HELIX ENERGY SOLUTIONS GROUP INC
Form 10-K
February 22, 2019

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018
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	95–3409686
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

3505 West Sam Houston Parkway North, Suite 400	
Houston, Texas	77043
(Address of principal executive offices)	(Zip Code)

(281) 618-0400
(Registrant's telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

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

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. þ 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 þ 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. þ Yes ¨ No
Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). þ Yes ¨ No
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer þ	Accelerated filer ¨	Non-accelerated filer ¨	Smaller reporting company ¨	Emerging growth company ¨

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨

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

The aggregate market value of the shares held by non-affiliates of the registrant as of June 30, 2018 was approximately $1.0 billion.

The number of shares of the registrant’s common stock outstanding as of February 15, 2019 was 148,785,311.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement for the Annual Meeting of Shareholders to be held on May 15, 2019 are incorporated by reference into Part III hereof.

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

Table of Contents

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,” “budget,” “expect,” “forecast,” “plan,” “project,” “propose,” “strategy,” “predict,” “envision,” “hope,” “intend,” “will,” “continue,” “may “could” 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 are subject to change;
- statements regarding projections of revenues, gross margins, expenses, earnings or losses, working capital, debt and liquidity, or other financial items;
- statements regarding our backlog and long-term contracts and rates thereunder;
- statements regarding our ability to enter into and/or perform commercial contracts, including the scope, timing and outcome of those contracts;
- statements regarding the acquisition, construction, upgrades or maintenance of vessels or equipment and any anticipated costs or downtime related thereto, including the construction of our Q7000 vessel;
- statements regarding any financing transactions or arrangements, or our ability to enter into such transactions;
- statements regarding anticipated legislative, governmental, regulatory, administrative or other public body actions, requirements, permits or decisions;
- statements regarding our trade receivables and their collectability;
- 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 markets in which we do business;
- statements regarding our ability to retain our senior management and other key employees;
- statements regarding 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 our 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:

- the impact of domestic and global economic conditions and the future impact of such conditions on the oil and gas industry;
- the impact of oil and gas price fluctuations and the cyclical nature of the oil and gas industry;
- the impact of any potential cancellation, deferral or modification of our work or contracts by our customers;
- the ability to effectively bid and perform our contracts;
- the impact of the imposition by our customers of rate reductions, fines and penalties with respect to our operating assets;
- unexpected future capital expenditures, including the amount and nature thereof;
- the effectiveness and timing of completion of our vessel upgrades and major maintenance items;
- unexpected delays in the delivery, chartering or customer acceptance, and terms of acceptance, of new assets for our well intervention and robotics fleet;

- the effects of our indebtedness and our ability to reduce capital commitments;
- the results of our continuing efforts to control costs and improve performance;
- the success of our risk management activities;
- the effects of competition;
- the availability of capital (including any financing) to fund our business strategy and/or operations;
- the impact of current and future laws and governmental regulations, including tax and accounting developments, such as the U.S. Tax Cuts and Jobs Act (the “2017 Tax Act”);
- the impact of the vote in the U.K. to exit the European Union (the “EU”), known as Brexit, on our business, operations and financial condition, which is unknown at this time;

Table of Contents

- the effect of adverse weather conditions and/or other risks associated with marine operations;
- the impact of foreign currency fluctuations;
- the effectiveness of our current and future hedging activities;
- the potential impact of a loss of one or more key employees; and
- the impact of general, market, industry or business conditions.

Our actual results could differ materially from those anticipated in any forward-looking statements as a result of a variety of factors, including those discussed in "Risk Factors" beginning on page 14 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 1979 and in 1983 was re-incorporated in the state of Minnesota. 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 maximizing production economics. We provide services primarily in deepwater in the U.S. Gulf of Mexico, Brazil, North Sea, Asia Pacific and West Africa regions. Our "life of field" services are segregated into three reportable business segments: Well Intervention, Robotics and Production Facilities. 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 June 2018. 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 our well intervention and robotics businesses. We believe that focusing on these services will deliver favorable long-term financial returns. From time to time, we may make strategic investments that expand our service capabilities or add capacity to existing services in our key operating regions. We expect our well intervention fleet to expand with the completion and delivery in 2019 of the Q7000, a newbuild semi-submersible vessel. Chartering newer vessels with additional capabilities, such as the three Grand Canyon vessels, should enable our robotics business to better serve the needs of our customers. From a longer-term perspective we also expect to benefit from our fixed fee agreement for the Helix Producer I (the "HP I"), a dynamically positioned floating production vessel that processes production from the Phoenix field for the field operator until at least June 1, 2023.

In January 2015, Helix, OneSubsea LLC, OneSubsea B.V., Schlumberger Technology Corporation, Schlumberger B.V. and Schlumberger Oilfield Holdings Ltd. 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 leverages the parties' capabilities to provide a unique, fully integrated offering to clients, combining marine support with well access and control technologies. We and OneSubsea jointly developed a 15,000 working p.s.i. intervention riser system

Table of Contents

("15K IRS"), each owning a 50% interest. The 15K IRS was completed and placed into service in January 2018. Our total investment in the 15K IRS was approximately $17 million. In October 2016, we and OneSubsea launched the development of our first Riserless Open-water Abandonment Module ("ROAM") for an estimated cost of approximately $6 million for our 50% interest. At December 31, 2018, our total investment in the ROAM was $5.6 million. The ROAM is expected to be available in 2019.

OUR OPERATIONS

We have three reportable business segments: Well Intervention, Robotics and Production Facilities. We provide a full range of services primarily in deepwater in the U.S. Gulf of Mexico, Brazil, 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 U.S. Gulf of Mexico, Brazil, the North Sea and West Africa. Our well intervention vessels include the Q4000, the Q5000, the Seawell, the Well Enhancer, and two chartered monohull vessels, the Siem Helix 1 and the Siem Helix 2. We also have a semi-submersible well intervention vessel under completion, the Q7000. Our well intervention equipment includes intervention riser systems ("IRSs"), some of which we provide on a stand-alone basis, and subsea intervention lubricators ("SILs"). Our Robotics segment includes remotely operated vehicles ("ROVs"), trenchers and ROVDrills, which are designed to complement offshore construction and well intervention services, and three ROV support vessels under long-term charter: the Grand Canyon, the Grand Canyon II and the Grand Canyon III. Our Production Facilities segment includes the HP I, the Helix Fast Response System (the "HFRS") and our investment in Independence Hub, LLC ("Independence Hub"). All of our production facilities activities are located in the Gulf of Mexico. See Note 13 for financial results related to our business segments.

Our current services include:

- Production. Well intervention; intervention engineering; production enhancement; inspection, repair and maintenance of production structures, trees, jumpers, risers, pipelines and subsea equipment; and life of field support.
- Decommissioning. Reclamation and remediation services; well plugging and abandonment services; pipeline abandonment services; and site inspections.
- Development. Installation of flowlines, control umbilicals, manifold assemblies and risers; trenching and 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 that 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 our HP I vessel as an oil and natural gas processing facility for services to oil and gas companies operating in the deepwater of the Gulf of Mexico. Currently, the HP I is being utilized to process production from the Phoenix field.
- Fast Response System. Provision of the HFRS as a response resource that can be identified in permit applications to federal and state agencies and respond to a well control incident.

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 conduct operations in the deepwater basins of the world, development of these reserves will often require the installation of subsea trees. Over time, we expect long-term demand for well intervention services to increase due to the growing number of subsea tree installations. Historically, drilling rigs were typically necessary for subsea well intervention to troubleshoot or enhance production, shift sleeves, log wells or perform recompletions. Our well intervention vessels serve as work platforms for well intervention services at costs that historically have been 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 demand for our services to increase due to potential efficiency gains from our specialized intervention assets and equipment.

Table of Contents

Our well intervention business currently operates six vessels providing services primarily in the U.S. Gulf of Mexico, Brazil, the North Sea and West Africa.

The Q4000 has worked as a rigless riser-based intervention vessel in increasingly deeper water in the Gulf of Mexico. In 2010, the Q4000 served as a key emergency response vessel in the Macondo well control and containment efforts. The Q4000 also serves an important role in the HFRS that was originally established in 2011. Our Q5000 semi-submersible well intervention vessel commenced operations in the Gulf of Mexico in late 2015. The vessel went on contracted rates in May 2016 under our five-year contract with BP.

In Brazil, we provide well intervention services to Petróleo Brasileiro S.A. (“Petrobras”) with two monohull vessels, the Siem Helix 1 and the Siem Helix 2, that we charter from Siem Offshore AS (“Siem”). The initial term of the agreements with Petrobras is for four years from commencement of operations with options to extend by agreement of both parties for an additional period of up to four years. The Siem Helix 1 commenced operations for Petrobras in mid-April 2017 and the Siem Helix 2 commenced operations for Petrobras in mid-December 2017. The initial term of the charter agreements with Siem is for seven years from the respective vessel delivery dates with options to extend.

In the North Sea, the Well Enhancer has performed well intervention, abandonment and coil tubing services since it joined our fleet in 2009. The Seawell has provided well intervention and abandonment services since 1987, and the vessel underwent major capital upgrades in 2015 to extend its estimated useful economic life by approximately 15 years. Our North Sea well intervention fleet also performs services in West Africa from time to time.

We currently have a newbuild semi-submersible well intervention vessel under completion, the Q7000. The vessel is built to North Sea standards. Pursuant to the shipyard contract and subsequent amendments, 20% of the contract price was paid upon the signing of the contract in 2013, 20% was paid in each of 2016, 2017 and 2018, and the remaining 20% will be paid upon the delivery of the vessel, which at our option can be deferred until December 31, 2019.

Robotics

We have been actively engaged in robotics for over three decades. We operate ROVs, trenchers and ROVDrills designed for offshore construction, maintenance and well intervention services, and often integrate these services with chartered vessels. As global marine construction support operates in deeper waters, the use and scope of ROV services has expanded. Our chartered vessels add value by supporting deployment of our ROVs and trenchers. We provide our customers with vessel availability and schedule flexibility to meet the technological challenges of their subsea activities worldwide. Our robotics assets include 46 ROVs, five trenching systems and one ROVDrill. Our robotics business unit primarily operates in the Gulf of Mexico, North Sea, West Africa and Asia Pacific regions. We charter vessels on a long-term basis to support our robotics operations. We also engage spot vessels on short-term charter agreements as needed. Vessels currently under long-term charter agreements include the Grand Canyon, the Grand Canyon II and the Grand Canyon III. We returned the Deep Cygnus to its owner during the first quarter of 2018.

Over the last decade there has been an increase in offshore activity associated with the growing alternative (renewable) energy industry. Specifically there has been an increase in demand for services to support 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 Grand Canyon and Grand Canyon III chartered vessels that are suitable for harsh offshore weather conditions, especially in Northern Europe where offshore wind farming is currently concentrated. In 2018, revenues derived from offshore renewables contracts accounted for 33% of our global robotics revenues. We believe that over the long term our robotics business unit is positioned to continue the services it provides to a range of clients in the alternative energy industry. 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.

Table of Contents

Production Facilities

We own the HP I, a ship-shaped dynamically positioned floating production vessel capable of processing up to 45,000 barrels of oil and 80 million cubic feet (“MMcf”) of natural gas per day. The HP I has been under contract to the Phoenix field operator since February 2013 and is currently under a fixed fee agreement through at least June 1, 2023.

We own a 20% interest in Independence Hub, which owns the Independence Hub platform located in 8,000 feet of water in the eastern Gulf of Mexico.

We developed the HFRS in 2011 as a culmination of our experience as a responder in the 2010 Macondo well control and containment efforts. The HFRS centers on our vessels currently operating in the Gulf of Mexico, the HP I , the Q4000 and the Q5000, combining them with certain well control equipment that can be deployed to respond to a well control incident. On January 16, 2019, we renewed the agreements that provide various operators with access to the HFRS for well control purposes through March 31, 2020. These agreements automatically renew on an annual basis absent proper notice of termination by one of the parties.

On January 18, 2019, we purchased from Marathon Oil Corporation (“Marathon Oil”) certain operating depths associated with the Droshky Prospect on offshore Gulf of Mexico Green Canyon Block 244, along with several wells and related infrastructure. As part of the transaction, Marathon Oil will pay us certain agreed upon amounts for the required plug and abandonment of the acquired assets, which we can perform as our schedules permit subject to regulatory timelines.

GEOGRAPHIC AREAS

We primarily operate in the U.S. Gulf of Mexico, Brazil, North Sea, Asia Pacific and West Africa regions. See Note 13 for revenues as well as property and equipment, net of accumulated depreciation, by geographic location.

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 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 percentages of consolidated revenues from major customers, those whose total represented 10% or more of our consolidated revenues is as follows: 2018 — Petrobras (28%) and BP (15%), 2017 — BP (19%), Petrobras (13%) and Talos (10%), and 2016 — BP (17%) and Shell (11%). We provided services to over 50 customers in 2018.

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 to competing in the industry. Our principal competitors in the well intervention business include Island Offshore Subsea AS, Wild Well Control, Oceaneering International, Inc., Expro Group and international drilling contractors. Our principal competitors in the robotics business include C-Innovation, LLC, DeepOcean Group, DOF Subsea Group, Fugro N.V. and Oceaneering International, Inc. Our competitors may have significantly more financial, personnel, technological and other resources available to them.

TRAINING, SAFETY, HEALTH, ENVIRONMENT AND QUALITY ASSURANCE

Our corporate vision of a zero incident workplace is based on the belief that all incidents should be preventable and that we can adjust our working conditions to drive safer behaviors. Helix strives to achieve this by focusing on controlling major hazard risks and managing 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” they believe is unsafe.

Table of Contents

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, we believe 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 employees.

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 on each vessel and regularly audit QHSE management systems; both are completed with assigned responsibilities and action due dates.

The management systems of our business units have been independently assessed and registered compliant to ISO 9001 (Quality Management Systems) and ISO 14001 (Environmental Management Systems). All of our safety management systems are created in accordance with and conform to OHSAS 18001.

GOVERNMENT REGULATION

Overview

We provide services primarily in deepwater in the U.S. Gulf of Mexico, Brazil, North Sea, Asia Pacific and West Africa regions, and as such we are subject to numerous laws and regulations, including international treaties, flag state requirements, environmental laws and regulations, requirements for obtaining operating and navigation licenses, local content requirements, and other national, state and local laws and regulations in force in the jurisdictions in which our vessels and other assets operate or are registered, all of which can significantly affect the ownership and operation of our vessels and other assets. In 2019, we acquired four end of life offshore oil and gas wells, two of which are currently producing, which we will ultimately decommission. Being an operator of these wells subjects us to additional regulatory oversight from the Bureau of Ocean Energy Management (“BOEM”) and the Bureau of Safety and Environmental Enforcement (“BSEE”).

International Conventions

Our vessels are subject to applicable international maritime convention requirements, which include, but are not limited to, the International Convention for the Prevention of Pollution from Ships (“MARPOL”), the International Convention on Civil Liability for Oil Pollution Damage of 1969, the International Convention on Civil Liability for Bunker Oil Pollution Damage of 2001 (ratified in 2008), the International Convention for the Safety of Life at Sea of 1974 (“SOLAS”), the International Safety Management Code for the Safe Operation of Ships and for Pollution Prevention (the “ISM Code”), the Code for the Construction and Equipment of Mobile Offshore Drilling Units (the “MODU Code”), and the International Convention for the Control and Management of Ships’ Ballast Water and Sediments (the “BWM Convention”). These regimes are applicable in most countries where we operate; however, the flag state and the country where we operate may impose additional requirements. In addition, these conventions impose liability for certain environmental discharges, including strict liability in some cases.

U.S. Overview

In the U.S., we are subject to the jurisdiction of the U.S. Coast Guard (the “Coast Guard”), the U.S. Environmental Protection Agency (the “EPA”) as well as state environmental protection agencies for those jurisdictions in which we operate, three divisions of the U.S. Department of the Interior, BOEM, BSEE, the Office of Natural Resource Revenue, and the U.S. Customs and Border Protection (the “CBP”), as well as classification societies such as the American Bureau of Shipping (the “ABS”). We are also subject to the requirements of the federal Occupational Safety and Health Act and comparable state laws that regulate the protection of employee health and safety for our land-based operations.

Table of Contents

International Overview

While we provide services globally and generally can be subject to local laws and regulations wherever we operate, the regulatory regimes of the U.K. and Brazil are of particular importance given the locations of our current operations. The U.K. Continental Shelf in the North Sea is regulated by the Oil and Gas Authority (the “OGA”) in accordance with the Petroleum Act 1998. The OGA controls all of the Petroleum Operations Notices with which we comply for various well intervention and subsea construction projects, as required. The OGA also regulates the environmental requirements for our operations in the North Sea. We comply as required by the Oil Pollution Prevention and Control Regulations 2005. In the North Sea, international regulations govern working hours and the working environment, as well as standards for diving procedures, equipment and diver health. We also note that the U.K.’s 2016 decision to exit from the EU may result in the imposition of new laws, rules or regulations affecting operations inside U.K. territorial waters.

Our operations in Brazil are predominantly regulated by the Brazilian National Agency of Petroleum, Natural Gas and Biofuels, the federal government agency responsible for the regulation of the oil sector. Additional regulatory oversight is provided, among others, by the Brazilian Institute of the Environment and Renewable Natural Resources, which oversees Brazilian environmental legislation, implements the National Environmental Policy and exercises control and supervision of the use of natural resources, the Brazilian Health Regulatory Agency, which regulates products and services subject to health regulations, and the Ministry of Labor, which regulates a variety of subjects including accident prevention to use of machinery and equipment.

Operating Certification

Each of our vessels is subject to regulatory requirements of the country in which the vessel is registered, the flag state. In addition, the country where the vessel is operating may have its own requirements with respect to safety and environmental protections. These requirements must be satisfied in order for the vessel to operate. Flag state requirements are largely established by international treaties such as SOLAS, MARPOL, the ISM Code and the MODU Code, and in some instances, specific requirements of the flag state. These include engineering, safety, safe manning and other requirements related to the maritime industry. Each of our vessels must also maintain its “in-class” status with a classification society, evidencing that the vessel has been built and maintained in accordance with the rules of the classification society and complies with applicable flag state rules and applicable international conventions. Our vessels generally must undergo a class survey once every five years. In the U.S., the Coast Guard sets safety standards and is authorized to investigate vessel and other marine casualty incidents, recommend improved safety standards, and inspect vessels at will. We also adhere to manning requirements implemented by the Coast Guard for operations on the U.S. Outer Continental Shelf (“OCS”).

Cabotage Rules

A number of jurisdictions where we operate require that certain work performed there may only be performed by vessels built and/or registered in that jurisdiction. In some instances, an exemption may be available, or we may be subject to an additional tax to use a non-local vessel. In the U.S., we are subject to the Coastwise Merchandise Statute (commonly known as the “Jones Act”), which provides that only vessels built in the U.S., owned 75% by U.S. citizens, and crewed by U.S. citizen seafarers may transport merchandise between points in the U.S. The Jones Act has been applied to offshore oil and gas work in the U.S. through interpretations by the CBP.

BOEM and BSEE

The operation of oil and gas properties located on the OCS is regulated primarily by BOEM and BSEE. Among other requirements, 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. 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. Following the Deepwater Horizon incident in April 2010, BSEE determined and implemented enhanced standards for companies engaged in the development of offshore oil and gas wells. As an operator of wells, we are also required to have a BSEE-approved Oil Spill Response Plan. In April 2016, BSEE issued the final Oil and Gas and Sulfur Operations in the Outer Continental Shelf-Blowout Preventer Systems and Well Control Rule, which updated requirements for equipment and operations for well control activities associated with drilling, completion, workover and decommissioning operations, and further provides guidance for the design and operation of remotely operated tools. On May 11, 2018, BSEE proposed to further revise the regulations for well control and blowout preventer systems in response to Executive and Secretarial Orders directing BSEE to review regulations that potentially burden development or use of domestically produced energy resources. The proposed rule would revise requirements for well design, well control, casing, cementing, real time monitoring, and subsea containment. Overall, the rulemaking would modify regulations that impact offshore oil and gas drilling, completions, workovers, and decommissioning activities.

Local Content Requirements

Governments in some countries, notably in Brazil and in the West Africa region, have become increasingly active in establishing and enforcing local content requirements with respect to equipment and crews utilized in operations such as ours, along with other aspects of the oil and gas industries in their respective countries.

Other Regulatory Impact

Additional proposals and proceedings before various international, federal and state regulatory agencies and courts could affect the oil and gas industry, including curtailing production and demand for fossil fuels such as oil and natural gas. We cannot predict when or whether any such proposals may become effective.

ENVIRONMENTAL REGULATION

Overview

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 these laws that are often complex, costly to comply with, and carry substantial administrative, civil and possibly criminal penalties for compliance failure. There is currently little uniformity among the regulations issued by the government agencies with authority over environmental regulation. Under these laws and regulations, we may be liable for remediation or removal costs, damages, civil, criminal, administrative penalties and other costs associated with releases of hazardous materials (including oil) into the environment, and that 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 those 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.

MARPOL

The United States is one of approximately 170 member countries party to the International Maritime Organization (“IMO”), an agency of the United Nations responsible for developing measures to improve the safety and security of international shipping and to prevent marine pollution from ships. The IMO has negotiated MARPOL, which imposes environmental standards on the shipping industry, relating to oil spills, management of garbage, the handling and disposal of noxious liquids, harmful substances in packaged forms, sewage, and air emissions.

OPA 90

The Oil Pollution Act of 1990, as amended (“OPA”), imposes a variety of requirements on offshore facility owners or operators, and the lessee or permittee of the area in which an offshore facility is located, as well as owners and operators of vessels. Any of these entities or persons can be “responsible parties” and are strictly liable for removal costs and damages arising from facility and vessel oil spills or threatened spills. Failure to comply with OPA may result in the assessment of civil, administrative and criminal penalties. 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 those vessels. A number of foreign jurisdictions also require us to present satisfactory evidence of financial responsibility. We satisfy these requirements through appropriate insurance coverage.

Table of Contents

Water Pollution

For operations in the U.S., the Clean Water Act imposes 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. Permits must be obtained to discharge pollutants into state and federal waters. The EPA issues Vessel General Permits ("VGPs") covering discharges incidental to normal vessel operations, including ballast water, and implements various training, inspection, monitoring, recordkeeping and reporting requirements, as well as corrective actions upon identification of each deficiency. Additionally, certain state regulations and VGPs 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. 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. Internationally, the BWM Convention covers mandatory ballast water exchange requirements.

Air Pollution and Emissions

A variety of regulatory developments, proposals or requirements and legislative initiatives focused on restricting the emissions of carbon dioxide, methane and other greenhouse gases apply to the jurisdictions in which we operate. Annex VI of MARPOL addresses air emissions, including emissions of sulfur and nitrous oxide, and requires the use of low sulfur fuels worldwide in both auxiliary and main propulsion diesel engines on vessels. Beginning in 2010, the IMO designated the waters off North America as an Emission Control Area, meaning that vessels operating in the United States must use fuel with a sulfur content no greater than 0.1%. Directives have been issued designed to reduce the emission of nitrogen oxides and sulfur oxides. These can impact both the fuel and the engines that may be used onboard vessels. EU Regulation 2015/757 requires monitoring and reporting of the emissions of vessels exceeding 5,000 gross tons that call at EU ports, with the first reports due in 2019. It is anticipated that in the future the EU may move from requiring reporting of emissions to regulations aimed at reducing them.

CERCLA

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") requires 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 that transport, dispose of or arrange for the disposal of, hazardous substances released at the sites.

OCSLA

The Outer Continental Shelf Lands Act, as amended ("OCSLA"), provides the federal government with broad authority to impose 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 can result in substantial civil and criminal penalties, as well as potential court injunctions that could curtail operations and cancellation of leases.

Current Compliance and Potential Material Impact

We believe that we are in compliance in all material respects with the applicable environmental laws and regulations to which we are subject. We maintain a robust operational compliance program to ensure that we maintain and update our programs to meet or exceed regulatory requirements in the areas in which we operate. 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 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. Environmental liability could have a material adverse effect on our financial position, results of operations and cash flows, and could have a significant impact on our financial ability to carry out our operations.

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 position, 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 (i.e., limited coverage considering the underlying cost).

Our current insurance program is valid until June 30, 2020.

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 Q5000, the HP I and the Well Enhancer, and $500,000 on the Seawell. 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 $750,000 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 as well as OPA insurance for our newly-acquired offshore properties with $35 million of coverage as required by BOEM. Our self-insured retention on our medical and health benefits program for employees is $300,000 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 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, and vice versa. 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. We analyze each claim for potential exposure and estimate the ultimate liability of each claim. 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.

EMPLOYEES

As of December 31, 2018, we had 1,546 employees. Of our total employees, we had 409 non-U.S. employees covered by collective bargaining agreements or similar arrangements. We consider our overall relationships with our employees to be satisfactory.

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/company/helix-energy-solutions-group). Copies of this Annual Report for the year ended December 31, 2018, 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 Business Conduct and 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 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 satisfy the requirement under Item 5.05 of Form 8-K to disclose any amendments to our Code of Business Conduct and 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 that 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:

Bureau of Ocean Energy Management (BOEM): 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.

Bureau of Safety and Environmental Enforcement (BSEE): 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.

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 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.

Intervention Riser System (IRS): A subsea system that establishes a direct connection from a well intervention vessel, through a rigid riser, to a conventional or horizontal subsea tree in depths up to 3,000 meters (9,840 feet). The system can be utilized for wireline intervention, production logging, coiled-tubing operations, well stimulation, and full plug and abandonment operations. The system provides the well control in order to safely access the well bore for these activities.

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

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

Pound Per Square Inch (p.s.i.): A unit of measurement for pressure or stress resulting from a force of one pound-force applied to an area of one square inch.

Riserless Open-water Abandonment Module (ROAM): An 18¾-inch large bore system that enhances well abandonment capabilities from a well intervention vessel.

Remotely Operated Vehicle (ROV): A robotic vehicle 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 (9,840 feet). Because the ROV 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 to perform specific projects.

Subsea Intervention Lubricator (SIL): A riserless system that facilitates access to subsea wells from a monohull vessel to provide safe, efficient and cost effective riserless well intervention and abandonment solutions. The system can be utilized for wireline, logging, light perforating, zone isolation, plug setting and removal, and decommissioning. The system provides access to the well bore while providing full well control safety for activities that do not require a riser conduit.

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.

Item 1A. Risk Factors

Shareholders should carefully consider the following risk factors in addition to the other information contained herein. We operate globally in challenging and highly competitive markets and thus our business is subject to a variety of risks. The risks and uncertainties described below are not the only ones facing Helix. We are also subject to a variety of risks that affect many other companies generally, as well as additional risks and uncertainties not known to us or that, as of the date of this Annual Report, we believe are not as significant as the risks described below. 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.

Table of Contents

Our business is adversely affected by low oil and gas prices, which occur from time to time in a cyclical oil and gas industry.

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 and other expenditures for offshore exploration, development, drilling and production operations. Although our services are used for other operations during the entire life cycle of a well, when industry conditions are unfavorable such as the current environment, oil and gas companies will likely continue to reduce their budgets for expenditures on all types of operations, and will defer certain activities to the extent possible. The level of both capital and operating expenditures generally depends on the prevailing view of future oil and gas prices, which are influenced by numerous factors, including:

- worldwide economic activity and general economic and business conditions;
- supply and demand for oil and natural gas, especially in the United States, Europe, China and India;
- political and economic uncertainty and geopolitical unrest, including 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 onshore shale oil and natural gas;
- the cost of offshore exploration for and production and transportation of oil and natural gas;
- the level of excess production capacity;
- the ability of oil and gas companies to generate funds or otherwise obtain external capital for capital projects 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;
- potential acceleration of the development of alternative fuels;
- shifts in end-customer preferences toward fuel efficiency and the use of natural gas;
- weather conditions and natural disasters;
- environmental and other governmental regulations; and
- tax laws, regulations and policies.

A prolonged period of low level of activity by offshore oil and gas operators may continue to adversely affect demand for our services and could lead to an even greater surplus of available vessels and therefore increasingly downward pressure on the rates we can charge for our services. In the short term, our customers, in reaction to negative market conditions, may continue to seek to renegotiate their contracts with us at lower rates, both during and at the expiration of the term of our contracts, to cancel earlier work and shift it to later periods, or to cancel their contracts with us even if cancellation involves their paying a cancellation fee. The extent of the impact of these conditions on our results of operations and cash flows depends on the length and severity of an unfavorable industry environment and the potential decreased demand for our services.

The majority of our current backlog is concentrated in a small number of long-term contracts.

Although historically our service contracts were of relatively short duration, over the last several years we have been entering into longer term contracts, such as the five-year contract with BP for work in the U.S. Gulf of Mexico, the four-year Petrobras contracts for well intervention services offshore Brazil and the seven-year contract for the HP I. As of December 31, 2018, the BP contract, the Petrobras contracts and the contract for the HP I represented approximately 90% of our total backlog. Due to the value at risk, any cancellation, termination or breach of those contracts would have a larger impact on our operating results and financial condition than shorter term contracts. The cancellation or termination of, or unwillingness to perform, these contracts could have a material adverse effect on our financial position, results of operations and cash flows.

15

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

As of December 31, 2018, backlog for our services supported by written agreements or contracts totaled $1.1 billion, of which $470 million is expected to be performed in 2019. We may incur capital costs (a substantial portion of which we expect to recover from these contracts), we may charter vessels for the purpose of performing these contracts, and/or we may forgo or not seek other contracting opportunities in light of these contracts.

We may not be able to perform under our contracts for various reasons giving our customers certain contractual rights under their contracts with us, which ultimately could include termination of a contract. 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 industry conditions affecting our customers and their own revenues. Some of these contracts provide for a cancellation fee that is substantially less than the expected rates from the contracts. In addition, some of our customers could experience liquidity issues or could otherwise be unable or unwilling to perform under a contract, in which case a customer may repudiate or seek to cancel or renegotiate the contract. The repudiation or 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.

Our inability or failure to perform well operationally under our contracts could result in reduced revenues, contractual penalties, and/or ultimately, contract termination.

Our equipment and services are very technical and the offshore environment poses its own challenges. Performing the work we do pursuant to the terms of our contracts can be difficult for various reasons, including equipment failure or reduced performance, human error, design flaws, weather, water currents or soil conditions. Failure to perform in accordance with contract specifications can result in reduced rates (or zero rates), contractual penalties, and ultimately, termination in the event of sustained non-performance. For example our services and charter agreements with Petrobras provide that Petrobras can assess fines based on a percentage of our daily operating rate for certain failures of equipment, vessels or personnel, and that ultimately Petrobras has the right to terminate its agreements with us should assessed penalties reach a certain level. Reduced revenues and/or contract termination because of our failure to perform operationally could have a material adverse effect on our financial position, results of operations and cash flows.

A sustained period of unfavorable industry conditions could jeopardize our customers’ and other counterparties’ ability to perform their obligations.

Continued uncertain industry conditions could jeopardize the ability of certain of our counterparties, including our customers, insurers and financial institutions, to perform their obligations. Although we assess the creditworthiness of our counterparties, a prolonged period of difficult industry conditions could lead to changes in a counterparty’s liquidity and increase our exposure to credit risk and bad debts. In particular, our robotics business unit tends to do business with smaller customers that may not be capitalized to the same extent as larger operators. In addition, we may offer extended payment terms to our customers in order to secure contracts. These circumstances may lead to more frequent collection issues. Our financial results and liquidity could be adversely affected and we could incur losses.

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 these agreements, and if we were unable to find suitable replacements at a reasonable cost, our financial position, results of operations and cash flows could be adversely impacted.

Table of Contents

Time chartering of vessels requires us to make ongoing payments regardless of utilization of and revenue generation from those vessels, and we may own vessels with ongoing costs that cannot be recouped if the vessels are not under contract.

Typically, we charter our ROV support vessels under long-term time charter agreements. We also have entered into long-term charter agreements for the Siem Helix 1 and Siem Helix 2 vessels to perform work under our contracts with Petrobras. Should our contracts with customers be canceled, terminated or breached and/or we do not secure work for the chartered vessels, we are still required to make charter payments. Making those payments absent revenue generation could have a material adverse effect on our financial position, results of operations and cash flows.

In addition, from time to time we may construct vessels and other assets for our fleet without first obtaining service contracts covering the cost of those assets. For example, our Q7000 vessel currently does not have any contracted backlog. Once constructed and in service, there are ongoing costs of owning these capital assets, including ongoing maintenance, limited manning, insurance and depreciation. Our failure to secure service contracts for vessels or other assets could adversely affect our financial position, results of operations and cash flows.

Fleet upgrade, modification, repair , dry dock and construction projects, and customer contractual acceptance of new vessels and equipment, are subject to risks, including delays, cost overruns, loss of revenue and failure to commence or maintain contracts.

The Q7000, our newbuild semi-submersible well intervention vessel, is under completion at the shipyard in Singapore, and equipment for the vessel is currently being installed. We also construct or make capital improvements to other pieces of equipment (such as the 15K IRS that we jointly constructed with OneSubsea). In addition, we incur significant upgrade, modification, refurbishment, repair and dry dock expenditures on our existing fleet from time to time. While some of these projects are planned, some are unplanned. Additionally, as vessels and equipment age, they are more likely to be subject to higher maintenance and repair activities. These projects are subject to risks of delay or cost overruns inherent in any large capital project.

Estimated capital expenditures could materially exceed our planned capital expenditures. Moreover, our assets undergoing upgrades, modifications, refurbishment or repair may not earn a day rate during the period they are out of service. Any significant period of unplanned maintenance and repairs related to our vessels and other income-producing assets could have a material adverse effect on our financial position, results of operations and cash flows.

In addition, delays in the delivery of vessels and other operating assets being constructed or undergoing upgrades, modifications, refurbishment, repair, or dry docks may result in delay in customer acceptance and/or 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 contracts with us and/or seek delay damages under applicable late delivery clauses. In the event of termination of a contract due to late delivery, we may not be able to secure a replacement contract on favorable terms, if at all.

Because we have certain capital, debt and other obligations, a prolonged period of low demand and rates for our services could eventually lead to a material adverse effect on our liquidity.

Although we continue to seek to reduce the level of our capital and other expenses and have raised capital by means of several securities offerings, in the event of a more prolonged period of the current industry environment, the failure of our customers to expend funds on our services or a longer period of lower rates for our services, coupled with certain fixed obligations that we have related to debt repayment, capital commitments, long-term time charter contracts for our vessels and certain other commitments related to ongoing operational activities, could eventually lead to a material adverse effect on our liquidity and financial position.

Table of Contents

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

The oilfield services business in which we operate is highly competitive. An oversupply of offshore drilling rigs coupled with a significant slowdown in industry activities results in increased competition from drilling rigs as well as substantially lower rates on work that is being performed. Several of our competitors are substantially larger and have greater financial and other resources to better withstand a prolonged period of difficult industry conditions. In order to compete for customers, these larger competitors may undercut us substantially by reducing rates to levels we are unable to withstand. If other companies relocate or acquire assets for operations in the regions in which we operate, levels of competition may increase further and our business could be adversely affected.

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, 2018, we had $440.3 million of consolidated indebtedness outstanding. The level of indebtedness may have an adverse effect on our future operations, including:

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

A prolonged period of weak economic conditions and other events beyond our control may make it increasingly difficult to comply with our covenants and other restrictions in agreements governing our debt. If we fail to comply with these covenants and other restrictions, it could lead to reduced liquidity, 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. These conditions and events may limit our access to the credit markets if we need to replace our existing debt, which could lead to increased costs and less favorable terms, including shorter repayment schedules and higher fees and interest rates.

Lack of access to the financial markets 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 be unable to refinance or we may incur increased costs and less favorable terms associated with refinancing of our maturing debt. Also, we may incur increased costs and less favorable terms associated with any additional financing that we may require for future operations. Limited access to the financial markets could adversely impact our ability to take advantage of business opportunities or react to changing economic and business conditions. 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. Certain of our customers could experience an inability to pay suppliers, including us, in the event they are unable to access financial 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 financial markets could also adversely affect our ability to implement our strategic objectives and dispose of non-core business assets.

Table of Contents

A further decline in the offshore energy services market could result in additional impairment charges.

Prolonged periods of low utilization and day rates could result in the recognition of impairment charges for our vessels and robotics assets if future cash flow estimates, based on information available to us at the time, indicate that their carrying value may not be recoverable.

Our North Sea 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 North Sea are seasonal and depend, in part, on weather conditions. Historically, we have enjoyed our highest North Sea vessel utilization rates during the summer and fall when weather conditions are favorable for offshore operations. We typically have experienced our lowest utilization rates in the North Sea 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.

Certain areas in and near the Gulf of Mexico and North Sea experience unfavorable weather conditions including hurricanes and extreme storms 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 weather events, we may experience disruptions in our operations because customers may curtail their offshore 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.

Vessel-based offshore services 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 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 financial position, results of operations and cash flows. Moreover, we cannot make assurances 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 require broad exclusions for losses due to war risk and terrorist acts, and limitations for wind storm damage. 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 assets 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 offshore operations. We can provide no assurance, however, that our customers will be willing or financially able to meet these indemnification obligations.

19

Table of Contents

Our oil and gas operations involve a high degree of operational risk, particularly risk of personal injury, damage, loss of equipment and environmental accidents.

In January 2019, we acquired certain currently producing oil and gas properties as part of our strategy to secure utilization for our vessels and other equipment. Engaging in oil and gas production and transportation operations subjects us to certain risks inherent in the operation of oil and gas wells, including but not limited to uncontrolled flows of oil, gas, brine or well fluids into the environment; blowouts; cratering; pipeline or other facility ruptures; mechanical difficulties or other equipment malfunction; fires, explosions or other physical damage; hurricanes, storms and other natural disasters and weather conditions; and pollution and other environmental damage; any of which could result in substantial losses to us. Although we maintain insurance against some of these risks we cannot insure against all possible losses. As a result, any damage or loss not covered by our insurance could have a material adverse effect on our financial condition, results of operations and cash flow.

Government regulations may affect our business operations, including making our operations more difficult and/or costly.

Our business is affected by changes in public policy and by federal, state, local and foreign laws and regulations relating to the offshore oil and gas industry. Offshore oil and gas operations are affected by tax, environmental, safety, labor, cabotage and other laws, by changes in those laws, application or interpretation of existing laws, and changes in related administrative regulations or enforcement priorities. It is also possible that these laws and regulations may in the future add significantly to our capital and operating costs or those of our customers or otherwise directly or indirectly affect our operations. For instance, in January 2017 CBP proposed a modification or revocation of numerous prior letter rulings regarding the interpretation of the Jones Act, which would have significantly changed how foreign flag vessels could operate on the OCS. While CBP withdrew this proposal in May 2017, CBP, its parent agency, the Department of Homeland Security, or the U.S. Congress could revisit the issue. If a policy change occurred along the lines proposed by CBP in January 2017, such a new interpretation of the Jones Act could adversely impact the operations of non-coastwise qualified vessels working in the U.S. Gulf of Mexico, and could potentially make it more difficult and/or costly to perform our offshore services in the area. Industry would undoubtedly challenge any such action to the extent that it seeks to limit the ability of non-coastwise qualified vessels from performing the operations they are currently permitted to perform, but such regulatory or legislative action could create the same uncertainty in the industry as the January 2017 CBP proposal did.

Tax laws are dynamic and subject to change as new laws are passed and new interpretations of the law are issued or applied. In 2017 the United States enacted significant tax reform, and certain provisions of the new law may adversely affect us. Certain members of the EU are undergoing significant changes to their tax systems, which may have an adverse effect on us. In addition, risks of substantial costs and liabilities related to environmental compliance issues are inherent in our operations. Our operations are subject to extensive federal, state, local and foreign laws and regulations relating to the generation, storage, handling, emission, transportation and discharge of materials into the environment. Permits are required for the operations of various facilities, and those permits are subject to revocation, modification and renewal. Government authorities have the power to enforce compliance with their regulations, and violations are subject to fines, injunctions or both. In some cases, those governmental requirements can impose liability for the entire cost of cleanup on any responsible party without regard to negligence or fault and impose liability on us for the conduct of others or conditions others have caused, or for our acts that complied with all applicable requirements when we performed them. It is possible that other developments, such as stricter environmental laws and regulations, and claims for damages to property or persons resulting from our operations, would result in substantial costs and liabilities. Our insurance policies and the contractual indemnity protection we seek to obtain from our customers may not be sufficient or effective to protect us under all circumstances or against all risk involving compliance with environmental laws and regulations.

Enhanced regulations for deepwater offshore drilling 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. To conduct deepwater drilling in the U.S. Gulf of Mexico, an operator is required to comply with existing and newly developed regulations and enhanced safety standards. Before drilling may commence, the BSEE conducts many inspections of deepwater drilling operations for compliance with its regulations, including the testing of blowout preventers. Operators also are required to comply with the Safety and Environmental Management System regulations ("SEMS") within the deadlines specified by the regulations, and ensure that their contractors have SEMS compliant safety and environmental policies and procedures. Additionally, each operator must demonstrate that it has containment resources that are

Table of Contents

available promptly in the event of a deepwater blowout, regardless of the company or operator involved. It is expected that the BOEM and the BSEE will continue to issue further regulations regarding deepwater offshore drilling. Our 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 other oil and gas operations are delayed or reduced due to increased costs of complying with regulations, demand for our services in the Gulf of Mexico may also decline. Moreover, if our assets are not redeployed to other locations where we can provide our services at a profitable rate, our business, financial condition, results of operations and cash flows would be materially adversely affected.

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. If the United States or other countries where our customers operate enact stricter restrictions on offshore drilling or further regulate offshore drilling and thereby increase costs and/or cause delays for our customers, and this results in decreased demand for or profitability of our services, our business, financial position, results of operations and cash flows could be materially adversely affected.

Failure to comply with anti-bribery laws could have a material 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 Brazil's 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 corruption to some degree. We have a robust ethics and compliance program that is designed to deter or detect violations of applicable laws and regulations through the application of our anti-corruption policies and procedures, Code of Business Conduct and Ethics, training, internal controls, investigation and remediation activities, and other measures. However, our ethics and compliance program may not be fully effective in preventing all employees, contractors or intermediaries from violating or circumventing our compliance requirements or applicable laws and regulations. Failure to comply with anti-bribery laws could subject us to civil and criminal penalties, and such failure, and in some instances even the mere allegation of such failure, could create termination or other rights in connection with our existing contracts, negatively impact our ability to obtain future work, or lead to other sanctions, all of which could have a material adverse effect on our business, financial position, results of operations and cash flows, and cause reputational damage. We could also face fines, sanctions and other penalties from authorities, including prohibition of our participating in or curtailment of business operations in certain jurisdictions and the seizure of vessels or other assets. Further, we may have competitors who are not subject to the same laws, which may provide them with a competitive advantage over us in securing business or gaining other preferential treatment.

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:

- 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 and quasi-governmental entities;
- changes in laws and policies governing operations of foreign-based companies;
- currency restrictions and exchange rate fluctuations;
- global 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.

Certain countries have in place or are in the process of developing complex laws for foreign companies doing business in these countries, such as local content requirements. Some of these laws are difficult to interpret, making compliance uncertain, and others increase the cost of doing business, which may make it difficult for us in some cases to be competitive. In addition, laws and policies of the United States affecting foreign trade and taxation may adversely affect our international operations.

Table of Contents

Our international operations are exposed to currency devaluation and fluctuation risk.

Since we are a global company, our international operations are exposed to foreign currency exchange rate risks on all contracts denominated in foreign currencies. For some of our international contracts, a portion of the revenue and local expenses is incurred in local currencies and we are at risk of changes in the exchange rates between the U.S. dollar and such currencies. In some instances, we receive payments in currencies that are not easily traded and may be illiquid. 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, changes 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.

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. Many companies, including us, have had employee lay-offs as a result of reduced business activities in an industry downturn. 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. For certain projects we may have competition for personnel with the requisite skill set, including from drilling companies.

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 almost every aspects of our business. Similar to other companies, we may be subject to cybersecurity breaches caused by, among other things, illegal hacking, computer viruses, phishing, malware, ransomware, or acts of vandalism or terrorism. Although we continue to refine our procedures, educate our employees and implement tools and security measures to protect against such cybersecurity risks, there can be no assurance that these measures will prevent or detect every type of attempt or attack. In addition, a cyberattack or security breach could go undetected for an extended period of time. A breach or failure of our information technology systems or networks, critical third-party systems on which we rely, or those of our customers or vendors, could result in an interruption in our operations, disruption to certain systems that are used to operate our vessels or ROVs; unplanned capital expenditures, unauthorized publication of our confidential business or proprietary information, unauthorized release of customer or employee data, theft or misappropriation of funds; violation of privacy or other laws, and exposure to litigation. Any such breach could have a material adverse effect on our business, reputation, financial position, results of operations and cash flows.

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

We are authorized to fix, without any action by our shareholders, the rights and preferences on up to 5,000,000 shares of 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 could 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.

Item 1B. Unresolved Staff Comments

None.

Table of Contents

Item 2. Properties

OUR VESSELS

We own a fleet of five vessels, six IRSs, three SILs, 46 ROVs, five trenchers and one ROVDrill. We also have five vessels under long-term charter. Currently all of our vessels, both owned and chartered, have DP capabilities specifically designed to meet the needs of our customers' deepwater activities. Our Seawell and Well Enhancer vessels have built-in saturation diving systems.

Listing of Vessels and Other Assets Related to Operations [1]

	Flag State	Placed in Service [2]	Length (Feet)	Saturation Diving	DP
Floating Production Unit —					
Helix Producer I [3]	Bahamas	4/2009	528	—	DP2
Well Intervention —					
Q4000 [4]	U.S.	4/2002	312	—	DP3
Seawell	U.K.	7/2002	368	Capable	DP2
Well Enhancer	U.K.	10/2009	432	Capable	DP2
Q5000 [5]	Bahamas	4/2015	358	—	DP3
Siem Helix 1 [6]	Bahamas	6/2016	521	—	DP3
Siem Helix 2 [6]	Bahamas	2/2017	521	—	DP3
6 IRSs and 3 SILs [7]	—	Various	—	—	—
Robotics —					
46 ROVs, 5 Trenchers and 1 ROVDrill [3], [8]	—	Various	—	—	—
Grand Canyon [6]	Norway	10/2012	419	—	DP3
Grand Canyon II [6]	Norway	4/2015	419	—	DP3
Grand Canyon III [6]	Norway	5/2017	419	—	DP3

(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 U.S. Coast Guard. 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 our owned vessels in service (rather than the date of commissioning) or the date the charters for our chartered vessels commenced, as applicable.

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

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

(5) Serves as security for our Nordea Q5000 Loan described in Note 6.

(6) Chartered vessel.

(7) We own a 50% interest in one of our IRSs, the 15K IRS, which we jointly developed with OneSubsea.

(8) Average age of our fleet of ROVs, trenchers and ROVDrills is approximately 8.9 years.

We incur routine dry dock, inspection, maintenance and repair costs pursuant to applicable statutory regulations in order to maintain our vessels in accordance with the rules of the applicable class society. In addition to complying with these requirements, we have our own vessel maintenance programs that we believe permit 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.

Table of Contents

PRODUCTION FACILITIES

We own a 20% interest in Independence Hub, which owns the Independence Hub platform located in the eastern Gulf of Mexico.

FACILITIES

Our corporate headquarters are located at 3505 West Sam Houston Parkway North, Suite 400, Houston, Texas. We currently lease all of our facilities. The list of our facilities as of December 31, 2018 is as follows:

Location	Function	Size
Houston, Texas	Helix Energy Solutions Group, Inc. Corporate Headquarters, Project Management, and Sales Office Helix Well Ops, Inc. Corporate Headquarters, Project Management and Sales Office Canyon Offshore, Inc. Corporate Headquarters, Project Management and Sales Office Kommandor LLC Corporate Headquarters	118,630 square feet (including 30,104 square feet subject to approximately five years remaining under a sub-lease agreement)
Houston, Texas	Helix Energy Solutions Group, Inc. Canyon Offshore, Inc. Warehouse and Storage Facility	5.5 acres (Building: 90,640 square feet)
Aberdeen, Scotland	Helix Well Ops (U.K.) Limited Corporate Offices and Operations Energy Resource Technology (U.K). Limited Corporate Offices	27,000 square feet
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)
Singapore	Canyon Offshore International Corp. Corporate, Operations and Sales Office Helix Offshore Crewing Service Pte. Ltd. Corporate Headquarters	22,486 square feet
Luxembourg	Helix Group Holdings S.à r.l. and subsidiaries Corporate Offices and Operations	161 square feet
Brazil	Helix do Brasil Serviços de Petróleo Ltda	3,338 square feet

Corporate, Operations and Sales
Office

Item 3. Legal Proceedings

We are, from time to time, party to litigation arising in the normal course of 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.

Table of Contents

Executive Officers of the Company

The executive officers of Helix are as follows:

Name	Age	Position
Owen Kratz	64	President, Chief Executive Officer and Director
Erik Staffeldt	47	Executive Vice President and Chief Financial Officer
Scott A. Sparks	45	Executive Vice President and Chief Operating Officer
Alisa B. Johnson	61	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 the position of President and Chief Executive Officer. He 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 (including as Chairman of the Board of Directors from May 1998 to July 2017). He served as Chief Operating Officer from 1990 through 1997. Mr. Kratz joined Cal Dive International, Inc. (now known as 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 once 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).

Erik Staffeldt is Executive Vice President and Chief Financial Officer of Helix. Mr. Staffeldt oversees Helix's finance, treasury, accounting, tax, information technology and corporate planning functions. Since joining Helix in July 2009 as Assistant Corporate Controller, Mr. Staffeldt has served as Director — Corporate Accounting from August 2011 until March 2013, Director of Finance from March 2013 until February 2014, Finance and Treasury Director February 2014 until July 2015, Vice President — Finance and Accounting from July 2015 to June 2017, and Senior Vice President and Chief Financial Officer from June 2017 until February 2018. Mr. Staffeldt was also designated as Helix's "principal accounting officer" for purposes of the Securities Act of 1933, the Securities Exchange Act of 1934 and the rules and regulations promulgated thereunder in July 2015. Mr. Staffeldt served in various financial and accounting capacities prior to joining Helix and has over 23 years of experience in the energy industry. Mr. Staffeldt is a graduate of the University of Notre Dame with a BBA in Accounting and an MBA from Loyola University in New Orleans, and is a Certified Public Accountant.

Scott A. ("Scotty") Sparks is Executive Vice President and Chief Operating Officer of Helix, having joined Helix in 2001. He served as Executive Vice President — Operations of Helix from May 2015 until February 2016. From October 2012 until May 2015, he was Vice President — Commercial and Strategic Development of Helix. He has also served in various positions within Helix's robotics subsidiary, Canyon Offshore, Inc., including as Senior Vice President from 2007 to September 2012. Mr. Sparks has over 29 years of experience in the subsea industry, including Operations Manager and Vessel Superintendent at Global Marine Systems and BT Marine Systems.

Alisa B. Johnson has served as Executive Vice President, General Counsel and Corporate Secretary of Helix since November 2008, and joined Helix as Senior Vice President, General Counsel and Secretary of Helix in September 2006. Ms. Johnson oversees the legal, human resources and contracts and insurance functions. Ms. Johnson has been involved with the energy industry for over 28 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 Energy, Inc., and 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.

Table of Contents

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." On February 15, 2019, the closing sale price of our common stock on the NYSE was $7.36 per share. As of February 15, 2019, there were 342 registered shareholders and approximately 21,100 beneficial shareholders of our common stock.

We have not declared or paid cash dividends on our common stock in the past nor do we 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, 2013 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: Dril-Quip, Inc., Forum Energy Technologies, Inc., Frank's International N.V., Hornbeck Offshore Services, Inc., Newpark Resources, Inc., Noble Corporation plc, 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, 2018 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, 2013 in our common stock at the closing price on that date price and on December 31, 2013 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 — (76.7)%; the Peer Group — (92.1)%; the OSX — (71.3)%; and S&P 500 — 50.3%. These results are not necessarily indicative of future performance.

Table of Contents

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

	As of December 31,					
	2013	2014	2015	2016	2017	2018
Helix	$100.0	$93.6	$22.7	$38.1	$32.5	$23.3
Peer Group Index	$100.0	$61.7	$26.7	$22.9	$14.4	$7.9
Oil Service Index	$100.0	$75.0	$56.1	$65.4	$53.2	$28.7
S&P 500	$100.0	$113.7	$115.3	$129.1	$157.2	$150.3

Source: Bloomberg

Issuer Purchases of Equity Securities

Period	(a) Total number of shares purchased (1)	(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 (2) (3)
October 1 to October 31, 2018	—	$ —	—	3,804,134
November 1 to November 30, 2018	3,768	7.35	—	3,804,134
December 1 to December 31, 2018	41,726	7.70	—	3,931,076
	45,494	$ 7.67	—	

(1) Includes shares forfeited by a former officer and certain members of our Board of Directors in satisfaction of tax obligations upon vesting of restricted shares.

(2) 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 12), increases the number of shares available for repurchase. For additional information regarding our stock repurchase program, see Note 9.

(3) In January 2019, we issued approximately 0.7 million shares of restricted stock to our executive officers, select management employees, and certain members of our Board of Directors who have elected to take their quarterly fees in stock in lieu of cash. These issuances increase the number of shares available for repurchase by a corresponding amount (Note 9).

Table of Contents

Item 6. Selected Financial Data.

The financial data presented below for each of the five years ended December 31, 2018 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.

	Year Ended December 31,				
	2018	2017	2016	2015	2014
	(in thousands, except per share amounts)				
Statement of Operations Data:					
Net revenues	$739,818	$581,383	$487,582	$695,082	$1,107,156
Gross profit (loss) [1]	121,684	62,166	46,516	(233,774)	344,036
Income (loss) from operations [2]	51,543	(1,130)	(63,235)	(307,360)	261,756
Net income (loss), including noncontrolling interests [3]	28,598	30,052	(81,445)	(376,980)	195,550
Net income applicable to noncontrolling interests	—	—	—	—	(503)
Net income (loss) applicable to common shareholders	28,598	30,052	(81,445)	(376,980)	195,047
Adjusted EBITDA [4]	161,709	107,216	89,544	172,736	378,010
Earnings (loss) per share of common stock:					
Basic	$0.19	$0.20	$(0.73)	$(3.58)	$1.85
Diluted	$0.19	$0.20	$(0.73)	$(3.58)	$1.85
Weighted average common shares outstanding:					
Basic	146,702	145,295	111,612	105,416	105,029
Diluted	146,830	145,300	111,612	105,416	105,045

(1) Amount in 2015 included impairment charges of $205.2 million for the Helix 534, $133.4 million for the HP I and $6.3 million for certain capitalized vessel project costs.

(2) Amount in 2016 included a $45.1 million goodwill impairment charge related to our robotics reporting unit (Note 2). Amount in 2015 included a $16.4 million goodwill impairment charge related to our U.K. well intervention reporting unit.

(3) Amount in 2017 included a $51.6 million income tax benefit as a result of the U.S. tax law changes enacted in December 2017 (Note 7). Amount in 2015 included losses totaling $124.3 million related to our investments in Deepwater Gateway and Independence Hub. Amount in 2015 also included unrealized losses totaling $18.3 million on our foreign currency exchange contracts associated with the Grand Canyon, Grand Canyon II and Grand Canyon III chartered vessels.

(4) 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), including noncontrolling interests.

	December 31,				
	2018	2017	2016	2015	2014
	(in thousands)				
Balance Sheet Data:					
Working capital	$259,440	$186,004	$336,387	$473,123	$468,660
Total assets	2,347,730	2,362,837	2,246,941	2,399,959	2,690,179
Total debt	440,315	495,627	625,967	749,335	540,853
Total shareholders' equity	1,617,779	1,567,393	1,281,814	1,278,963	1,653,474

Table of Contents

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"). Non-GAAP financial measures should be viewed in addition to, and not as an alternative to, our reported results prepared in accordance with GAAP. Users of this financial information should consider the types of events and transactions that are excluded from these measures.

We measure our operating performance based on EBITDA and free cash flow. EBITDA and free cash flow are non-GAAP financial measures that are commonly used but are not recognized accounting terms under GAAP. We use EBITDA and free cash flow to monitor and facilitate 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 that our measures of EBITDA and free cash flow provide 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 earnings before income taxes, net interest expense, net other income or expense, and depreciation and amortization expense. 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 these impairment charges are material for certain periods presented, we have reported them as a separate line item. Non-cash goodwill impairment and losses on equity investments are also added back if applicable. Loss on extinguishment of long-term debt is considered equivalent to additional interest expense and thus is added back to net income (loss), including noncontrolling interests.

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, when applicable, we exclude the noncontrolling interests related to the adjustment components of EBITDA. Our measure of Adjusted EBITDA also excludes gain or loss on disposition of assets. In addition, we include realized losses from foreign currency exchange contracts not designated as hedging instruments and other than temporary loss on note receivable, which are excluded from EBITDA as a component of net other income or expense.

We define free cash flow as cash flows from operating activities less capital expenditures, net of proceeds from sale of assets.

Other companies may calculate their measures of EBITDA, Adjusted EBITDA and free cash flow differently from the way we do, which may limit their usefulness as comparative measures. EBITDA, Adjusted EBITDA and free cash flow should not be considered in isolation or as a substitute for, but instead are supplemental to, income from operations, net income, cash flow from operating activities, or other income or cash flow data prepared in accordance with GAAP. The reconciliation of our net income (loss), including noncontrolling interests, to EBITDA and Adjusted EBITDA is as follows (in thousands):

Table of Contents

	Year Ended December 31,				
	2018	2017	2016	2015	2014
Net income (loss), including noncontrolling interests	$28,598	$30,052	$(81,445)	$(376,980)	$195,550
Adjustments:					
Income tax provision (benefit)	2,400	(50,424)	(12,470)	(101,190)	66,971
Net interest expense	13,751	18,778	31,239	26,914	17,859
Loss on extinguishment of long-term debt	1,183	397	3,540	—	—
Other (income) expense, net (1)	6,324	1,434	(3,510)	24,310	(814)
Depreciation and amortization	110,522	108,745	114,187	120,401	109,345
Asset impairments (2)	—	—	—	345,010	—
Goodwill impairments (3)	—	—	45,107	16,399	—
Losses on equity investments (4)	3,430	1,800	1,674	122,765	—
EBITDA	166,208	110,782	98,322	177,629	388,911
Adjustments:					
Noncontrolling interests	—	—	—	—	(661)
(Gain) loss on disposition of assets, net	(146)	39	(1,290)	(92)	(10,240)
Realized losses from foreign exchange contracts not designated as hedging instruments	(3,224)	(3,605)	(7,488)	(4,801)	—
Other than temporary loss on note receivable	(1,129)	—	—	—	—
Adjusted EBITDA	$161,709	$107,216	$89,544	$172,736	$378,010

(1) Amount in 2015 included unrealized losses totaling $18.3 million on our foreign currency exchange contracts associated with the Grand Canyon, Grand Canyon II and Grand Canyon III chartered vessels.

(2) Amount in 2015 reflects asset impairment charges for the Helix 534, the HP I and certain capitalized vessel project costs.

(3) Amount in 2016 reflects a goodwill impairment charge related to our robotics reporting unit (Note 2). Amount in 2015 reflects a goodwill impairment charge related to our U.K. well intervention reporting unit.

(4) Amount in 2015 primarily reflects losses from our share of impairment charges that Deepwater Gateway and Independence Hub recorded in December 2015 and the write-offs of the remaining capitalized interest related to these equity investments.

The reconciliation of our cash flows from operating activities to free cash flow is as follows (in thousands):

	Year Ended December 31,				
	2018	2017	2016	2015	2014
Cash flows from operating activities	$196,744	$51,638	$38,714	$110,805	$359,485
Less: Capital expenditures, net of proceeds from sale of assets	(137,058)	(221,127)	(173,310)	(302,719)	(323,338)
Free cash flow	$59,686	$(169,489)	$(134,596)	$(191,914)	$36,147

Table of Contents

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. We believe that focusing on these services will deliver favorable long-term financial returns. From time to time, we may make strategic investments that expand our service capabilities or add capacity to existing services in our key operating regions. We expect our well intervention fleet to expand with the completion and delivery in 2019 of the Q7000, a newbuild semi-submersible vessel. Chartering newer vessels with additional capabilities, such as the three Grand Canyon vessels, should enable our robotics business to better serve the needs of our customers. From a longer-term perspective we also expect to benefit from our fixed fee agreement for the HP I, a dynamically positioned floating production vessel that processes production from the Phoenix field for the field operator until at least June 1, 2023.

In January 2015, Helix, OneSubsea LLC, OneSubsea B.V., Schlumberger Technology Corporation, Schlumberger B.V. and Schlumberger Oilfield Holdings Ltd. 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 leverages the parties' capabilities to provide a unique, fully integrated offering to clients, combining marine support with well access and control technologies. We and OneSubsea jointly developed a 15K IRS, each owning a 50% interest. The 15K IRS was completed and placed into service in January 2018. Our total investment in the 15K IRS was approximately $17 million. In October 2016, we and OneSubsea launched the development of our first ROAM for an estimated cost of approximately $6 million for our 50% interest. At December 31, 2018, our total investment in the ROAM was $5.6 million. The ROAM is expected to be available in 2019.

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 spend on operational activities as well as capital projects. The performance of our business is also largely dependent on the prevailing market prices for oil and natural gas, which are impacted by domestic and global economic conditions, hydrocarbon production and capacity, geopolitical issues, weather, and several other factors, including:

- worldwide economic activity and general economic and business conditions, including available access to global capital and capital markets;
- supply and demand for oil and natural gas, especially in the United States, Europe, China and India;
- political and economic uncertainty and geopolitical unrest, including 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 onshore shale oil and natural gas;
- the cost of offshore exploration for and production and transportation of oil and natural gas;
- the level of excess production capacity;
- the ability of oil and gas companies to generate funds or otherwise obtain external capital for capital projects 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;
- potential acceleration of the development of alternative fuels;
- shifts in end-customer preferences toward fuel efficiency and the use of natural gas;
- weather conditions and natural disasters;
- environmental and other governmental regulations; and
- domestic and international tax laws, regulations and policies.

West Texas Intermediate oil prices rose to over $70 per barrel during 2018 before decreasing to around $45 per barrel towards the end of the year. Volatility in oil prices creates uncertainty in oil and gas exploration and production activities. For instance, an increase in oil and gas exploration and production activities (shale oil production in particular) is expected when major oil producing countries including the U.S. increase output as a result of rising oil prices. Increased supply without adequate levels of increase in demand, however, may weaken oil prices and industry prospects. The resulting industry environment may continue to curtail investments in offshore exploration and production as well as other offshore operational activities. Increased competition for limited offshore oil and gas projects has driven down rates that drilling rig contractors are charging for their services, which affects us, as drilling rigs historically have been the asset class used for intervention work. This rig overhang combined with lower volumes of work may affect the utilization and/or rates we can achieve for our assets. The current volatile and uncertain macroeconomic conditions in some countries around the world, such as Brazil and the U.K. following Brexit, may have a direct and/or indirect impact on our existing contracts and contracting opportunities and may introduce further currency volatility into our operations and/or financial results. In addition, the longer term effects of the 2017 Tax Act on capital spending by oil and gas companies are still uncertain.

Many oil and gas companies are increasingly focusing on optimizing production of their existing subsea wells. We believe that we have a competitive advantage in terms of performing well intervention services efficiently. Furthermore, we believe that when oil and gas companies begin to increase overall spending levels, it will likely be for production enhancement activities rather than for exploration projects. 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, we believe that fundamentals for our business remain favorable over the longer term as the need for prolongation of well life in oil and gas production is the primary driver of demand for our services.

Our current strategy is to be positioned for future recovery while managing a sustained period of weak activity. This strategy is based on the following factors: (1) the need to extend the life of subsea wells is significant to the commercial viability of the wells as plug and abandonment costs are considered; (2) our services offer commercially viable alternatives for reducing the finding and development costs of reserves as compared to new drilling as well as extending and enhancing the commercial life of subsea wells; and (3) in past cycles, well intervention and workover have been some of the first activities to recover, and in a prolonged market downturn are important to the commercial viability of deepwater wells. We could see the beginnings of an upturn in the demand for our services in the U.S. Gulf of Mexico, which are primarily driven by two factors: (1) long-term rig contracts are not being renewed thus removing rig overhang that was considered by our customers to be a sunk cost; and (2) work needed on aging wells, which has been deferred, is becoming less likely to be further deferred due to the decline in well performance.

Business Activity Summary

We have been focused on enhancing our financial position and strengthening our balance sheet through various means including securities offerings (the last of which occurred in March 2018), which has allowed us to strategically focus on our core well intervention and robotics businesses. After commencing operations for Petrobras in 2017, both the Siem Helix 1 and Siem Helix 2 vessels achieved a full year of operations with high utilization in 2018. Additionally in

2018 a third of our robotics revenues were derived from offshore renewables work involving seabed trenching (increased from prior years), and we expect the growing demand for our services from the alternative (renewable) energy industry to continue. Our robotics business also benefited from cost savings such as reduced charter costs as a result of returning the Deep Cygnus to its owner during the first quarter of 2018. Furthermore, the 15K IRS, which was jointly developed and ordered by us and OneSubsea, was placed into service in January 2018.

Table of Contents

RESULTS OF OPERATIONS

We have three reportable business segments: Well Intervention, Robotics and Production Facilities. 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 maximizing production economics. Our services cover the lifecycle of an offshore oil or gas field. We operate primarily in deepwater in the U.S. Gulf of Mexico, Brazil, North Sea, Asia Pacific and West Africa regions. In addition to serving the oil and gas market, our Robotics assets are contracted for the development of renewable energy projects (wind farms). As of December 31, 2018, our consolidated backlog that is supported by written agreements or contracts totaled $1.1 billion, of which $470 million is expected to be performed in 2019. The substantial majority of our backlog is associated with our Well Intervention business segment. As of December 31, 2018, our well intervention backlog was $0.9 billion, including $368 million expected to be performed in 2019. Our contract with BP to provide well intervention services with our Q5000 semi-submersible vessel, our agreements with Petrobras to provide well intervention services offshore Brazil with the Siem Helix 1 and Siem Helix 2 chartered vessels, and our fixed fee agreement for the HP I represent approximately 90% of our total backlog. At December 31, 2017, the total backlog associated with our operations was $1.6 billion. Backlog is not necessarily a reliable indicator of revenues derived from these contracts as services may be added or subtracted; contracts may be renegotiated, deferred, canceled and in many cases modified while in progress; and reduced rates, fines and penalties may be imposed by our customers. Furthermore, our contracts are in certain cases cancelable without penalty. If there are cancellation fees, the amount of those fees can be substantially less than the rates we would have generated had we performed the contract.

Comparison of Years Ended December 31, 2018 and 2017

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

	Year Ended December 31,		Increase/(Decrease)	
	2018	2017	Amount	Percent
Net revenues —				
Well Intervention	$560,568	$406,341	$154,227	38 %
Robotics	158,989	152,755	6,234	4 %
Production Facilities	64,400	64,352	48	— %
Intercompany eliminations	(44,139)	(42,065)	(2,074)	
	$739,818	$581,383	$158,435	27 %
Gross profit (loss) —				
Well Intervention	$101,129	$66,515	$34,614	52 %
Robotics	(4,978)	(31,986)	27,008	84 %
Production Facilities	27,626	28,568	(942)	(3)%
Corporate, eliminations and other	(2,093)	(931)	(1,162)	
	$121,684	$62,166	$59,518	96 %
Gross margin —				
Well Intervention	18 %	16 %		
Robotics	(3)%	(21)%		
Production Facilities	43 %	44 %		
Total company	16 %	11 %		

33

Table of Contents

	Year Ended December 31,	
	2018	2017
Number of vessels or robotics assets [1] / Utilization [2]		
Well Intervention vessels	6/83%	6/77%
Robotics assets	52/37%	55/42%
Chartered robotics vessels	3/76%	4/69%

(1) Represents the number of vessels or robotics assets as of the end of the period, including vessels under both short-term and long-term charters and excluding acquired vessels prior to their in-service dates, vessels taken out of service prior to their disposition and vessels jointly owned with third parties.

(2) Represents the average utilization rate, which is calculated by dividing the total number of days the vessels or robotics assets generated revenues by the total number of available calendar days in the applicable period. The average utilization rates of chartered robotics vessels in 2018 and 2017 include 245 and 170 spot vessel days, respectively, at near full utilization.

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 are as follows (in thousands):

	Year Ended December 31,		Increase/
	2018	2017	(Decrease)
Well Intervention	$14,218	$11,489	$ 2,729
Robotics	29,921	30,576	(655)
	$44,139	$42,065	$ 2,074

Net Revenues. Our total net revenues increased by 27% in 2018 as compared to 2017 primarily as a result of higher revenues in our Well Intervention and Robotics segments.

Well Intervention revenues increased by 38% in 2018 as compared to 2017 primarily reflecting higher revenues in Brazil and the North Sea, partially offset by a decrease in the Gulf of Mexico. In Brazil, the Siem Helix 1 commenced operations for Petrobras in mid-April 2017 and the Siem Helix 2 commenced operations for Petrobras in mid-December 2017. Both vessels had a full year of operations in 2018. The Siem Helix 1 and the Siem Helix 2 achieved 97% and 94% utilization, respectively, during 2018 as compared to 96% and 53% utilization, respectively, during 2017. Higher revenue in the North Sea in 2018 was primarily attributable to rate improvements with more diving and higher margin work for both vessels, offset in part by lower utilization for the Seawell. The Seawell was 72% utilized during 2018 as compared to being 78% utilized during 2017. The Well Enhancer was 79% utilized during 2018 as compared to being 74% utilized during 2017. Decreased revenue in the Gulf of Mexico was primarily attributable to lower utilization for the Q5000. The vessel was 82% utilized during 2018 as compared to being 91% utilized during 2017. Revenue from the Q4000 remained flat as a result of marginally higher rates while vessel utilization was 72% during 2018 as compared to 75% during 2017. The addition of the 15K IRS as well as higher utilization of our other IRS rental also contributed to the increased revenues in 2018.

Robotics revenues increased by 4% in 2018 as compared to 2017. The increase primarily reflects higher trenching activities that contributed to increased utilization of ROV support vessels (from 69% in 2017 to 76% in 2018), and was offset in part by lower ROV utilization.

Production Facilities revenues were consistent year over year.

Gross Profit (Loss). Our 2018 gross profit increased by 96% as compared to 2017 reflecting improvements in our Well Intervention and Robotics segments.

The gross profit related to our Well Intervention segment increased by 52% in 2018 as compared to 2017, primarily reflecting a full year of operations in Brazil and improvements in our operating results in the North Sea, offset in part by lower gross profit in the Gulf of Mexico.

The gross loss associated with our Robotics segment decreased by 84% in 2018 as compared to 2017 primarily reflecting cost reductions and higher trenching revenues with increased utilization for our ROV support vessels.

The gross profit related to our Production Facilities segment decreased by 3% in 2018 as compared to 2017 primarily reflecting higher fuel costs in 2018.

Selling, General and Administrative Expenses. Our selling, general and administrative expenses increased by $7.0 million in 2018 as compared to 2017 primarily as a result of increased costs related to employee incentive compensation and other employee benefits.

Equity in Losses of Investments. Equity in losses of investments was $3.9 million in 2018 as compared to $2.4 million in 2017 primarily reflecting an increase in our share of losses that were recorded by Independence Hub (Note 5).

Net Interest Expense. Our net interest expense totaled $13.8 million in 2018 as compared to $18.8 million in 2017 reflecting a decrease in interest expense and an increase in interest income, partially offset by a decrease in capitalized interest. The decrease in interest expense was primarily attributable to a significant reduction in our debt levels (long-term debt decreased from $495.6 million at December 31, 2017 to $440.3 million at December 31, 2018). Interest expense for 2017 also included charges of $1.6 million to accelerate the amortization of a pro-rata portion of debt issuance costs related to the lenders whose commitments in our revolving credit facility were reduced (Note 6). Interest income totaled $3.2 million for 2018 as compared to $2.6 million for 2017. Interest on debt used to finance capital projects is capitalized and thus reduces overall interest expense. Capitalized interest decreased from $16.9 million for 2017 to $15.6 million for 2018.

Loss on Extinguishment of Long-term Debt. The $1.2 million loss in 2018 was attributable to the write-off of the unamortized debt issuance costs related to the prepayment of $61 million of the Term Loan in March 2018 and costs associated with our repurchase of $59.3 million in aggregate principal amount of the 2032 Notes (Note 6). The $0.4 million loss in 2017 was associated with the write-off of the unamortized debt issuance costs related to certain lenders exiting from our then outstanding term loan prior to its June 2017 amendment and restatement.

Other Expense, Net. Net other expense increased by $4.9 million for 2018 as compared to 2017. Net other expense in 2018 and 2017 included foreign currency transaction losses of $4.3 million and $2.2 million, respectively. These amounts primarily reflect foreign exchange fluctuations in our non-U.S. dollar currencies. Also included in the comparable year over year periods were net losses (gains) of $0.9 million in 2018 and $(0.8) million in 2017 associated with our foreign currency exchange contracts that were not designated as cash flow hedges (Note 18). Net other expense for 2018 included a $1.1 million other than temporary loss on a note receivable (Note 3).

Income Tax Provision (Benefit). Income tax provision for 2018 was $2.4 million. Excluding a net deferred tax benefit of $51.6 million as a result of the effect of U.S. tax law changes enacted in 2017 and a $6.3 million tax charge in 2017 attributable to a change in tax position related to our foreign taxes, we had an income tax benefit of $5.1 million for 2017. The variance in our income taxes (excluding the 2017 tax changes) primarily reflects increased profitability in 2018 as compared to 2017. The effective tax rate was 7.7% for 2018 as compared to 247.5% for 2017. The variance was primarily attributable to the effect of the tax law changes and the change in tax position related to our foreign taxes in 2017 as well as the earnings mix between our higher and lower tax rate jurisdictions (Note 7).

Table of Contents

Comparison of Years Ended December 31, 2017 and 2016

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

	Year Ended December 31,		Increase/(Decrease)	
	2017	2016	Amount	Percent
Net revenues —				
Well Intervention	$406,341	$294,000	$112,341	38 %
Robotics	152,755	160,580	(7,825)	(5)%
Production Facilities	64,352	72,358	(8,006)	(11)%
Intercompany eliminations	(42,065)	(39,356)	(2,709)	
	$581,383	$487,582	$93,801	19 %
Gross profit (loss) —				
Well Intervention	$66,515	$26,879	$39,636	147 %
Robotics	(31,986)	(12,466)	(19,520)	157 %
Production Facilities	28,568	34,335	(5,767)	(17)%
Corporate, eliminations and other	(931)	(2,232)	1,301	
	$62,166	$46,516	$15,650	34 %
Gross margin —				
Well Intervention	16 %	9 %		
Robotics	(21)%	(8)%		
Production Facilities	44 %	47 %		
Total company	11 %	10 %		
Number of vessels or robotics assets (1) / Utilization (2)				
Well Intervention vessels	6/77%	5/54%		
Robotics assets	55/42%	59/48%		
Chartered robotics vessels	4/69%	3/64%		

(1) Represents the number of vessels or robotics assets as of the end of the period, including vessels under both short-term and long-term charters and excluding acquired vessels prior to their in-service dates, vessels taken out of service prior to their disposition and vessels jointly owned with third parties.

(2) Represents the average utilization rate, which is calculated by dividing the total number of days the vessels or robotics assets generated revenues by the total number of available 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 are as follows (in thousands):

	Year Ended December 31,		Increase/
	2017	2016	(Decrease)
Well Intervention	$11,489	$8,442	$ 3,047
Robotics	30,576	30,914	(338)
	$42,065	$39,356	$ 2,709

Table of Contents

Net Revenues. Our total net revenues increased by 19% in 2017 as compared to 2016. Increased revenues for 2017 reflected higher revenues in our Well Intervention segment, offset in part by revenue decreases in our Robotics and Production Facilities segments.

Well Intervention revenues increased by 38% in 2017 as compared to 2016 primarily reflecting higher revenues generated from all of the well intervention vessels except for the Q4000. In Brazil, the Siem Helix 1 achieved 96% utilization since it commenced operations for Petrobras in mid-April 2017. The Siem Helix 2 commenced operations for Petrobras in mid-December 2017 with 53% utilization. In the North Sea, the Well Enhancer was 74% utilized during 2017 while the vessel was 64% utilized during 2016. The Seawell was 78% utilized during 2017 whereas it was 42% utilized during 2016. In the Gulf of Mexico, the Q5000 was 91% utilized during 2017 as compared to being 65% utilized during 2016. The Q4000 was 75% utilized during 2017 as compared to being 98% utilized during 2016. The vessel was out of service for 49 days during the first half of 2017 undergoing its scheduled regulatory dry dock. Additionally in 2016, we recognized $15.6 million associated with cancellation of work originally scheduled to be performed by the Q4000 in late 2016.

Robotics revenues decreased by 5% in 2017 as compared to 2016. The decrease primarily reflected lower utilization of our robotics assets and performing work at reduced rates. Some of our ROV units have been affected by other industry participants laying up vessels or canceling work as a result of the oil and gas industry downturn.

Production Facilities revenues decreased by 11% in 2017 as compared to 2016, which reflected reduced retainer fees from the amended HFRS agreement which was effective February 1, 2017, no revenue from the HFRS for 33 days as the Q4000 underwent its regulatory dry dock, and lower revenues from the amendment of the agreement with the Phoenix field operator for the HP I to a fixed fee agreement that commenced June 1, 2016.

Gross Profit (Loss). Our 2017 gross profit increased by 34% as compared to 2016. The gross profit related to our Well Intervention segment increased by 147% in 2017 as compared to 2016, primarily reflecting higher revenues in our North Sea region.

The gross loss associated with our Robotics segment increased by 157% in 2017 as compared to 2016 primarily reflecting decreased utilization for our robotics assets and performing work with lower profit margins.

The gross profit related to our Production Facilities segment decreased by 17% in 2017 as compared to 2016 primarily reflecting revenue decreases for the HFRS and the HP I.

Goodwill Impairment. The $45.1 million impairment charge in 2016 reflects the write-off of the entire goodwill balance associated with our robotics reporting unit.

Gain on Disposition of Assets, Net. The $1.3 million net gain on disposition of assets in 2016 was attributable to the sale of the Helix 534 in December 2016.

Selling, General and Administrative Expenses. Our selling, general and administrative expenses decreased by $2.7 million in 2017 as compared to 2016. The decrease was primarily attributable to a $4.7 million decrease associated with the provision for uncertain collection of a portion of our then existing trade and note receivables as well as our overriding royalty interest asset being fully depreciated in April 2017, offset in part by an increase in payroll related costs including share-based compensation associated with our long-term incentive plan (Note 12).

Equity in Losses of Investments. Equity in losses of investments was $2.4 million in 2017 as compared to $2.2 million in 2016 primarily reflecting an increase in our share of losses that were recorded by Independence Hub (Note 5).

Table of Contents

Net Interest Expense. Our net interest expense totaled $18.8 million in 2017 as compared to $31.2 million in 2016 reflecting increases in interest income and capitalized interest and a decrease in interest expense. Interest income totaled $2.6 million for 2017 as compared to $2.1 million for 2016. Interest on debt used to finance capital projects is capitalized and thus reduces overall interest expense. Capitalized interest totaled $16.9 million for 2017 as compared to $11.8 million for 2016. The decrease in interest expense was primarily attributable to a significant reduction in our debt levels, including an $80 million principal reduction of our term loan in June 2017. Interest expense for 2017 and 2016 also included charges of $1.6 million and $2.5 million, respectively, to accelerate the amortization of a pro-rata portion of debt issuance costs related to the lenders whose commitments in our revolving credit facility were reduced (Note 6).

Loss on Extinguishment of Long-term Debt. The $0.4 million loss in 2017 was associated with the write-off of the unamortized debt issuance costs related to certain lenders exiting from the term loan then outstanding under our credit agreement prior to its amendment and restatement in June 2017 (Note 6). The $3.5 million loss in 2016 was associated with the repurchases of $139.9 million in aggregate principal amount of our 2032 Notes in 2016.

Other Income (Expense), Net. We reported other expense, net, of $1.4 million for 2017 as compared to other income, net, of $3.5 million for 2016. Other income (expense), net, in 2017 and 2016 included foreign currency transaction gains (losses) of $(2.2) million and $0.2 million, respectively. These amounts primarily reflect foreign exchange fluctuations in our non-U.S. dollar currencies. Also included in the comparable year-over-year periods were net gains of $0.8 million and $1.3 million associated with our foreign currency exchange contracts primarily reflecting gains related to the portions of the contracts that were not designated as cash flow hedges (Note 18). In addition, other income, net, for 2016 included a $2.0 million net foreign currency translation gain reclassified out of accumulated other comprehensive loss into earnings during the year.

Income Tax Benefit. Income taxes reflected a benefit of $50.4 million in 2017 as compared to $12.5 million in 2016 This variance is primarily due to the effect of U.S. tax law changes enacted in December 2017, offset in part by a decrease in pretax loss for the current year period and a tax charge in 2017 attributable to a change in tax position related to our foreign taxes. The effective tax rate was 247.5% for 2017 as compared to 13.3% for 2016. The increase was primarily attributable to the effect of the tax law changes, partially offset by the earnings mix between our higher and lower tax rate jurisdictions and the change in tax position related to our foreign taxes (Note 7).

LIQUIDITY AND CAPITAL RESOURCES

Overview

The following table presents certain information useful in the analysis of our financial condition and liquidity (in thousands):

	December 31, 2018	December 31, 2017
Net working capital	$259,440	$186,004
Long-term debt (1)	393,063	385,766
Liquidity (2)	426,813	348,207

(1) Long-term debt does not include the current maturities portion of our long-term debt as that amount is included in net working capital. Long-term debt is also net of unamortized debt discount and debt issuance costs. See Note 6 for information relating 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 that facility. Our liquidity at December 31, 2018 included cash and cash equivalents of $279.5 million and $147.4 million of available borrowing capacity under our Revolving Credit Facility (Note 6). Our liquidity at December 31, 2017 included

cash and cash equivalents of $266.6 million and $81.6 million of available borrowing capacity under our Revolving Credit Facility.

Table of Contents

The carrying amount of our long-term debt, including current maturities, net of unamortized debt discount and debt issuance costs, is as follows (in thousands):

	December 31,	
	2018	2017
Term Loan (matures June 2020)	$33,321	$95,842
Nordea Q5000 Loan (matures April 2020)	123,980	158,930
MARAD Debt (matures February 2027)	66,443	72,487
2022 Notes (mature May 2022) (1)	112,192	108,829
2023 Notes (mature September 2023) (2)	104,379	—
2032 Notes (redeemed May 2018)	—	59,539
Total debt	$440,315	$495,627

(1) The 2022 Notes will increase to their face amount through accretion of the debt discount through May 1, 2022.
(2) The 2023 Notes will increase to their face amount through accretion of the debt discount through September 15, 2023.

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

	Year Ended December 31,		
	2018	2017	2016
Cash provided by (used in):			
Operating activities	$196,744	$51,638	$38,714
Investing activities	(136,014)	(221,127)	(147,110)
Financing activities	(46,186)	77,482	(25,524)

Our current requirements for cash primarily reflect the need to fund capital spending 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 project financing, along with other debt and equity alternatives.

As a further response to the industry-wide spending reductions, we continue to remain 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 our cash on hand, internally generated cash flows and available borrowing capacity under our Revolving Credit Facility will be sufficient to fund our operations over at least the next 12 months.

In accordance with our Credit Agreement, the 2022 Notes, the 2023 Notes, the MARAD Debt agreements and the Nordea Credit Agreement, we are required to comply with certain covenants, including with respect to the Credit Agreement, certain financial ratios such as a consolidated interest coverage ratio and various leverage ratios, as well as the maintenance of a minimum cash balance, 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 Q5000 Loan) secured by the underlying asset, provided that such indebtedness is not guaranteed by us. Our 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 defined in our Credit Agreement). As of December 31, 2018 and 2017, we were in compliance with the covenants in our long-term debt agreements.

Table of Contents

A prolonged period of weak industry 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 and reduced EBITDA, our ability to fully access our Revolving Credit Facility may be impacted. At December 31, 2018, our available borrowing capacity under our Revolving Credit Facility, based on the applicable leverage ratio covenant, was restricted to $147.4 million, net of $2.6 million of letters of credit issued under that facility. We currently have no plans or forecasted requirements to borrow under our Revolving Credit Facility other than for the issuance of letters of credit. Our ability to comply with loan agreement covenants and other restrictions is affected by economic conditions and other events beyond our control. Our failure to comply with these covenants and other restrictions could lead to an event of default, the possible acceleration of our outstanding debt and the exercise of certain remedies by our lenders, including foreclosure against our collateral.

Subject to the terms and restrictions of the Credit Agreement, we may borrow and/or obtain letters of credit up to $25 million under our Revolving Credit Facility. See Note 6 for additional information relating to our long-term debt, including more information regarding our Credit Agreement and related covenants and collateral.

The 2022 Notes and the 2023 Notes can be converted into our common stock by the holders or redeemed by us prior to their stated maturity under certain circumstances specified in the applicable indenture governing the notes. We can settle any conversion in cash, shares of our common stock or a combination thereof.

We repurchased $59.3 million in aggregate principal amount of the 2032 Notes on March 20, 2018 and redeemed the remaining $0.8 million on May 4, 2018.

Operating Cash Flows

Total cash flows from operating activities increased by $145.1 million in 2018 as compared to 2017 primarily reflecting improvements in our operations, collection of accounts receivable and reductions in interest payments.

Total cash flows from operating activities increased by $12.9 million in 2017 as compared to 2016 primarily reflecting changes in our working capital.

Investing Activities

Capital expenditures represent cash paid principally for the acquisition, construction, upgrade, modification and refurbishment of long-lived property and equipment such as dynamically positioned vessels, topside equipment and subsea systems. Capital expenditures also include interest on property and equipment under development. Significant sources (uses) of cash associated with investing activities are as follows (in thousands):

	Year Ended December 31,		
	2018	2017	2016
Capital expenditures:			
Well Intervention	$(136,164)	$(230,354)	$(185,892)
Robotics	(151)	(648)	(720)
Production Facilities	(325)	—	(74)
Other	(443)	(125)	199
Distributions from equity investment (1)	—	—	1,200
Proceeds from sale of equity investment (1)	—	—	25,000
Proceeds from sale of assets (2)	25	10,000	13,177
Other	1,044	—	—
Net cash used in investing activities	$(136,014)	$(221,127)	$(147,110)

(1) Amounts in 2016 reflect cash received as a result of our former ownership interest in Deepwater Gateway (Note 5).

Amount in 2017 reflects cash received from the sale of our former spoolbase facility located in Ingleside, Texas.
(2) Amount in 2016 primarily reflects cash received from the sale of our office and warehouse property located in Aberdeen, Scotland and the sale of the Helix 534 (Note 4).

Table of Contents

Our capital expenditures have primarily included payments associated with the construction of our Q7000 vessel (see below), the investment in the topside well intervention equipment for the Siem Helix 1 and Siem Helix 2 vessels that we charter to perform our agreements with Petrobras (see below), and the investment in the 15K IRS and the ROAM.

In September 2013, we executed a contract for the construction of a newbuild semi-submersible well intervention vessel, the Q7000, to be built to North Sea standards. Pursuant to the contract and subsequent amendments, 20% of the contract price was paid upon the signing of the contract in 2013, 20% was paid in each of 2016, 2017 and 2018, and the remaining 20% will be paid upon the delivery of the vessel, which at our option can be deferred until December 31, 2019. We are also contractually committed to reimburse the shipyard for its costs in connection with the deferment of the Q7000's delivery beyond 2017. At December 31, 2018, our total investment in the Q7000 was $403.8 million, including $276.8 million of installment payments to the shipyard. Currently equipment is being manufactured and installed for the completion of the vessel. We plan to incur approximately $112 million related to the Q7000 in 2019, which includes the final shipyard payment of $69.2 million.

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 from commencement of operations with options to extend by agreement of both parties for an additional period of up to four years. In connection with the Petrobras agreements, we entered into charter agreements with Siem for two monohull vessels, the Siem Helix 1, which commenced operations for Petrobras in mid-April 2017, and the Siem Helix 2, which commenced operations for Petrobras in mid-December 2017.

Financing Activities

Cash flows from financing activities consist primarily of proceeds from debt and equity transactions and repayments of our long-term debt. Net cash outflows from financing activities were $46.2 million in 2018 as compared to net cash inflows of $77.5 million in 2017. In 2018, we repaid approximately $166 million of our indebtedness using cash and the net proceeds from the issuance in March 2018 of $125 million of our 2023 Notes (Note 6). Cash inflows from financing activities in 2017 included the net proceeds of approximately $220 million we received from our underwritten public equity offering in January 2017, offset in part by debt repayments in 2017.

Net cash inflows from financing activities were $77.5 million in 2017 as compared to net cash outflows of $25.5 million in 2016. We received approximately $220 million of net proceeds from our underwritten public equity offering in January 2017 (Note 8) and $100 million from our Term Loan borrowings in June 2017, while making early repayments of approximately $180 million of term loan then outstanding under the credit agreement prior to its June 2017 amendment and restatement (Note 6). In 2016, we received $96.5 million of net proceeds from the sale of our common stock under two separate at-the-market equity offering programs and $125 million from the issuance of our 2022 Notes, while making early repayments of $33 million on our term loan then outstanding and repurchasing $139.9 million in aggregate principal amount of the 2032 Notes including approximately $122 million with proceeds from the issuance of the 2022 Notes.

Free Cash Flow

Free cash flow increased by $229.2 million in 2018 as compared to 2017 primarily attributable to higher operating cash flows and reduced capital expenditures in 2018 as a result of the completion of the Siem Helix 1 and Siem Helix 2 vessels during 2017.

Free cash flow decreased by $34.9 million in 2017 as compared to 2016 primarily attributable to higher capital expenditures as a result of the completion of the Siem Helix 1 and Siem Helix 2 vessels during 2017.

Free cash flow is a non-GAAP financial measure. See Item 6 for the definition and calculation of free cash flow.

Table of Contents

Outlook

We anticipate that our capital expenditures, including capitalized interest, and deferred dry dock costs for 2019 will approximate $140 million. We believe that cash on hand, internally generated cash flows and availability under our Revolving Credit Facility will provide the capital necessary to continue funding our 2019 capital obligations and to meet our debt obligations due in 2019. Our estimate of future capital expenditures may change based on various factors. We may seek to reduce the level of our planned capital expenditures given a prolonged industry downturn.

Contractual Obligations and Commercial Commitments

The following table summarizes our contractual cash obligations as of December 31, 2018 and the scheduled years in which the obligations are contractually due (in thousands):

	Total [(1)]	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Term Loan	$33,693	$4,680	$29,013	$—	$—
Nordea Q5000 Loan	125,000	35,714	89,286	—	—
MARAD debt	70,468	6,858	14,760	16,270	32,580
2022 Notes [(2)]	125,000	—	—	125,000	—
2023 Notes [(3)]	125,000	—	—	125,000	—
Interest related to debt [(4)]	68,298	22,013	29,202	14,458	2,625
Property and equipment [(5)]	85,900	85,617	283	—	—
Operating leases [(6)]	480,724	122,501	196,541	151,234	10,448
Total cash obligations	$1,114,083	$277,383	$359,085	$431,962	$45,653

(1) Excludes unsecured letters of credit outstanding at December 31, 2018 totaling $2.6 million. These letters of credit may be issued to support various obligations, such as contractual obligations, contract bidding and insurance activities.

(2) Notes mature in May 2022. The 2022 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 $18.06 per share, which is 130% of the conversion price. At December 31, 2018, the conversion trigger was not met. See Note 6 for additional information.

(3) Notes mature in September 2023. The 2023 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 $12.31 per share, which is 130% of the conversion price. At December 31, 2018, the conversion trigger was not met. See Note 6 for additional information.

(4) Interest payment obligations were calculated using stated coupon rates for fixed rate debt and interest rates applicable at December 31, 2018 for variable rate debt.

(5) Primarily reflects costs associated with our Q7000 semi-submersible well intervention vessel currently under completion (Note 14).

(6) Operating leases include vessel charters and facility leases. At December 31, 2018, our vessel charter commitments totaled approximately $444 million.

Contingencies

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

Table of Contents

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.

Property and Equipment

We review our property and equipment for impairment indicators at least quarterly or whenever changes in facts and circumstances indicate that the carrying amount of the asset or asset group may not be recoverable. We base our evaluation on impairment indicators such as the nature of the asset (or asset group), the future economic benefits of the asset (or asset group), historical and estimated future profitability measures, and other external market conditions of factors that may be present. We often estimate future earnings and cash flows of our assets to corroborate our determination of whether impairment indicators exist. If impairment indicators suggest that the carrying amount of an asset may not be recoverable, we determine whether an impairment has occurred by estimating undiscounted cash flows of the asset to the asset’s carrying value. Impairment is recognized for the difference between the asset’s carrying value and its estimated fair value. 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.

The review of property and equipment for impairment indicators, the determination of the appropriate asset groups at which to evaluate impairment, the projection of future cash flows of property and equipment, and the estimated fair value of any property and equipment that may be deemed unrecoverable involve significant judgment and estimation on the part of management. Changes to those judgments and estimations could require us to recognize impairment charges in the future.

Income Taxes

We conduct business in numerous countries and earn income in various jurisdictions. Taxes have been provided based upon the tax laws and rates in those jurisdictions. The provision of our income taxes involves the interpretation of various laws and regulations, and changes in those laws and in our operations and/or legal structure could impact our income tax liabilities. Furthermore, our tax filings are subject to regular audits and examination by the local taxing authorities. 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. 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.

We record deferred taxes based on the differences between financial reporting and the tax basis of assets and liabilities. The carrying value of deferred tax assets are based on our estimates, judgments, and assumptions regarding future operating results and taxable income. Loss carryforwards and tax credits are assessed for realization, and 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 assets will not be realized. If we subsequently determine that we will be able to realize deferred tax assets in the future in excess of our net recorded amount, the resulting adjustment would increase earnings for the period in which such determination was made. We will continue to assess the adequacy of the valuation allowance on a quarterly basis. Any changes to our estimated valuation allowance could be material to our consolidated financial position and results of operations.

Table of Contents

The 2017 Tax Act requires the taxable repatriation of foreign earnings that had been reinvested in previous years. Subsequently, repatriation of foreign earnings will generally be free of U.S. federal tax with the possible exception of withholding taxes and state taxes. As of December 31, 2018, we had accumulated undistributed earnings generated by our non-U.S. subsidiaries without operations in the U.S. of approximately $93.2 million. We intend to indefinitely reinvest these earnings, as well as future earnings from our non-U.S. subsidiaries without operations in the U.S., to fund our international operations and our Nordea Q5000 Loan. We have not accrued for the possibility of withholding taxes. The computation of the potential deferred tax liability associated with the amount of reinvested earnings and other basis difference is not practicable.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

As of December 31, 2018, we were exposed to market risk in two areas: interest rates and foreign currency exchange rates.

Interest Rate Risk. As of December 31, 2018, $158.7 million of our outstanding debt was subject to floating rates. The interest rate applicable to our variable rate debt may continue to rise, thereby increasing our interest expense and related cash outlay. In June 2015, we entered into various interest rate swap contracts to fix the interest rate on a portion of our Nordea Q5000 Loan. These swap contracts, which are settled monthly, began in June 2015 and extend through April 2020. As of December 31, 2018, $93.8 million of our Nordea Q5000 Loan was hedged, and debt subject to variable rates after considering hedging activities was $64.9 million. The impact of interest rate risk is estimated using a hypothetical increase in interest rates of 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 $0.9 million in interest expense for the year ended December 31, 2018.

Foreign Currency Exchange Rate Risk. Because we operate in various regions around the world, we conduct a portion of our business in currencies other than the U.S. dollar. As such, our earnings are impacted by movements in foreign currency exchange rates when (i) transactions are denominated in currencies other than the functional currency of the relevant Helix entity, or (ii) the functional currency of our subsidiaries is not 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 to partially offset revenues that are denominated in the same local currencies. In addition, a substantial portion of our contracts provide for collections from customers in U.S. dollars.

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" in the shareholders' equity section of our consolidated balance sheets. At December 31, 2018, approximately 14% of our assets were impacted by changes in foreign currencies in relation to the U.S. dollar. We recorded foreign currency translation gains (losses) of $(7.2) million, $16.3 million and $(35.9) million to accumulated other comprehensive loss for the years ended December 31, 2018, 2017 and 2016, 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 without operations in the U.S. to be permanently reinvested.

We also have other foreign subsidiaries with a majority of their operations 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, 2018, 2017 and 2016, these amounts resulted in gains (losses) of $(4.3) million, $(2.2) million and $0.2 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 results of operations and cash flows. As a result, we entered into various foreign currency exchange contracts to stabilize expected cash outflows related to certain vessel charters denominated in Norwegian kroners. In February 2013, we entered into foreign currency exchange contracts to hedge our foreign currency exposure with respect to the Grand Canyon II and Grand Canyon III charter payments denominated in Norwegian kroner through July 2019 and February 2020, respectively. A portion of these foreign currency exchange contracts currently qualify for cash flow hedge accounting treatment. Foreign currency hedge ineffectiveness was immaterial for the years ended December 31, 2018, 2017 and 2016.

Table of Contents

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

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

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Helix Energy Solutions Group, Inc. and subsidiaries (the Company) as of December 31, 2018 and 2017, the related consolidated statements of operations, comprehensive income (loss), shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2018, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2018, 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) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 22, 2019 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ KPMG LLP

We have served as the Company's auditor since 2016.

Houston, Texas
February 22, 2019

Report of Independent Registered Public Accounting Firm

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

Opinion on Internal Control Over Financial Reporting

We have audited Helix Energy Solutions Group, Inc. and subsidiaries' (the Company) internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2018 and 2017, the related consolidated statements of operations, comprehensive income (loss), shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2018, and the related notes (collectively, the consolidated financial statements), and our report dated February 22, 2019 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. 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 of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

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.

/s/ KPMG LLP

Houston, Texas
February 22, 2019

Table of Contents

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

	December 31, 2018	2017
ASSETS		
Current assets:		
Cash and cash equivalents	$279,459	$266,592
Accounts receivable:		
Trade, net of allowance for uncollectible accounts of $0 and $2,752, respectively	67,932	113,336
Unbilled and other	51,943	29,947
Other current assets	51,594	41,768
Total current assets	450,928	451,643
Property and equipment	2,785,778	2,695,772
Less accumulated depreciation	(959,033)	(889,783)
Property and equipment, net	1,826,745	1,805,989
Other assets, net	70,057	105,205
Total assets	$2,347,730	$2,362,837
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$54,813	$81,299
Accrued liabilities	85,594	71,680
Income tax payable	3,829	2,799
Current maturities of long-term debt	47,252	109,861
Total current liabilities	191,488	265,639
Long-term debt	393,063	385,766
Deferred tax liabilities	105,862	103,349
Other non-current liabilities	39,538	40,690
Total liabilities	729,951	795,444
Shareholders' equity:		
Common stock, no par, 240,000 shares authorized, 148,203 and 147,740 shares issued, respectively	1,308,709	1,284,274
Retained earnings	383,034	352,906
Accumulated other comprehensive loss	(73,964)	(69,787)
Total shareholders' equity	1,617,779	1,567,393
Total liabilities and shareholders' equity	$2,347,730	$2,362,837

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

Table of Contents

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share amounts)

	Year Ended December 31,		
	2018	2017	2016
Net revenues	$739,818	$581,383	$487,582
Cost of sales	618,134	519,217	441,066
Gross profit	121,684	62,166	46,516
Goodwill impairment	—	—	(45,107)
Gain (loss) on disposition of assets, net	146	(39)	1,290
Selling, general and administrative expenses	(70,287)	(63,257)	(65,934)
Income (loss) from operations	51,543	(1,130)	(63,235)
Equity in losses of investment	(3,918)	(2,368)	(2,166)
Net interest expense	(13,751)	(18,778)	(31,239)
Loss on extinguishment of long-term debt	(1,183)	(397)	(3,540)
Other income (expense), net	(6,324)	(1,434)	3,510
Other income – oil and gas	4,631	3,735	2,755
Income (loss) before income taxes	30,998	(20,372)	(93,915)
Income tax provision (benefit)	2,400	(50,424)	(12,470)
Net income (loss)	$28,598	$30,052	$(81,445)
Earnings (loss) per share of common stock:			
Basic	$0.19	$0.20	$(0.73)
Diluted	$0.19	$0.20	$(0.73)
Weighted average common shares outstanding:			
Basic	146,702	145,295	111,612
Diluted	146,830	145,300	111,612

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

Table of Contents

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(in thousands)

	Year Ended December 31, 2018	2017	2016
Net income (loss)	$28,598	$30,052	$(81,445)
Other comprehensive income (loss), net of tax:			
Net unrealized gain (loss) on hedges arising during the period	(847)	3,323	2,366
Reclassifications to net income (loss)	7,201	12,915	12,851
Income taxes on hedges	(1,338)	(5,724)	(5,347)
Net change in hedges, net of tax	5,016	10,514	9,870
Unrealized gain (loss) on note receivable arising during the period	(629)	629	—
Income taxes on note receivable	132	(220)	—
Unrealized gain (loss) on note receivable, net of tax	(497)	409	—
Foreign currency translation gain (loss) arising during the period	(7,166)	16,264	(33,899)
Reclassification adjustment for net translation gain realized upon liquidation	—	—	(2,044)
Foreign currency translation gain (loss)	(7,166)	16,264	(35,943)
Other comprehensive income (loss), net of tax	(2,647)	27,187	(26,073)
Comprehensive income (loss)	$25,951	$57,239	$(107,518)

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

Table of Contents

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

	Common Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
	Shares	Amount			
Balance, December 31, 2015	106,289	$945,565	$404,299	$ (70,901)	$1,278,963
Net loss	—	—	(81,445)	—	(81,445)
Foreign currency translation adjustments	—	—	—	(35,943)	(35,943)
Unrealized gain on hedges, net of tax	—	—	—	9,870	9,870
Equity component of debt discount on convertible senior notes	—	10,719	—	—	10,719
Re-acquisition of equity component of debt discount on convertible senior notes	—	(1,625)	—	—	(1,625)
Issuance of common stock, net of transaction costs	13,019	96,547	—	—	96,547
Activity in company stock plans, net and other	1,322	463	—	—	463
Share-based compensation	—	5,767	—	—	5,767
Cumulative share-based compensation in excess of fair value of modified liability awards	—	203	—	—	203
Excess tax from share-based compensation	—	(1,705)	—	—	(1,705)
Balance, December 31, 2016	120,630	$1,055,934	$322,854	$ (96,974)	$1,281,814
Net income	—	—	30,052	—	30,052
Foreign currency translation adjustments	—	—	—	16,264	16,264
Unrealized gain on hedges, net of tax	—	—	—	10,514	10,514
Unrealized gain on note receivable, net of tax	—	—	—	409	409
Equity component of debt discount on convertible senior notes	—	(7)	—	—	(7)
Issuance of common stock, net of transaction costs	26,450	219,504	—	—	219,504
Activity in company stock plans, net and other	660	(1,887)	—	—	(1,887)
Share-based compensation	—	10,730	—	—	10,730
Balance, December 31, 2017	147,740	$1,284,274	$352,906	$ (69,787)	$1,567,393
Net income	—	—	28,598	—	28,598
Reclassification of stranded tax effect to retained earnings	—	—	1,530	(1,530)	—
Foreign currency translation adjustments	—	—	—	(7,166)	(7,166)
Unrealized gain on hedges, net of tax	—	—	—	5,016	5,016
Unrealized loss on note receivable, net of tax	—	—	—	(497)	(497)
Equity component of debt discount on convertible senior notes	—	15,411	—	—	15,411
Activity in company stock plans, net and other	463	(746)	—	—	(746)
Share-based compensation	—	9,770	—	—	9,770
Balance, December 31, 2018	148,203	$1,308,709	$383,034	$ (73,964)	$1,617,779

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

Table of Contents

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

	Year Ended December 31,		
	2018	2017	2016
Cash flows from operating activities:			
Net income (loss)	$28,598	$30,052	$(81,445)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	110,522	108,745	114,187
Non-cash goodwill impairment	—	—	45,107
Amortization of debt discounts	5,735	4,688	5,905
Amortization of debt issuance costs	3,592	6,154	7,733
Share-based compensation	9,925	10,877	5,862
Deferred income taxes	(2,430)	(54,585)	14,849
Equity in losses of investment	3,918	2,368	2,166
(Gain) loss on disposition of assets, net	(146)	39	(1,290)
Loss on extinguishment of long-term debt	1,183	397	3,540
Unrealized (gains) losses and ineffectiveness on derivative contracts, net	(2,324)	(4,423)	(8,800)
Changes in operating assets and liabilities:			
Accounts receivable, net	20,920	(28,424)	(22,437)
Other current assets	(9,904)	(15,680)	(2,386)
Income tax payable	964	3,949	(4,571)
Accounts payable and accrued liabilities	(352)	33,381	(630)
Other non-current, net	26,543	(45,900)	(39,076)
Net cash provided by operating activities	196,744	51,638	38,714
Cash flows from investing activities:			
Capital expenditures	(137,083)	(231,127)	(186,487)
Distributions from equity investment	—	—	1,200
Proceeds from sale of equity investment	—	—	25,000
Proceeds from sale of assets	25	10,000	13,177
Other	1,044	—	—
Net cash used in investing activities	(136,014)	(221,127)	(147,110)
Cash flows from financing activities:			
Issuance of convertible senior notes	125,000	—	125,000
Repurchase of convertible senior notes	(60,365)	—	(138,401)
Proceeds from term loan	—	100,000	—
Repayment of term loans	(63,807)	(194,758)	(62,742)
Repayment of Nordea Q5000 Loan	(35,714)	(35,715)	(35,714)
Repayment of MARAD Debt	(6,532)	(6,222)	(5,926)
Debt issuance costs	(3,867)	(3,717)	(4,655)
Net proceeds from issuance of common stock	—	219,504	96,547
Payments related to tax withholding for share-based compensation	(1,407)	(2,042)	(341)
Proceeds from issuance of ESPP shares	506	432	708
Net cash provided by (used in) financing activities	(46,186)	77,482	(25,524)
Effect of exchange rate changes on cash and cash equivalents	(1,677)	1,952	(3,625)

Net increase (decrease) in cash and cash equivalents	12,867	(90,055)	(137,545)
Cash and cash equivalents:			
Balance, beginning of year	266,592	356,647	494,192
Balance, end of year	$279,459	$266,592	$356,647

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 provide services primarily in deepwater in the U.S. Gulf of Mexico, Brazil, North Sea, Asia Pacific and West Africa regions.

Our Operations

We seek to provide services and methodologies that we believe are critical to maximizing production economics. Our “life of field” services are segregated into three reportable business segments: Well Intervention, Robotics and Production Facilities (Note 13).

Our Well Intervention segment includes our vessels and equipment used to perform well intervention services primarily in the U.S. Gulf of Mexico, Brazil, the North Sea and West Africa. Our well intervention vessels include the Q4000, the Q5000, the Seawell, the Well Enhancer, and two chartered monohull vessels, the Siem Helix 1 and the Siem Helix 2. We also have a semi-submersible well intervention vessel under completion, the Q7000. Our well intervention equipment includes intervention riser systems (“IRSs”), some of which we provide on a stand-alone basis, and subsea intervention lubricators (“SILs”).

Our Robotics segment includes remotely operated vehicles (“ROVs”), trenchers and ROVDrills, which are designed to complement offshore construction and well intervention services, and three ROV support vessels under long-term charter: the Grand Canyon, the Grand Canyon II, and the Grand Canyon III. We also utilize spot vessels as needed. We returned the Deep Cygnus to its owner during the first quarter of 2018.

Our Production Facilities segment includes the Helix Producer I (the “HP I”), a ship-shaped dynamically positioned floating production vessel, and the Helix Fast Response System (the “HFRS”), which combines our HP I, Q4000 and Q5000 vessels with certain well control equipment that can be deployed to respond to a well control incident in the Gulf of Mexico. On January 16, 2019, we renewed the agreements that provide various operators with access to the HFRS for well control purposes through March 31, 2020. These agreements automatically renew on an annual basis absent proper notice of termination by one of the parties. The HP I has been under contract to the Phoenix field operator since February 2013 and is currently under a fixed fee agreement through at least June 1, 2023. The Production Facilities segment also includes our ownership interest in Independence Hub, LLC (“Independence Hub”) (Note 5). On January 18, 2019, we purchased from Marathon Oil Corporation (“Marathon Oil”) certain operating depths associated with the Droshky Prospect on offshore Gulf of Mexico Green Canyon Block 244, along with several wells and related infrastructure. As part of the transaction, Marathon Oil will pay us certain agreed upon amounts for the required plug and abandonment of the acquired assets, which we can perform as our schedules permit subject to regulatory timelines. There also is a limited amount of production associated with two wells that were acquired as part of the transaction.
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 ownership interest in Independence Hub under the equity method of accounting. All material intercompany accounts and transactions have been eliminated.

Table of Contents

Basis of Presentation

Our consolidated financial statements have been prepared in conformity with U.S. generally accepted accounting principles ("GAAP") in U.S. dollars. 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. We have made all adjustments that we believe are necessary for a fair presentation of our consolidated financial statements.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures 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 may differ from those estimates.

Cash and Cash Equivalents

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

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. We establish an allowance for uncollectible accounts based on historical experience as well as 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 16).

Property and Equipment

Property and equipment is recorded at historical cost. Property and equipment is depreciated on a straight-line basis over the estimated useful life of an asset. The cost of improvements is capitalized whereas the cost of repairs and maintenance is expensed as incurred. For the years ended December 31, 2018, 2017 and 2016, repair and maintenance expense totaled $27.3 million, $28.1 million and $25.5 million, respectively.

Assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate that the carrying amount of an asset or asset group may not be recoverable because such carrying amount may exceed the asset's or asset group's expected cash flows. If, upon review, the sum of undiscounted future cash flows expected to be generated by the asset or asset group is less than its carrying amount and the carrying amount is greater than its fair value, an impairment charge 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 where there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. 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.

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 those assets are held for sale. Losses are measured as the difference between an asset’s 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.

Table of Contents

Capitalized Interest

Interest from external borrowings is capitalized on major projects until the assets are ready for their intended use. Capitalized interest is added to the cost of the underlying asset and is amortized over the useful life of the asset in the same manner as the underlying asset. Capitalized interest is excluded from our interest expense (Note 6).

Equity Investment

With respect to our investment accounted for using the equity method of accounting, in the event we incur losses in excess of the carrying amount of our equity investment and reduce our investment balance to zero, we would not record additional losses unless (i) we guaranteed the obligations of the investee, (ii) we are otherwise committed to provide further financial support for the investee, or (iii) it is anticipated that the investee’s return to profitability is imminent. If we provided a commitment to fund losses, we would continue to record losses resulting in a negative equity method investment, which is presented as a liability.

Goodwill

We previously had $45.1 million of goodwill related to our robotics reporting unit. As a result of our 2016 goodwill impairment analysis, we recorded an impairment charge to write off the entire goodwill balance. We had no goodwill remaining on our consolidated balance sheets at December 31, 2018 and 2017.

Deferred Recertification and Dry Dock Costs

Our vessels and certain well intervention equipment are required by regulation to be periodically recertified. Recertification costs for a vessel are typically incurred while the vessel is in dry dock. In addition, routine repairs and maintenance are performed, and at times, major replacements and improvements may also be made. We expense routine repairs and maintenance costs as they are incurred. We defer and amortize recertification costs, including vessel dry dock costs, over the length of time for which we expect to receive benefits from the recertification, which generally ranges from 30 to 60 months if the appropriate permitting is obtained. A recertification process, including vessel dry dock, typically lasts between one to three months, a period during which a vessel or a piece of equipment is idle and generally not available to earn revenue. Major replacements and improvements that extend the economic useful life or functional operating capability of a vessel or a piece of equipment are capitalized and depreciated over the asset’s remaining economic useful life.

As of December 31, 2018 and 2017, deferred recertification and dry dock costs, which were included within “Other assets, net” in the accompanying consolidated balance sheets (Note 3), totaled $8.5 million and $12.8 million (net of accumulated amortization of $15.4 million and $7.3 million), respectively. During the years ended December 31, 2018, 2017 and 2016, amortization expense related to deferred recertification and dry dock costs was $8.3 million, $7.0 million and $14.0 million, respectively.

Revenue Recognition

Revenue from Contracts with Customers

We generate revenue in our Well Intervention segment by supplying vessels, personnel, and equipment to provide well intervention services, which involve providing marine access, serving as a deployment mechanism to the subsea well, connecting to and maintaining a secure connection to the subsea well and maintaining well control through the duration of the intervention services. We also perform down-hole intervention work and provide certain engineering services. We generate revenue in our Robotics segment by operating ROVs, trenchers and ROVDrills to provide subsea construction, inspection, repair and maintenance services to oil and gas companies as well as subsea trenching and burial of pipelines and cables for the oil and gas and the renewable energy industries. We also provide integrated robotic services by supplying vessels that deploy the ROVs and trenchers. Our Production Facilities segment generates revenue by providing personnel, vessel and equipment for oil and natural gas processing as well as well control response services.

Table of Contents

Our revenues are derived from short-term and long-term service contracts with customers. Our service contracts generally contain either provisions for specific time, material and equipment charges that are billed in accordance with the terms of such contracts (dayrate contracts) or lump sum payment provisions (lump sum contracts). We record revenues net of taxes collected from customers and remitted to governmental authorities.

We generally account for our services under contracts with customers as a single performance obligation satisfied over time. The single performance obligation in our dayrate contracts is comprised of a series of distinct time increments in which we provide services. We do not account for activities that are immaterial or not distinct within the context of our contracts as separate performance obligations. Consideration for these activities as well as contract fulfillment activities is allocated to the single performance obligation on a systematic basis that depicts the pattern of the provision of our services to the customer.

The total transaction price for a contract is determined by estimating both fixed and variable consideration expected to be earned over the term of the contract. We do not generally provide significant financing to our customers and do not adjust contract consideration for the time value of money if extended payment terms are granted for less than one year. The estimated amount of variable consideration is constrained and is only included in the transaction price to the extent that it is probable that a significant reversal in the amount of cumulative revenue recognized will not occur. At the end of each reporting period, we reassess and update our estimates of variable consideration and amounts of that variable consideration that should be constrained.

Dayrate Contracts. Revenues generated from dayrate contracts generally provide for payment according to the rates per day as stipulated in the contract (e.g., operating rate, standby rate, and repair rate). The invoices billed to the customer are typically based on the varying rates applicable to operating status on an hourly basis. Dayrate consideration is allocated to the distinct hourly time increment to which it relates and is therefore recognized in line with the contractual rate billed for the services provided for any given hour. Similarly, revenues from contracts that stipulate a monthly rate are recognized ratably during the month.

Dayrate contracts also may contain fees charged to the customer for mobilizing and demobilizing equipment and personnel. Mobilization and demobilization fees are associated with contract fulfillment activities, and related revenue (subject to any constraint on estimates of variable consideration) is allocated to the single performance obligation and recognized ratably over the initial term of the contract. Mobilization fees are generally billable to the customer in the initial phase of a contract and generate contract liabilities until they are recognized as revenue. Demobilization fees are generally received at the end of the contract and generate contract assets when they are recognized as revenue prior to becoming receivables from the customer. See further discussion on contract liabilities under “Contract balances” below.

We receive reimbursements from our customers for the purchase of supplies, equipment, personnel services and other services provided at their request. Reimbursable revenues are variable and subject to uncertainty as the amounts received and timing thereof are dependent on factors outside of our influence. Accordingly, these revenues are constrained and not recognized until the uncertainty is resolved, which typically occurs when the related costs are incurred on behalf of the customer. We are generally considered a principal in these transactions and record the associated revenues at the gross amounts billed to the customer.

A dayrate contract modification involving an extension of the contract by adding additional days of services is generally accounted for prospectively as a separate contract, but may be accounted for as a termination of the existing contract and creation of a new contract if the consideration for the extended services does not represent their stand-alone selling prices.

55

Table of Contents

Lump Sum Contracts. Revenues generated from lump sum contracts are recognized over time. Revenue is recognized based on the extent of progress towards completion of the performance obligation. We generally use the cost-to-cost measure of progress for our lump sum contracts because it best depicts the progress toward satisfaction of our performance obligation, which occurs as we incur costs under those contracts. Under the cost-to-cost measure of progress, the extent of progress towards completion is measured based on the ratio of cumulative costs incurred to date to the total estimated costs at completion of the performance obligation. Consideration, including lump sum mobilization and demobilization fees billed to the customer, is recorded proportionally as revenue in accordance with the cost-to-cost measure of progress. Consideration for lump sum contracts is generally due from the customer based on the achievement of milestones. As such, contract assets are generated to the extent we recognize revenues in advance of our rights to collect contract consideration and contract liabilities are generated when contract consideration due or received is greater than revenues recognized to date.

We review and update our contract-related estimates regularly and recognize adjustments in estimated profit on contracts under the cumulative catch-up method. Under this method, the impact of the adjustment on profit recorded to date on a contract is recognized in the period in which the adjustment is identified. Revenue and profit in future periods of contract performance are recognized using the adjusted estimate. If a current estimate of total contract costs to be incurred exceeds the estimate of total revenues to be earned, we recognize the projected loss in full when it is identified. A modification to a lump sum contract is generally accounted for as part of the existing contract and recognized as an adjustment to revenue (either as an increase in or a reduction of revenue) on a cumulative catch-up basis.

We implemented a new accounting policy with respect to revenue from contracts with customers upon the adoption of Accounting Standards Update (“ASU”) No. 2014-09 on January 1, 2018. See “New Accounting Standards” below and Note 10 for additional disclosures.

Royalty Interests

Income from royalty interests are recognized according to monthly oil and gas production on an entitlement basis. Income for royalty interests is reflected in “Other income - oil and gas” in the consolidated statements of operations.

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 non-U.S. subsidiaries without operations in the U.S. 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, 2018, 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.

Share-Based Compensation

Share-based compensation is measured at the grant date based on the estimated fair value of an award. Share-based compensation based solely on service conditions is recognized on a straight-line basis over the vesting period of the related shares. Forfeitures are recognized as they occur.

Compensation cost for restricted stock is the product of the grant date fair value of each share and the number of shares granted and is recognized over the applicable vesting period on a straight-line basis.

The estimated fair value of performance share units ("PSUs") is determined using a Monte Carlo simulation model. Compensation cost for PSUs that are accounted for as equity awards is measured based on the estimated grant date fair value and recognized over the vesting period on a straight-line basis. PSUs that are accounted for as liability awards are measured at their estimated fair value at the balance sheet date, and changes in fair value of the awards are recognized in earnings. Cumulative compensation cost for vested liability PSU awards equals the actual payout value upon vesting. To the extent the recognized fair value of the modified liability awards at the end of a reporting period is less than the compensation cost associated with the grant date fair value of the original equity awards, the higher amount is recorded as share-based compensation. The amount of cumulative compensation cost recognized in excess of the fair value of the modified liability awards is recorded in equity.

Foreign Currency

Because we operate in various regions around the world, we conduct a portion of our business in currencies other than the U.S. dollar. Results of operations for our non-U.S. dollar subsidiaries are translated into U.S. dollars using average exchange rates during the period. Assets and liabilities of these non-U.S. dollar subsidiaries are translated into U.S. dollars using the exchange rate in effect at December 31, 2018 and 2017, and the resulting translation adjustments, which were unrealized gains (losses) of $(7.2) million and $16.3 million, respectively, are included in other comprehensive income (loss) ("OCI").

For transactions denominated in a currency other than a subsidiary's functional currency, the effects of changes in exchange rates are reported in other income or expense in the consolidated statements of operations. For the years ended December 31, 2018, 2017 and 2016, our foreign currency transaction gains (losses) totaled $(4.3) million, $(2.2) million and $0.2 million, respectively. These realized amounts are exclusive of any gains or losses from our foreign currency exchange derivative contracts.

Derivative Instruments and Hedging Activities

Our business is 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. To reduce the impact of these risks on earnings and increase the predictability of our cash flows, from time to time we enter into certain derivative contracts, including interest rate swaps and foreign currency exchange contracts. All derivative instruments are reflected in the accompanying consolidated balance sheets at fair value.

We engage solely in cash flow hedges. Cash flow hedges are entered into to hedge the variability of cash flows related to a forecasted transaction or to be received or paid related to a recognized asset or liability. Changes in the fair value of derivative instruments that are designated as cash flow hedges are reported in OCI to the extent that the hedges are effective. These changes are subsequently reclassified into earnings when the hedged transactions settle. 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 instrument that does not qualify for hedge accounting is recorded in earnings in the period in which the change occurs.

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 derivative instruments that are designated as hedging instruments 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 if 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, gains or losses on the hedging instruments are reclassified from accumulated OCI into earnings immediately. If the forecasted transaction continues to be probable of occurring, any unrealized gains or losses in accumulated OCI, a component of shareholders’ equity, are reclassified into earnings over the remaining period of the original forecasted transaction.

Table of Contents

Interest Rate Risk

From time to time, we enter into interest rate swaps to stabilize cash flows related to our long-term variable interest rate debt. The fair value of our interest rate swaps is calculated as the discounted cash flows of the difference between the rate fixed by the hedging instrument and the LIBOR forward curve over the remaining term of the hedging instrument. Changes in the fair value of interest rate swaps are reported in accumulated OCI to the extent the swaps are effective. These changes are subsequently reclassified into earnings when the anticipated interest is recognized as interest expense. The ineffective portion of the interest rate swaps, if any, is recognized immediately in earnings within "Net interest expense."

Foreign Currency Exchange Rate Risk

Because we operate in various regions around the world, we conduct a portion of our business in currencies other than the U.S. dollar. We enter into foreign currency exchange contracts from time to time to stabilize expected cash outflows related to our vessel charters that are denominated in foreign currencies. The fair value of our foreign currency exchange contracts is calculated as the discounted cash flows of the difference between the fixed payment specified by the hedging instrument and the expected cash inflow of the forecasted transaction using a foreign currency forward curve. Changes in the fair value of foreign currency exchange contracts are reported in accumulated OCI to the extent the contracts are effective. These changes are subsequently reclassified into earnings when the forecasted vessel charter payments are made and recorded as cost of sales. The ineffective portion of these foreign currency exchange contracts, if any, and changes in the fair value of foreign currency exchange contracts that do not qualify as cash flow hedges, are recognized immediately in earnings within "Other income (expense), net."

Earnings Per Share

The presentation of basic earnings per share ("EPS") amounts on the face of the accompanying consolidated statements of operations is computed by dividing net income or loss by the weighted average shares of our common stock outstanding. The calculation of diluted EPS is similar to that for basic EPS, except that the denominator includes dilutive common stock equivalents and the numerator excludes the effects of dilutive common stock equivalents, if any. We have shares of restricted stock issued and outstanding that are currently unvested. Holders of shares of unvested restricted stock are entitled to the same liquidation and dividend rights as the holders of our unrestricted common stock, and the shares of restricted stock are thus considered participating securities. Under applicable accounting guidance, the undistributed earnings for each period are allocated based on the participation rights of both common shareholders and the holders of any participating securities as if earnings for the respective periods had been distributed. Because both the liquidation and dividend rights are identical, the undistributed earnings are allocated on a proportionate basis. Further, we are required to compute EPS under the two class method in periods in which we have earnings. 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 obligated to share in such losses.

Major Customers and Concentration of Credit Risk

The market for our products and services is primarily the offshore oil and gas and renewable industries. 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, which are subject to many external factors that 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 percentages of consolidated revenue from major customers (those representing 10% or more of our consolidated revenues) is as follows: 2018 — Petrobras (28%) and BP (15%), 2017 — BP (19%), Petrobras

(13%) and Talos (10%), and 2016 — BP (17%) and Shell (11%). Most of the concentration of revenues was generated by our Well Intervention business.

Table of Contents

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 approaches as described in Note 17.

New Accounting Standards

New accounting standards adopted

In May 2014, the Financial Accounting Standards Board (the "FASB") issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)" ("ASC 606"). The FASB also issued several subsequent updates to promote more consistent interpretation and application of the principles outlined in the standard. ASC 606 provides a five-step approach to account for revenue arising from contracts with customers in order for an entity 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.

We adopted ASC 606 effective January 1, 2018 using the modified retrospective method by applying the five-step model to all contracts that were not completed as of the date of adoption. For contracts that were modified before the date of adoption, we have considered the modification guidance within the new standard and determined that the revenues recognized prior to adoption for such modified contracts were not impacted. We did not record any cumulative effect adjustment to the opening balance of our retained earnings as of January 1, 2018 as the adoption of ASC 606 had an insignificant impact on our prior year earnings. On our consolidated balance sheet, contract assets that were previously presented as "Other accounts receivable" are now a component of "Other current assets." The comparative information is not being restated and continues to be reported under the accounting standards in effect for those periods. ASC 606 requires additional disclosures with regard to the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. We do not expect the adoption of this guidance to have a material impact on the measurement or recognition of our revenues on an ongoing basis. The impact of ASC 606 for the year ended December 31, 2018 is as follows (in thousands):

	December 31, 2018		
	As Reported	Pro Forma Without Adoption of ASC 606	Effect of Change
Balance Sheet			
Assets			
Unbilled and other	$51,943	$ 57,772	$(5,829)
Other current assets	51,594	45,765	5,829
Liabilities			

Accrued liabilities	85,594	85,491	103
Deferred tax liabilities	105,862	105,884	(22)
Equity			
Retained earnings	383,034	383,115	(81)

Table of Contents

	Year Ended December 31, 2018		
	As Reported	Pro Forma Without Adoption of ASC 606	Effect of Change
Statement of Operations			
Net revenues	$739,818	$739,921	$(103)
Income from operations	51,543	51,646	(103)
Income before income taxes	30,998	31,101	(103)
Income tax provision	2,400	2,422	(22)
Net income	28,598	28,679	(81)

In February 2018, the FASB issued ASU No. 2018-02, "Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income." This ASU allows a reclassification from accumulated OCI to retained earnings for stranded tax effects resulting from the U.S. Tax Cuts and Jobs Act (the "2017 Tax Act") that was enacted on December 22, 2017. We adopted this guidance as of January 1, 2018 by making the election to reclassify $1.5 million of net stranded tax benefits from accumulated OCI to retained earnings (Note 8). On an ongoing basis, we release the income tax effects of individual items in accumulated OCI as those items are sold or settled at the applicable statutory rate.

New accounting standards issued but not yet effective

In February 2016, the FASB issued ASU No. 2016-02, "Leases (Topic 842)" ("ASC 842"). The FASB also issued several subsequent updates to the new guidance. The new guidance requires a lessee to recognize a lease right-of-use asset and related lease liability for most leases, including those classified as operating leases under current GAAP. ASC 842 also changes the definition of a lease and requires expanded quantitative and qualitative disclosures for both lessees and lessors. Management's assessment based on our current portfolio of leases (a significant component of which is our vessel charters) is that our assets and liabilities will increase between $250 and $270 million upon our adoption of ASC 842. In addition, the remaining deferred gain on our 2016 sale and leaseback transaction of $5.1 million (Notes 3 and 4) will be reclassified to retained earnings and no longer amortized into earnings. Additionally, leases in foreign currency will generate foreign currency gains and losses that would not have been reported under legacy GAAP. Aside from these changes, we do not expect the new guidance to have a significant impact on our earnings or cash flows. We will adopt ASC 842 by applying the new guidance in the first quarter of 2019 and recognizing a cumulative-effect adjustment to the opening balance of retained earnings on January 1, 2019.

In June 2016, the FASB issued ASU No. 2016-13, "Measurement of Credit Losses on Financial Instruments." This ASU replaces the current incurred loss model for measurement of credit losses on financial assets including trade receivables with a forward-looking expected loss model based on historical experience, current conditions and reasonable and supportable forecasts. The guidance is effective for annual reporting periods beginning after December 15, 2019, including interim periods. We are currently evaluating the impact this guidance will 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.

Table of Contents

Note 3 — Details of Certain Accounts

Other current assets consist of the following (in thousands):

	December 31, 2018	December 31, 2017
Contract assets (Note 10)	$5,829	$—
Prepaids	10,306	10,102
Deferred costs (Note 10)	27,368	27,204
Other	8,091	4,462
Total other current assets	$51,594	$41,768

Other assets, net consist of the following (in thousands):

	December 31, 2018	December 31, 2017
Note receivable, net (1)	$—	$3,758
Prepaids	5,896	7,666
Deferred recertification and dry dock costs, net (Note 2)	8,525	12,769
Deferred costs (Note 10)	38,574	63,767
Charter fee deposit (2)	12,544	12,544
Other	4,518	4,701
Total other assets, net	$70,057	$105,205

(1) The amount at December 31, 2017 reflects the fair value of a note receivable that was issued to us by a customer as part of a payment forgiveness arrangement. On July 6, 2018, a third party acquired this note receivable for $2.0 million. During the year ended December 31, 2018, we reversed a $0.6 million unrealized gain previously recorded in accumulated OCI and recorded a $1.1 million other than temporary loss to account for the reduction in the fair value of our note receivable.

(2) This amount was deposited with the vessel owner and is to be used to reduce our final charter payments for the Siem Helix 2.

Accrued liabilities consist of the following (in thousands):

	December 31, 2018	December 31, 2017
Accrued payroll and related benefits	$43,079	$30,685
Deferred revenue (Note 10)	10,103	12,609
Derivative liability (Note 18)	9,311	10,625
Other	23,101	17,761
Total accrued liabilities	$85,594	$71,680

Table of Contents

Other non-current liabilities consist of the following (in thousands):

	December 31,	
	2018	2017
Investee losses in excess of investment (Note 5)	$6,035	$7,567
Deferred gain on sale of property (Note 4)	5,052	5,838
Deferred revenue (Note 10)	15,767	8,744
Derivative liability (Note 18)	884	8,150
Other	11,800	10,391
Total other non-current liabilities	$39,538	$40,690

Note 4 — Property and Equipment

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

		December 31,	
	Estimated Useful Life	2018	2017
Vessels	15 to 30 years	$2,185,409	$2,083,267
ROVs, trenchers and ROVDrills	10 years	284,172	298,227
Machinery, equipment and leasehold improvements	5 to 15 years	316,197	314,278
Total property and equipment		$2,785,778	$2,695,772

In January 2016, we sold our office and warehouse property located in Aberdeen, Scotland for approximately $11 million and entered into a separate agreement with the same party to lease back the facility for a lease term of 15 years with two five-year options to extend the lease at our option. A gain of approximately $7.6 million from the sale of this property is deferred and amortized over the 15-year minimum lease term. See Note 2 for the effect of the adoption of ASC 842 on this deferred gain.

In December 2016, we sold the Helix 534 vessel to a third party for approximately $2.8 million, including $0.4 million held in escrow, which was not subsequently realized. We recorded a gain of approximately $1.3 million from the sale, net of selling expenses.

Note 5 — Equity Investments

We have a 20% ownership interest in Independence Hub that we account for using the equity method of accounting. Independence Hub owns the “Independence Hub” platform located in Mississippi Canyon Block 920 in the U.S. Gulf of Mexico in a water depth of 8,000 feet. Since we are committed to providing our pro-rata portion of the necessary level of financial support for Independence Hub to pay its obligations as they become due, we recorded a liability of $11.2 million and $9.8 million at December 31, 2018 and 2017, respectively, for our share of the estimated obligations, net of remaining working capital. This liability is reflected in “Accrued liabilities” and “Other non-current liabilities” in the accompanying consolidated balance sheets. For the years ended December 31, 2018, 2017 and 2016, we recorded losses totaling $3.9 million, $2.4 million and $2.2 million, respectively, to account for our share of losses from Independence Hub. We did not receive any cash distributions from Independence Hub in 2016, 2017 or 2018.

We previously had a 50% ownership interest in Deepwater Gateway, the owner of a tension leg platform production hub primarily for Anadarko Petroleum Corporation’s Marco Polo field in the Deepwater Gulf of Mexico. In February 2016, we received a cash distribution of $1.2 million and sold our ownership interest in Deepwater Gateway for $25 million.

Table of Contents

Note 6 — Long-Term Debt

Long-term debt consists of the following (in thousands):

	December 31,	
	2018	2017
Term Loan (matures June 2020)	$33,693	$97,500
2022 Notes (mature May 2022)	125,000	125,000
2023 Notes (mature September 2023)	125,000	—
2032 Notes (redeemed May 2018)	—	60,115
MARAD Debt (matures February 2027)	70,468	77,000
Nordea Q5000 Loan (matures April 2020)	125,000	160,714
Unamortized debt discounts	(28,802)	(14,406)
Unamortized debt issuance costs	(10,044)	(10,296)
Total debt	440,315	495,627
Less current maturities	(47,252)	(109,861)
Long-term debt	$393,063	$385,766

Credit Agreement

On June 30, 2017, we entered into an Amended and Restated Credit Agreement (the “Credit Agreement”) with a group of lenders led by Bank of America, N.A. (“Bank of America”). The amended and restated credit facility is comprised of a $100 million term loan (the “Term Loan”) and a revolving credit facility (the “Revolving Credit Facility”) of up to $150 million (the “Revolving Loans”). The Revolving Credit Facility permits us to obtain letters of credit up to a sublimit of $25 million. Pursuant to the Credit Agreement, subject to existing lender participation and/or the participation of new lenders, and subject to standard conditions precedent, we may request aggregate commitments up to $100 million with respect to an increase in the Revolving Credit Facility, additional term loans or a combination thereof. The $100 million proceeds from the Term Loan as well as cash on hand were used to repay the approximately $180 million term loan then outstanding under the credit facility prior to its June 2017 amendment and restatement. As of December 31, 2018, we had no borrowings under the Revolving Credit Facility, and our available borrowing capacity under that facility, based on the applicable leverage ratio covenant, totaled $147.4 million, net of $2.6 million of letters of credit issued under that facility.

The Term Loan and the Revolving Loans (together, the “Loans”), at our election, bear interest at the Bank of America’s base rate, to a LIBOR rate or a combination thereof. The Term Loan bearing interest at the base rate will bear interest at a per annum rate equal to Bank of America’s base rate plus a margin of 3.25%. The Term Loan bearing interest at a LIBOR rate will bear interest per annum at the LIBOR rate selected by us plus a margin of 4.25%. The interest rate on the Term Loan was 6.77% as of December 31, 2018. The Revolving Loans bearing interest at the base rate will bear interest at a per annum rate equal to Bank of America’s base rate plus a margin ranging from 1.75% to 3.25%. The Revolving Loans bearing interest at a LIBOR rate will bear interest per annum at the LIBOR rate selected by us plus a margin ranging from 2.75% to 4.25%. A letter of credit fee is payable by us equal to its applicable margin for LIBOR rate Loans times the daily amount available to be drawn under the applicable letter of credit. Margins on the Revolving Loans will vary in relation to the Consolidated Total Leverage Ratio (as defined below) as provided for in the Credit Agreement. We also pay a fixed commitment fee of 0.50% per annum on the unused portion of our Revolving Credit Facility.

The Term Loan principal is required to be repaid in quarterly installments totaling 5% in the first loan year, 10% in the second loan year and 15% in the third loan year, with a balloon payment at maturity. Installment amounts are subject to adjustment for any prepayments on the Term Loan. We may elect to prepay indebtedness outstanding under the Term Loan without premium or penalty, but may not reborrow any amounts prepaid. We may prepay indebtedness outstanding under the Revolving Credit Facility without premium or penalty, and may reborrow any amounts prepaid up to the amount of the Revolving Credit Facility. The Loans mature on June 30, 2020.

The Credit Agreement and the other loan documents entered into in connection with the Credit Agreement include terms and conditions, including covenants, which we consider customary for this type of facility. The covenants include certain restrictions on our and our subsidiaries' ability to grant liens, incur indebtedness, make investments, merge or consolidate, sell or transfer assets, pay dividends and make capital expenditures. In addition, the Credit Agreement obligates us to meet minimum ratios of EBITDA to interest charges ("Consolidated Interest Coverage Ratio") and funded debt to EBITDA ("Consolidated Total Leverage Ratio"), and provided there are no Loans outstanding, the funded debt ratio requirement permits us to offset a certain amount of cash against the funded debt used in the calculation ("Consolidated Net Leverage Ratio"). After the Term Loan is repaid in full, if there are any Loans outstanding, including unreimbursed draws under letters of credit issued under the Revolving Credit Facility, we also are required to ensure that the ratio of our total secured indebtedness to EBITDA ("Consolidated Secured Leverage Ratio") does not exceed a maximum permitted ratio. The Credit Agreement also obligates us to maintain certain cash levels depending on the type of indebtedness that is outstanding.

We may from time to time designate one or more of our foreign subsidiaries as subsidiaries not generally subject to the covenants in the Credit Agreement (the "Unrestricted Subsidiaries"). The debt and EBITDA of the Unrestricted Subsidiaries are not included in the calculations of our financial covenants, except for the debt and EBITDA of Helix Q5000 Holdings, S.a.r.l., a wholly owned subsidiary incorporated in Luxembourg ("Q5000 Holdings"). Our obligations under the Credit Agreement are guaranteed by our domestic subsidiaries (except Cal Dive I - Title XI, Inc.) and by Canyon Offshore Limited, a wholly owned Scottish subsidiary. Our obligations under the Credit Agreement, and of our subsidiary guarantors under their guarantee, are secured by (i) most of the assets of the parent company, (ii) the shares of our domestic subsidiaries (other than Cal Dive I - Title XI, Inc.) and of Canyon Offshore Limited, and (iii) most of the assets of our domestic subsidiaries (other than Cal Dive I - Title XI, Inc.) and of Canyon Offshore Limited. In addition, these obligations are secured by pledges of up to 66% of the shares of certain foreign subsidiaries.

In March 2018, we prepaid $61 million of the Term Loan with a portion of the net proceeds from the 2023 Notes. We recognized a $0.9 million loss to write off the related unamortized debt issuance costs. In June 2017, we recognized a $0.4 million loss to write off the unamortized debt issuance costs related to certain lenders exiting from the term loan then outstanding under our principal corporate credit facility prior to its June 2017 amendment and restatement. These losses are presented as "Loss on early extinguishment of long-term debt" in the accompanying consolidated statements of operations. In connection with decreases in lenders' commitments under our revolving credit facility, in June 2017 and February 2016, we recorded interest charges of $1.6 million and $2.5 million, respectively, to accelerate the amortization of a pro-rata portion of debt issuance costs related to the lenders whose commitments were reduced.

On January 18, 2019, contemporaneously with our purchase from Marathon Oil of certain operating depths associated with the Droshky Prospect on offshore Gulf of Mexico Green Canyon Block 244, along with several wells and related infrastructure, we entered into an amendment to our Credit Agreement which permits us to issue certain security to third parties for required plug and abandonment obligations and to make certain capital expenditures in connection with the acquired assets (Note 1).

Convertible Senior Notes Due 2022

On November 1, 2016, we completed a public offering and sale of our Convertible Senior Notes due 2022 (the "2022 Notes") in the aggregate principal amount of $125 million. The 2022 Notes bear interest at a rate of 4.25% per annum, and are payable semi-annually in arrears on November 1 and May 1 of each year, beginning on May 1, 2017. The 2022 Notes mature on May 1, 2022 unless earlier converted, redeemed or repurchased. During certain periods and subject to certain conditions, the 2022 Notes are convertible by the holders into shares of our common stock at an initial conversion rate of 71.9748 shares of our common stock per $1,000 principal amount (which represents an initial conversion price of approximately $13.89 per share of common stock), subject to adjustment in certain circumstances.

We have the right and the intention to settle the principal amount of any such future conversions in cash.

Prior to November 1, 2019, the 2022 Notes are not redeemable. On or after November 1, 2019, if certain conditions are met, we may redeem all or any portion of the 2022 Notes at a redemption price payable in cash equal to 100% of the principal amount to be redeemed, plus accrued and unpaid interest, and a "make-whole premium" (as defined in the indenture governing the 2022 Notes). Holders of the 2022 Notes may require us to repurchase the notes following a "fundamental change" (as defined in the indenture governing the 2022 Notes).

Table of Contents

The indenture governing the 2022 Notes contains customary terms and covenants, including that upon certain events of default occurring and continuing, either the trustee under the Indenture or the holders of not less than 25% in aggregate principal amount then outstanding under the 2022 Notes may declare the entire principal amount of all the notes, and the interest accrued on such notes, if any, to be immediately due and payable. In the case of certain events of bankruptcy, insolvency or reorganization relating to us or a significant subsidiary, the principal amount of the 2022 Notes together with any accrued and unpaid interest thereon will become immediately due and payable.

The 2022 Notes are accounted for by separating the net proceeds between long-term debt and shareholders' equity. In connection with the issuance of the 2022 Notes, we recorded a debt discount of $16.9 million ($11.0 million net of tax) as a result of separating the equity component. The effective interest rate for the 2022 Notes is 7.3% after considering the effect of the accretion of the related debt discount that represented the equity component of the 2022 Notes at their inception. For the years ended December 31, 2018, 2017 and 2016, interest expense (including amortization of the debt discount) related to the 2022 Notes totaled $8.1 million, $7.9 million and $1.3 million, respectively. The remaining unamortized amount of the debt discount of the 2022 Notes was $11.0 million and $13.9 million at December 31, 2018 and 2017, respectively.

Convertible Senior Notes Due 2023

On March 20, 2018, we completed a public offering and sale of our 2023 Notes in the aggregate principal amount of $125 million. The net proceeds from the issuance of the 2023 Notes were approximately $121 million, after deducting the underwriters' discounts and commissions and offering expenses. We used the net proceeds from the issuance of the 2023 Notes to fund the required repurchase of $59.3 million in principal of the 2032 Notes and to prepay $61 million of our Term Loan.

The 2023 Notes bear interest at a rate of 4.125% per annum, and are payable semi-annually in arrears on March 15 and September 15 of each year, beginning on September 15, 2018. The 2023 Notes mature on September 15, 2023 unless earlier converted, redeemed or repurchased. During certain periods and subject to certain conditions, the 2023 Notes are convertible by the holders into shares of our common stock at an initial conversion rate of 105.6133 shares of our common stock per $1,000 principal amount (which represents an initial conversion price of approximately $9.47 per share of common stock), subject to adjustment in certain circumstances. We have the right and the intention to settle the principal amount of any such future conversions in cash.

Prior to March 15, 2021, the 2023 Notes are not redeemable. On or after March 15, 2021, if certain conditions are met, we may redeem all or any portion of the 2023 Notes at a redemption price payable in cash equal to 100% of the principal amount to be redeemed, plus accrued and unpaid interest, and a "make-whole premium" (as defined in the indenture governing the 2023 Notes). Holders of the 2023 Notes may require us to repurchase the notes following a "fundamental change" (as defined in the indenture governing the 2023 Notes).

The indenture governing the 2023 Notes contains customary terms and covenants, including that upon certain events of default occurring and continuing, either the trustee under the indenture or the holders of not less than 25% in aggregate principal amount then outstanding under the 2023 Notes may declare the entire principal amount of all the notes, and the interest accrued on such notes, if any, to be immediately due and payable. In the case of certain events of bankruptcy, insolvency or reorganization relating to us or a significant subsidiary, the principal amount of the 2023 Notes together with any accrued and unpaid interest thereon will become immediately due and payable.

The 2023 Notes are accounted for by separating the net proceeds between long-term debt and shareholders' equity. In connection with the issuance of the 2023 Notes, we recorded a debt discount of $20.1 million ($15.9 million net of tax) as a result of separating the equity component. The effective interest rate for the 2023 Notes is 7.8% after considering the effect of the accretion of the related debt discount that represented the equity component of the 2023

Notes at their inception. For the year ended December 31, 2018, interest expense (including amortization of the debt discount) related to the 2023 Notes totaled $6.4 million. The remaining unamortized amount of the debt discount of the 2023 Notes was $17.8 million at December 31, 2018.

Table of Contents

MARAD Debt

This U.S. government guaranteed financing (the "MARAD Debt"), pursuant to Title XI of the Merchant Marine Act of 1936 administered by the Maritime Administration, was used to finance the construction of the Q4000. The MARAD Debt is collateralized by the Q4000 and is guaranteed 50% by us. The MARAD Debt is payable in equal semi-annual installments, matures in February 2027 and bears interest at a rate of 4.93%.

Nordea Credit Agreement

In September 2014, Q5000 Holdings entered into a credit agreement (the "Nordea Credit Agreement") with a syndicated bank lending group for a term loan (the "Nordea Q5000 Loan") in an amount of up to $250 million. The Nordea Q5000 Loan was funded in the amount of $250 million in April 2015 at the time the Q5000 vessel was delivered to us. The parent company of Q5000 Holdings, Helix Vessel Finance S.à r.l., also a wholly owned Luxembourg subsidiary, guaranteed the Nordea Q5000 Loan. The loan is secured by the Q5000 and its charter earnings as well as by a pledge of the shares of Q5000 Holdings. This indebtedness is non-recourse to Helix.

The Nordea Q5000 Loan bears interest at a LIBOR rate plus a margin of 2.5%. The Nordea Q5000 Loan matures on April 30, 2020 and is repayable in scheduled quarterly principal installments of $8.9 million with a balloon payment of $80.4 million at maturity. Q5000 Holdings may elect to prepay indebtedness outstanding under the Nordea Q5000 Loan without premium or penalty, but may not reborrow any amounts prepaid. Quarterly principal installments are subject to adjustment for any prepayments on this debt. In June 2015, we entered into various interest rate swap contracts to fix the one-month LIBOR rate on a portion of our borrowings under the Nordea Q5000 Loan (Note 18). The total notional amount of the swaps (initially $187.5 million) decreases in proportion to the reduction in the principal amount outstanding under our Nordea Q5000 Loan. The fixed LIBOR rates are approximately 150 basis points.

The Nordea Credit Agreement and related loan documents include terms and conditions, including covenants and prepayment requirements, that we consider 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 certain minimum financial requirements, including liquidity, consolidated debt service coverage and collateral maintenance.

Convertible Senior Notes Due 2032

In March 2012, we issued $200 million of 3.25% Convertible Senior Notes, which were originally scheduled to mature on March 15, 2032 (the "2032 Notes"). We elected to repurchase $7.3 million, $7.6 million and $125 million in aggregate principal amount of the 2032 Notes in June, July and November of 2016, respectively. In March 2018, we made a tender offer for the repurchase of the 2032 Notes outstanding on the first repurchase date as required by the indenture governing the 2032 Notes, and as a result we repurchased $59.3 million in aggregate principal amount of the 2032 Notes on March 20, 2018. The total repurchase price was $59.5 million, including $0.2 million in fees. For the years ended December 31, 2018 and 2016, we recognized net losses of $0.2 million and $3.5 million, respectively, related to the repurchases of the 2032 Notes. These losses are presented as "Loss on early extinguishment of long-term debt" in the accompanying consolidated statements of operations. On May 4, 2018, we redeemed the remaining $0.8 million in aggregate principal amount of the 2032 Notes.

Other

In accordance with our Credit Agreement, the 2022 Notes, the 2023 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 various leverage ratios, as well as the maintenance of minimum cash balance, net worth, working capital and debt-to-equity requirements. As of December 31, 2018, we were in compliance with these covenants.

Table of Contents

Scheduled maturities of our long-term debt outstanding as of December 31, 2018 are as follows (in thousands):

	Term Loan [1]	2022 Notes	2023 Notes	MARAD Debt	Nordea Q5000 Loan	Total
Less than one year	$4,680	$—	$—	$6,858	$35,714	$47,252
One to two years	29,013	—	—	7,200	89,286	125,499
Two to three years	—	—	—	7,560	—	7,560
Three to four years	—	125,000	—	7,937	—	132,937
Four to five years	—	—	125,000	8,333	—	133,333
Over five years	—	—	—	32,580	—	32,580
Gross debt	33,693	125,000	125,000	70,468	125,000	479,161
Unamortized debt discounts [2]	—	(11,043)	(17,759)	—	—	(28,802)
Unamortized debt issuance costs [3]	(372)	(1,765)	(2,862)	(4,025)	(1,020)	(10,044)
Total debt	33,321	112,192	104,379	66,443	123,980	440,315
Less current maturities	(4,680)	—	—	(6,858)	(35,714)	(47,252)
Long-term debt	$28,641	$112,192	$104,379	$59,585	$88,266	$393,063

(1) Term Loan borrowing pursuant to the Credit Agreement matures in June 2020. Scheduled principal repayments of the Term Loan have been adjusted to reflect prepayments made in March 2018.

(2) The 2022 Notes will increase to their face amount through accretion of the debt discount through May 2022. The 2023 Notes will increase to their face amount through accretion of the debt discount through September 2023.

(3) Debt issuance costs are amortized to interest expense over the term of the applicable debt agreement.

The following table details the components of our net interest expense (in thousands):

	Year Ended December 31,		
	2018	2017	2016
Interest expense	$32,617	$38,274	$45,110
Interest income	(3,237)	(2,590)	(2,086)
Capitalized interest	(15,629)	(16,906)	(11,785)
Net interest expense	$13,751	$18,778	$31,239

Note 7 — Income Taxes

On December 22, 2017, the 2017 Tax Act was enacted. The 2017 Tax Act is comprehensive tax reform legislation that contains significant changes to corporate taxation, including a permanent reduction of the corporate income tax rate from 35% to 21%, a mandatory one-time tax on un-repatriated accumulated earnings of foreign subsidiaries, a partial limitation on the deductibility of business interest expense, and a shift from U.S. taxation on worldwide income of multinational corporations to a partial territorial system (along with rules that create a new U.S. minimum tax on earnings of foreign subsidiaries).

We recognized the income tax effects of the 2017 Tax Act in accordance with Staff Accounting Bulletin No. 118, “Income Tax Accounting Implications of the Tax Cuts and Jobs Act” (“SAB 118”), which provided SEC staff guidance for the application of ASC Topic 740, Income Taxes, to the 2017 Tax Act. SAB 118 allowed for a measurement period of up to one year after the enactment date to finalize the recording of the related tax impacts. Due to the changes to U.S. tax laws as a result of the 2017 Tax Act, we recorded a provisional $51.6 million net income tax benefit during the fourth quarter of 2017 for the estimated tax impacts. This amount was comprised of the following:

Table of Contents

Reduction of the U.S. Corporate Income Tax Rate

We measure deferred tax assets and liabilities using enacted tax rates that will apply in the years in which the temporary differences are expected to reverse. Accordingly, our deferred tax assets and liabilities were re-measured to reflect the reduction in the U.S. corporate income tax rate from 35% to 21%, resulting in a provisional $59.7 million deferred income tax benefit recorded during the fourth quarter of 2017 and a corresponding decrease in net deferred tax liabilities as of December 31, 2017.

Transition Tax on Foreign Earnings

The one-time transition tax was based on our total post-1986 foreign earnings and profits ("E&P") deemed repatriated to the U.S. to the extent the E&P has not already been subject to U.S. taxation. We recorded a provisional deferred income tax expense of $8.1 million during the fourth quarter of 2017 related to the one-time transition tax on certain foreign earnings. This resulted in a corresponding provisional decrease in deferred tax assets of $8.1 million due to the utilization of U.S. net operating losses against the deemed mandatory repatriation income inclusion.

In the fourth quarter of 2017, we recorded tax charges for the impact of the 2017 Tax Act using the current available information and technical guidance on the interpretations of the 2017 Tax Act. As permitted by SAB 118, we recorded provisional estimates and have subsequently finalized our accounting analysis based on guidance, interpretations, and data available as of December 31, 2018. Adjustments made in 2018 upon finalization of our accounting analysis were immaterial to our consolidated financial statements.

We and our subsidiaries file a consolidated U.S. federal income tax return. We believe that our recorded deferred tax assets and liabilities are reasonable. However, tax laws and regulations are subject to interpretation, and the outcomes of tax disputes are inherently uncertain; 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) reflected in the consolidated statements of operations consist of the following (in thousands):

	Year Ended December 31,		
	2018	2017	2016
Current	$4,830	$4,161	$(27,319)
Deferred	(2,430)	(54,585)	14,849
	$2,400	$(50,424)	$(12,470)
Domestic	$(3,161)	$(53,044)	$(9,631)
Foreign	5,561	2,620	(2,839)
	$2,400	$(50,424)	$(12,470)

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

	Year Ended December 31,		
	2018	2017	2016
Domestic	$(28,838)	$(221)	$(61,484)
Foreign	59,836	(20,151)	(32,431)
	$30,998	$(20,372)	$(93,915)

Table of Contents

Income taxes are provided based on the U.S. statutory rate 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 U.S. statutory rate and our effective rate are as follows:

	Year Ended December 31,		
	2018	2017	2016
Statutory rate	21.0 %	35.0 %	35.0 %
Foreign provision	(15.9)	(6.2)	(5.1)
Change in U.S. statutory rate (1)	—	293.1	—
Mandatory U.S. repatriation (1)	—	(39.7)	—
Change in tax position (2)	—	(31.1)	—
Goodwill impairment	—	—	(16.8)
Other	2.6	(3.6)	0.2
Effective rate	7.7 %	247.5 %	13.3 %

(1) As a result of the U.S. tax law changes, we recorded a net deferred tax benefit of $51.6 million during the fourth quarter of 2017 (see above).

(2) As a result of a change in tax position related to our foreign taxes, we recorded a tax charge of $6.3 million in June 2017.

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 are as follows (in thousands):

	December 31,	
	2018	2017
Deferred tax liabilities:		
Depreciation	$149,974	$135,824
Debt discount on 2022 Notes, 2023 Notes and 2032 Notes	5,902	7,727
Prepaid and other	1,309	437
Total deferred tax liabilities	$157,185	$143,988
Deferred tax assets:		
Net operating losses	$(47,916)	$(33,480)
Reserves, accrued liabilities and other	(21,347)	(19,496)
Total deferred tax assets	(69,263)	(52,976)
Valuation allowance	17,940	12,337
Net deferred tax liabilities	$105,862	$103,349

At December 31, 2018, our U.S. net operating losses available for carryforward totaled $165.6 million. The U.S. net operating loss carryforwards prior to 2018 in the amount of $112.3 million will begin to expire in 2035 if unused. Realization is dependent on generating sufficient taxable income prior to expiration of the loss carryforwards. Although realization is not assured, management believes it is more likely than not that all of these tax attributes will be utilized. The amount of the deferred tax asset considered realizable, however, could be reduced if estimates of future taxable income during the carryforward period are reduced.

At December 31, 2018, we had a $3.0 million valuation allowance recorded against our U.S. deferred tax assets for foreign tax credits. Management believes it is more likely than not that we will not be able to utilize the foreign tax credits prior to expiration.

At December 31, 2018, we had a $15.0 million valuation allowance related to certain non-U.S. deferred tax assets, primarily net operating losses generated in Brazil and from our oil and gas operations in the U.K., as management believes it is more likely than not that we will not be able to utilize the tax benefits. Additional valuation allowances may be made in the future if in management's opinion it is more likely than not that future tax benefits will not be utilized.

At December 31, 2018, we had accumulated undistributed earnings generated by our non-U.S. subsidiaries without operations in the U.S. of approximately $93.2 million. Due to the enactment of the 2017 Tax Act, repatriations of foreign earnings will generally be free of U.S. federal tax but may result in other withholding taxes or state taxes. Indefinite reinvestment is determined by management's intentions concerning our future operations. We intend to indefinitely reinvest these earnings, as well as future earnings from our non-U.S. subsidiaries without operations in the U.S., to fund our international operations and foreign credit facility. In addition, we expect future U.S. cash generation will be sufficient to meet future U.S. cash needs. We have not provided deferred income taxes on the accumulated earnings and profits from our non-U.S. subsidiaries without operations in the U.S. as we consider them permanently reinvested. Due to complexities in the tax laws and the manner of repatriation, it is not practicable to estimate the unrecognized amount of deferred income taxes and the related dividend withholding taxes associated with these undistributed earnings.

We account for tax-related interest in interest expense and tax penalties in selling, general and administrative expenses. No significant penalties or interest expense were accrued on our uncertain tax positions. We had unrecognized tax benefits of $0.3 million related to uncertain tax positions as of December 31, 2018, 2017 and 2016, which if recognized would affect the annual effective tax rate.

A reconciliation of the beginning and ending amount of unrecognized tax benefits for the years ended December 31, 2018 and 2017 is as follows (in thousands):

	2018	2017	2016
Balance at January 1,	$318	$343	$—
Additions for tax positions of prior years	—	—	343
Reductions for tax positions of prior years	(12)	(25)	—
Balance at December 31,	$306	$318	$343

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 taxing authorities would not have a material impact on our financial position. In 2016, we received $28.4 million in U.S. and foreign income tax refunds for losses that were carried back to prior years. The tax periods from 2015 through 2018 remain open to review and examination by the Internal Revenue Service. In non-U.S. jurisdictions, the open tax periods include 2013 through 2018.

Note 8 — 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.

On January 10, 2017, we completed an underwritten public offering (the "Offering") of 26,450,000 shares of our common stock at a public offering price of $8.65 per share. The net proceeds from the Offering approximated $220 million, after deducting underwriting discounts and commissions and offering expenses. We used the net proceeds from the Offering for general corporate purposes, including debt repayment, capital expenditures, working capital and investments in our subsidiaries.

In 2016, we sold a total of 13,018,732 shares of our common stock for $100 million under an at-the-market ("ATM") equity offering program. The proceeds from this ATM program totaled $96.5 million, net of transaction costs, including commissions of $2.3 million to Wells Fargo Securities, LLC.

Table of Contents

The components of accumulated OCI are as follows (in thousands):

	December 31, 2018	December 31, 2017
Cumulative foreign currency translation adjustment	$(69,855)	$(62,689)
Net unrealized loss on hedges, net of tax (1)	(4,109)	(7,507)
Unrealized gain on note receivable, net of tax (2)	$—	$409
Accumulated other comprehensive loss	$(73,964)	$(69,787)

(1) Relates to foreign currency hedges for the Grand Canyon II and Grand Canyon III charters as well as interest rate swap contracts for the Nordea Q5000 Loan (Note 18). Balance at December 31, 2018 was net of deferred income taxes totaling $1.0 million. Balance at December 31, 2017 was net of deferred income taxes of $4.0 million, $1.6 million of which was reclassified to retained earnings on January 1, 2018 pursuant to the adoption of ASU No. 2018-02 (Note 2).

(2) Balance at December 31, 2017 was net of deferred income taxes of $0.2 million, $0.1 million of which was reclassified to retained earnings on January 1, 2018 pursuant to the adoption of ASU No. 2018-02 (Note 2).

Note 9 — Stock Buyback Program

Our Board of Directors (the "Board") has 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 share-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 12). 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. We have not purchased any shares available under this program since 2015. As of December 31, 2018, 3,931,076 shares of our common stock were available for repurchase under the program.

Note 10 — Revenue from Contracts with Customers

Disaggregation of revenue

The following table provides information about disaggregated revenue by contract duration for the year ended December 31, 2018 (in thousands):

	Well Intervention	Robotics	Production Facilities	Intercompany Eliminations (1)	Total Revenue
Short-term	$ 199,294	$89,072	$ —	$ —	$288,366
Long-term (2)	361,274	69,917	64,400	(44,139)	451,452
Total	$ 560,568	$158,989	$ 64,400	$ (44,139)	$739,818

(1) Intercompany revenues between Robotics and Well Intervention are under agreements that are considered long-term.

(2) Contracts are classified as long-term if all or part of the contract is to be performed over a period extending beyond 12 months from the effective date of the contract. Long-term contracts may include multi-year agreements whereby the commitment for services in any one year may be short in duration.

Contract balances

Accounts receivable are recognized when our right to consideration becomes unconditional. Accounts receivable that have been billed to customers are recorded as trade accounts receivable while accounts receivable that have not been billed to customers are recorded as unbilled accounts receivable.

Table of Contents

Contract assets are rights to consideration in exchange for services that we have provided to a customer when those rights are conditional on our future performance. Contract assets generally consist of (i) demobilization fees recognized ratably over the contract term but invoiced upon completion of the demobilization activities and (ii) revenue recognized in excess of the amount billed to the customer for lump sum contracts when the cost-to-cost method of revenue recognition is utilized. Contract assets are reflected in “Other current assets” on the accompanying condensed consolidated balance sheet. Contract assets as of January 1, 2018 were immaterial while contract assets as of December 31, 2018 were $5.8 million. Impairment losses recognized on our accounts receivable were immaterial for the year ended December 31, 2018.

Contract liabilities are obligations to provide future services to a customer for which we have already received, or have the unconditional right to receive, the consideration for those services from the customer. Contract liabilities may consist of (i) advance payments received from customers, including upfront mobilization fees allocated to the single performance obligation and recognized ratably over the contract term and (ii) the amount billed to the customer in excess of revenue recognized for lump sum contracts when the cost-to-cost method of revenue recognition is utilized. Contract liabilities are reflected as “Deferred revenue,” a component of “Accrued liabilities” and “Other non-current liabilities” on the accompanying condensed consolidated balance sheet. Contract liabilities as of January 1, 2018 and December 31, 2018 totaled $21.4 million and $25.9 million, respectively. Revenue recognized for the year ended December 31, 2018 included $11.6 million that were included in the contract liability balance as of January 1, 2018.

We report the net contract asset or contract liability position on a contract-by-contract basis as of December 31, 2018.

Performance obligations

As of December 31, 2018, $1.1 billion related to unsatisfied performance obligations was expected to be recognized as revenue in the future, with $470.1 million in 2019, $396.3 million in 2020 and $277.6 million in 2021 and thereafter. These amounts included fixed consideration and estimated variable consideration for both wholly and partially unsatisfied performance obligations, including mobilization and demobilization fees. These amounts are derived from the specific terms within our contracts, and the expected timing for revenue recognition is based on the estimated start date and duration of each contract according to the information known at December 31, 2018.

For the year ended December 31, 2018, revenues recognized from performance obligations satisfied (or partially satisfied) in previous years were immaterial.

Contract costs

Contract fulfillment costs consist of costs incurred in fulfilling a contract with a customer. Our contract fulfillment costs primarily relate to costs incurred for mobilization of personnel and equipment at the beginning of a contract and costs incurred for demobilization at the end of a contract. Mobilization costs are deferred and amortized ratably over the contract term (including anticipated contract extensions) based on the pattern of the provision of services to which the contract costs relate. Demobilization costs are recognized when incurred at the end of the contract. Deferred contract costs are reflected as “Deferred costs,” a component of “Other current assets” and “Other assets, net” on the accompanying condensed consolidated balance sheets (Note 3). Our deferred contract costs totaled $65.9 million as of December 31, 2018. For the year ended December 31, 2018, we recorded $33.1 million related to amortization of deferred contract costs existing as of January 1, 2018 and there were no associated impairment losses.

Table of Contents

Note 11 — Earnings Per Share

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 are as follows (in thousands):

	Year Ended December 31,					
	2018		2017		2016	
	Income	Shares	Income	Shares	Income	Shares
Basic:						
Net income (loss)	$28,598		$30,052		$(81,445)	
Less: Undistributed earnings allocated to participating securities	(273)		(356)		—	
Undistributed earnings (loss) allocated to common shares	$28,325	146,702	$29,696	145,295	$(81,445)	111,612
Diluted:						
Undistributed earnings (loss) allocated to common shares	$28,325	146,702	$29,696	145,295	$(81,445)	111,612
Effect of dilutive securities:						
Share-based awards other than participating securities	—	128	—	5	—	—
Undistributed earnings reallocated to participating securities	1	—	—	—	—	—
Net income (loss)	$28,326	146,830	$29,696	145,300	$(81,445)	111,612

We had a net loss for the year ended December 31, 2016. Accordingly, our diluted EPS calculation for this period was equivalent to our basic EPS calculation since diluted EPS excluded any assumed exercise or conversion of common stock equivalents. These common stock equivalents were excluded because they were deemed to be anti-dilutive, meaning their inclusion would have reduced the reported net loss per share in the applicable period. Shares that otherwise would have been included in the diluted EPS calculation assuming we had earnings are as follows (in thousands):

	Year Ended December 31, 2016
Diluted shares (as reported)	111,612
Share-based awards	440
Total	112,052

In addition, the following potentially dilutive shares related to the 2022 Notes, the 2023 Notes and the 2032 Notes were excluded from the diluted EPS calculation as they were anti-dilutive (in thousands):

	Year Ended December 31,		
	2018	2017	2016
2022 Notes	8,997	8,997	1,475
2023 Notes	10,344	—	—
2032 Notes [1]	524	2,403	6,891

(1) The 2032 Notes were fully redeemed in May 2018.

Table of Contents

Note 12 — Employee Benefit Plans

Defined Contribution Plan

We sponsor a defined contribution 401(k) retirement plan. We suspended our discretionary contributions for an indefinite period beginning February 2016.

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 0.5 million shares were available for issuance as of December 31, 2018. 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 and Section 423 of the Internal Revenue Code. The per 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. In February 2016, we suspended ESPP purchases for the January through April 2016 purchase period and indefinitely imposed a purchase limit of 130 shares per employee for subsequent purchase periods.

Long-Term Incentive Plan

We currently have one active long-term incentive plan, the 2005 Long-Term Incentive Plan, as amended and restated effective January 1, 2017 (the "2005 Incentive Plan"). The 2005 Incentive Plan is administered by the Compensation Committee of our Board. 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, PSUs and cash awards. Awards that have been granted to employees under the 2005 Incentive Plan have a vesting period of three years (or 33% per year) with the exception of PSUs, which vest 100% on the third anniversary date of the grant. The 2005 Incentive Plan has 10.3 million shares authorized for issuance, which includes a maximum of 2.0 million shares that may be granted as incentive stock options. As of December 31, 2018, there were 1.7 million shares available for issuance under the 2005 Incentive Plan.

The following grants of share-based awards were made in 2018 under the 2005 Incentive Plan:

Date of Grant	Shares	Grant Date Fair Value Per Share/Unit	Vesting Period
January 2, 2018 (1)	449,271	$ 7.54	33% per year over three years
January 2, 2018 (2)	449,271	$ 10.44	100% on January 2, 2021
January 2, 2018 (3)	8,247	$ 7.54	100% on January 1, 2020
April 2, 2018 (3)	11,064	$ 5.79	100% on January 1, 2020
July 2, 2018 (3)	6,565	$ 8.33	100% on January 1, 2020
August 21, 2018 (4)	6,093	$ 8.97	100% on August 21, 2019
October 1, 2018 (3)	6,104	$ 9.88	100% on January 1, 2020
December 13, 2018 (5)	126,942	$ 7.09	100% on December 13, 2019

(1) Reflects grants of restricted stock to our executive officers.
(2)

Reflects grants of PSUs to our executive officers. These awards when vested can only be settled in shares of our common stock.

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

(4) Reflects a grant of restricted stock made to an independent member of our Board upon his joining our Board.

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

Table of Contents

In January 2019, we granted our executive officers and select management employees 688,540 shares of restricted stock and 688,540 PSUs under the 2005 Incentive Plan. The market value of the restricted shares was $5.41 per share or $3.7 million. The grant date fair value of the PSUs was $7.60 per share. Also in January 2019, we granted $4.4 million of fixed value cash awards to other select management employees under the 2005 Incentive Plan.

Restricted Stock Awards

We grant restricted stock to members of our Board, executive officers and select management employees. The following table summarizes information about our restricted stock:

	Year Ended December 31,					
	2018		2017		2016	
	Shares	Grant Date Fair Value (1)	Shares	Grant Date Fair Value (1)	Shares	Grant Date Fair Value (1)
Awards outstanding at beginning of year	1,579,218	$ 7.63	1,577,973	$ 7.86	661,124	$ 16.28
Granted	614,286	7.46	829,143	8.39	1,298,121	5.70
Vested (2)	(823,310)	7.88	(817,791)	8.84	(305,588)	16.94
Forfeited	(49,205)	7.62	(10,107)	7.01	(75,684)	7.76
Awards outstanding at end of year	1,320,989	$ 7.40	1,579,218	$ 7.63	1,577,973	$ 7.86

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

(2) Total fair value of restricted stock that vested during the years ended December 31, 2018, 2017 and 2016 was $6.4 million, $6.9 million and $2.2 million, respectively.

For the years ended December 31, 2018, 2017 and 2016, $6.0 million, $7.9 million and $5.8 million, respectively, were recognized as share-based compensation related to restricted stock. Future compensation cost associated with unvested restricted stock at December 31, 2018 totaled approximately $5.0 million. The weighted average vesting period related to unvested restricted stock at December 31, 2018 was approximately 1.0 year.

Performance Share Units Awards

We grant PSUs to our executive officers and from time to time select management employees. The payout at vesting of PSUs is based on the performance of our common stock over a three-year period compared to the performance of other companies in a peer group selected by the Compensation Committee of our Board, with the maximum amount of the award being 200% of the original awarded PSUs and the minimum amount being zero. PSUs granted prior to 2017 could be settled in either cash or shares of our common stock upon vesting at the discretion of the Compensation Committee of our Board. As a result of our Board's decision to cash settle the vesting of the 2012 PSU awards in 2015, PSUs granted before 2017, including those that were previously accounted for as equity awards, are treated as liability awards. PSUs granted beginning in 2017 are to be settled solely in shares of our common stock and therefore are accounted for as equity awards.

We issued 449,271 PSUs in 2018 with a grant date fair value of $10.44 per unit, 671,771 PSUs in 2017 with a grant date fair value of $12.64 per unit and 1,161,672 PSUs in 2016 with a grant date fair value of $7.13 per unit. For the years ended December 31, 2018, 2017 and 2016, $4.7 million, $7.4 million and $6.8 million, respectively, were recognized as share-based compensation related to PSUs. For the year ended December 31, 2016, we recorded $0.2

million in equity reflecting the cumulative compensation cost recognized in excess of the estimated fair value of the modified liability PSU awards. At December 31, 2018 and 2017, the liability balance for unvested PSUs was $11.1 million. During 2016, 2017 and 2018, we paid $0.2 million, $0.6 million and $0.9 million, respectively, to cash settle the PSUs granted in 2013, 2014 and 2015. We paid $11.1 million to cash settle the 2016 grant of PSUs when they vested in January 2019.

Table of Contents

Cash Awards

In 2018, we granted $5.2 million of fixed value cash awards to select management employees under the 2005 Incentive Plan. The value of these cash awards is recognized on a straight-line basis over a vesting period of three years. For the year ended December 31, 2018, $1.7 million was recognized as compensation cost, which reflects the liability balance as of December 31, 2018 for the cash payout made in January 2019.

Note 13 — Business Segment Information

We have three reportable business segments: Well Intervention, Robotics and Production Facilities. Our U.S., U.K. and Brazil well intervention operating segments are aggregated into the Well Intervention business segment for financial reporting purposes. Our Well Intervention segment includes our vessels and equipment used to perform well intervention services primarily in the U.S. Gulf of Mexico, Brazil, the North Sea and West Africa. Our well intervention vessels include the Q4000, the Q5000, the Seawell, the Well Enhancer, and the chartered Siem Helix 1 and Siem Helix 2 vessels. The Siem Helix 1 commenced well intervention operations for Petrobras offshore Brazil in April 2017 and the Siem Helix 2 commenced operations for Petrobras in December 2017. We returned the Skandi Constructor to its owner in March 2017 upon the expiration of the vessel charter. Our well intervention equipment includes IRSs, some of which we provide on a stand-alone basis, and SILs. Our Robotics segment includes ROVs, trenchers and ROVDrills, which are designed to complement offshore construction and well intervention services, and three ROV support vessels under long-term charter: the Grand Canyon, the Grand Canyon II and the Grand Canyon III. We returned the Deep Cygnus to its owner during the first quarter of 2018. Our Production Facilities segment includes the HP I, the HFRS and our investment in Independence Hub that is accounted for under the equity method. All material intercompany transactions between the segments have been eliminated.

We evaluate our performance based on operating income of each reportable segment. Certain financial data by reportable segment are summarized as follows (in thousands):

	Year Ended December 31,		
	2018	2017	2016
Net revenues —			
Well Intervention	$560,568	$406,341	$294,000
Robotics	158,989	152,755	160,580
Production Facilities	64,400	64,352	72,358
Intercompany eliminations	(44,139)	(42,065)	(39,356)
Total	$739,818	$581,383	$487,582
Income (loss) from operations —			
Well Intervention [1]	$87,643	$52,733	$14,910
Robotics [2]	(14,054)	(42,289)	(72,250)
Production Facilities	27,263	28,172	33,861
Segment operating income	100,852	38,616	(23,479)
Corporate, eliminations and other	(49,309)	(39,746)	(39,756)
Total	51,543	(1,130)	(63,235)
Net interest expense	(13,751)	(18,778)	(31,239)
Other non-operating income (expense), net	(6,794)	(464)	559
Income (loss) before income taxes	$30,998	$(20,372)	$(93,915)

Table of Contents

	Year Ended December 31,		
	2018	2017	2016
Capital expenditures —			
Well Intervention	$136,164	$230,354	$185,892
Robotics	151	648	720
Production Facilities	325	—	74
Corporate and other	443	125	(199)
Total	$137,083	$231,127	$186,487
Depreciation and amortization —			
Well Intervention	$76,943	$68,301	$68,392
Robotics	19,175	23,626	25,848
Production Facilities	14,070	13,936	13,952
Corporate and eliminations	334	2,882	5,995
Total	$110,522	$108,745	$114,187

(1) Amount in 2016 included a $1.3 million gain on the sale of the Helix 534 in December 2016.
(2) Amount in 2016 included a $45.1 million goodwill impairment charge related to our robotics reporting unit.

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 are as follows (in thousands):

	Year Ended December 31,		
	2018	2017	2016
Well Intervention	$14,218	$11,489	$8,442
Robotics	29,921	30,576	30,914
Total	$44,139	$42,065	$39,356

Revenues by individually significant geographic location are as follows (in thousands):

	Year Ended December 31,		
	2018	2017	2016
United States	$271,260	$283,933	$298,279
United Kingdom	194,434	155,954	123,581
Brazil	208,054	70,710	2,543
Other	66,070	70,786	63,179
Total	$739,818	$581,383	$487,582

Table of Contents

Our operational assets, primarily our vessels, work throughout the year in various regions around the world such as the U.S. Gulf of Mexico, Brazil, the North Sea, Asia Pacific and West Africa. The following table provides our property and equipment, net of accumulated depreciation, by individually significant geographic location (in thousands):

	December 31,	
	2018	2017
United States	$862,334	$894,680
United Kingdom (1)	236,512	270,499
Brazil	324,083	334,454
Singapore (2)	403,816	295,798
Other	—	10,558
Total	$1,826,745	$1,805,989

(1) Includes certain assets that are based in the United Kingdom but may operate in the North Sea and West Africa regions.

(2) Primarily includes the Q7000 vessel currently under completion at the shipyard in Singapore. The vessel may be deployed globally once completed.

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, most notably the majority of our cash and cash equivalents. The following table reflects total assets by reportable segment (in thousands):

	December 31,	
	2018	2017
Well Intervention	$1,916,638	$1,830,733
Robotics	147,602	179,853
Production Facilities	120,845	138,292
Corporate and other	162,645	213,959
Total	$2,347,730	$2,362,837

Note 14 — Commitments and Contingencies and Other Matters

Commitments

Commitments Related to Our Fleet

We have charter agreements with Siem Offshore AS (“Siem”) for the Siem Helix 1 and Siem Helix 2 vessels used in connection with our contracts with Petrobras to perform well intervention work offshore Brazil. The initial term of the charter agreements with Siem is for seven years from the respective vessel delivery dates with options to extend. We have charter agreements for the Grand Canyon, Grand Canyon II and Grand Canyon III vessels for use in our robotics operations. The charter agreements expire in October 2019 for the Grand Canyon, in April 2021 for the Grand Canyon II and in May 2023 for the Grand Canyon III. We also had a charter agreement for the Deep Cygnus. On February 9, 2018, we terminated our charter for the vessel and returned it to its owner. The charter had originally been scheduled to end on March 31, 2018.

Table of Contents

In September 2013, we executed a contract for the construction of a newbuild semi-submersible well intervention vessel, the Q7000, to be built to North Sea standards. Pursuant to the contract and subsequent amendments, 20% of the contract price was paid upon the signing of the contract in 2013, 20% was paid in each of 2016, 2017 and 2018, and the remaining 20% will be paid upon the delivery of the vessel, which at our option can be deferred until December 31, 2019. We are also contractually committed to reimburse the shipyard for its costs incurred in connection with the deferment of the Q7000's delivery beyond 2017. At December 31, 2018, our total investment in the Q7000 was $403.8 million, including $276.8 million of installment payments to the shipyard. Currently equipment is being manufactured and/or installed for the completion of the vessel.

Lease Commitments

We lease facilities and equipment as well as charter vessels under non-cancelable operating leases and vessel charters expiring at various dates through 2031. Future minimum rental payments at December 31, 2018 are as follows (in thousands):

	Vessels	Facilities and Other	Total
2019	$116,620	$5,881	$122,501
2020	96,800	5,340	102,140
2021	89,216	5,185	94,401
2022	90,371	5,064	95,435
2023	51,266	4,533	55,799
Thereafter	—	10,448	10,448
Total lease commitments	$444,273	$36,451	$480,724

For the years ended December 31, 2018, 2017 and 2016, total rental expense was approximately $147.8 million, $114.5 million and $87.8 million, respectively.

We sublease some of our facilities under non-cancelable sublease agreements. For the years ended December 31, 2018, 2017 and 2016, total rental income was $1.4 million, $1.3 million and $1.6 million, respectively. As of December 31, 2018, the minimum rentals to be received in the future totaled $3.5 million.

In January 2016, we entered into an agreement to lease back our former office and warehouse property located in Aberdeen, Scotland for 15 years with two five-year options to extend the lease. The annual minimum lease payment is approximately $0.8 million.

Contingencies and Claims

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

Litigation

We are involved in various other legal proceedings, some 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 and employment-related disputes, in the normal course of business.

Table of Contents

Note 15 — Statement of Cash Flow Information

The following table provides supplemental cash flow information (in thousands):

	Year Ended December 31,		
	2018	2017	2016
Interest paid, net of interest capitalized	$7,369	$10,367	$18,749
Income taxes paid	5,705	6,015	5,635

Our non-cash investing activities include the acquisition of property and equipment for which payment has not been made. As of December 31, 2018 and 2017, these non-cash capital additions totaled $9.9 million and $16.9 million, respectively.

Note 16 — 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, 2018 (in thousands):

	Allowance for Uncollectible Accounts	Deferred Tax Asset Valuation Allowance
Balance at December 31, 2015	$ 350	$ 1,936
Additions (1)	1,778	—
Deductions (2)	(350)	—
Adjustments (3)	—	1,835
Balance at December 31, 2016	1,778	3,771
Additions (1) (4)	1,206	2,788
Deductions (2)	(232)	—
Adjustments (3)	—	5,778
Balance at December 31, 2017	2,752	12,337
Deductions (2)	(2,752)	—
Adjustments (5)	—	5,603
Balance at December 31, 2018	$ —	$ 17,940

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

(2) The decrease in allowance for uncollectible accounts reflects the write-offs of trade receivables that are either settled or deemed uncollectible.

(3) The increase in valuation allowance primarily reflects additional net operating losses in Brazil and in our Robotics segment in the U.K. for which insufficient future taxable income exists to offset the losses.

(4) The addition of a deferred tax asset valuation allowance reflects management's view that we will not be able to fully realize our foreign tax credits available from 2015 within the carryforward period.

(5) The increase in valuation allowance primarily reflects additional net operating losses in our Robotics segment in the U.K. for which insufficient future taxable income exists to offset the losses.

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

Table of Contents

Note 17 — Fair Value Measurements

Assets and liabilities measured at fair value are based on one or more of three valuation approaches 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, receivables, accounts payable, long-term debt and derivative instruments. The carrying amount of cash and cash equivalents, trade and other current receivables as well as accounts payable approximates fair value due to the short-term nature of these instruments. The fair value of our derivative instruments (Note 18) and of our note receivable that is accounted for as an investment in available-for-sale debt securities (Note 3) 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, volatility and liquidity based on market data. Our actual results may differ from our estimates, and these differences could be positive or negative. The following tables provide additional information relating to those financial instruments measured at fair value on a recurring basis (in thousands):

	Fair Value Measurements at December 31, 2018 Using				Valuation Approach
	Level 1	Level 2	Level 3	Total	
Assets:					
Interest rate swaps	$ —	$ 1,064	$ —	$ 1,064	(c)
Liabilities:					
Foreign exchange contracts — hedging instruments	—	6,211	—	6,211	(c)
Foreign exchange contracts — non-hedging instruments	—	3,984	—	3,984	(c)
Total net liability	$ —	$ 9,131	$ —	$ 9,131	

	Fair Value Measurements at December 31, 2017 Using				Valuation Approach
	Level 1	Level 2	Level 3	Total	
Assets:					
Note receivable	$ —	$ 3,758	$ —	$ 3,758	(c)
Interest rate swaps	—	966	—	966	(c)
Liabilities:					
Foreign exchange contracts — hedging instruments	—	12,467	—	12,467	(c)
Foreign exchange contracts — non-hedging instruments	—	6,308	—	6,308	(c)
Total net liability	$ —	$ 14,051	$ —	$ 14,051	

81

Table of Contents

The principal amount and estimated fair value of our long-term debt are as follows (in thousands):

	December 31,			
	2018		2017	
	Principal Amount (1)	Fair Value (2)	Principal Amount (1)	Fair Value (2)
Term Loan (matures April 2020)	$33,693	$33,314	$97,500	$98,231
Nordea Q5000 Loan (matures April 2020)	125,000	122,500	160,714	160,111
MARAD Debt (matures February 2027)	70,468	74,406	77,000	82,058
2022 Notes (mature May 2022)	125,000	114,298	125,000	124,219
2023 Notes (mature September 2023)	125,000	114,688	—	—
2032 Notes (redeemed May 2018)	—	—	60,115	60,040
Total debt	$479,161	$459,206	$520,329	$524,659

(1) Principal amount includes current maturities and excludes the related unamortized debt discount and debt issuance costs. See Note 6 for additional disclosures on our long-term debt.

(2) The estimated fair value of the 2022 Notes, the 2023 Notes and the 2032 Notes was determined using Level 1 inputs under the market approach. The fair value of the Term Loan, the Nordea Q5000 Loan and the MARAD Debt was estimated using Level 2 fair value inputs under the market approach, which 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.

(3) The principal amount and fair value of the 2022 Notes, the 2023 Notes and the 2032 Notes are for the entire instrument inclusive of the conversion feature reported in shareholder's equity.

Note 18 — Derivative Instruments and Hedging Activities

In June 2015, we entered into interest rate swap contracts to fix the interest rate on $187.5 million of our Nordea Q5000 Loan borrowings (Note 6). These swap contracts, which are settled monthly, began in June 2015 and extend through April 2020. Our interest rate swap contracts qualify for cash flow hedge accounting treatment. The amount of ineffectiveness associated with our interest rate swap contracts was immaterial for all periods presented.

In February 2013, we entered into foreign currency exchange contracts to hedge our foreign currency exposure associated with the Grand Canyon II and Grand Canyon III charter payments denominated in Norwegian kroner through July 2019 and February 2020, respectively. Unrealized losses associated with the effective portion of our foreign currency exchange contracts that qualify for hedge accounting treatment are reflected in "Accumulated other comprehensive loss" in the shareholders' equity section of the accompanying consolidated balance sheets (net of tax). Changes in unrealized losses associated with the foreign currency exchange contracts that are not designated as cash flow hedges are reflected in "Other income (expense), net" in the accompanying consolidated statements of operations. Hedge ineffectiveness also is reflected in "Other income (expense), net" in the accompanying consolidated statements of operations. The amount of ineffectiveness associated with our foreign currency exchange contracts was immaterial for all periods presented.

Table of Contents

The following table presents the balance sheet location and fair value of our derivative instruments that were designated as hedging instruments (in thousands):

	December 31, 2018 Balance Sheet Location	Fair Value	2017 Balance Sheet Location	Fair Value
Asset Derivative Instruments:				
Interest rate swaps	Other current assets	$863	Other current assets	$311
Interest rate swaps	Other assets, net	201	Other assets, net	655
		$1,064		$966
Liability Derivative Instruments:				
Foreign exchange contracts	Accrued liabilities	$5,857	Accrued liabilities	$7,492
Foreign exchange contracts	Other non-current liabilities	354	Other non-current liabilities	4,975
		$6,211		$12,467

The following table presents the balance sheet location and fair value of our derivative instruments that were not designated as hedging instruments (in thousands):

	December 31, 2018 Balance Sheet Location	Fair Value	2017 Balance Sheet Location	Fair Value
Liability Derivative Instruments:				
Foreign exchange contracts	Accrued liabilities	$ 3,454	Accrued liabilities	$ 3,133
Foreign exchange contracts	Other non-current liabilities	530	Other non-current liabilities	3,175
		$ 3,984		$ 6,308

The following tables present the impact that derivative instruments designated as hedging instruments had on our accumulated OCI (net of tax) and our consolidated statements of operations (in thousands). We estimate that as of December 31, 2018, $4.0 million of net losses in accumulated OCI associated with our derivative instruments is expected to be reclassified into earnings within the next 12 months.

	Unrealized Gain (Loss) Recognized in OCI Year Ended December 31, 2018	2017	2016
Foreign exchange contracts	$(1,453)	$2,672	$3,630
Interest rate swaps	606	651	(1,264)
	$(847)	$3,323	$2,366

Table of Contents

	Location of Gain (Loss) Reclassified from Accumulated OCI into Earnings	Gain (Loss) Reclassified from Accumulated OCI into Earnings Year Ended December 31,		
		2018	2017	2016
Foreign exchange contracts	Cost of sales	$(7,709)	$(12,300)	$(10,827)
Interest rate swaps	Net interest expense	508	(615)	(2,024)
		$(7,201)	$(12,915)	$(12,851)

The following table presents the impact that derivative instruments not designated as hedging instruments had on our consolidated statements of operations (in thousands):

	Location of Gain (Loss) Recognized in Earnings	Gain (Loss) Recognized in Earnings Year Ended December 31,		
		2018	2017	2016
Foreign exchange contracts	Other income (expense), net	$(901)	$818	$1,198
		$(901)	$818	$1,198

Note 19 — Quarterly Financial Information (Unaudited)

In addition to being affected by the timing of oil and gas company expenditures, offshore marine construction activities may fluctuate as a result of weather conditions. Historically, a substantial portion of our services has been performed during the summer and fall months. As a result, a disproportionate portion of our revenues and net income is earned during such period. The following is a summary of consolidated quarterly financial information (in thousands, except per share amounts):

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
2018				
Net revenues	$164,262	$204,625	$212,575	$158,356
Gross profit	12,983	42,897	51,993	13,811
Net income (loss)	(2,560)	17,784	27,121	(13,747)
Basic earnings (loss) per common share	$(0.02)	$0.12	$0.18	$(0.09)
Diluted earnings (loss) per common share	$(0.02)	$0.12	$0.18	$(0.09)

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
2017				
Net revenues	$104,528	$150,329	$163,260	$163,266
Gross profit (loss)	(825)	18,367	21,141	23,483
Net income (loss) [1]	(16,415)	(6,403)	2,290	50,580
Basic earnings (loss) per common share	$(0.11)	$(0.04)	$0.02	$0.34
Diluted earnings (loss) per common share	$(0.11)	$(0.04)	$0.02	$0.34

(1) Amount in the fourth quarter of 2017 included a $51.6 million income tax benefit as a result of the U.S. tax law changes enacted in December 2017.

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, 2018 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.

(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, 2018. 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). Based on this assessment, management concluded that, as of December 31, 2018, 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, 2018 has been audited by KPMG 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 2018 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 2019 Annual Meeting of Shareholders to be held on May 15, 2019. See also “Executive Officers of the Company” appearing in Part I of this Annual Report.

Table of Contents

Code of Ethics

We have a Code of Business Conduct and Ethics for all of our 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

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 2019 Annual Meeting of Shareholders to be held on May 15, 2019.

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 2019 Annual Meeting of Shareholders to be held on May 15, 2019.

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 2019 Annual Meeting of Shareholders to be held on May 15, 2019.

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 2019 Annual Meeting of Shareholders to be held on May 15, 2019.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(1) Financial Statements

The following financial statements included on pages 45 through 84 in this Annual Report are for the fiscal year ended December 31, 2018.

- Report of Independent Registered Public Accounting Firm — KPMG
- Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting — KPMG
- Consolidated Balance Sheets as of December 31, 2018 and 2017
- Consolidated Statements of Operations for the Years Ended December 31, 2018, 2017 and 2016
- Consolidated Statements of Comprehensive Income (Loss) for the Years Ended December 31, 2018, 2017 and 2016
- Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2018, 2017 and 2016
- Consolidated Statements of Cash Flows for the Years Ended December 31, 2018, 2017 and 2016
- 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.

Table of Contents

(2) Exhibits

The documents set forth below are filed herewith or incorporated by reference to the location indicated. 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.

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	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)
4.8	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)
4.9	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)
4.10	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)
4.11	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)
4.12	Form of United States Government Guaranteed Ship Financing Bonds, Q4000 Series 4.93% Sinking Fund Bonds Due February 1, 2027.	Exhibit A to Exhibit 4.5 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)

4.13	Form of Third Amended and Restated Promissory Note to United States of America.	Exhibit 4.7 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)
4.14	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)

Table of Contents

Exhibits	Description	Filed or Furnished Herewith or Incorporated by Reference from the Following Documents (Registration or File Number)
4.15	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)
4.16	Amendment No. 1 to the Credit Agreement, dated as of May 13, 2015, by and among Helix Energy Solutions Group, Inc. and Bank of America, N.A., as administrative agent, swing line lender and letters of credit issuer, together with the other lenders party thereto.	Exhibit 4.1 to the Current Report on Form 8-K filed on May 14, 2015 (001-32936)
4.17	Amendment No. 2 to the Credit Agreement, dated as of January 19, 2016, by and among Helix Energy Solutions Group, Inc. and Bank of America, N.A., as administrative agent, swing line lender and letters of credit issuer, together with the other lenders party thereto.	Exhibit 4.1 to the Current Report on Form 8-K filed on January 25, 2016 (001-32936)
4.18	Amendment No. 3 to the Credit Agreement, dated as of February 9, 2016, by and among Helix Energy Solutions Group, Inc. and Bank of America, N.A., as administrative agent, swing line lender and letters of credit issuer, together with the other lenders party thereto.	Exhibit 4.1 to the Current Report on Form 8-K filed on February 11, 2016 (001-32936)
4.19	Amendment and Restated Credit Agreement dated June 30, 2017, by and among Helix Energy Solutions Group, Inc. and Bank of America, N.A., as administrative agent, swing line lender and letters of credit issuer, together with the other lenders party thereto.	Exhibit 4.1 to the Current Report on Form 8-K filed on June 30, 2017 (001-32936)
4.20	Amendment No. 1 to the Amendment and Restated Credit Agreement, dated as of January 18, 2019, by and among Helix Energy Solutions Group, Inc. and Bank of America, N.A., as administrative agent, swing line lender and letters of credit issuer, together with the other lenders party thereto.	Exhibit 4.1 to the Current Report on Form 8-K filed on January 22, 2019 (001-32936)
4.21	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)
4.22	Senior Debt Indenture, dated as of November 1, 2016, by and 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 November 1, 2016 (001-32936)
4.23	First Supplemental Indenture, dated as of November 1, 2016, by and between Helix Energy Solutions Group, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee.	Exhibit 4.2 to the Current Report on Form 8-K filed on November 1, 2016 (001-32936)
4.24	Second Supplemental Indenture, dated as of March 20, 2018, by and between Helix Energy Solutions Group, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee.	Exhibit 4.2 to the Current Report on Form 8-K filed on March 21, 2018 (001-32936)
10.1 *	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)
10.2 *	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)
10.3 *		

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)

Table of Contents

Exhibits	Description	Filed or Furnished Herewith or Incorporated by Reference from the Following Documents (Registration or File Number)
10.4 *	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)
10.5 *	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)
10.6 *	2005 Long-Term Incentive Plan, as Amended and Restated Effective January 1, 2017.	Exhibit 10.1 to the Current Report on Form 8-K filed on December 5, 2016 (001-32936)
10.7 *	Form of Performance Share Unit Award Agreement.	Exhibit 10.1 to the Current Report on Form 8-K filed on December 14, 2018 (001-32936)
10.8 *	Form of Restricted Stock Award Agreement.	Exhibit 10.3 to the Current Report on Form 8-K filed on December 15, 2011 (001-32936)
10.9 *	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)
10.10 *	Amendment to the Helix Energy Solutions Group, Inc. Employee Stock Purchase Plan.	Exhibit 10.12 to the 2015 Form 10-K filed on February 29, 2016 (001-32936)
10.11 *	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)
10.12 *	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)
10.13 *	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)
10.14 *	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)
10.15 *	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)
10.16 *	Employment Agreement by and between Helix Energy Solutions Group, Inc. and Scotty Sparks dated May 11, 2015.	Exhibit 10.1 to the Current Report on Form 8-K/A filed on May 12, 2015 (001-32936)
10.17 *	Deferred Compensation Agreement by and between Helix Energy Solutions Group, Inc. and Scotty Sparks dated January 1, 2012.	Exhibit 10.2 to the Current Report on Form 8-K/A filed on May 12, 2015 (001-32936)
10.18 *	Employment Agreement by and between Helix Energy Solutions Group, Inc. and Erik Staffeldt dated June 5, 2017.	Exhibit 10.1 to the Current Report on Form 8-K filed on June 5, 2017 (001-32936)
10.19	Equity Distribution Agreement dated April 25, 2016 between Helix Energy Solutions Group, Inc. and Wells Fargo Securities LLC.	Exhibit 1.1 to the Current Report on Form 8-K filed on April 25, 2016 (001-32936)

10.20	Equity Distribution Agreement dated August 11, 2016 between Helix Energy Solutions Group, Inc. and Wells Fargo Securities LLC.	Exhibit 1.1 to the Current Report on Form 8-K filed on August 11, 2016 (001-32936)
10.21	Underwriting Agreement dated as of October 26, 2016, between Helix Energy Solutions Group, Inc. and Raymond James & Associates, Inc.	Exhibit 1.1 to the Current Report on Form 8-K filed on November 1, 2016 (001-32936)
10.22	Underwriting Agreement dated as of January 4, 2017, between Helix Energy Solutions Group, Inc. and Credit Suisse Securities (USA) LLC and Wells Fargo Securities, LLC, as representatives of the several underwriters named therein.	Exhibit 1.1 to the Current Report on Form 8-K filed on January 6, 2017 (001-32936)

Table of Contents

Exhibits	Description	Filed or Furnished Herewith or Incorporated by Reference from the Following Documents (Registration or File Number)
10.23	Underwriting Agreement dated as of March 13, 2018, by and among Helix Energy Solutions Group, Inc., Wells Fargo Securities, LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated.	Exhibit 1.1 to the Current Report on Form 8-K filed on March 19, 2018 (001-32936)
10.24	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)
10.25	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)
10.26	Amendment No. 1, dated as of June 8, 2015, to Construction Contract 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 June 11, 2015 (001-32936)
10.27	Amendment No. 2, dated December 2, 2015, to Construction Contract 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 December 7, 2015 (001-32936)
10.28	Amendment No. 3, dated November 15, 2017, to Construction Contract 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 November 20, 2017 (001-32936)
10.29	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 Annual Report on Form 10-K filed on February 23, 2018
21.1	List of Helix's Subsidiaries.	Filed herewith
23.1	Consent of KPMG LLP.	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 Erik Staffeldt, 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

Item 16. Form 10-K Summary

None.

Table of Contents

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/ ERIK STAFFELDT
Erik Staffeldt
Executive Vice President and
Chief Financial Officer

February 22, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ OWEN KRATZ Owen Kratz	President, Chief Executive Officer and Director (principal executive officer)	February 22, 2019
/s/ ERIK STAFFELDT Erik Staffeldt	Executive Vice President and Chief Financial Officer (principal financial officer and principal accounting officer)	February 22, 2019
/s/ AMERINO GATTI Amerino Gatti	Director	February 22, 2019
/s/ JOHN V. LOVOI John V. Lovoi	Director	February 22, 2019
/s/ NANCY K. QUINN Nancy K. Quinn	Director	February 22, 2019
/s/ JAN A. RASK Jan A. Rask	Director	February 22, 2019
/s/ WILLIAM L. TRANSIER William L. Transier	Director	February 22, 2019
/s/ JAMES A. WATT James A. Watt	Director	February 22, 2019