
4.2	Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of August 16, 2000.	Exhibit 4.4 to the 2001 Form 10-K filed on March 28, 2002 (000-22739)
4.3	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.	Exhibit 4.9 to the 2002 Form 10-K/A filed on April 8, 2003 (000-22739)
4.4	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.	Exhibit 4.4 to the Form S-3 filed on February 26, 2003 (333-103451)
4.5	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.	Exhibit 4.12 to the 2004 Form 10-K filed on March 16, 2005 (000-22739)
4.6	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.	Exhibit 4.13 to the 2004 Form 10-K filed on March 16, 2005 (000-22739)
4.7	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.	Exhibit 4.3 to the Current Report on Form 8-K filed on April 4, 2005 (000-22739)
4.8	Trust Indenture, dated as of August 16, 2000, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee.	Exhibit 4.1 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)
4.9	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.	Exhibit 4.2 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)
4.10	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.	Exhibit 4.3 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)
4.11	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.	Exhibit 4.4 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)

4.12	Supplement No. 4 to Trust Indenture, dated September 30, 2005, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee.	Exhibit 4.5 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)
4.13	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 4.23 (000-22739)
4.14	Form of Third Amended and Restated Promissory Note to United States of America.	Exhibit 4.6 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)
4.15	Indenture dated as of March 12, 2012 between Helix Energy Solutions Group, Inc. and The Bank of New York Mellon Trust Company, N.A., as Trustee.	Exhibit 4.1 to the Current Report on Form 8-K filed on March 12, 2012 (001-32936)

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Exhibits	Description	Filed or Furnished Herewith or Incorporated by Reference from the Following Documents (Registration or File Number)
4.16	Credit Agreement dated June 19, 2013 by and among Helix Energy Solutions Group, Inc., as borrower, Bank of America, N.A., as administrative agent, swing line lender and letters of credit issuer, and other lender parties named thereto.	Exhibit 4.1 to the Current Report on Form 8-K filed on June 19, 2013 (001-32936)
4.17	Credit Agreement dated September 26, 2014, by and among Helix Q5000 Holdings S.à r.l., Helix Vessel Finance S.à r.l. and Nordea Bank Finland PLC, London Branch as administrative agent and collateral agent, together with the other lenders party thereto.	Exhibit 4.1 to the Current Report on Form 8-K filed on September 30, 2014 (001-32936)
10.1 *	1995 Long Term Incentive Plan, as amended.	Exhibit 10.3 to the Form S-1 filed on September 4, 1996 (333-11399)
10.2 *	Amendment to 1995 Long Term Incentive Plan of Helix Energy Solutions Group, Inc.	Exhibit 10.2 to the 2008 Form 10-K filed on March 2, 2009 (001-32936)
10.3 *	2009 Long-Term Incentive Cash Plan of Helix Energy Solutions Group, Inc.	Exhibit 10.1 to the Current Report on Form 8-K filed on January 6, 2009 (001-32936)
10.4 *	Form of Award Letter related to the 2009 Long-Term Incentive Cash Plan.	Exhibit 10.2 to the Current Report on Form 8-K filed on January 6, 2009 (001-32936)
10.5 *	Employment Agreement between Owen Kratz and the Company dated February 28, 1999.	Exhibit 10.5 to the 1998 Form 10-K filed on March 31, 1999 (000-22739)
10.6 *	Employment Agreement between Owen Kratz and the Company dated November 17, 2008.	Exhibit 10.1 to the Current Report on Form 8-K filed on November 19, 2008 (001-32936)
10.7 *	Helix 2005 Long Term Incentive Plan, including the Form of Restricted Stock Award Agreement.	Exhibit 10.1 to the Current Report on Form 8-K filed on May 12, 2005 (000-22739)
10.8 *	Amendment to 2005 Long Term Incentive Plan of Helix Energy Solutions Group, Inc.	Exhibit 10.10 to the 2008 Form 10-K filed on March 2, 2009 (001-32936)
10.9 *	Employment Agreement between Alisa B. Johnson and the Company dated November 17, 2008.	Exhibit 10.3 to the Current Report on Form 8-K filed on November 19, 2008 (001-32936)
10.10	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.	Exhibit 10.1 to the Current Report on Form 8-K filed on December 21, 2007 (001-32936)
10.11	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.	Exhibit 10.2 to the Current Report on Form 8-K filed on December 21, 2007 (001-32936)

10.12 *	Employment Agreement between Anthony Tripodo and the Company dated June 25, 2008.	Exhibit 10.2 to the Current Report on Form 8-K filed on June 30, 2008 (001-32936)
10.13 *	First Amendment to Employment Agreement between Anthony Tripodo and the Company dated November 17, 2008.	Exhibit 10.5 to the Current Report on Form 8-K filed on November 19, 2008 (001-32936)
10.14 *	Employment Agreement by and between Helix Energy Solutions Group, Inc. and Clifford Chamblee dated May 11, 2011.	Exhibit 10.3 to the Quarterly Report on Form 10-Q filed on July 27, 2011 (001-32936)
10.15 *	Form of Cash Award Agreement.	Exhibit 10.1 to the Current Report on Form 8-K filed on December 15, 2011 (001-32936)

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Exhibits	Description	Filed or Furnished Herewith or Incorporated by Reference from the Following Documents (Registration or File Number)
10.16 *	Form of Performance Share Unit Award Agreement.	Exhibit 10.1 to the Current Report on Form 8-K filed on December 10, 2014 (001-32936)
10.17 *	Form of Restricted Stock Award Agreement.	Exhibit 10.3 to the Current Report on Form 8-K filed on December 15, 2011 (001-32936)
10.18	Construction contract dated as of March 12, 2012 between Helix Energy Solution Group, Inc. and Jurong Shipyard Pte Ltd.	Exhibit 10.1 to the Current Report on Form 8-K filed on March 16, 2012 (001-32936)
10.19	The MODU Sale Agreement between Helix Energy Solutions Group, Inc. and Transocean Discoverer 534 LLC dated July 23, 2012.	Exhibit 10.2 to the Quarterly Report on Form 10-Q filed on July 25, 2012 (001-32936)
10.20 *	Amended and Restated 2005 Long-Term Incentive Plan of Helix Energy Solutions Group, Inc. dated May 9, 2012.	Exhibit 10.3 to the Quarterly Report on Form 10-Q filed on July 25, 2012 (001-32936)
10.21 *	Employee Stock Purchase Plan of Helix Energy Solutions Group, Inc. dated May 9, 2012.	Exhibit 10.4 to the Quarterly Report on Form 10-Q filed on July 25, 2012 (001-32936)
10.22	The Pipelay Asset Sale Agreement between Helix Energy Solutions Group, Inc. and Coastal Trade Limited dated October 15, 2012.	Exhibit 10.1 to the Current Report on Form 8-K filed on October 17, 2012 (001-32936)
10.23	Equity Purchase Agreement dated December 12, 2012, between Helix Energy Solutions Group, Inc. and Talos Production LLC.	Exhibit 10.1 to the Current Report on Form 8-K filed on December 13, 2012 (001-32936)
10.24	Third Correction Assignment of Overriding Royalty Interest dated December 12, 2012, by and between Energy Resource Technology GOM, Inc. and OKCD Investments, Ltd.	Exhibit 10.2 to the Current Report on Form 8-K filed on December 13, 2012 (001-32936)
10.25	Form of Indemnification Agreement, by and among Talos Production LLC, Energy Resource Technology GOM, LLC, CKB Petroleum, LLC, and Helix Energy Solutions Group, Inc.	Exhibit 10.3 to the Current Report on Form 8-K filed on December 13, 2012 (001-32936)
10.26	Amendment No. 1 to Equity Purchase Agreement dated January 27, 2013, between Helix Energy Solutions Group, Inc. and Talos Production LLC.	Exhibit 10.1 to the Current Report on Form 8-K filed on January 28, 2013 (001-32936)
10.27	Amendment No. 2 to Equity Purchase Agreement dated February 6, 2013, between Helix Energy Solutions Group, Inc. and Talos Production LLC.	Exhibit 10.1 to the Current Report on Form 8-K filed on February 12, 2013 (001-32936)
10.28 *	Separation and Release Agreement dated April 24, 2013 between Helix Energy Solutions Group, Inc. and Lloyd A. Hajdik.	Exhibit 10.3 to the Quarterly Report on Form 10-Q filed on April 24, 2013 (001-32936)
10.29	Construction Contract dated as of September 11, 2013 between Helix Q7000 Vessel Holdings S.à r.l. and Jurong Shipyard Pte Ltd.	Exhibit 10.1 to the Current Report on Form 8-K filed on September 13, 2013 (001-32936)
10.30		

	Strategic Alliance Agreement dated January 5, 2015 among Helix Energy Solutions Group, Inc., OneSubsea LLC, OneSubsea B.V., Schlumberger Technology Corporation, Schlumberger B.V., and Schlumberger Oilfield Holdings Ltd.	Exhibit 10.1 to the Current Report on Form 8-K filed on January 6, 2015 (001-32936)
14.1	Code of Ethics for Chief Executive Officer and Senior Financial Officers.	Exhibit 14.1 to the Registrant's Current Report on Form 8-K filed on December 8, 2009 (001-32936)
21.1	List of Subsidiaries of the Company.	Filed herewith
23.1	Consent of Ernst & Young LLP.	Filed herewith
23.2	Consent of Deloitte & Touche LLP. (Deepwater Gateway L.L.C.).	Filed herewith

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Exhibits	Description	Filed or Furnished Herewith or Incorporated by Reference from the Following Documents (Registration or File Number)
23.3	Consent of Deloitte & Touche LLP. (Independence Hub LLC).	Filed herewith
31.1	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Owen Kratz, Chief Executive Officer.	Filed herewith
31.2	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Anthony Tripodo, Chief Financial Officer.	Filed herewith
32.1	Certification of Helix's Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes — Oxley Act of 2002.	Furnished herewith
101.INS	XBRL Instance Document.	Furnished herewith
101.SCH	XBRL Schema Document.	Furnished herewith
101.CAL	XBRL Calculation Linkbase Document.	Furnished herewith
101.PRE	XBRL Presentation Linkbase Document.	Furnished herewith
101.DEF	XBRL Definition Linkbase Document.	Furnished herewith
101.LAB	XBRL Label Linkbase Document.	Furnished herewith

* Management contracts or compensatory plans or arrangements