HELIX ENERGY SOLUTIONS GROUP INC
Form 10-Q
July 22, 2016

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
Form 10-Q
þ Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended June 30, 2016
or
¨ Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from__________ to__________
Commission File Number 001-32936

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

Minnesota (State or other jurisdiction of incorporation or organization)	95–3409686 (I.R.S. Employer Identification No.)
3505 West Sam Houston Parkway North Suite 400 Houston, Texas (Address of principal executive offices)	77043 (Zip Code)

(281) 618–0400
(Registrant's telephone number, including area code)
NOT APPLICABLE
(Former name, former address and former fiscal year, if changed since last report)
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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). þ Yes ¨ No
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.
Large accelerated filer þ Accelerated filer ¨ Non-accelerated filer ¨ (Do not check if a smaller reporting company) Smaller reporting company ¨
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ¨ Yes þ No
As of July 19, 2016, 112,639,372 shares of common stock were outstanding.

TABLE OF CONTENTS

Table of Contents

PART I. FINANCIAL INFORMATION
Item 1. Financial Statements
HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(in thousands)

	June 30, 2016 (Unaudited)	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$492,190	$494,192
Accounts receivable:		
Trade, net of allowance for uncollectible accounts of $316 and $350, respectively	59,888	76,287
Unbilled revenue and other	16,216	20,465
Current deferred tax assets	14,211	53,573
Income tax receivable	21,311	—
Other current assets	41,465	39,518
Total current assets	645,281	684,035
Property and equipment	2,565,180	2,544,857
Less accumulated depreciation	(983,218)	(941,848)
Property and equipment, net	1,581,962	1,603,009
Other assets:		
Equity investments	—	26,200
Goodwill	45,107	45,107
Other assets, net	42,018	41,608
Total assets	$2,314,368	$2,399,959
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$48,013	$65,370
Accrued liabilities	71,009	71,641
Income tax payable	—	2,261
Current maturities of long-term debt	71,786	71,640
Total current liabilities	190,808	210,912
Long-term debt	638,985	677,695
Deferred tax liabilities	166,557	180,974
Other non-current liabilities	52,829	51,415
Total liabilities	1,049,179	1,120,996
Commitments and contingencies		
Shareholders’ equity:		
Common stock, no par, 240,000 shares authorized, 112,627 and 106,289 shares issued, respectively	986,239	945,565
Retained earnings	365,805	404,299
Accumulated other comprehensive loss	(86,855)	(70,901)
Total shareholders’ equity	1,265,189	1,278,963
Total liabilities and shareholders’ equity	$2,314,368	$2,399,959

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

Table of Contents

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

	Three Months Ended June 30, 2016	2015
Net revenues	$107,267	$166,016
Cost of sales	101,609	141,808
Gross profit	5,658	24,208
Selling, general and administrative expenses	(14,953)	(16,534)
Income (loss) from operations	(9,295)	7,674
Equity in losses of investments	(121)	(323)
Net interest expense	(7,480)	(5,235)
Gain on repurchase of long-term debt	302	—
Other income (expense), net	1,308	(5,036)
Other income – oil and gas	396	899
Loss before income taxes	(14,890)	(2,021)
Income tax provision (benefit)	(4,219)	614
Net loss	$(10,671)	$(2,635)
Loss per share of common stock:		
Basic	$(0.10)	$(0.03)
Diluted	$(0.10)	$(0.03)
Weighted average common shares outstanding:		
Basic	107,767	105,357
Diluted	107,767	105,357

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

4

Table of Contents

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

	Six Months Ended June 30, 2016	2015
Net revenues	$198,306	$355,657
Cost of sales	209,578	296,502
Gross profit (loss)	(11,272)	59,155
Selling, general and administrative expenses	(28,779)	(29,153)
Income (loss) from operations	(40,051)	30,002
Equity in losses of investments	(244)	(302)
Net interest expense	(18,164)	(9,305)
Gain on repurchase of long-term debt	302	—
Other income (expense), net	3,188	(6,192)
Other income – oil and gas	2,968	3,825
Income (loss) before income taxes	(52,001)	18,028
Income tax provision (benefit)	(13,507)	1,021
Net income (loss)	$(38,494)	$17,007
Earnings (loss) per share of common stock:		
Basic	$(0.36)	$0.16
Diluted	$(0.36)	$0.16
Weighted average common shares outstanding:		
Basic	106,838	105,324
Diluted	106,838	105,324

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

Table of Contents

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

	Three Months Ended June 30,	
	2016	2015
Net loss	$(10,671)	$(2,635)
Other comprehensive income (loss), net of tax:		
Unrealized gain (loss) on hedges arising during the period	(2,344)	3,346
Reclassification adjustments for loss included in net loss	3,054	3,258
Income taxes on unrealized (gain) loss on hedges	(236)	(2,311)
Unrealized gain on hedges, net of tax	474	4,293
Foreign currency translation gain (loss)	(14,641)	15,889
Other comprehensive income (loss), net of tax	(14,167)	20,182
Comprehensive income (loss)	$(24,838)	$17,547

	Six Months Ended June 30,	
	2016	2015
Net income (loss)	$(38,494)	$17,007
Other comprehensive loss, net of tax:		
Unrealized gain (loss) on hedges arising during the period	1,032	(8,365)
Reclassification adjustments for loss on hedges included in net income (loss)	6,494	4,931
Income taxes on unrealized (gain) loss on hedges	(2,553)	1,202
Unrealized gain (loss) on hedges, net of tax	4,973	(2,232)
Foreign currency translation gain (loss) arising during the period	(21,216)	2,020
Reclassification adjustment for translation loss realized upon liquidation	289	—
Foreign currency translation gain (loss)	(20,927)	2,020
Other comprehensive loss, net of tax	(15,954)	(212)
Comprehensive income (loss)	$(54,448)	$16,795

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

Table of Contents

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

	Six Months Ended June 30,	
	2016	2015
Cash flows from operating activities:		
Net income (loss)	$(38,494)	$17,007
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	57,239	53,528
Amortization of debt issuance costs	5,138	2,596
Share-based compensation	2,867	3,515
Amortization of debt discount	3,134	2,928
Deferred income taxes	(10,047)	(2,454)
Excess tax benefit from share-based compensation	—	(86)
Equity in losses of investments	244	—
Gain on repurchase of long-term debt	(302)	—
Unrealized (gain) loss and ineffectiveness on derivative contracts, net	(6,147)	1,941
Changes in operating assets and liabilities:		
Accounts receivable, net	19,062	(29,006)
Other current assets	(3,055)	11,904
Income tax receivable, net of income tax payable	8,843	(9,472)
Accounts payable and accrued liabilities	(7,979)	(35,318)
Other noncurrent, net	(5,614)	(14,050)
Net cash provided by operating activities	24,889	3,033
Cash flows from investing activities:		
Capital expenditures	(57,563)	(232,872)
Distributions from equity investments, net of earnings	1,200	3,842
Proceeds from sale of equity investment	25,000	—
Proceeds from sale of assets	10,887	7,500
Net cash used in investing activities	(20,476)	(221,530)
Cash flows from financing activities:		
Proceeds from Nordea Q5000 Loan	—	250,000
Repayment of Nordea Q5000 Loan	(17,858)	—
Repayment of Term Loan	(15,000)	(7,500)
Repayment of MARAD Debt	(2,927)	(2,788)
Repurchase of Convertible Senior Notes due 2032	(6,480)	—
Debt issuance costs	(1,230)	(1,533)
Net proceeds from issuance of common stock	38,773	—
Repurchase of common stock	(187)	(1,056)
Excess tax benefit from share-based compensation	—	86
Proceeds from issuance of ESPP shares	600	2,512
Net cash provided by (used in) financing activities	(4,309)	239,721
Effect of exchange rate changes on cash and cash equivalents	(2,106)	2,346
Net increase (decrease) in cash and cash equivalents	(2,002)	23,570

Cash and cash equivalents:		
Balance, beginning of year	494,192	476,492
Balance, end of period	$492,190	$500,062

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

Table of Contents

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)
Note 1 — Basis of Presentation and New Accounting Standards

The accompanying condensed consolidated financial statements include the accounts of Helix Energy Solutions Group, Inc. and its subsidiaries (collectively, "Helix" or the "Company"). Unless the context indicates otherwise, the terms "we," "us" and "our" in this report refer collectively to Helix and its subsidiaries. All material intercompany accounts and transactions have been eliminated. These unaudited condensed consolidated financial statements have been prepared pursuant to instructions for the Quarterly Report on Form 10-Q required to be filed with the Securities and Exchange Commission (the "SEC"), and do not include all information and footnotes normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles ("U.S. GAAP").

The accompanying condensed consolidated financial statements have been prepared in conformity with U.S. GAAP and are consistent in all material respects with those applied in our 2015 Annual Report on Form 10-K ("2015 Form 10-K"). The preparation of these financial statements requires us to make estimates and judgments that affect the amounts reported in the financial statements and the related disclosures. Actual results may differ from our estimates. We have made all adjustments (which were normal recurring adjustments) that we believe are necessary for a fair presentation of the condensed consolidated balance sheets, statements of operations, statements of comprehensive income (loss), and statements of cash flows, as applicable. The operating results for the three- and six-month periods ended June 30, 2016 are not necessarily indicative of the results that may be expected for the year ending December 31, 2016. Our balance sheet as of December 31, 2015 included herein has been derived from the audited balance sheet as of December 31, 2015 included in our 2015 Form 10-K. These unaudited condensed consolidated financial statements should be read in conjunction with the annual audited consolidated financial statements and notes thereto included in our 2015 Form 10-K.

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.

In May 2014, the Financial Accounting Standards Board (the "FASB") issued Accounting Standards Update ("ASU") No. 2014-09, "Revenue from Contracts with Customers (Topic 606)." This ASU provides a single five-step approach to account for revenue arising from contracts with customers. The ASU requires 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. This revenue standard was originally effective prospectively for annual reporting periods beginning after December 15, 2016, including interim periods. In August 2015, the FASB issued ASU No. 2015-14 to defer the effective date of ASU No. 2014-09 by one year to annual reporting periods beginning after December 15, 2017. Adoption as of the original effective date is permitted. In March 2016, the FASB issued ASU No. 2016-08, which amends the guidance to clarify the implementation guidance on principal versus agent considerations (gross versus net revenue presentation). In April 2016, the FASB issued ASU No. 2016-10, which amends the guidance with respect to certain implementation issues on identifying performance obligations and accounting for licenses of intellectual property. In May 2016, the FASB issued ASU No. 2016-12, which provides certain narrow-scope improvements and practical expedients to the guidance. The new revenue standard permits companies to either apply the requirements retrospectively to all prior periods presented or apply the requirements in the year of adoption through a cumulative adjustment. We are currently evaluating our existing revenue recognition policies to determine the types of contracts that are within the scope of this guidance and the impact the adoption of this standard may have on our consolidated financial statements. We have not yet determined if we will apply the full retrospective or the modified retrospective method.

Table of Contents

In April 2015, the FASB issued ASU No. 2015-03, "Simplifying the Presentation of Debt Issuance Costs." This ASU requires that debt issuance costs related to a recognized debt liability be reported on the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. In August 2015, the FASB issued ASU No. 2015-15, "Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements." This ASU includes an SEC staff announcement that the SEC staff will not object to an entity presenting the cost of securing a revolving line of credit as an asset, regardless of whether a balance is outstanding. The subject of this ASU was not previously addressed by ASU No. 2015-03. We adopted this guidance retrospectively in the first quarter of 2016. As a result, we presented $12.0 million of unamortized debt issuance costs that had been included in "Other assets, net" in our consolidated balance sheet as of December 31, 2015 as direct deductions from the carrying amounts of the related debt liabilities.

In November 2015, the FASB issued ASU No. 2015-17, "Balance Sheet Classification of Deferred Taxes." This ASU requires companies to classify all deferred tax assets and liabilities as non-current on the balance sheet instead of separating deferred taxes into current and non-current amounts. The current requirement that deferred tax liabilities and assets of a tax-paying component of an entity be offset and presented as a single amount is not affected by this guidance. The guidance is effective prospectively for annual reporting periods beginning after December 15, 2016, including interim periods. Early adoption is permitted. This guidance will not affect our statements of operations or statements of cash flows.

In February 2016, the FASB issued ASU No. 2016-02, "Leases (Topic 842)." This ASU amends the existing accounting standards for leases. The amendments are intended to increase transparency and comparability among organizations by requiring recognition of lease assets and lease liabilities on the balance sheet and disclosure of key information about leasing arrangements. The guidance is effective for annual reporting periods beginning after December 15, 2018, including interim periods. Early adoption is permitted. The guidance is required to be adopted at the earliest period presented using a modified retrospective approach. We are currently evaluating the impact these amendments will have on our consolidated financial statements.

In March 2016, the FASB issued ASU No. 2016-09, "Improvements to Employee Share-Based Payment Accounting." This ASU simplifies several aspects of the accounting for share-based payment transactions, including the income tax consequences, forfeitures, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The guidance is effective for annual reporting periods beginning after December 15, 2016, including interim periods. Early adoption is permitted. An entity that elects early adoption of the amendment under this ASU must adopt all aspects of the amendment in the same period. We are currently evaluating the impact this guidance will have on our consolidated financial statements.

Note 2 — Company Overview

We are an international offshore energy services company that provides specialty services to the offshore energy industry, with a focus on well intervention and robotics operations. We seek to provide services and methodologies that we believe are critical to developing offshore reservoirs and maximizing production economics. We provide services primarily in deepwater in the U.S. Gulf of Mexico, North Sea, Asia Pacific and West Africa regions, and are expanding our operations offshore Brazil. Our "life of field" services are segregated into three reportable business segments: Well Intervention, Robotics and Production Facilities (Note 11).

Our Well Intervention segment includes our vessels and equipment used to perform well intervention services primarily in the U.S. Gulf of Mexico and North Sea regions. Our Well Intervention segment also includes intervention riser systems ("IRSs"), some of which we rent out on a stand-alone basis, and subsea intervention lubricators ("SILs"). Our well intervention vessels include the Q4000, the Q5000, the Well Enhancer, the Seawell, the Helix 534 and the Skandi Constructor, which is a chartered vessel. In April 2016, the Q5000, a newbuild semi-submersible well intervention vessel, commenced operations in the Gulf of Mexico under our five-year contract with BP. The vessel went on contracted rates on May 19, 2016, and we have been notified by BP that they will not take more than the minimum 270 contracted days in 2017. We currently have another semi-submersible well intervention vessel under construction, the Q7000. We are chartering the Siem Helix 1 and have contracted to charter the Siem Helix 2. These two newbuild monohull vessels are to be used in connection with our contracts to provide well intervention services offshore Brazil.

Table of Contents

Our Robotics segment includes remotely operated vehicles ("ROVs"), trenchers and ROVDrills designed to complement offshore construction and well intervention services, and currently operates three chartered ROV support vessels following the expiration of the Rem Installer charter on July 12, 2016. Another chartered ROV support vessel, the Grand Canyon III, was delivered by the shipyard to the vessel owner in May 2016. The vessel is currently stacked by the owner and is expected to be in service for us in May 2017.

Our Production Facilities segment includes the Helix Producer I vessel ("HP I"), a ship-shaped dynamic positioning floating production unit, and the Helix Fast Response System ("HFRS"), which provides certain operators access to our Q4000 and HP I vessels in the event of a well control incident in the Gulf of Mexico. The HP I is currently contracted to process production from the Phoenix field. Our existing contract for service to the Phoenix field has been extended until at least December 31, 2017. The Production Facilities segment also includes our ownership interest in Independence Hub, LLC ("Independence Hub") and included our former ownership interest in Deepwater Gateway, L.L.C. ("Deepwater Gateway") that we sold for $25 million in February 2016 (Note 5).

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 minimum 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 will be amortized over the 15-year minimum lease term.

Note 3 — Details of Certain Accounts

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

	June 30, 2016	December 31, 2015
Note receivable [(1)]	$10,000	$ 10,000
Prepaid insurance	222	5,433
Other prepaids	12,689	10,142
Deferred costs	4,903	609
Spare parts inventory	4,601	4,985
Value added tax receivable	8,774	7,842
Other	276	507
Total other current assets	$41,465	$ 39,518

(1) Relates to the balance of the promissory note we received in connection with the sale of our former Ingleside spoolbase in January 2014. Interest on the note is payable quarterly at a rate of 6% per annum. Under the terms of the note, the remaining $10 million principal balance is required to be paid on December 31, 2016.

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

	June 30, 2016	December 31, 2015
Deferred dry dock expenses, net	$12,472	$ 19,615
Deferred costs	11,024	—
Deferred financing costs, net [(1)]	4,823	7,863
Charter fee deposit (Note 12)	12,544	12,544
Other	1,155	1,586
Total other assets, net	$42,018	$ 41,608

(1) Represents unamortized debt issuance costs related to our Revolving Credit Facility (Note 6).

10

Table of Contents

Accrued liabilities consist of the following (in thousands):

	June 30, 2016	December 31, 2015
Accrued payroll and related benefits	$14,671	$ 14,775
Deferred revenue	13,400	12,841
Accrued interest	4,155	4,854
Derivative liability (Note 14)	20,538	23,192
Taxes payable excluding income tax payable	9,988	8,136
Other	8,257	7,843
Total accrued liabilities	$71,009	$ 71,641

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

	June 30, 2016	December 31, 2015
Loss in excess of equity investment (Note 5)	$8,315	$ 8,308
Deferred gain on sale of property (Note 2)	6,430	—
Deferred revenue	6,333	—
Derivative liability (Note 14)	28,276	39,709
Other	3,475	3,398
Total other non-current liabilities	$52,829	$ 51,415

Note 4 — Statement of Cash Flow Information

We define cash and cash equivalents as cash and all highly liquid financial instruments with original maturities of three months or less. The following table provides supplemental cash flow information (in thousands):

	Six Months Ended June 30,	
	2016	2015
Interest paid, net of interest capitalized	$10,321	$3,729
Income taxes paid	$3,845	$13,285

Our non-cash investing activities include accruals for property and equipment capital expenditures. These non-cash investing accruals totaled $12.6 million and $18.7 million as of June 30, 2016 and December 31, 2015, respectively.

Note 5 — Equity Investments

We have a 20% ownership interest in Independence Hub, LLC ("Independence Hub") that we account for using the equity method of accounting. We previously had a 50% ownership interest in Deepwater Gateway, L.L.C., which we sold in February 2016 to a subsidiary of Genesis Energy, L.P., the other owner, for $25 million with no resulting gain or loss. Both equity investments are included in our Production Facilities segment.

Independence Hub owns the "Independence Hub" platform located in Mississippi Canyon Block 920 in a water depth of 8,000 feet. Our share of the losses reported by Independence Hub exceeded the carrying amount of our investment by $8.3 million as of June 30, 2016 and December 31, 2015 reflecting our share of Independence Hub's obligations (primarily its estimated asset retirement obligations to decommission the platform), net of remaining working capital. This liability is reflected in "Other non-current liabilities" in the accompanying condensed consolidated balance sheets.

Table of Contents

We received the following distributions from our equity method investments (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Deepwater Gateway	$—	$1,700	$1,200	$2,700
Independence Hub	—	440	—	840
Total	$—	$2,140	$1,200	$3,540

Note 6 — Long-Term Debt

Scheduled maturities of our long-term debt outstanding as of June 30, 2016 are as follows (in thousands):

	Term Loan	2032 Notes (1)	MARAD Debt	Nordea Q5000 Loan	Total
Less than one year	$30,000	$—	$6,072	$35,714	$71,786
One to two years	30,000	—	6,375	35,715	72,090
Two to three years	180,000	—	6,693	35,714	222,407
Three to four years	—	—	7,027	107,142	114,169
Four to five years	—	—	7,378	—	7,378
Over five years	—	192,750	52,676	—	245,426
Total debt	240,000	192,750	86,221	214,285	733,256
Current maturities	(30,000)	—	(6,072)	(35,714)	(71,786)
Long-term debt, less current maturities	210,000	192,750	80,149	178,571	661,470
Unamortized debt discount (2)	—	(11,400)	—	—	(11,400)
Unamortized debt issuance costs (3)	(1,855)	(1,036)	(5,245)	(2,949)	(11,085)
Long-term debt	$208,145	$180,314	$74,904	$175,622	$638,985

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

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

(3) Debt issuance costs are amortized over the life of the applicable debt agreement.

Below is a summary of certain components of our indebtedness:

Credit Agreement

In June 2013, we entered into a credit agreement (the "Credit Agreement") with a group of lenders pursuant to which we borrowed $300 million under a term loan (the "Term Loan") and, subject to the terms of the Credit Agreement, may borrow additional amounts (the "Revolving Loans") and/or obtain letters of credit under a revolving credit facility (the "Revolving Credit Facility") up to $600 million (reduced to $400 million by the February 2016 amendment to the Credit Agreement, as described below). Pursuant to our Credit Agreement, subject to existing lender participation and/or the participation of new lenders, and subject to standard conditions precedent, we may obtain an increase of up to $200 million in aggregate commitments with respect to the Revolving Credit Facility, additional term loans or a combination thereof. At June 30, 2016, we had no borrowings under the Revolving Credit Facility and our available borrowing capacity under that facility, based on the leverage ratio covenant, totaled $50.8 million, net of $6.0 million of letters of credit issued.

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

Table of Contents

The Loans or portions thereof bearing interest at the base rate currently bear interest at a per annum rate equal to the base rate plus a margin ranging from 1.00% to 3.00%. The Loans or portions thereof bearing interest at a LIBOR rate currently bear interest at the LIBOR rate selected by us plus a margin ranging from 2.00% to 4.00%. A letter of credit fee is payable by us equal to our applicable margin for LIBOR rate Loans multiplied by the daily amount available to be drawn under outstanding letters of credit. Margins on the Loans vary in relation to the consolidated coverage ratio, as provided by the Credit Agreement. We currently also pay a fixed commitment fee of 0.50% on the unused portion of our Revolving Credit Facility. The Term Loan currently bears interest at the one-month LIBOR rate plus 4.00%. In September 2013, we entered into various interest rate swap contracts to fix the one-month LIBOR rate on a portion of our borrowings under the Term Loan (Note 14). The total notional amount of the swaps (initially $148.1 million) decreases in proportion to the reduction in the principal amount outstanding under our Term Loan. The fixed LIBOR rates are between 74 and 75 basis points.

The Term Loan is repayable in scheduled principal installments (currently 10% or $30 million per year), payable quarterly, with a balloon payment of $180 million at maturity. These installment amounts are subject to adjustment for any prepayments on the Term Loan. We may elect to prepay amounts outstanding under the Term Loan without premium or penalty, but may not reborrow any amounts prepaid. We may prepay amounts outstanding under the Revolving Loans without premium or penalty, and may reborrow any amounts paid up to the amount of the Revolving Credit Facility. The Loans mature on June 19, 2018. In certain circumstances, we will be required to prepay the Loans.

The Credit Agreement and the other documents entered into in connection with the Credit Agreement (together, the "Loan Documents") include terms and conditions, including covenants, that we consider customary for this type of transaction. The covenants include restrictions on our and our subsidiaries' ability to grant liens, incur indebtedness, make investments, merge or consolidate, sell or transfer assets, pay dividends and incur capital expenditures. In addition, the Credit Agreement obligates us to meet certain financial ratios, including the Consolidated Interest Coverage Ratio and the Consolidated Leverage Ratio (as defined in the Credit Agreement).

In January 2016, we amended the Credit Agreement to permit the sale and lease back of certain office and warehouse property located in Aberdeen, Scotland. In February 2016, we amended the Credit Agreement to decrease the lenders' commitment under the Revolving Credit Facility from $600 million to $400 million. As a result, we recorded a $2.5 million interest charge to accelerate the amortization of debt issuance costs in proportion to the reduced commitment.

Also pursuant to the February 2016 amendment to the Credit Agreement:

(a) The minimum permitted Consolidated Interest Coverage Ratio was revised as follows:

Four Fiscal Quarters Ending	Minimum Consolidated Interest Coverage Ratio	
March 31, 2016 through and including September 30, 2016	2.50	to 1.00
December 31, 2016 through and including March 31, 2017	2.75	to 1.00
June 30, 2017 and each fiscal quarter thereafter	3.00	to 1.00

(b) The maximum permitted Consolidated Leverage Ratio was revised as follows:

Four Fiscal Quarters Ending	Maximum Consolidated

	Leverage Ratio
March 31, 2016	5.50 to 1.00
June 30, 2016	5.25 to 1.00
September 30, 2016 through and including December 31, 2016	5.00 to 1.00
March 31, 2017	4.75 to 1.00
June 30, 2017	4.25 to 1.00
September 30, 2017	3.75 to 1.00
December 31, 2017 and each fiscal quarter thereafter	3.50 to 1.00

Table of Contents

(c) A new financial covenant was established requiring us to maintain a minimum cash balance if our Consolidated Leverage Ratio is 3.50x or greater, as described below. This minimum cash balance is not required to be maintained in any particular bank account or to be segregated from other cash balances in bank accounts that we use in our ordinary course of business. Because the use of this cash is not legally restricted notwithstanding this maintenance covenant, we present it as cash and cash equivalents on our balance sheet. As of June 30, 2016, we needed to maintain an aggregate cash balance of at least $150 million in order to comply with this covenant.

Consolidated Leverage Ratio	Minimum Cash
Greater than or equal to 4.50x	$150,000,000.00
Greater than or equal to 4.00x but less than 4.50x	$100,000,000.00
Greater than or equal to 3.50x but less than 4.00x	$50,000,000.00
Less than 3.50x	$0.00

We have designated five of our foreign subsidiaries, and may designate any newly established foreign subsidiaries, as subsidiaries that are not generally subject to the Credit Agreement's covenants (the "Unrestricted Subsidiaries"), provided we meet certain liquidity requirements, in which case EBITDA (net of cash distributions to the parent) of the Unrestricted Subsidiaries is not included in the calculations with respect to our financial covenants. Our obligations under the Credit Agreement are guaranteed by our wholly owned domestic subsidiaries (except Cal Dive I – Title XI, Inc.) and Canyon Offshore Limited, a wholly owned Scottish subsidiary. Our obligations under the Credit Agreement, and of the guarantors under their guaranty, are secured by most of our assets of the parent and our wholly owned domestic subsidiaries (except Cal Dive I – Title XI, Inc.) and Canyon Offshore Limited, plus pledges of up to two-thirds of the shares of certain foreign subsidiaries.

Convertible Senior Notes Due 2032

In March 2012, we completed a public offering and sale of Convertible Senior Notes in the aggregate principal amount of $200 million due 2032 (the "2032 Notes"). The 2032 Notes bear interest at a rate of 3.25% per annum, and are payable semi-annually in arrears on March 15 and September 15 of each year, beginning on September 15, 2012. The 2032 Notes mature on March 15, 2032 unless earlier converted, redeemed or repurchased. The 2032 Notes are convertible in certain circumstances and during certain periods at an initial conversion rate of 39.9752 shares of common stock per $1,000 principal amount (which represents an initial conversion price of approximately $25.02 per share of common stock), subject to adjustment in certain circumstances as set forth in the Indenture governing the 2032 Notes. We have the right and the intention to settle any such future conversions in cash.

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

In connection with the issuance of the 2032 Notes, we recorded a discount of $35.4 million as required under existing accounting rules. To arrive at this discount amount, we estimated the fair value of the liability component of the 2032 Notes as of the date of their issuance (March 12, 2012) using an income approach. To determine this estimated fair value, we used borrowing rates of similar market transactions involving comparable liabilities at the time of issuance and an expected life of 6.0 years. In selecting the expected life, we selected the earliest date the holders could require us to repurchase all or a portion of the 2032 Notes (March 15, 2018). The effective interest rate for the 2032 Notes is 6.9% after considering the effect of the accretion of the related debt discount that represented the equity component of the 2032 Notes at their inception. We recorded $22.5 million related to the carrying amount of the equity component of the 2032 Notes. The remaining unamortized amount of the debt discount of the 2032 Notes was $11.4 million at June 30, 2016 and $15.0 million at December 31, 2015.

In June 2016, we repurchased $7.3 million in aggregate principal amount of the 2032 Notes for $6.5 million. The purchase price reflects the market price of the notes at the time of purchase. We recognized a total gain of $0.3 million which is presented as “Gain on repurchase of long-term debt” in the accompanying consolidated statements of operations. The gain includes the $0.8 million discount on the 2032 Notes, offset in part by charges totaling $0.5 million for the acceleration of a pro rata portion of unamortized debt discount and debt issuance costs related to the 2032 Notes.

MARAD Debt

This U.S. government guaranteed financing (the “MARAD Debt”) is pursuant to Title XI of the Merchant Marine Act of 1936 administered by the Maritime Administration, and was used to finance the construction of the Q4000. The MARAD Debt is payable in equal semi-annual installments beginning in August 2002 and matures in February 2027. The MARAD Debt is collateralized by the Q4000, is guaranteed 50% by us, and initially bore interest at a floating rate that approximated AAA Commercial Paper yields plus 20 basis points. As required by the MARAD Debt agreements, in September 2005, we fixed the interest rate on the debt through the issuance of a 4.93% fixed-rate note with the same maturity date.

Nordea Credit Agreement

In September 2014, a wholly owned subsidiary incorporated in Luxembourg, Helix Q5000 Holdings S.à r.l. (“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%, with an undrawn fee of 0.875% prior to funding on April 30, 2015. 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 amounts outstanding under the Nordea Q5000 Loan without premium or penalty, but may not reborrow any amounts prepaid. Installment amounts are subject to adjustment for any prepayments on this debt. In certain circumstances, Q5000 Holdings will be required to prepay the loan. 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 14). 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 between 149 and 152 basis points.

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

Table of Contents

Other

In accordance with our Credit Agreement, the 2032 Notes, the MARAD Debt agreements, and the Nordea Credit Agreement, we are required to comply with certain covenants, including certain financial ratios such as a consolidated interest coverage ratio and a consolidated leverage ratio, as well as the maintenance of minimum net worth, working capital and debt-to-equity requirements. As of June 30, 2016, we were in compliance with these covenants.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Interest expense	$10,435	$9,751	$23,479	$18,160
Interest income	(436)	(457)	(880)	(1,107)
Capitalized interest	(2,519)	(4,059)	(4,435)	(7,748)
Net interest expense	$7,480	$5,235	$18,164	$9,305

Note 7 — Income Taxes

Our estimated annual effective tax rate, adjusted for discrete tax items, is applied to interim periods' pretax earnings. We believe that our recorded deferred tax assets and liabilities are reasonable. However, tax laws and regulations are subject to interpretation and tax litigation is inherently uncertain, and therefore our assessments can involve a series of complex judgments about future events and rely heavily on estimates and assumptions.

The effective tax rates for the three- and six-month periods ended June 30, 2016 were 28.3% and 26.0%, respectively. The effective tax rates for the three- and six-month periods ended June 30, 2015 were (30.4)% and 5.7%, respectively. The variance was primarily attributable to the earnings mix between our higher and lower tax rate jurisdictions.

Income taxes are provided based on the U.S. statutory rate of 35% and at the local statutory rate for each foreign jurisdiction adjusted for items that are allowed as deductions for federal and foreign income tax reporting purposes, but not for book purposes. The primary differences between the U.S. statutory rate and our effective rate are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
U.S. statutory rate	35.0 %	35.0 %	35.0 %	35.0 %
Foreign provision	(8.3)	(54.6)	(9.3)	(31.5)
Other	1.6	(10.8)	0.3	2.2
Effective rate	28.3 %	(30.4)%	26.0 %	5.7 %

Note 8 — Shareholders' Equity

On April 25, 2016, we launched an at-the-market ("ATM") offering program and executed an Equity Distribution Agreement with Wells Fargo Securities, LLC ("Wells Fargo") to sell up to $50 million of our common stock through Wells Fargo. As of June 30, 2016, we sold a total of 5,081,339 shares of our common stock under the ATM program for $40.5 million, or an average of $7.98 per share, and received proceeds of $38.8 million, net of transaction costs, including commissions of $1.0 million that were paid to Wells Fargo.

16

Table of Contents

The components of Accumulated Other Comprehensive Income (Loss) ("OCI") are as follows (in thousands):

	June 30, 2016	December 31, 2015
Cumulative foreign currency translation adjustment	$(63,937)	$ (43,010)
Unrealized loss on hedges, net [1]	(22,918)	(27,891)
Accumulated other comprehensive loss	$(86,855)	$ (70,901)

(1) Amounts relate to foreign currency hedges for the Grand Canyon, Grand Canyon II and Grand Canyon III charters as well as interest rate swap contracts for the Term Loan and the Nordea Q5000 Loan, and are net of deferred income taxes totaling $12.5 million at June 30, 2016 and $15.1 million at December 31, 2015 (Note 14).

Note 9 — Earnings Per Share

We have shares of restricted stock issued and outstanding that currently are unvested. Holders of such shares of unvested restricted stock are entitled to the same liquidation and dividend rights as the holders of our outstanding unrestricted common stock and the shares 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 the common shareholders and holders of any participating securities as if earnings for the respective periods had been distributed. Because both the liquidation and dividend rights are identical, the undistributed earnings are allocated on a proportionate basis. Further, we are required to compute earnings per share ("EPS") amounts under the two class method in periods in which we have earnings from continuing operations.

The presentation of basic EPS amounts on the face of the accompanying condensed consolidated statements of operations is computed by dividing the net income applicable to our common shareholders by the weighted average shares of our outstanding common stock. The calculation of diluted EPS is similar to basic EPS, except that the denominator includes dilutive common stock equivalents and the income included in the numerator excludes the effects of the impact of dilutive common stock equivalents, if any. The computations of the numerator (income) and denominator (shares) to derive the basic and diluted EPS amounts presented on the face of the accompanying condensed consolidated statements of operations are as follows (in thousands):

	Three Months Ended June 30, 2016		Three Months Ended June 30, 2015	
	Income	Shares	Income	Shares
Basic:				
Net loss	$(10,671)		$(2,635)	
Less: Undistributed earnings allocated to participating securities	—		—	
Undistributed loss allocated to common shares	$(10,671)	107,767	$(2,635)	105,357
Diluted:				
Undistributed loss allocated to common shares	$(10,671)	107,767	$(2,635)	105,357
Effect of dilutive securities:				
Share-based awards other than participating securities	—	—	—	—
Undistributed earnings reallocated to participating securities	—	—	—	—
Net loss	$(10,671)	107,767	$(2,635)	105,357

Table of Contents

	Six Months Ended June 30, 2016		Six Months Ended June 30, 2015	
	Income	Shares	Income	Shares
Basic:				
Net income (loss)	$(38,494)		$17,007	
Less undistributed earnings allocated to participating securities	—		(96)	
Undistributed earnings (loss) allocated to common shares	$(38,494)	106,838	$16,911	105,324
Diluted:				
Undistributed earnings (loss) allocated to common shares	$(38,494)	106,838	$16,911	105,324
Effect of dilutive securities:				
Share-based awards other than participating securities	—	—	—	—
Undistributed earnings reallocated to participating securities	—	—	—	—
Net income (loss)	$(38,494)	106,838	$16,911	105,324

We had a net loss for the three- and six-month periods ended June 30, 2016. Accordingly, our diluted EPS calculation for the three- and six-month periods ended June 30, 2016 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 per share calculation assuming we had earnings are as follows (in thousands):

	Three Months Ended	Six Months Ended
	June 30, 2016	
Diluted shares (as reported)	107,767	106,838
Share-based awards	377	187
Total	108,144	107,025

In addition, the following potentially dilutive shares related to the 2032 Notes were excluded from the diluted EPS calculation because we have the right and the intention to settle any such future conversions in cash (Note 6) (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
2032 Notes	7,959	7,995	7,977	7,995

Table of Contents

Note 10 — Employee Benefit Plans

Long-Term Incentive Stock-Based Plan

As of June 30, 2016, there were 3.8 million shares of our common stock available for issuance under our active long-term incentive stock-based plan, the 2005 Long-Term Incentive Plan, as amended and restated (the "2005 Incentive Plan"). During the six-month period ended June 30, 2016, the following grants of share-based awards were made under the 2005 Incentive Plan:

Date of Grant	Shares	Grant Date Fair Value Per Share	Vesting Period
January 4, 2016 (1)	1,143,062	$ 5.26	33% per year over three years
January 4, 2016 (2)	1,143,062	$ 7.13	100% on January 3, 2019
January 4, 2016 (3)	11,763	$ 5.26	100% on January 1, 2018
February 1, 2016 (1)	18,610	$ 4.03	33% per year over three years
February 1, 2016 (2)	18,610	$ 7.13	100% on January 31, 2019
April 1, 2016 (3)	13,727	$ 5.60	100% on January 1, 2018

(1) Reflects the grant of restricted stock to our executive officers and select management employees.

(2) Reflects the grant of performance share units ("PSUs") to our executive officers and select management employees. The PSUs provide for an award based on the performance of our common stock over a three-year period with the maximum amount of the award being 200% of the original awarded PSUs and the minimum amount being zero. The vested PSUs may be settled in either cash or shares of our common stock at the discretion of the Compensation Committee of our Board of Directors (the "Board").

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

Compensation cost for restricted stock is the product of grant date fair value of each share and the number of shares granted and is recognized over the applicable vesting period on a straight-line basis. For the three- and six-month periods ended June 30, 2016, $1.4 million and $2.9 million, respectively, were recognized as share-based compensation related to restricted stock. For the three- and six-month periods ended June 30, 2015, $1.5 million and $2.9 million, respectively, were recognized as share-based compensation related to restricted stock.

The estimated fair value of the 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 based on the 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 cash payout amount upon vesting. In January 2015, in connection with the vesting of the 2012 PSU awards, a decision was made by the Compensation Committee of our Board to settle these PSUs in cash (rather than with an equivalent number of shares of our common stock, which was the default payment method for PSU awards). Accordingly, PSUs, including those that were previously accounted for as equity awards, are treated as liability awards. To the extent the recognized fair value of the modified liability awards is less than the compensation cost associated with the grant date fair value of the original equity awards at the end of a reporting period, the higher amount is recorded as share-based compensation. The amount of cumulative compensation expense recognized in excess of the fair value of the modified liability awards is recorded in equity. For the three- and six-month periods ended June 30, 2016, $1.7 million and $2.8 million, respectively, were recognized as share-based compensation related to PSUs. For the three-month period ended June 30, 2015, $0.2 million was recognized as share-based compensation related to PSUs. For the six-month period ended June 30, 2015, we recorded a net reduction of $0.9 million of previously recognized compensation cost to reflect the estimated fair value of unvested PSUs as of June 30, 2015. The equity balance at June 30, 2016 and December 31, 2015 included $3.1 million and $2.9 million, respectively, reflecting the cumulative compensation expense recognized in excess of the estimated fair value of the modified liability PSU awards at the respective balance sheet dates. The liability balance for unvested PSUs was $3.0 million at June 30, 2016 and $0.7 million at December 31, 2015. We paid $0.2 million in cash to settle the 2013 grant of PSUs when they vested in January 2016.

Table of Contents

Long-Term Incentive Cash Plans

We have certain long-term incentive cash plans (the "LTI Cash Plans") that provide long-term cash-based compensation to eligible employees. Cash awards are indexed to our common stock with the payment amount at each vesting date, if any, determined by the performance of our common stock. Payment amounts under these awards are calculated based on the ratio of the average stock price during the applicable measurement period over the original base price determined by the Compensation Committee of our Board at the time of the award. Cash awards have a vesting period of three years and payments under these awards are made each year during the vesting period on the anniversary date of the award. The LTI Cash Plans are considered liability plans and as such are re-measured to fair value each reporting period with corresponding changes in the liability amount being reflected in our results of operations.

No long-term incentive cash awards were granted in 2015 or 2016. Compensation expense for the three- and six-month periods ended June 30, 2016 was immaterial. For the three- and six-month periods ended June 30, 2015, we recorded reductions of $0.6 million and $2.5 million, respectively, of previously recognized compensation expense associated with the cash awards issued pursuant to the LTI Cash Plans, reflecting the effect that decreases in our stock price had on the value of our liability plan. The liability balance for the cash awards issued under the LTI Cash Plans was less than $0.1 million at June 30, 2016 and December 31, 2015.

Employee Stock Purchase Plan

We also have an employee stock purchase plan (the "ESPP"). The ESPP has 1.5 million shares authorized for issuance, of which 0.7 million shares were available for issuance as of June 30, 2016. In February 2016, we suspended ESPP purchases for the January through April 2016 purchase period and a purchase limit of 130 shares per employee was imposed for subsequent purchase periods. Share-based compensation with respect to the ESPP was less than $0.1 million for the three- and six-month periods ended June 30, 2016 and $0.3 million and $0.6 million for the three- and six-month periods ended June 30, 2015.

For more information regarding our employee benefit plans, including our long-term incentive stock-based and cash plans and our employee stock purchase plan, see Note 12 to our 2015 Form 10-K.

Note 11 — 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 and North Sea regions. Our well intervention vessels include the Q4000, the Q5000, the Helix 534, the Seawell, the Well Enhancer and the Skandi Constructor, which is a chartered vessel. Our well intervention segment also includes IRSs, some of which we rent out on a stand-alone basis, and SILs. Our Robotics segment includes ROVs, trenchers and ROVDrills designed to complement offshore construction and well intervention services, and currently operates three chartered ROV support vessels. Our Production Facilities segment includes the HP I, the HFRS and our investment in Independence Hub that is accounted for under the equity method, and included our former ownership interest in Deepwater Gateway that we sold in February 2016 (Note 5). All material intercompany transactions between the segments have been eliminated.

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

Table of Contents

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Net revenues —				
Well Intervention	$59,919	$85,675	$105,975	$189,726
Robotics	38,914	75,101	70,908	155,272
Production Facilities	18,957	20,293	37,439	38,678
Intercompany elimination	(10,523)	(15,053)	(16,016)	(28,019)
Total	$107,267	$166,016	$198,306	$355,657
Income (loss) from operations —				
Well Intervention	$(538)	$4,135	$(17,226)	$18,929
Robotics	(8,823)	4,303	(21,573)	13,760
Production Facilities	9,730	8,444	16,913	13,022
Corporate and other	(9,827)	(9,009)	(18,496)	(15,616)
Intercompany elimination	163	(199)	331	(93)
Total	$(9,295)	$7,674	$(40,051)	$30,002

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):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Well Intervention	$2,201	$6,417	$2,842	$11,363
Robotics	8,322	8,636	13,174	16,656
Total	$10,523	$15,053	$16,016	$28,019

The following table reflects total assets by reportable segment (in thousands):

	June 30, 2016	December 31, 2015
Well Intervention	$1,475,066	$ 1,484,109
Robotics	240,393	274,926
Production Facilities	158,999	182,007
Corporate and other	439,910	458,917
Total	$2,314,368	$ 2,399,959

Table of Contents

Note 12 — Commitments and Contingencies and Other Matters

Commitments

We have charter agreements for the Grand Canyon, Grand Canyon II and Grand Canyon III vessels for use in our robotics operations. Pursuant to the charter amendments in February 2016, in connection with charter rate reductions for the vessels, the term of the vessel charters was revised such that the Grand Canyon charter expires in October 2019, the Grand Canyon II charter expires in April 2021 and the Grand Canyon III charter expires in May 2023. We also have a charter agreement for the Deep Cygnus which expires in March 2018.

In September 2013, we executed a contract with the same shipyard in Singapore that constructed the Q5000. This contract is for the construction of a newbuild semi-submersible well intervention vessel, the Q7000, which is being built to North Sea standards. This $346.0 million shipyard contract represents the majority of the expected costs associated with the construction of the Q7000. Pursuant to the original terms of this contract, 20% of the contract price was paid upon the signing of the contract. Pursuant to the first contract amendment we entered into in June 2015, we agreed to pay the shipyard incremental costs of up to $14.5 million to extend the scheduled delivery of the Q7000 from mid-2016 to July 30, 2017 and to defer certain payment obligations. We paid $7.3 million of these costs in July 2015 and the remaining costs were to be paid upon the delivery of the vessel. Pursuant to the second contract amendment we entered into in December 2015, the remaining 80% will be paid in three installments, with 20% in June 2016 (which will be paid in the second half of 2016), 20% upon issuance of the Completion Certificate, which is to be issued on or before December 31, 2017, and 40% upon the delivery of the vessel, which at our option can be deferred until December 30, 2018. Also pursuant to this second amendment, we agreed to reimburse the shipyard for incremental costs in connection with the further deferment of the Q7000's delivery. Incremental costs are capitalized as they are incurred during the construction of the vessel. At June 30, 2016, our total investment in the Q7000 was $117.4 million, including the $69.2 million paid to the shipyard upon signing the contract.

In February 2014, we entered into agreements with Petróleo Brasileiro S.A. ("Petrobras") to provide well intervention services offshore Brazil, and in connection with the Petrobras agreements, we entered into charter agreements with Siem Offshore AS for two newbuild monohull vessels, the Siem Helix 1 and the Siem Helix 2. The initial term of the agreements with Petrobras is for four years with options to extend. As part of Petrobras's efforts to reduce its costs structure with many of its suppliers, we had been in discussions with Petrobras since mid-2015 with respect to potentially amending our contracts in a manner that addressed Petrobras's objectives and was acceptable to us as well. Those negotiations were finalized in early June 2016 such that the contracts for the Siem Helix 1, originally scheduled to begin no later than July 22, 2016, were amended to commence between July 22, 2016 and October 21, 2016, with the day rate reduced to a mutually acceptable level, and the contracts for the Siem Helix 2, originally scheduled to begin no later than January 21, 2017, were amended to commence between October 1, 2017 and December 31, 2017, with no change in the day rate.

In early April 2016, a small localized fire occurred on the Siem Helix 1 while it was being constructed for the vessel owner at the shipyard. In our estimation, the repairs to the damage caused by this fire will result in approximately a one-month delay in the vessel being in Brazil, but does not alter our estimate that the Siem Helix 1 will be in service for Petrobras in the fourth quarter of 2016. The Siem Helix 1 vessel was delivered to us and the charter term began on June 14, 2016. We are currently integrating and commissioning our topside equipment onboard the vessel. The Siem Helix 2 is under construction for the owner at the same shipyard that built the Siem Helix 1, and we anticipate that the vessel will be available for work in the second quarter of 2017 prior to commencing services for Petrobras in the fourth quarter of 2017. At June 30, 2016, our total investment in the topside equipment for the two vessels was $157.6 million. In November 2014, we paid a charter fee deposit of $12.5 million, which will be used to reduce our final charter payments for the Siem Helix 2.

Contingencies and Claims

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

Table of Contents

Litigation

On July 31, 2015, a purported stockholder, Parviz Izadjoo, filed a class action lawsuit styled Parviz Izadjoo v. Owen Kratz and Helix Energy Solutions Group, Inc. against the Company and Mr. Kratz, our President and Chief Executive Officer, in the United States District Court for the Southern District of Texas on behalf of a putative class of all purchasers of shares of our common stock between October 21, 2014, and July 21, 2015, inclusive (the "Class Period"). The lawsuit asserts violations of Section 10(b) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and SEC Rule 10b-5 as to both us and Mr. Kratz, and Section 20(a) of the Exchange Act against Mr. Kratz, based on alleged misrepresentations and omissions in SEC filings and other public disclosures regarding projections for 2015 dry docks of two of our vessels working in the Gulf of Mexico that allegedly caused the price at which putative class members bought stock during the proposed class period to be artificially inflated. On January 28, 2016, the judge in the case approved a motion for the appointment of lead plaintiff and lead counsel. On March 14, 2016, the plaintiffs filed an amended class action complaint, adding Mr. Tripodo (our Executive Vice President and Chief Financial Officer) and Mr. Chamblee (our former Executive Vice President and Chief Operating Officer) as individual defendants, alleging the same types of claims made in the original complaint (alleged violations during the Class Period of Section 10(b) of the Exchange Act and SEC Rule 10b-5 with respect to all defendants, and Section 20(a) of the Exchange Act against the individual defendants), but asserting that the alleged misrepresentations and omissions in SEC filings and other public disclosures are related to the condition of and repairs to certain equipment aboard the Q4000 vessel. The defendants filed a motion to dismiss on April 28, 2016 and the parties have completed briefing on that motion. We believe this lawsuit to be without merit and intend to vigorously defend against it.

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 disputes, in the normal course of business.

Note 13 — Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value accounting rules establish a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value as follows:

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

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

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

Our financial instruments include cash and cash equivalents, accounts receivable, accounts payable, long-term debt and various derivative instruments. The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to the short-term nature of these instruments. The following tables provide additional information relating to other financial instruments measured at fair value on a recurring basis (in thousands):

23

Table of Contents

	Fair Value Measurements at June 30, 2016 Using				
	Level 1	Level 2 (1)	Level 3	Total	Valuation Technique
Liabilities:					
Foreign exchange contracts	$ —	$ 45,286	$ —	$ 45,286	(c)
Interest rate swaps	—	3,528	—	3,528	(c)
Total liability	$ —	$ 48,814	$ —	$ 48,814	

	Fair Value Measurements at December 31, 2015 Using				
	Level 1	Level 2 (1)	Level 3	Total	Valuation Technique
Assets:					
Interest rate swaps	$ —	$ 413	$ —	$ 413	(c)
Liabilities:					
Foreign exchange contracts	—	61,427	—	61,427	(c)
Interest rate swaps	—	1,473	—	1,473	(c)
Total net liability	$ —	$ 62,487	$ —	$ 62,487	

(1) Unless otherwise indicated, the fair value of our Level 2 derivative instruments reflects our best estimate and is based upon exchange or over-the-counter quotations whenever they are available. Quoted valuations may not be available due to location differences or terms that extend beyond the period for which quotations are available. Where quotes are not available, we utilize other valuation techniques or models to estimate market values. These modeling techniques require us to make estimations of future prices, price correlation and market volatility and liquidity based on market data. Our actual results may differ from our estimates, and these differences could be positive or negative. See Note 14 for further discussions on the fair value of our derivative instruments.

The carrying values and estimated fair values of our long-term debt are as follows (in thousands):

	June 30, 2016		December 31, 2015	
	Carrying Value (1)	Fair Value (2)	Carrying Value (1)	Fair Value (2)
Term Loan (matures June 2018)	$ 240,000	$ 237,300	$ 255,000	$ 248,467
Nordea Q5000 Loan (matures April 2020)	214,285	207,724	232,143	221,553
MARAD Debt (matures February 2027)	86,221	98,233	89,148	104,897
2032 Notes (mature March 2032)	192,750	169,620	200,000	150,250
Total debt	$ 733,256	$ 712,877	$ 776,291	$ 725,167

(1) Carrying value 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 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. The fair value of the Term Loan, the Nordea Q5000 Loan and the MARAD Debt was determined using a third party evaluation of the remaining average life and outstanding principal balance of the indebtedness as compared to other obligations in the marketplace with similar terms.

24

Table of Contents

Note 14 — 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 derivatives are reflected in the accompanying condensed consolidated balance sheets at fair value.

We engage solely in cash flow hedges. Hedges of cash flow exposure are entered into to hedge a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability. Changes in the fair value of derivatives that are designated as cash flow hedges are deferred to the extent that the hedges are effective. These fair value changes are recorded as a component of Accumulated OCI (a component of shareholders' equity) until the hedged transactions occur and are recognized in earnings. The ineffective portion of changes in the fair value of cash flow hedges is recognized immediately in earnings. In addition, any change in the fair value of a derivative that does not qualify for hedge accounting is recorded in earnings in the period in which the change occurs.

For additional information regarding our accounting for derivatives, see Notes 2 and 18 to our 2015 Form 10-K.

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. In September 2013, we entered into various interest rate swap contracts to fix the interest rate on $148.1 million of our Term Loan borrowings (Note 6). These contracts, which are settled monthly, began in October 2013 and extend through October 2016. Additionally, in June 2015 we entered into various 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. Changes in the fair value of interest rate swaps are deferred to the extent the swaps are effective. These changes are recorded as a component of Accumulated OCI until the anticipated interest is recognized as interest expense. The ineffective portion of the interest rate swaps, if any, is recognized immediately in earnings within the line titled "Net interest expense." The amount of ineffectiveness associated with our interest rate swap contracts was immaterial for all periods presented.

Foreign Currency Exchange Rate Risk

Because we operate in various regions 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.

In January 2013, we entered into foreign currency exchange contracts to hedge through September 2017 the foreign currency exposure associated with the Grand Canyon charter payments ($104.6 million) denominated in Norwegian kroner (NOK591.3 million). In February 2013, we entered into similar foreign currency exchange contracts to hedge our foreign currency exposure with respect to the Grand Canyon II and Grand Canyon III charter payments ($100.4 million and $98.8 million, respectively) denominated in Norwegian kroner (NOK594.7 million and NOK595.0 million, respectively), through July 2019 and February 2020, respectively.

Table of Contents

During discussions with the owner of the Grand Canyon, Grand Canyon II and Grand Canyon III vessels with respect to amending the charter agreements, it became apparent in December 2015 that a portion of previously forecasted charter payments in NOK would no longer be made. We concluded that the foreign currency exchange contracts associated with the charter payments for the Grand Canyon still qualified for cash flow hedge accounting treatment. However, the foreign currency exchange contracts associated with the charter payments for the Grand Canyon II and the Grand Canyon III vessels no longer qualified as cash flow hedges. As a result, we de-designated these hedges and re-designated the hedging relationship between a portion of our foreign currency exchange contracts and our forecasted Grand Canyon II and Grand Canyon III charter payments of NOK434.1 million and NOK185.2 million, respectively, that were expected to remain highly probable of occurring. Unrealized losses associated with the effective portion of the re-designated foreign currency exchange contracts that qualify for hedge accounting treatment are included in our Accumulated OCI (net of tax). Changes in unrealized losses associated with the ineffective portion of the re-designated foreign currency exchange contracts are reflected in “Other income (expense), net” in the accompanying condensed consolidated statement of operations. “Other income (expense), net” also includes changes in unrealized losses associated with the foreign currency exchange contracts that are no longer designated as cash flow hedges.

Quantitative Disclosures Relating to Derivative Instruments

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

	June 30, 2016		December 31, 2015	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Asset Derivatives:				
Interest rate swaps	Other assets, net	$—	Other assets, net	$413
		$—		$413
Liability Derivatives:				
Foreign exchange contracts	Accrued liabilities	$14,337	Accrued liabilities	$14,955
Interest rate swaps	Accrued liabilities	1,629	Accrued liabilities	1,473
Foreign exchange contracts	Other non-current liabilities	18,254	Other non-current liabilities	28,458
Interest rate swaps	Other non-current liabilities	1,899	Other non-current liabilities	—
		$36,119		$44,886

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

	June 30, 2016		December 31, 2015	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Liability Derivatives:				
Foreign exchange contracts	Accrued liabilities	$4,572	Accrued liabilities	$6,763
Foreign exchange contracts	Other non-current liabilities	8,123	Other non-current liabilities	11,251
		$12,695		$18,014

Table of Contents

For the three- and six-month periods ended June 30, 2016, we recorded unrealized gains of $0.5 million and $0.1 million, respectively, related to the Grand Canyon and Grand Canyon III hedge ineffectiveness. For the three- and six-month periods ended June 30, 2015, we recorded unrealized gains of $0.2 million and unrealized losses of $3.2 million, respectively, related to the Grand Canyon III hedge ineffectiveness. We also recorded realized losses of $0.2 million related to the Grand Canyon II hedge ineffectiveness during the first quarter of 2015. The following tables present the impact that derivative instruments designated as hedging instruments had on our Accumulated OCI (net of tax) and our condensed consolidated statements of operations (in thousands). We estimate that as of June 30, 2016, $9.8 million of losses in Accumulated OCI associated with our derivatives is expected to be reclassified into earnings within the next 12 months.

	Gain (Loss) Recognized in OCI on Derivatives, Net of Tax (Effective Portion)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Foreign exchange contracts	$674	$5,002	$6,496	$(1,359)
Interest rate swaps	(200)	(709)	(1,523)	(873)
	$474	$4,293	$4,973	$(2,232)

	Location of Loss Reclassified from Accumulated OCI into Earnings	Loss Reclassified from Accumulated OCI into Earnings (Effective Portion)			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2016	2015	2016	2015
Foreign exchange contracts	Cost of sales	$(2,507)	$(2,921)	$(5,370)	$(4,395)
Interest rate swaps	Net interest expense	(547)	(337)	(1,124)	(536)
		$(3,054)	$(3,258)	$(6,494)	$(4,931)

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

	Location of Gain (Loss) Recognized in Earnings on Derivatives	Gain (Loss) Recognized in Earnings on Derivatives			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2016	2015	2016	2015
Foreign exchange contracts	Other income (expense), net	$(465)	$ —	$2,066	$ —
		$(465)	$ —	$2,066	$ —

27

Table of Contents

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations
FORWARD-LOOKING STATEMENTS AND ASSUMPTIONS

This Quarterly Report on Form 10-Q 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 Exchange Act. All statements included herein or incorporated herein by reference that are predictive in nature, that depend upon or refer to future events or conditions, or that use terms and phrases such as "achieve," "anticipate," "believe," "estimate," "expect," "forecast," "plan," "project," "propose," "strategy," "predict," "intend," "will," "continue," "may," "potential," "should," "could" and similar terms and phrases are forward-looking statemen
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 the construction, upgrades or acquisition of vessels or equipment and any anticipated costs related thereto, including the construction of our Q7000 vessel, and the commissioning of our topside equipment onboard the Siem Helix 1 chartered vessel and the construction of the Siem Helix 2 to be used in connection with our contracts to provide well intervention services offshore Brazil (Note 12);
- statements regarding projections of revenues, gross margin, expenses, earnings or losses, working capital, debt and liquidity, or other financial items;
- statements regarding our backlog and long-term contracts;
- statements regarding any financing transactions or arrangements, or ability to enter into such transactions;
- statements regarding anticipated legislative, governmental, regulatory, administrative or other public body actions, requirements, permits or decisions;
- statements regarding 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 market areas in which we do business;
- statements regarding our ability to retain key members of our senior management and 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 and the demand for our services;
- 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;
- unexpected delays in the delivery or chartering or acceptance testing of new vessels for our well intervention and robotics fleet, including the Q7000, the Grand Canyon III, and the Siem Helix 1 and the Siem Helix 2 to be used to perform contracted well intervention work offshore Brazil;
- unexpected future capital expenditures, including the amount and nature thereof;
- the effectiveness and timing of completion of our vessel upgrades and major maintenance items;
- the 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 (or lack thereof) 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;
- the effect of adverse weather conditions and/or other risks associated with marine operations;
- the effectiveness of our current and future hedging activities;

Table of Contents

- 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 described in Item 1A. "Risk Factors" in our 2015 Form 10-K. 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.

Executive Summary

Business 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 make strategic investments that expand our service capabilities or add capacity to existing services in our key operating regions. Our well intervention fleet has expanded following the delivery of the Siem Helix 1 chartered vessel in June 2016 and is expected to further expand following the completion and delivery of the Q7000, a newbuild semi-submersible vessel, in late 2017 or in 2018, and the delivery of the Siem Helix 2 chartered vessel in late 2016. With respect to our robotics business, the Grand Canyon III chartered vessel was delivered by the shipyard to the vessel owner in May 2016. The vessel is currently stacked by the owner and is expected to be in service for us in May 2017. The Rem Installer charter expired in July 2016.

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 is expected to leverage the parties' capabilities to provide a unique, fully integrated offering to clients, combining marine support with well access and control technologies. In April 2015, we and OneSubsea jointly ordered a 15,000 working p.s.i. IRS, which is expected to be completed by July 2017 for a total cost of approximately $27.5 million (approximately $13.8 million for our 50% interest). At June 30, 2016, our total investment in the IRS was $4.3 million.

Economic Outlook and Industry Influences

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

- worldwide economic activity, 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;
- regional conflicts and economic and political conditions in the Middle East and other oil-producing regions;
- actions taken by the Organization of Petroleum Exporting Countries ("OPEC");
- the availability and discovery rate of new oil and natural gas reserves in offshore areas;
- the exploration and production of shale oil and natural gas;
- the cost of offshore exploration for and production and transportation of oil and natural gas;
- the level of excess production capacity;

- the ability of oil and gas companies to generate funds or otherwise obtain external capital for exploration, development and production operations;
- the sale and expiration dates of offshore leases in the United States and overseas;
- technological advances affecting energy exploration, production, transportation and consumption;
- 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.

Table of Contents

The significant decline in oil prices since mid-year 2014 as a result of continued global supply of oil in excess of demand has had a significant adverse impact on investments in oil and gas exploration and production. Many oil and gas companies have terminated or not renewed contracts for more than half of their contracted rigs and have drastically cut investments in exploration and production as well as other operational activities. We expect these challenging industry conditions to continue through 2016 and beyond if oil and gas prices fail to increase to a level conducive to increased activity levels. Increased competition for limited offshore oil and gas projects has driven down rates that drilling rig contractors are charging for their services, which affects all offshore oil and gas services contractors, including us. Increased competition is also expected to affect utilization of our assets, and increasingly for 2016, our robotics assets. In addition, the current volatile and uncertain macroeconomic conditions in some countries around the world, such as Brazil and more recently the U.K. following its vote to exit the European Union, 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.

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 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 over the longer term, we believe that fundamentals for our business remain favorable 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 coping with 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; and (3) in past cycles, well intervention and workover have been one of the first activities to recover, and in a prolonged market downturn are important to the commercial viability of deepwater wells.

Helix Fast Response System

We developed the HFRS as a culmination of our experience as a responder in the 2010 Macondo well control and containment efforts. The HFRS centers on two of our vessels, the HP I and the Q4000, both of which played a key role in the Macondo well control and containment efforts and are currently operating in the Gulf of Mexico. In 2011, we signed an agreement with Clean Gulf Associates (“CGA”), a non-profit industry group, allowing, in exchange for a retainer fee, the HFRS to be named as a response resource in permit applications to federal and state agencies and making the HFRS available to certain CGA participants who executed utilization agreements with us that specified the day rates to be charged should the HFRS be deployed in connection with a well control incident. The original set of agreements expired on March 31, 2013, and we entered into a new set of substantially similar agreements, effective April 1, 2013, with the operators who formed HWCG LLC, a Delaware limited liability company comprised of some of the original CGA members as well as other industry participants, to perform the same functions as CGA with respect to the HFRS. In March 2015, HWCG LLC exercised an option to extend the agreement with us through March 31, 2018.

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 condensed consolidated financial statements, including our consolidated results of operations.

We seek to provide services and methodologies that we believe are critical to developing offshore reservoirs and maximizing production economics. Our services cover the lifecycle of an offshore oil or gas field. We operate primarily in deepwater in the U.S. Gulf of Mexico, North Sea, Asia Pacific and West Africa regions, and are expanding our operations offshore Brazil. In addition to servicing the oil and gas market, our Robotics operations are contracted for the development of renewable energy projects (wind farms). As of June 30, 2016, our consolidated backlog that is supported by written agreements or contracts totaled $1.7 billion, of which $217.7 million is expected to be performed in 2016. The substantial majority of our backlog is associated with our Well Intervention business segment. As of June 30, 2016, our well intervention backlog was $1.6 billion, including $149.2 million expected to be performed in 2016. Our five-year contract with BP to provide well intervention

Table of Contents

services with our Q5000 semi-submersible vessel and our four-year agreements with Petrobras to provide well intervention services offshore Brazil with the Siem Helix 1 and Siem Helix 2 chartered vessels represent approximately 85% of our total backlog. Backlog contracts are cancelable sometimes without penalty. In addition, 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. Accordingly, backlog is not necessarily a reliable indicator of total annual revenues for our services as contracts may be added, renegotiated, deferred, canceled and in many cases modified while in progress.

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

We measure our operating performance based on EBITDA, a non-GAAP financial measure that is commonly used but is not a recognized accounting term under U.S. GAAP. We use EBITDA to monitor and facilitate the internal evaluation of the performance of our business operations, to facilitate external comparison of our business results to those of others in our industry, to analyze and evaluate financial and strategic planning decisions regarding future investments and acquisitions, to plan and evaluate operating budgets, and in certain cases, to report our results to the holders of our debt as required by our debt covenants. We believe that our measure of EBITDA provides useful information to the public regarding our ability to service debt and fund capital expenditures and may help our investors understand our operating performance and compare our results to other companies that have different financing, capital and tax structures.

We define EBITDA as earnings before income taxes, net interest expense, gain on repurchase on long-term debt, net other income or expense, and depreciation and amortization expense. To arrive at our measure of Adjusted EBITDA, when applicable, we include realized losses from the cash settlements of our ineffective foreign currency exchange contracts, which are excluded from EBITDA as a component of net other income or expense. In the following reconciliation, we provide amounts as reflected in our accompanying condensed consolidated financial statements unless otherwise footnoted.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Net income (loss)	$(10,671)	$(2,635)	$(38,494)	$17,007
Adjustments:				
Income tax provision (benefit)	(4,219)	614	(13,507)	1,021
Net interest expense	7,480	5,235	18,164	9,305
Gain on repurchase of long-term debt	(302)	—	(302)	—

Other (income) expense, net	(1,308)	5,036	(3,188)	6,192
Depreciation and amortization	25,674	27,439	57,239	53,528
EBITDA	16,654	35,689	19,912	87,053
Adjustments:				
Realized losses from cash settlements of ineffective foreign currency exchange contracts	(1,722)	—	(3,958)	—
Adjusted EBITDA	$14,932	$35,689	$15,954	$87,053

31

Table of Contents

Comparison of Three Months Ended June 30, 2016 and 2015

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

	Three Months Ended June 30,		Increase/ (Decrease)
	2016	2015	
Net revenues —			
Well Intervention	$59,919	$85,675	$(25,756)
Robotics	38,914	75,101	(36,187)
Production Facilities	18,957	20,293	(1,336)
Intercompany elimination	(10,523)	(15,053)	4,530
	$107,267	$166,016	$(58,749)
Gross profit (loss) —			
Well Intervention	$2,702	$7,254	$(4,552)
Robotics	(6,613)	9,420	(16,033)
Production Facilities	9,823	8,578	1,245
Corporate and other	(417)	(845)	428
Intercompany elimination	163	(199)	362
	$5,658	$24,208	$(18,550)
Gross margin —			
Well Intervention	5%	8%	
Robotics	(17)%	13%	
Production Facilities	52%	42%	
Total company	5%	15%	
Number of vessels or robotics assets (1) / Utilization (2)			
Well Intervention vessels	5/54%	4/63%	
Robotics assets	60/48%	61/61%	
Chartered robotics vessels	4/61%	5/81%	

(1) Represents number of vessels or robotics assets as of the end of the period excluding acquired vessels prior to their in-service dates, vessels taken out of service prior to their disposition and vessels jointly owned with a third party. The Helix 534 was excluded from the numbers for the second quarter of 2016 as it was cold stacked and out of service. The Seawell was excluded from the numbers for the second quarter of 2015 as it was out of service undergoing major capital upgrades.

(2) Represents 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 calendar days in the applicable period.

Table of Contents

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):

	Three Months Ended June 30, 2016	2015	Increase/ (Decrease)
Well Intervention	$2,201	$6,417	$ (4,216)
Robotics	8,322	8,636	(314)
	$10,523	$15,053	$ (4,530)

Net Revenues. Our total net revenues decreased by 35% for the three-month period ended June 30, 2016 as compared to the same period in 2015. In general, decreased revenues for the three-month period in 2016 reflect both reduced opportunities for work and the acceptance of work at reduced rates for some of our assets in light of the continuation of the industry-wide downturn as a result of the substantial decline in oil prices since late 2014.

Our Well Intervention revenues decreased by 30% for the three-month period ended June 30, 2016 as compared to the same period in 2015 primarily reflecting lower revenues in our North Sea region due to lack of work. In the North Sea, the Well Enhancer was 75% utilized during the second quarter of 2016 while the vessel was fully utilized during the same period in 2015. The Skandi Constructor was warm stacked during the second quarter of 2016 as compared to being 68% utilized during the same period in 2015. The Seawell was re-activated and utilized for 21 days in June 2016 as compared to being out of service undergoing major capital upgrades to extend its estimated useful life during the same period in 2015. In the Gulf of Mexico, the Q4000 was essentially fully utilized during the second quarter of 2016 as compared to working 26 days during the same period in 2015 following completion of its regularly scheduled regulatory dry dock in early June 2015. The Q5000, which was delivered to us in April 2015, went on contracted rates under our five-year contract with BP on May 19, 2016. The Helix 534 was cold stacked and out of service during the second quarter of 2016 while the vessel was 55% utilized during the same period in 2015.

Robotics revenues decreased by 48% for the three-month period ended June 30, 2016 as compared to the same period in 2015. The decrease primarily reflects the reduction and lower utilization of our available Robotics assets, including our chartered vessels, and accepting 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. Utilization of our chartered ROV support vessels decreased primarily reflecting reduction in work opportunities as a result of further market deterioration in the offshore energy industry.

Our Production Facilities revenues decreased by 7% for the three-month period ended June 30, 2016 as compared to the same period in 2015, which reflects the decrease in our variable throughput fee primarily as a result of lower pricing, offset in part by slightly higher production volumes in the Phoenix field.

Gross Profit (Loss). Our total gross profit decreased by 77% for the three-month period ended June 30, 2016 as compared to the same period in 2015. The gross profit related to our Well Intervention segment decreased by 63% for the three-month period ended June 30, 2016 as compared to the same period in 2015 primarily reflecting a reduction in gross profit due to lack of available projects in our North Sea region as a result of the ongoing industry downturn.

Table of Contents

The gross profit associated with our Robotics segment decreased from $9.4 million for the three-month period ended June 30, 2015 to a $6.6 million loss for the three-month period ended June 30, 2016 primarily reflecting decreased utilization for our Robotics assets, including our chartered vessels, and accepting work with lower profit margins.

The gross profit related to our Production Facilities segment increased by 15% for the three-month period ended June 30, 2016 as compared to the same period in 2015. The increase primarily reflects lower repair and maintenance costs and a decrease in depreciation expense related to the HP I as a result of the vessel's impairment in December 2015.

Selling, General and Administrative Expenses. Our selling, general and administrative expenses decreased by $1.6 million for the three-month period ended June 30, 2016 as compared to the same period in 2015. The decrease was primarily attributable to overhead cost saving measures including headcount reductions, which were partially offset by an increase in payroll related costs associated with our variable performance-based incentive compensation programs (Note 10). In addition, selling, general and administrative expenses for the three-month period ended June 30, 2015 included charges of $2.5 million associated with the provision for uncertain collection of a portion of our trade receivables.

Net Interest Expense. Our net interest expense increased by $2.2 million for the three-month period ended June 30, 2016 as compared to the same period in 2015 primarily reflecting an increase in interest expense and a decrease in capitalized interest. The increase in interest expense was primarily attributable to increases in interest rates on the Term Loan and the Nordea Q5000 Loan. Interest on debt used to finance capital projects is capitalized and thus reduces overall interest expense. Capitalized interest totaled $2.5 million for the three-month period ended June 30, 2016 as compared to $4.1 million for the same period in 2015.

Gain on Repurchase of Long-Term Debt. The $0.3 million gain for the three-month period ended June 30, 2016 was associated with the repurchase in June 2016 of $7.3 million in aggregate principal amount of our 2032 Notes (Note 6).

Other Income (Expense), Net. We reported other income, net, of $1.3 million for the three-month period ended June 30, 2016 as compared to other expense, net, of $5.0 million for the same period in 2015. These amounts primarily reflect foreign exchange fluctuations in our non-U.S. dollar functional currencies. We recorded foreign currency transaction gains (losses) of $1.2 million and $(5.2) million, respectively, in the comparable year-over-year periods.

Other Income – Oil and Gas. Our other income – oil and gas decreased by $0.5 million for the three-month period ended June 30, 2016 as compared to the same period in 2015. The decrease was primarily attributable to the reduction in the overriding royalty income which is significantly affected by the decline in oil prices and lower volumes.

Income Tax Provision (Benefit). Income taxes reflect a benefit of $4.2 million for the three-month period ended June 30, 2016 as compared to a provision of $0.6 million for the same period in 2015. The variance primarily reflects decreased profitability in the current year period. The effective tax rate was a 28.3% benefit for the three-month period ended June 30, 2016 as compared to a (30.4)% expense for the same period in 2015. The variance was primarily attributable to the earnings mix between our higher and lower tax rate jurisdictions.

Table of Contents

Comparison of Six Months Ended June 30, 2016 and 2015

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

	Six Months Ended June 30, 2016	2015	Increase/ (Decrease)
Net revenues —			
Well Intervention	$105,975	$189,726	$(83,751)
Robotics	70,908	155,272	(84,364)
Production Facilities	37,439	38,678	(1,239)
Intercompany elimination	(16,016)	(28,019)	12,003
	$198,306	$355,657	$(157,351)
Gross profit (loss) —			
Well Intervention	$(10,979)	$25,802	$(36,781)
Robotics	(16,961)	22,110	(39,071)
Production Facilities	17,221	13,347	3,874
Corporate and other	(884)	(2,011)	1,127
Intercompany elimination	331	(93)	424
	$(11,272)	$59,155	$(70,427)
Gross margin —			
Well Intervention	(10)%	14%	
Robotics	(24)%	14%	
Production Facilities	46%	35%	
Total company	(6)%	17%	
Number of vessels or robotics assets (1) / Utilization (2)			
Well Intervention vessels	5/38%	4/65%	
Robotics assets	60/44%	61/61%	
Chartered robotics vessels	4/57%	5/83%	

(1) Represents number of vessels or robotics assets as of the end of the period excluding acquired vessels prior to their in-service dates, vessels taken out of service prior to their disposition and vessels jointly owned with a third party. The Helix 534 was excluded from the numbers for the first half of 2016 as it was cold stacked and out of service. The Seawell was excluded from the numbers for the first half of 2015 as it was out of service undergoing major capital upgrades.

(2) Represents 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 calendar days in the applicable period.

Table of Contents

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):

	Six Months Ended June 30,		Increase/ (Decrease)
	2016	2015	
Well Intervention	$2,842	$11,363	$(8,521)
Robotics	13,174	16,656	(3,482)
	$16,016	$28,019	$(12,003)

Net Revenues. Our total net revenues decreased by 44% for the six-month period ended June 30, 2016 as compared to the same period in 2015. In general, decreased revenues for the six-month period in 2016 reflect both reduced opportunities for work and the acceptance of work at reduced rates for some of our assets in light of the continuation of industry-wide downturn as a result of the substantial decline in oil prices since late 2014.

Our Well Intervention revenues decreased by 44% for the six-month period ended June 30, 2016 as compared to the same period in 2015 primarily reflecting significantly lower revenue in our North Sea region due to lack of work. In the North Sea, the Well Enhancer was 44% utilized during the first half of 2016 while the vessel was essentially fully utilized during the same period in 2015. The Skandi Constructor was warm stacked during the first half of 2016 as compared to being 40% utilized during the same period in 2015. The Seawell was re-activated and utilized for 21 days in June 2016 as compared to being out of service undergoing major capital upgrades to extend its estimated useful life during the same period in 2015. In the Gulf of Mexico, the Q4000 was essentially fully utilized during the first half of 2016 as compared to being utilized for 108 days during the same period in 2015 primarily as a result of it completing its regularly scheduled regulatory dry dock in the second quarter of 2015 (64 days) as well as some downtime attributable to IRS mechanical issues in January 2015. The Q5000, which was delivered to us in April 2015, went on contracted rates under our five-year contract with BP on May 19, 2016. The Helix 534 was cold stacked and out of service during the first half of 2016 while the vessel was 63% utilized during the same period in 2015.

Robotics revenues decreased by 54% for the six-month period ended June 30, 2016 as compared to the same period in 2015. The decrease primarily reflects the reduction and lower utilization of our available Robotics assets, including our chartered vessels, and accepting 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. Utilization of our chartered ROV support vessels decreased primarily reflecting reduction in work opportunities as a result of further market deterioration in the offshore energy industry.

Our Production Facilities revenues decreased by 3% for the six-month period ended June 30, 2016 as compared to the same period in 2015, which reflects the slight decrease in our variable throughput fee primarily as a result of lower pricing, offset in part by slightly higher production volumes in the Phoenix field.

Gross Profit (Loss). Our total gross profit decreased by 119% from $59.2 million for the six-month period ended June 30, 2015 to a $11.3 million loss for the six-month period ended June 30, 2016. The gross profit related to our Well Intervention segment decreased from $25.8 million for the six-month period ended June 30, 2015 to a $11.0 million loss for the six-month period ended June 30, 2016 primarily reflecting no utilization or significantly lower utilization of most of our well intervention vessels during the first quarter of 2016 due to lack of available projects as a result of the ongoing industry downturn.

Table of Contents

The gross profit associated with our Robotics segment decreased from $22.1 million for the six-month period ended June 30, 2015 to a $17.0 million loss for the six-month period ended June 30, 2016 primarily reflecting decreased utilization for our Robotics assets, including our chartered vessels, and accepting work with lower profit margins.

The gross profit related to our Production Facilities segment increased by 29% for the six-month period ended June 30, 2016 as compared to the same period in 2015. The increase primarily reflects lower repair and maintenance costs and a decrease in depreciation expense related to the HP I as a result of the vessel's impairment in December 2015.

Selling, General and Administrative Expenses. Our selling, general and administrative expenses decreased by $0.4 million for the six-month period ended June 30, 2016 as compared to the same period in 2015. The decrease was primarily attributable to overhead cost saving measures including headcount reductions, which were partially offset by payroll related costs associated with our variable performance-based incentive compensation programs (Note 10). In addition, selling, general and administrative expenses for the six-month period ended June 30, 2015 included charges of $3.0 million associated with the provision for uncertain collection of a portion of our trade receivables.

Net Interest Expense. Our net interest expense increased by $8.9 million for the six-month period ended June 30, 2016 as compared to the same period in 2015 primarily reflecting an increase in interest expense and decreases in interest income and capitalized interest. The increase in interest expense was primarily attributable to nearly four months of additional interest on the Nordea Q5000 Loan, which was funded in April 2015, as well as increases in interest rates on the Term Loan and the Nordea Q5000 Loan. Interest expense for the six-month period ended June 30, 2016 also included a $2.5 million charge to accelerate the amortization of debt issuance costs in proportion to the reduced commitment under our Revolving Credit Facility in February 2016 (Note 6). Interest income totaled $0.9 million for the six-month period ended June 30, 2016 as compared to $1.1 million for the same period in 2015. Interest on debt used to finance capital projects is capitalized and thus reduces overall interest expense. Capitalized interest totaled $4.4 million for the six-month period ended June 30, 2016 as compared to $7.7 million for the same period in 2015.

Gain on Repurchase of Long-Term Debt. The $0.3 million gain for the six-month period ended June 30, 2016 was associated with the repurchase in June 2016 of $7.3 million in aggregate principal amount of our 2032 Notes (Note 6).

Other Income (Expense), Net. We reported other income, net, of $3.2 million for the six-month period ended June 30, 2016 as compared to other expense, net, of $6.2 million for the same period in 2015. Net other income for the six-month period ended June 30, 2016 primarily reflects net gains totaling $2.2 million associated with our foreign currency exchange contracts primarily reflecting gains related to the contracts that were not designated as cash flow hedges (Note 14). Net other expense for the six-month period ended June 30, 2015 primarily reflects losses totaling $3.4 million related to our hedge ineffectiveness. Also included in other income (expense), net, were foreign currency transaction gains (losses) of $1.0 million and $(2.8) million, respectively, in the comparable year-over-year periods.

Other Income – Oil and Gas. Our other income – oil and gas decreased by $0.9 million for the six-month period ended June 30, 2016 as compared to the same period in 2015. The decrease was primarily attributable to the reduction in the overriding royalty income which is significantly affected by the decline in oil prices and lower volumes.

Income Tax Provision (Benefit). Income taxes reflect a benefit of $13.5 million for the six-month period ended June 30, 2016 as compared to a provision of $1.0 million for the same period in 2015. The variance primarily reflects decreased profitability in the current year period. The effective tax rate was a 26.0% benefit for the six-month period ended June 30, 2016 as compared to a 5.7% expense for the same period in 2015. The variance was primarily attributable to the earnings mix between our higher and lower tax rate jurisdictions.

37

Table of Contents

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

	June 30, 2016	December 31, 2015
Net working capital	$454,473	$ 473,123
Long-term debt (1)	$638,985	$ 677,695
Liquidity (2)	$542,977	$ 743,577

(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. It 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 the facility. Our liquidity at June 30, 2016 included cash and cash equivalents of $492.2 million (including $150 million of minimum cash balance) and $50.8 million of available borrowing capacity under our Revolving Credit Facility (Note 6). Our liquidity at December 31, 2015 included cash and cash equivalents of $494.2 million and $249.4 million of available borrowing capacity under our Revolving Credit Facility.

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):

	June 30, 2016	December 31, 2015
Term Loan (matures June 2018)	$238,145	$ 253,181
Nordea Q5000 Loan (matures April 2020)	211,336	228,840
MARAD Debt (matures February 2027)	80,976	83,659
2032 Notes (mature March 2032) (1)	180,314	183,655
Total debt	$710,771	$ 749,335

(1) The 2032 Notes will increase to their face amount through accretion of non-cash interest charges through March 15, 2018, which is the first date on which the holders of the notes may require us to repurchase the notes.

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

	Six Months Ended June 30, 2016	2015
Cash provided by (used in):		
Operating activities	$24,889	$3,033
Investing activities	$(20,476)	$(221,530)
Financing activities	$(4,309)	$239,721

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

As a further response to the industry-wide spending reductions, we remain even more focused on maintaining a strong balance sheet and adequate liquidity. Over the near term, we may seek to reduce, defer or cancel certain planned capital expenditures. We believe that our cash on hand, internally generated cash flows, proceeds from sale of our common stock 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 2032 Notes, the MARAD Debt agreements, and the Nordea Credit Agreement, we are required to comply with certain covenants, including certain financial ratios such as a consolidated interest coverage ratio and a consolidated leverage ratio, as well as the maintenance of 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 June 30, 2016 and December 31, 2015, we were in compliance with all of the covenants of our long-term debt.

A prolonged period of weak industry activity may make it difficult to comply with our covenants and other restrictions in agreements governing our debt. We may be compelled to pay down certain indebtedness in order to be in compliance with our leverage ratio covenant. Furthermore, during any period of sustained weak economic activity and reduced EBITDA, our ability to access the full available commitment under our Revolving Credit Facility may be impacted. At June 30, 2016, our available borrowing capacity under our Revolving Credit Facility, based on the leverage ratio covenant, was restricted to $50.8 million, net of $6.0 million of letters of credit issued. We anticipate that our borrowing capacity under the Revolving Credit Facility may continue to decrease. However, for the remainder of 2016, we have no current plans or forecasted requirements to borrow under our Revolving Credit Facility other than for issuances of letters of credit. Our ability to comply with these covenants and other restrictions is affected by economic conditions and other events beyond our control. If we fail to comply with these covenants and other restrictions, that failure could lead to an event of default, the possible acceleration of our repayment of outstanding debt and the exercise of certain remedies by our lenders, including foreclosure against our collateral.

Subject to the terms and restrictions of the Credit Agreement, as amended, we may borrow and/or obtain letters of credit up to $400 million under our Revolving Credit Facility. Pursuant to our Credit Agreement, subject to existing lender participation and/or the participation of new lenders, and subject to standard conditions precedent, we may obtain an increase of up to $200 million in aggregate commitments with respect to the Revolving Credit Facility, additional term loans or a combination thereof. See Note 6 for additional information relating to our long-term debt, including more information regarding our Credit Agreement, including covenants and collateral.

The 2032 Notes can be converted to our common stock prior to their stated maturity upon certain triggering events specified in the Indenture governing the notes. Beginning in March 15, 2018, the holders of the 2032 Notes may require us to repurchase these notes or we may at our own option elect to repurchase them. To the extent we do not have cash on hand or long-term financing secured to cover the conversion, the 2032 Notes would be classified as current liabilities in our condensed consolidated balance sheet. No conversion triggers were met during the six-month periods ended June 30, 2016 and 2015.

Table of Contents

Operating Cash Flows

Total cash flows from operating activities increased by $21.9 million for the six-month period ended June 30, 2016 as compared to the same period in 2015. This increase primarily reflects changes in our working capital. Our operating cash flows for the six-month period ended June 30, 2016 included the receipt of $15.7 million income tax refund.

Investing Activities

Capital expenditures consist principally of the construction of dynamically positioned vessels as well as improvements and modifications to existing assets. Significant sources (uses) of cash associated with investing activities are as follows (in thousands):

	Six Months Ended June 30,	
	2016	2015
Capital expenditures:		
Well Intervention	$(57,281)	$(222,968)
Robotics	(413)	(8,981)
Production Facilities	(74)	(823)
Other	205	(100)
Distributions from equity investments, net [(1)]	1,200	3,842
Proceeds from sale of equity investment [(2)]	25,000	—
Proceeds from sale of assets [(3)]	10,887	7,500
Net cash used in investing activities	$(20,476)	$(221,530)

(1) Distributions from equity investments are net of undistributed equity earnings from our equity investments. Gross distributions from our equity investments for the six-month periods ended June 30, 2016 and 2015 were $1.2 million and $3.5 million, respectively (Note 5).
(2) Amount in 2016 reflects cash received from the sale of our former ownership interest in Deepwater Gateway.
(3) Amount in 2015 reflects cash received from the sale of our former Ingleside spoolbase.

Capital expenditures associated with our business primarily have included payments associated with the construction of our Q5000 and Q7000 vessels (see below), payments in connection with the Seawell life extension activities in 2015, the investment in the topside well intervention equipment for the Siem Helix 1 and Siem Helix 2 vessels chartered to perform under our agreements with Petrobras (see below), and the acquisition of additional ROVs for our robotics business.

In March 2012, we entered into a contract with a shipyard in Singapore for the construction of the Q5000. Pursuant to the terms of this contract, payments were made as a fixed percentage of the contract price, together with any variations, on contractually scheduled dates. The Q5000 was delivered to us in the second quarter of 2015. The vessel commenced operations in the Gulf of Mexico under our five-year contract with BP and went on contracted rates on May 19, 2016.

Table of Contents

In September 2013, we executed a second contract with the same shipyard in Singapore that constructed the Q5000. This contract is for the construction of a newbuild semi-submersible well intervention vessel, the Q7000, which is being built to North Sea standards. This $346.0 million shipyard contract represents the majority of the expected costs associated with the construction of the Q7000. Pursuant to the original terms of this contract, 20% of the contract price was paid upon the signing of the contract. In June 2015, we entered into a contract amendment with the shipyard to extend the scheduled delivery of the Q7000 from mid-2016 to July 30, 2017 and to defer certain payment obligations, and in connection with this extension, we agreed to pay the shipyard incremental costs of up to $14.5 million. In December 2015, we entered into a second contract amendment with the shipyard. Pursuant to this amendment, the remaining 80% will be paid in three installments, with 20% in June 2016, 20% upon issuance of the Completion Certificate, which is to be issued on or before December 31, 2017, and 40% upon the delivery of the vessel, which at our option can be deferred until December 30, 2018. Also pursuant to this second amendment, we agreed to reimburse the shipyard for incremental costs in connection with the further deferment of the Q7000's delivery. At June 30, 2016, our total investment in the Q7000 was $117.4 million, including $69.2 million paid to the shipyard upon signing the contract. We plan to incur approximately $90 million of costs related to the construction of the Q7000 over the remainder of 2016, including $69.2 million which will be paid in the second half of 2016.

In February 2014, we entered into agreements with Petrobras to provide well intervention services offshore Brazil. The initial term of the agreements with Petrobras is for four years with options to extend. In connection with the Petrobras agreements, we entered into charter agreements with Siem Offshore AS for two newbuild monohull vessels, the Siem Helix 1, which is expected to be in service for Petrobras in the fourth quarter of 2016, and the Siem Helix 2, which is expected to be in service in 2017. Our total investment in the topside equipment for both vessels is expected to be approximately $260 million. We have invested $157.6 million as of June 30, 2016 and plan to invest approximately $56 million in the topside equipment over the remainder of 2016.

Financing Activities

Cash flows from financing activities consist primarily of proceeds from debt and equity financing activities and repayments of our long-term debt. Our $250 million Nordea Q5000 Loan was funded in April 2015 at the time the Q5000 vessel was delivered to us. We sold 5,081,339 shares of our common stock under the ATM program for $40.5 million and received net proceeds of $38.8 million in the second quarter of 2016. Repayments of our long-term debt increased by $32.0 million during the six-month period ended June 30, 2016 as compared to the same period in 2015 primarily reflecting the repayment of $17.9 million of the Nordea Q5000 Loan, an additional $7.5 million in repayment of the Term Loan and the payments to repurchase $7.3 million of the 2032 Notes.

Outlook

We anticipate that our capital expenditures for fiscal year 2016 will approximate $230 million. This estimate may change based on various economic factors. We may seek to further reduce the level of our planned future capital expenditures given a prolonged industry downturn. We believe that our cash on hand, internally generated cash flows, proceeds from the sale of our common stock under the ATM program and availability under our Revolving Credit Facility if necessary will provide the capital necessary to continue funding our 2016 capital expenditures.

Table of Contents

Contractual Obligations and Commercial Commitments

The following table summarizes our contractual cash obligations as of June 30, 2016 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	$240,000	$30,000	$210,000	$—	$—
Nordea Q5000 Loan	214,285	35,714	71,429	107,142	—
MARAD debt	86,221	6,072	13,068	14,405	52,676
2032 Notes [2]	192,750	—	—	—	192,750
Interest related to debt [3]	170,820	31,255	43,333	21,403	74,829
Property and equipment [4]	347,213	129,317	217,896	—	—
Operating leases [5]	908,590	150,220	300,774	236,007	221,589
Total cash obligations	$2,159,879	$382,578	$856,500	$378,957	$541,844

(1) Excludes unsecured letters of credit outstanding at June 30, 2016 totaling $6.0 million. These letters of credit support various obligations, such as contractual obligations, customs duties, contract bidding and insurance activities.

(2) Notes mature in 2032. The 2032 Notes can be converted prior to their stated maturity if the closing price of our common stock for at least 20 days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter exceeds 130% of their issuance price on that 30th trading day (i.e., $32.53 per share). At June 30, 2016, the conversion trigger was not met. The first date that the holders of these notes may require us to repurchase the notes is March 15, 2018. See Note 6 for additional information.

(3) Interest payment obligations were calculated using stated coupon rates for fixed rate debt and interest rates applicable at June 30, 2016 for variable rate debt.

(4) Primarily reflects the costs associated with our Q7000 semi-submersible vessel currently under construction and the topside equipment for the Siem Helix 1 and Siem Helix 2 chartered vessels (Note 12).

(5) Operating leases include vessel charters and facility leases. At June 30, 2016, our vessel charter commitments totaled approximately $859.7 million, including the Grand Canyon III that we expect to place in service in May 2017, the Siem Helix 1, which is expected to be in service for Petrobras in the fourth quarter of 2016, and the yet to be delivered Siem Helix 2. The Rem Installer’s charter expired in July 2016.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our discussion and analysis of our financial condition and results of operations are based upon our condensed consolidated financial statements. We prepare these financial statements and related footnotes 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. For additional information regarding our critical accounting policies and estimates, please read our “Critical Accounting Policies and Estimates” as disclosed in our 2015 Form 10-K.

Table of Contents

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are currently exposed to market risk in two areas: interest rates and foreign currency exchange rates.

Interest Rate Risk. As of June 30, 2016, $454.3 million of our outstanding debt was subject to floating rates. The interest rate applicable to our variable rate debt may rise, thereby increasing our interest expense and related cash outlay. To reduce the impact of this market risk, in September 2013, we entered into various interest rate swap contracts to fix the interest rate on $148.1 million of our Term Loan debt. These swap contracts, which are settled monthly, began in October 2013 and extend through October 2016. Additionally, in June 2015 we entered into various interest rate swap contracts to fix the interest rate on $187.5 million of our Nordea Q5000 Loan debt. These swap contracts, which are settled monthly, began in June 2015 and extend through April 2020. The impact of interest rate risk is estimated using a hypothetical increase in interest rates by 100 basis points for our variable rate long-term debt that is not hedged. Based on this hypothetical assumption, we would have incurred an additional $0.9 million in interest expense for the six-month period ended June 30, 2016.

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 (primarily with respect to our North Sea operations). As such, our earnings are subject to movements in foreign currency exchange rates when transactions are denominated in (i) currencies other than the U.S. dollar, which is our functional currency, or (ii) the functional currency of our subsidiaries, which is not necessarily the U.S. dollar. In order to mitigate the effects of exchange rate risk in areas outside the United States, we generally pay a portion of our expenses in local currencies. In addition, a substantial portion of our contracts provide for collections from customers in U.S. dollars. During the six-month period ended June 30, 2016, we recognized gains of $1.0 million related to foreign currency transactions in “Other income (expense), net” in our condensed consolidated statement of operations.

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 January 2013, we entered into foreign currency exchange contracts to hedge through September 2017 the foreign currency exposure associated with the Grand Canyon charter payments ($104.6 million) denominated in Norwegian kroner (NOK591.3 million). In February 2013, we entered into similar foreign currency exchange contracts to hedge our foreign currency exposure with respect to the Grand Canyon II and the Grand Canyon III charter payments ($100.4 million and $98.8 million, respectively) denominated in Norwegian kroner (NOK594.7 million and NOK595.0 million, respectively), through July 2019 and February 2020, respectively. In December 2015, we re-designated the hedging relationship between a portion of our foreign currency exchange contracts and our forecasted Grand Canyon II and Grand Canyon III charter payments of NOK434.1 million and NOK185.2 million, respectively, that were expected to remain highly probable of occurring (Note 14). The foreign currency exchange contracts associated with the Grand Canyon charter payments and the re-designated contracts associated with the Grand Canyon II and Grand Canyon III charter payments currently qualify for cash flow hedge accounting treatment. For the six-month period ended June 30, 2016, we recorded gains totaling $0.1 million in “Other income (expense), net” related to foreign currency hedge ineffectiveness.

Table of Contents

Item 4. Controls and Procedures

(a) Evaluation of disclosure controls and procedures. Our management, with the participation of our principal executive officer and principal financial officer, has evaluated the effectiveness of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act, as of June 30, 2016. Based on this evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of June 30, 2016 to ensure that information that is required to be disclosed by us in the reports we file or submit under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms; and (ii) accumulated and communicated to our management, as appropriate, to allow timely decisions regarding required disclosure.

(b) Changes in internal control over financial reporting. There have been no changes in our internal control over financial reporting that occurred during the quarter ended June 30, 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Table of Contents

Part II. OTHER INFORMATION
Item 1. Legal Proceedings

See Part I, Item 1, Note 12 to the Condensed Consolidated Financial Statements, which is incorporated herein by reference.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Issuer Purchases of Equity Securities

Period	(a) Total number of shares purchased	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced program	(d) Maximum number of shares that may yet be purchased under the program (1)
April 1 to April 30, 2016	—	$ ——		2,199,748
May 1 to May 31, 2016	—	—	—	2,199,748
June 1 to June 30, 2016	—	—	—	2,199,748
	—	$ ——		

(1) Under the terms of our stock repurchase program, the issuance of shares to members of our Board and to certain employees, including shares issued to our employees under the ESPP (Note 10), increases the amount of shares available for repurchase. For additional information regarding our stock repurchase program, see Note 10 to our 2015 Form 10-K.

Item 6. Exhibits

The exhibits to this report are listed in the Exhibit Index on Page 47 hereof.

Table of Contents

SIGNATURES

Pursuant to the requirements 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. (Registrant)
Date: July 22, 2016	By:	/s/ Owen Kratz Owen Kratz President and Chief Executive Officer (Principal Executive Officer)
Date: July 22, 2016	By:	/s/ Anthony Tripodo Anthony Tripodo Executive Vice President and Chief Financial Officer (Principal Financial Officer)

Table of Contents

INDEX TO EXHIBITS
OF
HELIX ENERGY SOLUTIONS GROUP, INC.

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 Helix.	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)
10.1	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)
31.1	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Owen Kratz, Chief Executive Officer.	Filed herewith
31.2	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Anthony Tripodo, Chief Financial Officer.	Filed herewith
32.1	Certification of Helix's Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes — Oxley Act of 2002.	Furnished herewith
101.INS	XBRL Instance Document.	Furnished herewith
101.SCH	XBRL Schema Document.	Furnished herewith
101.CAL	XBRL Calculation Linkbase Document.	Furnished herewith
101.PRE	XBRL Presentation Linkbase Document.	Furnished herewith
101.DEF	XBRL Definition Linkbase Document.	Furnished herewith
101.LAB	XBRL Label Linkbase Document.	Furnished herewith