HELIX ENERGY SOLUTIONS GROUP INC
Form 10-Q
October 23, 2013

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

Form 10-Q

[X] Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended September 30, 2013

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.

Yes [√] No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes [√] No [ ]

Indicate by check mark 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 [√]	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 [ ] No [√]

As of October 18, 2013, 105,801,248 shares of common stock were outstanding.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

	September 30, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 480,181	$ 437,100
Accounts receivable:		
Trade, net of allowance for uncollectible accounts of $6,121 and $5,152, respectively	150,625	152,233
Unbilled revenue	25,057	26,992
Costs in excess of billing	2,529	6,848
Other current assets	80,480	96,934
Current assets of discontinued operations	—	84,000
Total current assets	738,872	804,107
Property and equipment	1,913,000	2,051,796
Less accumulated depreciation	(411,320)	(565,921)
Property and equipment, net	1,501,680	1,485,875
Other assets:		
Equity investments	161,200	167,599
Goodwill	62,815	62,935
Other assets, net	47,339	49,837
Non-current assets of discontinued operations	—	816,227
Total assets	$2,511,906	$3,386,580
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$75,035	$92,398
Accrued liabilities	83,359	161,514
Income tax payable	18,946	—
Current maturities of long-term debt	20,376	16,607
Current liabilities of discontinued operations	—	182,527
Total current liabilities	197,716	453,046
Long-term debt	548,204	1,002,621
Deferred tax liabilities	260,649	359,237
Other non-current liabilities	18,274	5,025
Non-current liabilities of discontinued operations	—	147,237
Total liabilities	1,024,843	1,967,166
Commitments and contingencies		
Shareholders' equity:		
	937,501	932,742

Common stock, no par, 240,000 shares authorized, 105,794 and 105,763 shares issued, respectively		
Retained earnings	549,729	476,310
Accumulated other comprehensive loss	(25,502)	(15,667)
Total controlling interest shareholders' equity	1,461,728	1,393,385
Noncontrolling interest	25,335	26,029
Total equity	1,487,063	1,419,414
Total liabilities and shareholders' equity	$2,511,906	$3,386,580

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

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

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012
Net revenues	$220,117	$217,110
Cost of sales:		
Cost of sales	150,660	148,559
Impairments	—	10,632
Cost of sales	150,660	159,191
Gross profit	69,457	57,919
Gain (loss) on sale of assets	15,812	(12,933)
Selling, general and administrative expenses	(22,610)	(24,770)
Income from operations	62,659	20,216
Equity in earnings of investments	857	1,392
Net interest expense	(6,585)	(11,285)
Loss on early extinguishment of long-term debt	(8,572)	—
Other income, net	2,366	2,109
Other income – oil and gas	1,681	—
Income before income taxes	52,406	12,432
Income tax provision	7,058	1,270
Income from continuing operations	45,348	11,162
Income from discontinued operations, net of tax	44	4,503
Net income, including noncontrolling interests	45,392	15,665
Less net income applicable to noncontrolling interests	(799)	(800)
Net income applicable to Helix	$44,593	$14,865
Basic earnings per share of common stock:		
Continuing operations	$0.42	$0.10
Discontinued operations	—	0.04
Net income per common share	$0.42	$0.14
Diluted earnings per share of common stock:		
Continuing operations	$0.42	$0.10
Discontinued operations	—	0.04
Net income per common share	$0.42	$0.14
Weighted average common shares outstanding:		
Basic	105,029	104,256
Diluted	105,136	104,729

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

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Net revenues	$649,724	$644,413
Cost of sales:		
Cost of sales	458,603	453,409
Impairments	1,600	32,164
Cost of sales	460,203	485,573
Gross profit	189,521	158,840
Loss on commodity derivative contracts	(14,113)	—
Gain (loss) on sale of assets	14,727	(12,933)
Selling, general and administrative expenses	(65,041)	(68,754)
Income from operations	125,094	77,153
Equity in earnings of investments	2,150	7,547
Net interest expense	(28,252)	(37,407)
Loss on early extinguishment of long-term debt	(12,100)	(17,127)
Other income (expense), net	(1,884)	468
Other income – oil and gas	5,781	—
Income before income taxes	90,789	30,634
Income tax provision (benefit)	16,078	(1,405)
Income from continuing operations	74,711	32,039
Income from discontinued operations, net of tax	1,073	95,572
Net income, including noncontrolling interests	75,784	127,611
Less net income applicable to noncontrolling interests	(2,365)	(2,378)
Net income applicable to Helix	$73,419	$125,233
Basic earnings per share of common stock:		
Continuing operations	$0.68	$0.28
Discontinued operations	0.01	0.91
Net income per common share	$0.69	$1.19
Diluted earnings per share of common stock:		
Continuing operations	$0.68	$0.28
Discontinued operations	0.01	0.91
Net income per common share	$0.69	$1.19
Weighted average common shares outstanding:		
Basic	105,036	104,450
Diluted	105,152	104,897

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

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

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012
Net income, including noncontrolling interests	$45,392	$15,665
Other comprehensive income (loss), net of tax:		
Unrealized gain (loss) on hedges arising during the period	1,117	(30,532)
Reclassification adjustments for (gain) loss included in net income	396	(293)
Income taxes on unrealized (gain) loss on hedges	(529)	10,789
Unrealized gain (loss) on hedges, net of tax	984	(20,036)
Foreign currency translation gain	11,311	3,905
Other comprehensive income (loss), net of tax	12,295	(16,131)
Comprehensive income (loss)	57,687	(466)
Less comprehensive income applicable to noncontrolling interests	(799)	(800)
Comprehensive income (loss) applicable to Helix	$56,888	$(1,266)

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Net income, including noncontrolling interests	$75,784	$127,611
Other comprehensive loss, net of tax:		
Unrealized loss on hedges arising during the period	(16,050)	(24,439)
Reclassification adjustments for (gain) loss included in net income	900	(8,112)
Income taxes on unrealized loss on hedges	5,303	11,393
Unrealized loss on hedges, net of tax	(9,847)	(21,158)
Foreign currency translation gain	12	5,219
Other comprehensive loss, net of tax	(9,835)	(15,939)
Comprehensive income	65,949	111,672
Less comprehensive income applicable to noncontrolling interests	(2,365)	(2,378)
Comprehensive income applicable to Helix	$63,584	$109,294

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

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

	Nine Months Ended September 30, 2013	2012
Cash flows from operating activities:		
Net income, including noncontrolling interests	$75,784	$127,611
Adjustments to reconcile net income, including noncontrolling interests to net cash provided by operating activities:		
Income from discontinued operations	(1,073)	(95,572)
Depreciation and amortization	71,542	72,185
Asset impairment charge	—	19,184
Amortization of deferred financing costs	4,091	4,990
Stock-based compensation expense	7,297	5,561
Amortization of debt discount	3,850	7,253
Deferred income taxes	(23,911)	26,495
Excess tax from stock-based compensation	(168)	1,151
(Gain) loss on sale of assets	(14,727)	12,933
Loss on early extinguishment of debt	12,100	17,127
Unrealized (gain) loss and ineffectiveness on derivative contracts, net	140	(200)
Changes in operating assets and liabilities:		
Accounts receivable, net	2,046	(37,873)
Other current assets	7,904	(17,598)
Income tax payable	(37,806)	(12,591)
Accounts payable and accrued liabilities	(46,313)	(15,867)
Oil and gas asset retirement costs	(9,886)	(35,746)
Other noncurrent, net	(561)	(23,580)
Net cash provided by operating activities	50,309	55,463
Net cash provided by (used in) discontinued operations	(30,503)	252,689
Net cash provided by operating activities	19,806	308,152
Cash flows from investing activities:		
Capital expenditures	(275,935)	(216,951)
Distributions from equity investments, net	6,110	6,174
Proceeds from sale of assets	189,054	14,500
Net cash used in investing activities	(80,771)	(196,277)
Net cash provided by (used in) discontinued operations	582,965	(85,695)
Net cash provided by (used in) investing activities	502,194	(281,972)
Cash flows from financing activities:		
Early extinguishment of Senior Unsecured Notes	(281,490)	(209,500)
Borrowings under revolving credit facility	47,617	100,000
Repayment of revolving credit facility	(147,617)	—
Issuance of Convertible Senior Notes due 2032	—	200,000
Repurchase of Convertible Senior Notes due 2025	(3,487)	(143,945)
Proceeds from term loans	300,000	100,000

Repayment of term loans	(370,931)	(10,585)
Repayment of MARAD borrowings	(5,120)	(4,877)
Deferred financing costs	(10,948)	(7,766)
Distributions to noncontrolling interest	(3,059)	(4,249)
Repurchases of common stock	(5,562)	(7,510)
Excess tax from stock-based compensation	168	(1,151)
Exercise of stock options, net and other	95	1,264
Proceeds from issuance of ESPP shares	2,711	—
Net cash provided by (used in) financing activities	(477,623)	11,681
Effect of exchange rate changes on cash and cash equivalents	(1,296)	(532)
Net increase in cash and cash equivalents	43,081	37,329
Cash and cash equivalents:		
Balance, beginning of year	437,100	546,465
Balance, end of period	$480,181	$583,794

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

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Note 1 — Basis of Presentation and Recent Accounting Standards

The accompanying condensed consolidated financial statements include the accounts of Helix Energy Solutions Group, Inc. and its wholly- and majority-owned 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 wholly- and majority-owned 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.

The accompanying condensed consolidated financial statements have been prepared in conformity with U.S. generally accepted accounting principles (“U.S. GAAP”) and are consistent in all material respects with those applied in our 2012 Annual Report on Form 10-K (“2012 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. Management has made all adjustments (which were normal recurring adjustments unless otherwise disclosed herein) that it believes 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 nine-month periods ended September 30, 2013 are not necessarily indicative of the results that may be expected for the year ending December 31, 2013. Our balance sheet as of December 31, 2012 included herein has been derived from the audited balance sheet as of December 31, 2012 included in our 2012 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 2012 Form 10-K.

Certain reclassifications were made to previously reported amounts in the condensed consolidated financial statements and notes thereto to make them consistent with the current presentation format. The most significant of these reclassifications are associated with our discontinued operations and a modification of our business segments (Note 12). As noted in Note 2, we exited our oil and gas business in February 2013 upon the sale of our former wholly-owned subsidiary, Energy Resource Technology GOM, Inc. (“ERT”).

Note 2 — Company Overview

Contracting Services Operations

We are an international offshore energy company that provides specialty services to the offshore energy industry, with a focus on our well intervention and robotics operations. We seek to provide services and methodologies that we believe are critical to developing offshore reservoirs and maximizing production economics. Our “life of field” services are segregated into four disciplines: well intervention, robotics, subsea construction and production facilities. Historically, we disaggregated our operations into two reportable segments: Contracting Services and Production Facilities. However, with the recent completion of the sale of our remaining subsea construction pipelay vessels and related equipment and the continued emphasis on expanding and growing our well intervention and robotics operations, we will, commencing this quarter, disaggregate our former Contracting Services segment into three business segments: Well Intervention, Robotics and Subsea Construction (Note 12). Our Production Facilities segment includes our majority ownership of the Helix Producer I (“HP I”) vessel as well as our equity investments in Deepwater Gateway, L.L.C. (“Deepwater Gateway”) and Independence Hub, LLC (“Independence Hub”) (Note 6). It also includes the Helix Fast Response System (“HFRS”), which includes access to our Q4000 and HP I vessels.

In October 2012, we entered into an agreement to sell our two remaining pipelay vessels, the Caesar and the Express, and other related pipelay equipment for a total sales price of $238.3 million. In June 2013, we completed the sale of the Caesar and related equipment for $138.3 million, which amount included $30 million of funds deposited with us at the time the agreement was entered (Note 3). We used $80.1 million of the proceeds from the sale of the Caesar to reduce our indebtedness under our former credit agreement (Note 7) and we are investing the remainder in our continuing operations, including supporting

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the expansion of our well intervention and robotics operations. This sale resulted in a pre-tax loss of $1.1 million that is reflected in “Gain (loss) on sale of assets” in the accompanying condensed consolidated statement of operations. In July 2013, we completed the sale of the Express for $100 million, including the remaining $20 million of previously deposited funds. A pre-tax gain of $15.6 million was recorded on the sale of the Express in the third quarter of 2013. We also entered into an agreement to sell our spoolbase and adjoining property at Ingleside, Texas for a total sales price of $45 million to the same group of companies that purchased the Caesar and the Express. The facility and adjoining property is being leased to the purchaser during the second half of 2013 and the sale is expected to close in January 2014. At the time the agreement was signed, we received a $5 million deposit, which is only refundable under limited circumstances. An additional $10 million will be paid by the purchaser at the closing of the sale with the remaining $30 million being payable over three years.

Discontinued Operations

In December 2012, we announced a definitive agreement for the sale of ERT. On February 6, 2013, we sold ERT for $624 million plus additional consideration in the form of overriding royalty interests in ERT’s Wang well and certain other of its future exploration prospects. As a result, we have presented the assets and liabilities included in the sale of ERT and the historical operating results of our former Oil and Gas segment as discontinued operations in the accompanying condensed consolidated financial statements. See Note 4 for additional information regarding our discontinued oil and gas operations and Note 7 regarding the use of a portion of the sale proceeds to reduce our indebtedness under our former credit agreement.

Note 3 — Details of Certain Accounts

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

	September 30, 2013	December 31, 2012
Other receivables	$ 856	$ 1,086
Prepaid insurance	10,224	11,999
Other prepaids	12,066	11,751
Spare parts inventory	3,423	2,480
Income tax receivable	—	14,201
Current deferred tax assets	45,711	43,942
Derivative assets	6	5,946
Other	8,194	5,529
Total other current assets	$ 80,480	$ 96,934

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

	September 30, 2013	December 31, 2012
Deferred dry dock expenses, net	$ 19,838	$ 22,704
Deferred financing costs, net	25,412	24,338
Intangible assets with finite lives, net	597	491
Other	1,492	2,304
Total other assets, net	$ 47,339	$ 49,837

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Accrued liabilities consist of the following (in thousands):

	September 30, 2013	December 31, 2012
Accrued payroll and related benefits	$ 47,860	$ 51,561
Current asset retirement obligations	2,471	2,898
Unearned revenue	10,553	6,137
Billing in excess of cost	2,994	6,445
Accrued interest	1,488	17,451
Derivative liability (Note 16)	2,392	16,266
Taxes payable excluding income tax payable	5,307	5,164
Pipelay assets sale deposit (Note 2)	5,000	50,000
Other	5,294	5,592
Total accrued liabilities	$ 83,359	$ 161,514

Note 4 — Oil and Gas Properties

Results of Discontinued Operations

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

	Periods Ended September 30,		
	Nine Months 2013 (1)	Three Months 2012	Nine Months 2012
Revenues	$ 48,847	$ 119,124	$ 447,142
Costs:			
Production (lifting) costs	16,017	47,364	124,633
Exploration expenses	3,514	623	2,469
Depreciation, depletion, amortization and accretion	1,226	38,697	126,269
Proved property impairment and abandonment	(152)	4,602	11,919
Loss on sale of oil and gas properties	—	—	1,714
Hedge ineffectiveness and non-hedge gain on commodity derivative contracts	—	9,427	1,697
Selling, general and administrative expenses	1,229	3,252	9,535
Net interest expense and other (2)	2,732	6,959	21,209
Total costs	24,566	110,924	299,445
Pretax income from discontinued operations	24,281	8,200	147,697
Income tax provision	8,499	3,697	52,125
Income from operations of discontinued operations	15,782	4,503	95,572
Loss on sale of business, net of tax	(14,709)	—	—
Income from discontinued operations, net of tax	$ 1,073	$ 4,503	$ 95,572

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

(2) Net interest expense of $2.7 million for the nine-month period ended September 30, 2013, and $6.9 million and $20.9 million for the three- and nine-month periods ended September 30, 2012, respectively, was allocated to ERT primarily consisting of interest associated with indebtedness directly attributed to the substantial oil and gas acquisition made in 2006. This includes interest related to debt required to be repaid upon the disposition of ERT.

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Note 5 — 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):

	Nine Months Ended September 30,	
	2013	2012
Interest paid, net of interest capitalized	$39,754	$61,637
Income taxes paid	$78,408	$39,011

Total non-cash investing activities for the nine-month periods ended September 30, 2013 and 2012 include $10.2 million and $33.1 million, respectively, of accruals for property and equipment capital expenditures.

Note 6 — Equity Investments

As of September 30, 2013, we had two investments that we account for using the equity method of accounting: Deepwater Gateway and Independence Hub, both of which are included in our Production Facilities segment.

Deepwater Gateway, L.L.C. In June 2002, we, along with Enterprise Products Partners L.P. (“Enterprise”), formed Deepwater Gateway, each with a 50% interest, to design, construct, install, own and operate a tension leg platform production hub primarily for Anadarko Petroleum Corporation's Marco Polo field in the Deepwater Gulf of Mexico. Our investment in Deepwater Gateway totaled $87.5 million and $91.4 million as of September 30, 2013 and December 31, 2012, respectively (including capitalized interest of $1.3 million at September 30, 2013 and December 31, 2012).

Independence Hub, LLC. In December 2004, we acquired a 20% interest in Independence Hub, an affiliate of Enterprise. Independence Hub owns the “Independence Hub” platform located in Mississippi Canyon Block 920 in a water depth of 8,000 feet. Our investment in Independence Hub was $73.7 million and $76.2 million as of September 30, 2013 and December 31, 2012, respectively (including capitalized interest of $4.3 million and $4.6 million at September 30, 2013 and December 31, 2012, respectively).

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Deepwater Gateway	$1,600	$3,407	$5,100	$6,807
Independence Hub	800	2,113	3,160	6,913
Total	$2,400	$5,520	$8,260	$13,720

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Note 7 — Long-Term Debt

Scheduled maturities of long-term debt outstanding as of September 30, 2013 are as follows (in thousands):

	Term Loan (1)	MARAD Debt	2032 Notes (2)	Total
Less than one year	$15,000	$5,376	$—	$20,376
One to two years	18,750	5,644	—	24,394
Two to three years	30,000	5,926	—	35,926
Three to four years	30,000	6,222	—	36,222
Four to five years	202,500	6,532	—	209,032
Over five years	—	70,468	200,000	270,468
Total debt	296,250	100,168	200,000	596,418
Current maturities	(15,000)	(5,376)	—	(20,376)
Long-term debt, less current maturities	281,250	94,792	200,000	576,042
Unamortized debt discount (3)	—	—	(27,838)	(27,838)
Long-term debt	$281,250	$94,792	$172,162	$548,204

(1) Amount reflects the borrowings made in July 2013 (see “Credit Agreement” below).

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

(3) The Convertible Senior Notes due 2032 will increase to their principal amount through accretion of non-cash interest charges through March 2018.

Included below is a summary of certain components of our indebtedness. For additional information regarding our debt, see Note 7 to our 2012 Form 10-K.

Credit Agreement

In June 2013, we entered into a Credit Agreement (the “Credit Agreement”) with a group of lenders pursuant to which we may borrow up to $300 million in a term loan (the “Term Loan”) and may borrow revolving loans (the “Revolving Loans”) under a revolving credit facility up to an outstanding amount of $600 million (the “Revolving Credit Facility”). The Revolving Credit Facility also permits us to obtain letters of credit up to the full amount of the Revolving Credit Facility. Subject to customary conditions, we may request an increase of up to $200 million in aggregate commitments with respect to the Revolving Credit Facility, additional term loans or a combination thereof. In July 2013, we borrowed $300 million under the Term Loan in connection with our early redemption of the remaining $275 million Senior Unsecured Notes outstanding (see “Senior Unsecured Notes” below).

The Term Loan and the Revolving Loans (together, the “Loans”) will, at our election, bear interest either in relation to the base rate established by Bank of America N.A. or to a LIBOR rate, provided that all Swing Line Loans (as defined in the Credit Agreement) will be base rate loans. The Term Loan currently bears interest at the LIBOR Rate plus 2.5%. In September 2013, we entered into interest rate swap contracts to fix the interest rate on $148.1 million of the Term Loan (Note 16).

The Loans or portions thereof bearing interest at the base rate will bear interest at a per annum rate equal to the base rate plus a margin ranging from 1.00% to 2.00%. The Loans or portions thereof bearing interest at a LIBOR rate will bear interest at the LIBOR rate selected by us plus a margin ranging from 2.00% to 3.00%. A letter of credit fee is payable by us equal to our applicable margin for LIBOR rate Loans multiplied by the daily amount available to be drawn under outstanding letters of credit. Margins on the Loans will vary in relation to the consolidated coverage ratio, as provided by the Credit Agreement. We also pay a fixed commitment fee of 0.5% on the unused portion of our Revolving Credit Facility. At September 30, 2013, our availability under the Revolving Credit Facility totaled $593.4 million, net of $6.6 million of letters of credit issued.

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The Term Loan is repayable in scheduled principal installments of 5% in each of the initial two loan years ($15 million per year), and 10% in each of the remaining three loan years ($30 million per year), payable quarterly, with a balloon payment of $180 million at maturity. These installment amounts are subject to adjustment for any prepayments on the Term Loan. We may elect to prepay amounts outstanding under the Term Loan without premium or penalty, but may not reborrow any amounts prepaid. We may prepay amounts outstanding under the Revolving Loans without premium or penalty, and may reborrow any amounts paid up to the amount of the Revolving Credit Facility. The Loans mature on June 19, 2018. In certain circumstances, we will be required to prepay the Loans.

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

Former Credit Facility

Our former credit facility also contained both term loan and revolving loan components. This indebtedness was scheduled to mature on July 1, 2015. In February 2013, we repaid $318.4 million of borrowings outstanding under our former credit facility with the proceeds from the sale of ERT. In connection with the repayment of this debt in February 2013, we recorded a $2.9 million charge to accelerate a pro rata portion of the deferred financing costs associated with our former term loan debt. This charge is reflected as a component of "Loss on early extinguishment of long-term debt" in the accompanying condensed consolidated statements of operations.

In June 2013, we fully repaid the remaining $70.3 million of indebtedness outstanding under our former credit facility. Prior to that repayment, the principal amounts outstanding were reduced by repayments of $80.1 million of the proceeds from the sale of the Caesar in June 2013 (Note 2). Our former credit facility was replaced by our new Credit Agreement in June 2013. In connection with the repayment and termination of our former credit agreement, we recorded a $0.6 million charge to accelerate the remaining deferred financings costs associated with our indebtedness under the term loan component of our former credit facility. This charge is also a component of "Loss on early extinguishment of long-term debt" in the accompanying condensed consolidated statements of operations.

Senior Unsecured Notes

In December 2007, we issued $550 million of 9.5% Senior Unsecured Notes due 2016 (the "Senior Unsecured Notes"). Interest on the Senior Unsecured Notes was payable semi-annually in arrears on each January 15 and July 15, commencing July 15, 2008. The Senior Unsecured Notes were fully and unconditionally guaranteed by substantially all of our existing restricted domestic subsidiaries, except for Cal Dive I-Title XI, Inc. The Indenture governing the Senior Unsecured Notes provided that, prior to their stated maturity, we may redeem all or a portion of the Senior Unsecured Notes on no less than 30 days' and no more than 60 days' prior notice at the redemption prices (expressed as percentages of the principal amount) set forth below, plus accrued and unpaid interest thereon, if any, to the applicable redemption date.

Year	Redemption Price
2013	102.375%
2014 and thereafter	100.000%

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In June 2013, we elected to redeem our remaining Senior Unsecured Notes outstanding. On July 22, 2013, we paid $282.0 million to fully redeem the Senior Unsecured Notes, including $275.0 million with respect to the principal amount outstanding, $6.5 million of call premium and $0.5 million in accrued and unpaid interest. Our third-quarter 2013 results of operations include a loss on early extinguishment of debt totaling $8.6 million, which reflects the $6.5 million call premium and a $2.1 million charge to accelerate the remaining deferred financing costs associated with the original issuance of the Senior Unsecured Notes.

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

Convertible Senior Notes Due 2032

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

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

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

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 that 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.

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MARAD Debt

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

Convertible Senior Notes Due 2025

In March 2005, we issued $300 million of 3.25% Convertible Senior Notes due 2025 at 100% of the principal amount to certain qualified institutional buyers (the “2025 Notes”).

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

Other

In accordance with our Credit Agreement, 2032 Notes and MARAD Debt agreements, we are required to comply with certain covenants and restrictions, including certain financial ratios such as consolidated interest coverage ratio and consolidated leverage ratio, as well as the maintenance of minimum net worth, working capital and debt-to-equity requirements. As of September 30, 2013, we were in compliance with these covenants and restrictions.

Unamortized deferred financing costs are included in “Other assets, net” in the accompanying condensed consolidated balance sheets and are amortized over the life of the respective debt agreements. The following table reflects the components of our deferred financing costs (in thousands):

	September 30, 2013			December 31, 2012		
	Gross Carrying Amount	Accumulated Amortization	Net	Gross Carrying Amount	Accumulated Amortization	Net
Term Loans (mature July 2015) (1)	$ —	$ —	$ —	$ 15,318	$ (11,595)	$ 3,723
Revolving Credit Facility (matures July 2015) (1)	—	—	—	20,021	(12,466)	7,555
Term Loan (matures June 2018) (2)	3,635	(182)	3,453	—	—	—
	13,272	(663)	12,609	—	—	—

Revolving Credit Facility (matures June 2018) (2)						
2025 Notes (mature December 2025)	—	—	—	8,189	(8,189)	—
2032 Notes (mature March 2032)	3,759	(995)	2,764	4,251	(534)	3,717
Senior Unsecured Notes (mature January 2016) (3)	—	—	—	10,643	(8,252)	2,391
MARAD Debt (matures February 2027)	12,200	(5,614)	6,586	12,200	(5,248)	6,952
Total deferred financing costs	$ 32,866	$ (7,454)	$ 25,412	$ 70,622	$ (46,284)	$ 24,338

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(1) Relates to the term loans and revolving credit facility under our former credit agreement, which was terminated in June 2013.

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

(3) In July 2013, we redeemed our remaining Senior Unsecured Notes. In connection with this redemption, we recorded a charge of $2.1 million to accelerate the remaining deferred financing costs associated with the original issuance of this debt.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Interest expense (1)	$9,416	$12,720	$35,971	$40,660
Interest income	(271)	(228)	(903)	(569)
Capitalized interest	(2,560)	(1,207)	(6,816)	(2,684)
Net interest expense	$6,585	$11,285	$28,252	$37,407

(1) Interest expense of $2.8 million for the nine-month period ended September 30, 2013, and $7.1 million and $21.7 million for the three- and nine-month periods ended September 30, 2012, respectively, was allocated to ERT and is included in discontinued operations. Following the sale of ERT in February 2013, we ceased allocation of interest expense to ERT, which constitutes a discontinued operation.

Note 8 — Income Taxes

The effective tax rates for the three- and nine-month periods ended September 30, 2013 were 13.5% and 17.7%, respectively. This was less favorable than the effective tax rates for the three- and nine-month periods ended September 30, 2012. The variance is primarily attributable to projected year-over-year increases in profitability in the United States.

We believe our recorded assets and liabilities are reasonable; however, tax laws and regulations are subject to interpretation and tax litigation is inherently uncertain, and therefore our assessments can involve a series of complex judgments about future events and rely heavily on estimates and assumptions. Income taxes have been provided based on the U.S. statutory rate of 35% and at the local statutory rate for each foreign jurisdiction adjusted for items that are allowed as deductions for federal and foreign income tax reporting purposes, but not for book purposes. The primary differences between the statutory rate and our effective rate from continuing operations are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Statutory rate	35.0 %	35.0 %	35.0 %	35.0 %
Foreign provision	(12.3)	(6.3)	(11.8)	(30.8)
Tax return to accrual adjustment	(4.0)	(2.8)	(2.3)	(1.1)
Change in U.K. tax rate	(5.6)	(12.8)	(3.3)	(5.2)
Other	0.4	(2.9)	0.1	(2.5)

Effective rate	13.5 %	10.2 %	17.7 %	(4.6) %

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Note 9 — Accumulated Other Comprehensive Loss

The components of accumulated other comprehensive loss are as follows (in thousands):

	September 30, 2013	December 31, 2012
Cumulative foreign currency translation adjustment	$ (15,655)	$ (15,667)
Unrealized loss on hedges, net (1)	(9,847)	—
Accumulated other comprehensive loss	$ (25,502)	$ (15,667)

(1) Amount at September 30, 2013 is related to foreign currency hedges for the Grand Canyon, the Grand Canyon II and the Grand Canyon III as well as interest rate swap contracts we entered into in September 2013, and is net of deferred income taxes totaling $5.3 million (Notes 7 and 16).

Note 10 — Earnings Per Share

We have shares of restricted stock issued and outstanding, which remain subject to vesting requirements. Holders of such shares of unvested restricted stock are entitled to the same liquidation and dividend rights as the holders of our outstanding common stock and are thus considered participating securities. Under applicable accounting guidance, the undistributed earnings for each period are allocated based on the participation rights of both the common shareholders and holders of any participating securities as if earnings for the respective periods had been distributed. Because both the liquidation and dividend rights are identical, the undistributed earnings are allocated on a proportionate basis. Further, we are required to compute earnings per share ("EPS") amounts under the two class method in periods in which we have earnings from continuing operations. For periods in which we have a net loss we do not use the two class method as holders of our restricted shares are not contractually obligated to share in such losses.

The 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 Helix common shareholders by the weighted average shares of outstanding common stock. The calculation of diluted EPS is similar to basic EPS, except that the denominator includes dilutive common stock equivalents and the income included in the numerator excludes the effects of the impact of dilutive common stock equivalents, if any. The 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 September 30, 2013		Three Months Ended September 30, 2012	
	Income	Shares	Income	Shares
Basic:				
Continuing operations:				
Net income applicable to Helix	$ 44,593		$ 14,865	
Less: Income from discontinued operations, net of tax	(44)		(4,503)	
Income from continuing operations	44,549		10,362	
Less: Undistributed income allocable to participating securities – continuing operations	(337)		(104)	
Income applicable to common shareholders – continuing operations	$ 44,212	105,029	$ 10,258	104,256

Discontinued operations:							
Income from discontinued operations, net of tax	$	44		$	4,503		
Less: Undistributed income allocable to participating securities – discontinued operations		—			(45	)	
Income applicable to common shareholders – discontinued operations	$	44	105,029	$	4,458		104,256

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	Three Months Ended September 30, 2013		Three Months Ended September 30, 2012	
	Income	Shares	Income	Shares
Diluted:				
Continuing operations:				
Income applicable to common shareholders – continuing operations	$ 44,212	105,029	$ 10,258	104,256
Effect of dilutive securities:				
Share-based awards other than participating securities	—	107	—	112
Convertible preferred stock	—	—	10	361
Income applicable to common shareholders – continuing operations	$ 44,212	105,136	$ 10,268	104,729
Discontinued operations:				
Income from discontinued operations, net of tax	$ 44	105,136	$ 4,503	104,729

	Nine Months Ended September 30, 2013		Nine Months Ended September 30, 2012	
	Income	Shares	Income	Shares
Basic:				
Continuing operations:				
Net income applicable to Helix	$ 73,419		$ 125,233	
Less: Income from discontinued operations, net of tax	(1,073)		(95,572)	
Income from continuing operations	72,346		29,661	
Less: Undistributed income allocable to participating securities – continuing operations	(525)		(299)	
Income applicable to common shareholders – continuing operations	$ 71,821	105,036	$ 29,362	104,450
Discontinued operations:				
Income from discontinued operations, net of tax	$ 1,073		$ 95,572	
Less: Undistributed income allocable to participating securities – discontinued operations	(8)		(962)	
Income applicable to common shareholders – discontinued operations	$ 1,065	105,036	$ 94,610	104,450
Diluted:				
Continuing operations:				
Income applicable to common shareholders – continuing operations	$ 71,821	105,036	$ 29,362	104,450
Effect of dilutive securities:				
Share-based awards other than participating securities	—	116	—	86
Undistributed income reallocated to participating securities	—	—	2	—

Convertible preferred stock		—	—		30	361
Income applicable to common shareholders – continuing operations	$	71,821	105,152	$	29,394	104,897
Discontinued operations:						
Income from discontinued operations, net of tax	$	1,073	105,152	$	95,572	104,897

No diluted shares were included for the 2032 Notes for the three- and nine-month periods ended September 30, 2013 and 2012 as the conversion trigger of $32.53 per share was not met, and because we have the right to settle any such future conversions in cash at our sole discretion (Note 7). No diluted shares were included for the 2025 Notes for the three- and nine-month periods ended September 30, 2012 as the conversion trigger of $38.57 per share was not met.

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Note 11 — Employee Benefit Plans

Stock-Based Compensation Plans

We have two stock-based compensation plans: the 1995 Long-Term Incentive Plan, as amended (the "1995 Incentive Plan"), and the 2005 Long-Term Incentive Plan, as amended and restated effective May 9, 2012 (the "2005 Incentive Plan"). As of September 30, 2013, there were 6.5 million shares available for issuance under the 2005 Incentive Plan, which includes a maximum of 2.0 million shares that may be granted as incentive stock options. There were no stock option grants in the three- and nine-month periods ended September 30, 2013 and 2012. During the nine-month period ended September 30, 2013, the following grants of other share-based awards were made to executive officers and non-employee members of our Board of Directors under the 2005 Incentive Plan:

Date of Grant	Shares	Grant Date Fair Value Per Share	Vesting Period
January 2, 2013 (1)	89,329	$ 20.64	33% per year over three years
January 2, 2013 (2)	89,329	30.96	100% on January 1, 2016
January 2, 2013 (3)	1,620	20.64	100% on January 1, 2015
April 1, 2013 (3)	2,814	22.88	100% on January 1, 2015
July 1, 2013 (3)	2,740	23.04	100% on January 1, 2015

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

(2) Reflects the grant of performance share units ("PSUs") to our executive officers. The estimated fair value of the PSUs on grant date was determined using a Monte Carlo simulation model. The PSUs provide for an award based on the performance of our common stock over a three-year period with the maximum award being 200% of the original awarded PSUs and the minimum amount being zero. The vested PSUs will be settled in an equivalent number of shares of our common stock unless the Compensation Committee of our Board of Directors elects to pay in cash.

(3) Reflects the grant of restricted shares to certain members of our Board of Directors who have made an election to take their 2013 quarterly fees in stock in lieu of cash.

Compensation cost is recognized over the respective vesting periods on a straight-line basis. For the three- and nine-month periods ended September 30, 2013, $1.6 million and $6.7 million, respectively, were recognized as stock-based compensation expense related to share-based awards as compared with $1.8 million and $5.5 million for the three- and nine-month periods ended September 30, 2012, respectively. Additionally, for the first quarter of 2013, $1.3 million of stock-based compensation expense was reflected within our discontinued operations as a component of "Loss on sale of business, net of tax" (Note 4).

Long-Term Incentive Cash Plan

The 2005 Incentive Plan and the 2009 Long-Term Incentive Cash Plan (the "LTI Plans") provide long-term cash-based compensation to eligible employees. Cash awards historically have been both fixed sum amounts payable (for non-executive management only) as well as cash awards indexed to our common stock with the payment amount at each vesting date fluctuating based on the performance of our common stock (for both executive and non-executive management). These are measured based on the performance of our stock price over the applicable award period compared to a base price determined by the Compensation Committee of our Board of Directors at the time of the award. Cash award payments under the LTI Plans are made each year on the anniversary date of the award. Cash awards granted prior to 2012 have a vesting period of five years and cash awards granted in 2012 and 2013 have a vesting period of three years. The LTI 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.

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The cash awards made under the LTI Plans totaled $5.9 million in 2013 and $4.2 million in 2012. These awards were made to our executive officers and selected management employees in 2013 and to our executive officers in 2012. No cash awards were given to non-executive employees in 2012. Total compensation expense associated with the cash awards issued pursuant to the LTI Plans was $3.3 million ($2.1 million related to our executive officers) and $7.5 million ($4.4 million related to our executive officers) for the three- and nine-month periods ended September 30, 2013, respectively. For the three- and nine-month periods ended September 30, 2012, total compensation expense associated with the cash awards issued pursuant to the LTI Plans was $2.5 million ($2.2 million related to our executive officers) and $6.1 million ($5.1 million related to our executive officers), respectively. The liability balance for the cash awards issued under the LTI Plans was $13.2 million at September 30, 2013 and $13.0 million at December 31, 2012, including $10.2 million at September 30, 2013 and $11.7 million at December 31, 2012 associated with the cash awards issued to our executive officers under the LTI plans.

Employee Stock Purchase Plan

In May 2012, our shareholders approved the Helix Energy Solutions Group, Inc. Employee Stock Purchase Plan (the “ESPP”). The ESPP has 1.5 million authorized shares of our common stock, of which 1.3 million shares were available for issuance as of September 30, 2013. Eligible employees who participate in the ESPP may purchase shares of our common stock through payroll deductions on an after-tax basis over a four-month period beginning on January 1, May 1, and September 1 of each year during the term of the ESPP, subject to certain restrictions and limitations established by the Compensation Committee of our Board of Directors and Section 423 of the Internal Revenue Code. The per share price of common stock purchased under the ESPP is equal to 85% of the lesser of (i) its fair market value on the first trading day of the purchase period or (ii) its fair market value on the last trading day of the purchase period. The first purchase period under the ESPP began on September 1, 2012. The total value of the ESPP awards is calculated using the component approach where each award is computed as the sum of 15% of a share of non-vested stock, a call option on 85% of a share of non-vested stock, and a put option on 15% of a share of non-vested stock. Share-based compensation expense with respect to the ESPP was $0.2 million and $0.6 million for the three- and nine-month periods ended September 30, 2013, respectively. For the three- and nine-month periods ended September 30, 2012, share-based compensation expense with respect to the ESPP was $0.1 million.

For more information regarding our employee benefit plans, including our stock-based compensation plans, our long-term incentive cash plan and our employee stock purchase plan, see Note 9 to our 2012 Form 10-K.

Note 12 — Business Segment Information

Our operations are currently disaggregated into four business segments: Well Intervention, Robotics, Subsea Construction and Production Facilities. Our Well Intervention segment includes our vessels and related equipment that are used to perform both heavy and light well intervention services primarily in the Gulf of Mexico and North Sea regions. Our well intervention vessels include the Q4000, the Seawell, the Well Enhancer and the Skandi Constructor, which is chartered. We are currently constructing two additional well intervention vessels, the Q5000 and the Q7000. Additionally, the Helix 534, a refurbished drillship, is expected to join our fleet in December 2013. Our Robotics segment currently operates five chartered vessels and also includes ROVs, trenchers and ROVDrills designed to complement offshore construction and well intervention services. We have sold substantially all of the assets associated with our former Subsea Construction operations (Note 2). The Production Facilities segment includes our consolidated investment in the HP I and Kommandor LLC as well as our equity investments in Deepwater Gateway and Independence Hub that are accounted for under the equity method. All material intercompany transactions between the segments have been eliminated. In February 2013, we sold ERT and as a result, we have presented the assets and liabilities included in the sale of ERT and the historical operating results of our former Oil and Gas segment as discontinued operations in the accompanying condensed consolidated financial statements. See Note 4 for additional information regarding our discontinued operations.

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We evaluate our performance based on operating income and income before income taxes of each segment. Segment assets are comprised of all assets attributable to the reportable segment. Certain financial data by reportable segment are summarized as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Revenues —				
Well Intervention	$114,238	$88,711	$319,893	$274,249
Robotics	90,370	95,107	242,940	238,762
Subsea Construction	4,120	37,673	69,305	162,581
Production Facilities	24,366	20,024	68,933	60,009
Intercompany elimination	(12,977)	(24,405)	(51,347)	(91,188)
Total	$220,117	$217,110	$649,724	$644,413
Income (loss) from operations —				
Well Intervention	$33,544	$17,405	$93,906	$53,647
Robotics	16,392	22,627	28,991	50,301
Subsea Construction (1)	15,088	(7,020)	29,031	7,411
Production Facilities	14,136	10,180	39,964	30,111
Corporate and other	(16,522)	(23,015)	(64,260)	(61,434)
Intercompany elimination	21	39	(2,538)	(2,883)
Total	$62,659	$20,216	$125,094	$77,153
Equity in earnings of equity investments	$857	$1,392	$2,150	$7,547

(1) The 2013 amounts include the $1.1 million loss on the sale of the Caesar in June 2013 and the $15.6 million gain on the sale of the Express in July 2013 (Note 2).

Intercompany segment revenues are as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Well Intervention	$4,784	$5,797	$15,052	$18,231
Robotics	8,193	7,099	31,305	34,684
Subsea Construction	—	—	317	3,720
Production Facilities	—	11,509	4,673	34,553
Total	$12,977	$24,405	$51,347	$91,188

Intercompany segment profits (losses) (which only relate to intercompany capital projects) are as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Well Intervention	$(45)	$(57)	$(91)	$1,259

Robotics	67	62	2,602	98
Subsea Construction	—	—	158	1,657
Production Facilities	(43)	(44)	(131)	(131)
Total	$(21)	$(39)	$2,538	$2,883

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Segment assets are comprised of all assets attributable to each reportable segment. Corporate and other includes all assets not directly identifiable with our business segments, most notably the majority of our cash and cash equivalents. The following table reflects total assets by reportable segment (in thousands):

	September 30, 2013	December 31, 2012
Well Intervention	$ 1,191,001	$ 936,926
Robotics	276,057	258,117
Subsea Construction	57,623	303,479
Production Facilities	491,535	504,828
Corporate and other	495,690	483,003
Discontinued operations	—	900,227
Total	$ 2,511,906	$ 3,386,580

Note 13 — Related Party Transactions

Our Chief Executive Officer, Owen Kratz, through Class A limited partnership interests in OKCD Investments, Ltd. ("OKCD"), personally owns approximately 84% of the partnership. OKCD receives a royalty from ERT, which was a wholly owned subsidiary of Helix until ERT was sold in February 2013. Payments to OKCD during the period in which Helix owned ERT totaled $0.6 million in the three-month period ended March 31, 2013, and $1.8 million and $5.6 million, respectively, in the three- and nine-month periods ended September 30, 2012.

Note 14 — Commitments and Contingencies and Other Matters

Commitments

In March 2012, we executed a contract with a shipyard in Singapore for the construction of a newbuild semi-submersible well intervention vessel, the Q5000. This $386.5 million shipyard contract represents the majority of the expected costs associated with the construction of the Q5000. Under the terms of this contract, payments are made in a fixed percentage of the contract price, together with any variations, on contractually scheduled dates. At September 30, 2013, our total investment in the Q5000 was $207.6 million, including $173.8 million of scheduled payments made to the shipyard.

In July 2012, we contracted to charter the Skandi Constructor for use in our North Sea well intervention operations. The vessel was delivered to us on April 1, 2013. The initial term of the charter will expire in March 2016.

In August 2012, we acquired the Discoverer 534 drillship from a subsidiary of Transocean Ltd. for $85 million. The vessel, renamed the Helix 534, is undergoing upgrades and modifications to render it suitable for use as a well intervention vessel. At September 30, 2013, our investment in the acquisition and subsequent upgrades to and modifications of the Helix 534 totaled $184.7 million, including related well control equipment.

In January 2013, we contracted to charter the Rem Installer for use in our robotics operations. The vessel was delivered to us in July 2013. The initial term of the charter will expire in July 2016.

In February 2013, we contracted to charter the Grand Canyon II and Grand Canyon III for use in our robotics operations. The terms of the charters will be five years from the respective delivery dates, which are expected to be in 2014 and 2015.

In September 2013, we executed a contract with the same shipyard in Singapore that is currently constructing the Q5000. This contract provides for the construction of a newbuild semi-submersible well intervention vessel, the Q7000, which will be built to North Sea standards. This $346.0 million shipyard contract represents the majority of the expected costs associated with the construction of the Q7000. Under the terms of this contract, 20% of the contract price was paid upon the signing of the contract and the remaining 80% will be paid upon the delivery of the vessel. At September 30, 2013, our total investment in the Q7000 was $74.4 million, including the $69.2 million paid to the shipyard upon signing the contract.

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Contingencies and Claims

Under terms of the equity purchase agreement for the sale of ERT, we required the buyer to provide bonding in a sufficient amount as determined by the Bureau of Ocean Energy Management ("BOEM") to cover the decommissioning costs of ERT's lease properties and thus to replace and allow for a full discharge of our existing guaranty to the BOEM for ERT's lease obligations. The buyer posted the bonding required by the equity purchase agreement, and we have submitted a formal request to the BOEM for a release of our guaranty.

In 2007, we were subcontracted to perform development work for a large gas field offshore India. Work commenced in the fourth quarter of 2007 and we completed our scope of work in the third quarter of 2009. To date we have collected approximately $303 million related to this project with an amount of trade receivables yet to be collected. We have requested arbitration in India pursuant to the terms of the subcontract to pursue our claims and the prime contractor has also requested arbitration and has asserted certain counterclaims against us. If we are not successful in resolving these matters through ongoing discussions with the prime contractor, then arbitration in India remains a potential remedy. Based on a number of factors associated with the ongoing negotiations with the prime contractor, in 2010 we established a $4 million allowance against our trade receivable balance that reduces its balance to an amount we believe is ultimately realizable ($17.5 million). At the time of this filing no final commercial resolution of this matter has been reached.

We have received value added tax (VAT) assessments from the State of Andhra Pradesh, India (the "State") in the amount of approximately $28 million for the tax years 2010, 2009, 2008 and 2007 related to an Indian subsea construction and diving contract that we entered into in December 2006. The State claims that we owe unpaid taxes related to products consumed by us during the period of the contract. We are of the opinion that the State has arbitrarily made these assessments and has no foundation for them. We believe that we have complied with all rules and regulations as related to VAT in the State. We also believe that our position is supported by law and intend to vigorously defend our position. However, the ultimate outcome of these assessments and our potential liability from them, if any, cannot be determined at this time. If the current assessments are upheld, they may have a material negative effect on our consolidated results of operations while also impacting our financial position.

Litigation

On July 8, 2011, a shareholder derivative lawsuit styled City of Sterling Heights Police & Fire Retirement System v. Owen Kratz, et al. was filed in the United States District Court for the Southern District of Texas, Houston Division. In the suit, the plaintiff makes claims against our Board of Directors, certain of our former directors, certain of our current and former executives, and the independent compensation consultant to the Compensation Committee of our Board of Directors, for breaches of the fiduciary duty of loyalty, unjust enrichment and aiding and abetting the alleged breaches of fiduciary duty relating to the long-term equity awards granted in 2010 to the Company's then executive officers who are defendants. The Company filed a motion to dismiss the claim asserting that the plaintiff has not (i) pled specific facts excusing its failure to make pre-suit demand on the Company's Board of Directors as required by Minnesota law; (ii) filed proper verification; or (iii) stated a claim. A ruling regarding the motion is pending.

On May 12, 2012, a shareholder derivative lawsuit styled Mark Lucas v. Owen Kratz, et al. was filed in the 270th Judicial District in the District Court of Harris County, Texas. In the suit, the plaintiff makes claims against our Board of Directors, certain of our former directors, certain of our current and former executive officers and the independent compensation consultant to the Compensation Committee of our Board of Directors, for breaches of the fiduciary duties of candor, good faith and loyalty, unjust enrichment and aiding and abetting the alleged breaches of fiduciary duty relating to the long-term equity awards granted in 2010 to certain of our executive officers. This case is essentially a "copycat" complaint asserting similar causes of action arising out of the same facts as set forth in the federal action described above. The plaintiff is generally demanding disgorgement of the excessive compensation, restraint on the disposition/exercise of the alleged improperly awarded equity, implementation of additional internal controls, and attorney's fees and costs of litigation. We filed motions to stay and dismiss the proceeding, which motions were denied by the trial court judge. We filed a petition for a writ of mandamus with the state appellate court, in which we requested that court to direct the district court to grant our motion to stay or dismiss the case. The appellate court denied the request to grant mandamus with respect to this requested

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relief, but did grant a conditional writ of mandamus ordering the lower court to vacate its ruling to the extent the plaintiff failed to plead with particularity that our Board of Directors wrongfully refused his demand, and that he was a shareholder of record at the relevant time.

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

Note 15 — Fair Value Measurements

Certain of our financial assets and liabilities are measured and reported at fair value on a recurring basis as required under applicable accounting requirements. These requirements establish a hierarchy for inputs used in measuring fair value. The fair value is to be calculated based on assumptions that market participants would use in pricing assets and liabilities and not on assumptions specific to the entity. The statement requires that each asset and liability carried at fair value be classified into one of the following categories:

- 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).

The following table provides additional information related to other financial instruments measured at fair value on a recurring basis at September 30, 2013 (in thousands):

	Level 1	Level 2 (1)	Level 3	Total	Valuation Technique
Assets:					
Foreign exchange contracts	$ —	$ 6	$ —	$ 6	(c)
Interest rate swaps	—	421	—	421	(c)
Liabilities:					
Fair value of long-term debt (2)	562,259	111,547	—	673,806	(a)
Foreign exchange contracts	—	14,839	—	14,839	(c)
Interest rate swaps	—	732	—	732	(c)
Total net liability	$ 562,259	$ 126,691	$ —	$ 688,950	

(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.

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(2) See Note 7 for additional information regarding our long-term debt. The fair value of our debt is as follows:

	September 30, 2013	
	Carrying Value	Fair Value (b)
Term Loan (matures June 2018)	$ 296,250	$ 295,509
2032 Notes (mature March 2032) (a)	200,000	266,750
MARAD Debt (matures February 2027)	100,168	111,547
Total debt	$ 596,418	$ 673,806

(a) Carrying value excludes the related unamortized debt discount of $27.8 million at September 30, 2013.

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

Note 16 — Derivative Instruments and Hedging Activities

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

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 derivative fair values 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 other comprehensive income or loss (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 17 to our 2012 Form 10-K.

Interest Rate Risk

We enter into interest rate swaps to stabilize cash flows related to our long-term debt subject to variable interest rates. In September 2013, we entered into interest rate swap contracts to fix the interest rate on $148.1 million of our Term Loan debt. These monthly contracts begin in October 2013 and extend through October 2016. Changes in the fair value of an interest rate swap are deferred to the extent the swap is effective. These changes are recorded as a component of accumulated other comprehensive income (loss) until the anticipated interest payments occur and are recognized in interest expense. The ineffective portion of the interest rate swap, if any, will be recognized immediately in earnings within the line titled "Net interest expense."

Foreign Currency Exchange Rate Risk

Because we operate in various regions in the world, we conduct a portion of our business in currencies other than the U.S. dollar. We entered into various foreign currency forwards to stabilize expected cash outflows relating to certain vessel charters that are denominated in British pounds and Norwegian kroner.

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In January 2013, we entered into foreign currency exchange contracts to hedge the foreign currency exposure associated with the Grand Canyon charter payments ($104.6 million) denominated in Norwegian kroner (NOK591.3 million), through September 2017. In February 2013, we entered into similar foreign currency exchange contracts for the Grand Canyon II and Grand Canyon III charter payments ($100.4 million and $98.8 million) denominated in Norwegian kroner (NOK594.7 million and NOK595.0 million), through July 2019 and February 2020, respectively. These contracts currently qualify for hedge accounting treatment. All of our remaining foreign exchange contracts are not accounted for as hedge contracts and changes in their fair value are marked-to-market each reporting period.

Quantitative Disclosures Related to Derivative Instruments

As a result of the announcement in December 2012 of the sale of ERT, we de-designated all of our remaining oil and natural gas derivative contracts as hedging instruments. In addition, under the terms of our former credit agreement (Note 7), we were required to use a portion of the proceeds from the sales of ERT, the Caesar and the Express to make payments to reduce our indebtedness. Because of the probability that the former term loan debt would be totally repaid before the expiration of our then existing interest rate swaps, we also concluded that those swaps also no longer qualified as cash flow hedges. In February 2013, we settled all of our outstanding commodity derivative contracts and then existing interest rate swap contracts for approximately $22.5 million and $0.6 million, respectively.

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

	As of September 30, 2013		As of December 31, 2012	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Asset Derivatives:				
Oil contracts	Other current assets	$—	Other current assets	$5,800
Foreign exchange contracts	Other current assets	6	Other current assets	146
		$6		$5,946
Liability Derivatives:				
Oil contracts	Accrued liabilities	$—	Accrued liabilities	$15,777
Interest rate swaps	Accrued liabilities	—	Accrued liabilities	489
Interest rate swaps	Other non-current liabilities	—	Other non-current liabilities	32
		$—		$16,298

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

	As of September 30, 2013		As of December 31, 2012	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Asset Derivatives:				
Interest rate swaps	Other assets, net	$421	Other assets, net	$—
		$421		$—
Liability Derivatives:				
Foreign exchange contracts	Accrued liabilities	$1,660	Accrued liabilities	$—
Interest rate swaps	Accrued liabilities	732	Accrued liabilities	—

Foreign exchange contracts	Other non-current liabilities	13,179	Other non-current liabilities	—
		$15,571		$—

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Ineffectiveness associated with our foreign exchange and interest rate swap contracts was immaterial for all periods presented. The following tables present the impact that derivative instruments designated as cash flow hedges had on our accumulated other comprehensive income (loss) (net of tax), and our condensed consolidated statements of operations (in thousands).

	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Foreign exchange contracts	$1,186	$—	$(9,645)	$—
Oil and natural gas commodity contracts	—	(19,868)	—	(20,664)
Interest rate swaps	(202)	(168)	(202)	(494)
	$984	$(20,036)	$(9,847)	$(21,158)

	Location of Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2013	2012	2013	2012
Oil and natural gas commodity contracts	Income from discontinued operations, net of tax	$—	$414	$—	$8,546
Interest rate swaps	Net interest expense	—	(121)	—	(434)
Foreign exchange contracts	Cost of sales	(396)	—	(900)	—
		$(396)	$293	$(900)	$8,112

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

	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2013	2012	2013	2012
Oil and natural gas commodity contracts	Income from discontinued operations, net of tax	$—	$633	$—	$633
Oil and natural gas commodity contracts	Loss on commodity derivative contracts	—	—	(14,113)	—
Interest rate swaps	Other expense, net	—	—	(86)	—
Foreign exchange contracts	Other expense, net	498	217	(693)	381
		$498	$850	$(14,892)	$1,014

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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 Securities Exchange Act of 1934, as amended (the “Exchange Act”). All statements included herein or incorporated herein by reference that are predictive in nature, that depend upon or refer to future events or conditions, or that use terms and phrases such as “achieve,” “anticipate,” “believe,” “estimate,” “expect,” “forecast,” “project,” “propose,” “strategy,” “predict,” “envision,” “hope,” “intend,” “will,” “continue,” “may,” “potential,” “should,” “cou terms and phrases are forward-looking statements. Included in forward-looking statements are, among other things:

- statements regarding our business strategy or any other business plans, forecasts or objectives, any or all of which are subject to change;
- statements relating to the construction or acquisition of vessels or equipment and any anticipated costs related thereto, including the construction of the Q5000 and the Q7000 and the upgrades to and modifications of the Helix 534 (Note 14);
- statements regarding projections of revenues, gross margin, expenses, earnings or losses, working capital or other financial items;
- statements regarding any financing transactions or arrangements, or ability to enter into such transactions;
- statements regarding anticipated legislative, governmental, regulatory, administrative or other public body actions, requirements, permits or decisions;
- statements regarding the collectability of our trade receivables;
- statements regarding anticipated developments, industry trends, performance or industry ranking;
- statements regarding general economic or political conditions, whether international, national or in the regional and local market areas in which we do business;
- statements related to our ability to retain key members of our senior management and key employees;
- statements related to the underlying assumptions related to any projection or forward-looking statement; and
- any other statements that relate to non-historical or future information.

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

- impact of domestic and global economic conditions and the future impact of such conditions on the oil and gas industry and the demand for our services;
- unexpected delays in the delivery to or chartering of new vessels for our well intervention and robotics fleet, including the Helix 534 (expected in the fourth quarter of 2013), the Q5000 (expected in 2015), the Q7000 (expected in 2016), the Grand Canyon II (expected in 2014) and the Grand Canyon III (expected in 2015);
- unexpected future capital expenditures (including the amount and nature thereof);
- the results of our continuing efforts to control costs and improve performance;
- the success of our risk management activities;

- the effects of competition;
- the effects of indebtedness, which could adversely restrict our ability to operate, could make us vulnerable to general adverse economic and industry conditions, could place us at a competitive disadvantage compared to our competitors that have less debt and could have other adverse consequences to us;
- the 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;

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- the long-term availability (or lack thereof) of capital (including any financing) to fund our business strategy and/or operations, and the terms of any such financing;
- the 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 2012 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

Our Business Strategy

We are an international offshore energy company that provides specialty services to the offshore energy industry, with a focus on our well intervention and robotics operations. Since 2008 we have focused on improving our balance sheet and increasing our liquidity through dispositions of non-core business assets and the related repayment of a significant portion of our indebtedness, as well as the reduction in our capital spending through 2011. This goal was substantially accomplished with the sale of ERT in February 2013 and the sales in June and July 2013 of our two remaining pipelay vessels and related equipment. As such, we are now positioned for growth and expansion.

Our focus is to expand our well intervention and robotics businesses. We believe that focusing on these services will deliver higher long-term financial returns to us than the businesses and assets that we have chosen to monetize. We are making strategic investments that expand our service capabilities or add capacity to existing services in our key operating regions. We are strengthening our well intervention fleet by constructing two newbuild semi-submersible vessels, the Q5000 and the Q7000, and by our acquisition of the Discoverer 534 drillship (renamed the Helix 534), which is undergoing upgrades and modifications to render it suitable for use as a well intervention vessel. We have also chartered the Skandi Constructor, which has now been fully equipped and integrated into our North Sea well intervention operations. In addition, we are expanding our robotics operations by acquiring additional remotely operated vehicles ("ROVs") and trenchers as well as taking delivery of a newbuild chartered ROV support vessel, the Grand Canyon. In 2013, we entered into charter agreements for two similar vessels, the Grand Canyon II and Grand Canyon III, which are expected to be delivered in 2014 and 2015, respectively. We also chartered the Rem Installer, which was delivered to us in July 2013.

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. Generally, spending for our services fluctuates directly with the direction of oil and natural gas prices. The performance of our operations is also largely dependent on prevailing market prices for oil and natural gas, which are impacted by global economic conditions, hydrocarbon production and capacity, geopolitical issues, weather, and several other factors, including but not limited to:

- worldwide economic activity, including available access to global capital and capital markets;
- demand for oil and natural gas, especially in the United States, Europe, China and India;

- economic and political conditions in the Middle East and other oil-producing regions;
- the effect of regulations on offshore Gulf of Mexico oil and gas operations;
- actions taken by the Organization of the Petroleum Exporting Countries;
- 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 gas;
- the ability of oil and natural gas companies to generate funds or otherwise obtain external capital for exploration, development and production operations;
- the sale and expiration dates of offshore leases in the United States and overseas;
- technological advances affecting energy exploration production transportation and consumption;
- weather conditions;

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- environmental and other governmental regulations; and
- domestic and international tax policies.

Despite strong financial market performances in recent months, the global economy may grow at a slower rate than many economists had previously forecasted for the remainder of 2013, weighed by modest recovery in mature markets and gradual slowdown in major emerging markets. The U.S. economy showed some positive signs in the second quarter of 2013 with steady job growth, especially in the private sector, and a modest increase in consumer confidence. However, the recent shutdown of the U.S. Federal government and the resulting short-term budget and debt ceiling deals could potentially introduce additional volatility into the market that may have a negative effect not only on the U.S. economy but also on the global economy. Any impact associated with the recent events in Washington D.C. may not be known over the near term. The European economy remains weak despite stable financial market performances and some improvements in business and consumer confidence. The slowdown in many emerging economies is continuing. Weak economic data could affect the global equity and commodity markets as well as effectively hampering normal business activities. The oil and natural gas industry has been adversely affected by the uncertainty of the general timing and level of the economic recovery as well the uncertainties concerning increased government regulation of the industry in the United States. Over the longer term, the fundamentals for our business remain generally favorable as the need for the continual replenishment of oil and gas production is the primary driver of demand for our services.

We believe that the long-term industry fundamentals are positive based on the following factors: (1) long-term increasing world demand for oil and natural gas emphasizing the need for continual replenishment of oil and gas production; (2) mature global production rates for offshore and subsea wells; (3) globalization of the natural gas market; (4) an increasing number of mature and small reservoirs; (5) increasing offshore activity, particularly in deepwater; and (6) an increasing number of subsea developments.

Helix Fast Response System

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

RESULTS OF OPERATIONS

Historically, we disaggregated our well intervention, robotics, subsea construction and production facilities operations into two reportable segments: Contracting Services and Production Facilities. However, following the recent completion of the sale of our remaining subsea construction pipelay vessels and related equipment (Note 2) and the continued emphasis on expanding and growing our well intervention and robotics operations, we have now disaggregated our former Contracting Services segment into three reportable segments: Well Intervention, Robotics and Subsea Construction. Production Facilities remains a business segment. Previously, we had an additional business segment, Oil and Gas. In December 2012, we announced a definitive agreement for the sale of ERT. The sale occurred on February 6, 2013. Accordingly, the results of ERT are presented as discontinued operations for all periods presented in this Quarterly Report on Form 10-Q.

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

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Contracting Services Operations

We seek to provide services and methodologies that we believe are critical to developing offshore reservoirs and maximizing production economics. Our services include Well Intervention, Robotics and Subsea Construction (see Note 2 regarding the dispositions of our remaining subsea construction vessels and related equipment) business segments. Our businesses operate primarily in the Gulf of Mexico, North Sea, Asia Pacific and West Africa regions, with services that cover the lifecycle of an offshore oil or gas field. In addition, our robotics operations are often contracted for the development of renewable energy projects (wind farms). Backlog contracts are cancelable without penalty in many cases. Backlog is not necessarily a reliable indicator of total annual revenue for our services as contracts may be added, cancelled and in many cases modified while in progress. As of September 30, 2013, our consolidated backlog totaled approximately $2.0 billion, including $166.1 million expected to be performed over the remainder of 2013. The substantial majority of our backlog is associated with our Well Intervention and Production Facilities business segments. In early April of 2013, we entered into a five-year contract with BP to provide well intervention services with our deepwater well intervention semi-submersible vessel, the Q5000, currently being constructed in Singapore and expected to be delivered in 2015.

Our Production Facilities segment reflects the results associated with the operations of the HP I as well as our equity investments in two Gulf of Mexico production facilities (Note 6). In connection with the sale of ERT, an amended fee arrangement for usage of the HP I at the Phoenix field was agreed upon with the new owner of ERT. Under the terms of this arrangement, ERT will pay us a lower fixed annual demand fee; however, ERT also will pay us a variable throughput fee. We anticipate that the total combined fees will approximate at least the previous fixed annual demand fee over the life of the contract. Currently, the fees that we are receiving exceed the previous fixed annual demand fee. The revised terms now also provide that the HP I will continue to provide service to ERT's Phoenix field through at least December 31, 2016.

Discontinued Operations

In February 2013, we sold ERT for $624 million plus consideration in the form of overriding royalty interests in ERT's Wang well and certain other of its future exploration prospects. As a result, we have presented the assets and liabilities included in the sale of ERT and the historical operating results of our former Oil and Gas segment as discontinued operations in the accompanying condensed consolidated financial statements (Notes 2 and 4). The Wang well commenced production in April 2013.

Non-GAAP Financial Measures

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

We define EBITDA as income from continuing operations plus income taxes, net interest expense and other and depreciation and amortization expense. We separately disclose our non-cash asset impairment charges, which, if not material, would be reflected as a component of our depreciation and amortization expense. Loss on early extinguishment of long-term debt is considered equivalent to additional interest expense.

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

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We also provide a measure of Adjusted EBITDAX, which combines our measure of Adjusted EBITDA from continuing operations and the measure of Adjusted EBITDAX from discontinued operations. Our discontinued operations represent ERT which was sold in February 2013. We define Adjusted EBITDAX from discontinued operations as income from discontinued operations, net of tax (Note 4) plus income taxes, net interest expense and other, depreciation, depletion, amortization and accretion expense and exploration expenses.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Net income from continuing operations	$45,348	$11,162	$74,711	$32,039
Adjustments:				
Income tax provision (benefit)	7,058	1,270	16,078	(1,405)
Net interest expense and other	4,219	9,176	30,136	36,939
Loss on extinguishment of long-term debt	8,572	—	12,100	17,127
Depreciation and amortization	21,850	24,797	71,542	72,185
Asset impairment charges	—	4,594	—	19,184
EBITDA from continuing operations	87,047	50,999	204,567	176,069
Adjustments:				
Noncontrolling interest Kommandor LLC	(1,037)	(1,037)	(3,078)	(3,089)
(Gain) loss on sale of assets	(15,812)	12,933	(14,727)	12,933
ADJUSTED EBITDA from continuing operations	$70,198	$62,895	$186,762	$185,913
ADJUSTED EBITDA from continuing operations	$70,198	$62,895	$186,762	$185,913
ADJUSTED EBITDAX from discontinued operations (1)	—	64,539	31,754	301,688
ADJUSTED EBITDAX	$70,198	$127,434	$218,516	$487,601

(1) Amounts relate to ERT, which was sold in February 2013 (Notes 2 and 4). Below is a reconciliation of our net income from discontinued operations to Adjusted EBITDAX from discontinued operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Net income from discontinued operations	$44	$4,503	$1,073	$95,572
Adjustments:				
Income tax provision	24	3,697	579	52,125
Net interest expense and other	—	6,959	2,732	21,209
Depreciation and amortization	—	38,697	1,226	126,269
Exploration expenses	—	623	3,514	2,469
Hedge ineffectiveness on commodity derivative contracts	—	10,060	—	2,330
(Gain) loss on sale of assets	(68)	—	22,630	1,714

ADJUSTED EBITDAX from discontinued operations	$—	$64,539	$31,754	$301,688

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Comparison of Three Months Ended September 30, 2013 and 2012

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

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Increase/ (Decrease)
Revenues (in thousands) —			
Well Intervention	$114,238	$88,711	$25,527
Robotics	90,370	95,107	(4,737)
Subsea Construction	4,120	37,673	(33,553)
Production Facilities	24,366	20,024	4,342
Intercompany elimination	(12,977)	(24,405)	11,428
	$220,117	$217,110	$3,007
Gross profit (in thousands) —			
Well Intervention	$36,406	$22,260	$14,146
Robotics	19,685	25,126	(5,441)
Subsea Construction	(335)	7,108	(7,443)
Production Facilities	14,287	10,300	3,987
Corporate and other	(607)	(6,914)	6,307
Intercompany elimination	21	39	(18)
	$69,457	$57,919	$11,538
Gross Margin —			
Well Intervention	32%	25%	
Robotics	22%	26%	
Subsea Construction	(8)%	19%	
Production Facilities	59%	51%	
Total company	32%	27%	
Number of vessels (1) / Utilization (2)			
Contracting Services:			
Well Intervention vessels	4/84%	3/81%	
ROVs	57/68%	53/73%	
Robotics vessels	5/98%	7/98%	
Subsea Construction vessels	N/A	2/93%	

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

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

Intercompany segment revenues are as follows (in thousands):

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Increase/ (Decrease)

Well Intervention	$4,784	$5,797	$(1,013)
Robotics	8,193	7,099	1,094
Production Facilities	—	11,509	(11,509)
	$12,977	$24,405	$(11,428)

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Intercompany segment profit is as follows (in thousands):

	Three Months Ended September 30,		Increase/
	2013	2012	(Decrease)
Well Intervention	$(45)	$(57)	$12
Robotics	67	62	5
Production Facilities	(43)	(44)	1
	$(21)	$(39)	$18

In reviewing the discussion below of our results of operations, please refer to the tables above and Note 12 for supplemental information regarding our business segment results. This discussion specifically refers to our Well Intervention, Robotics and Production Facilities segments. We recently sold our remaining Subsea Construction vessels and related equipment (Note 2). Information regarding our former Oil and Gas segment is presented under "Discontinued Operations — Oil and Gas" below and in Note 4.

Revenues. Our total revenues increased by 1% for the three-month period ended September 30, 2013 as compared to the same period in 2012 primarily reflecting the increases in our Well Intervention revenues and all of our Production Facilities revenues becoming third party revenues following the sale of ERT. The increase in our revenues was negatively affected by the sales of our subsea construction pipelay vessels and related equipment in June and July 2013 (Note 2).

Our Well Intervention revenues increased by 29% for the three-month period ended September 30, 2013 as compared to the same period in 2012. These higher revenues are primarily attributable to the addition of one chartered vessel, the Skandi Constructor, to the well intervention fleet effective April 1, 2013 and increased utilization of our other well intervention vessels.

Our Robotics revenues decreased by 5% during the third quarter of 2013 from the same period last year reflecting two fewer spot market vessels and lower utilization of our ROV assets, offset in part by an increased number of ROVs and higher ROVDrill revenues. Our Robotics segment also continues to be affected by lower year-over-year trenching revenues reflecting the deferral of some expected projects until the end of 2013 or into 2014.

Our Production Facilities revenues increased by 22% for the three-month period ended September 30, 2013 as compared to the same period in 2012, which reflects a substantial increase in our total revenues under the new fee arrangement with ERT for processing of production from the Phoenix field (see "Contracting Services Operations" above). The quarterly HFRS retainer fees also increased effective April 1, 2013 as a result of new four-year agreements (see "Helix Fast Response System" above).

Gross Profit. Our total gross profit increased by 20% for the three-month period ended September 30, 2013 as compared to the same period in 2012. The gross profit associated with our Well Intervention segment increased by 64% during the third quarter of 2013 as compared to the same period in 2012 reflecting the Skandi Constructor re-entering our fleet in early September after downtime earlier in the quarter to upgrade and equip the vessel for well intervention operations, and higher utilization rates for the other three well intervention vessels. During the third quarter of 2012, we recorded a $4.4 million impairment charge to reduce the remaining well intervention assets of our former Australian operations to their then estimated fair value.

The approximate 22% decrease in the gross profit associated with our Robotics segment during the three-month period ended September 30, 2013 as compared to the same period in 2012 is primarily attributable to the reduction in revenues reflecting two fewer spot market vessels in the current year period and the increased idle time related to some of our older model ROVs, offset in part by the addition of a number of newer model ROVs and trenchers.

Gain (Loss) on Sale of Assets. The gain on sale of assets for the three-month period ended September 30, 2013 primarily reflects the sale of the Express in July 2013 (Note 2). The $12.9 million loss for the three-month period ended September 30, 2012 reflects the sale of the Intrepid in September 2012.

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Selling, General and Administrative Expenses. Our selling, general and administrative expenses decreased by $2.2 million for the three-month period ended September 30, 2013 as compared to the same period in 2012. The decrease reflects the reduction in the size of our organization following the sale of ERT in February 2013, the winding up of our subsea construction operations, and the related effect of these transactions on the level of our corporate staffing. The decrease was partially offset by a $2.1 million charge to increase our allowance for uncollectible accounts in the third quarter of 2013.

Equity in Earnings of Investments. Equity in earnings of investments decreased by $0.5 million for the three-month period ended September 30, 2013 as compared to the same period in 2012. The decrease reflects lower throughput at both the Deepwater Gateway and Independence Hub facilities.

Net Interest Expense. Our net interest expense totaled $6.6 million for the three-month period ended September 30, 2013 as compared to $11.3 million for the same period in 2012. The decrease reflects a reduction in interest expense and increases in capitalized interest and interest income. The decrease in interest expense from $12.7 million in 2012 to $9.4 million in 2013 reflects the substantial reduction in our indebtedness, including the $318.4 million repayment of debt in February 2013 following the sale of ERT and our redemption in July 2013 of the remaining $275 million of 9.5% Senior Unsecured Notes outstanding. Capitalized interest totaled $2.6 million for the third quarter of 2013 as compared to $1.2 million for the third quarter of 2012. Generally, our capitalized interest will be increasing as the construction of the Q5000 and the Q7000 and the upgrades to and modifications of the Helix 534 progress. Interest income totaled $0.3 million for the third quarter of 2013 as compared to $0.2 million for the same period in 2012.

Loss on Early Extinguishment of Long-term Debt. The $8.6 million loss in the third quarter of 2013 was associated with our redemption of the remaining $275 million Senior Unsecured Notes outstanding. The loss reflects the $6.5 million call premium and the acceleration of the remaining $2.1 million of unamortized deferred financing fees related to the original issuance of the Senior Unsecured Notes (Note 7).

Other Income, Net. We reported net other income of $2.4 million for the three-month period ended September 30, 2013 as compared to $2.1 million for the same period in 2012. These amounts primarily reflect foreign exchange fluctuations in our non-U.S. dollar functional currencies. The foreign exchange gains were attributed to the weakening of the U.S. dollar against other global currencies. Included in these foreign exchange gains were $0.5 million and $0.2 million related to our foreign exchange forward contracts in the third quarters of 2013 and 2012, respectively (Note 16).

Other Income – Oil and Gas. The $1.7 million income for the three-month period ended September 30, 2013 primarily represents the proceeds associated with our overriding royalty interests in ERT’s Wang well following its initial production in late April 2013. The Wang well is currently shut in while the HP I vessel is undergoing its regulatory dry dock requirements. It is expected that the HP I will return to the Phoenix field in November 2013 and production from that field, including the Wang well, will be reestablished.

Income Tax Provision. Income taxes reflected an expense of $7.1 million in the third quarter of 2013 as compared to $1.3 million in the same period last year. The variance primarily reflects increased profitability in the current year period. The effective tax rate of 13.5% for the third quarter of 2013 was less favorable than 10.2% that was recorded for the third quarter of 2012 as a result of projected year-over-year increases in profitability in the United States.

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Comparison of Nine Months Ended September 30, 2013 and 2012

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

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012	Increase/ (Decrease)
Revenues (in thousands) —			
Well Intervention	$319,893	$274,249	$45,644
Robotics	242,940	238,762	4,178
Subsea Construction	69,305	162,581	(93,276)
Production Facilities	68,933	60,009	8,924
Intercompany elimination	(51,347)	(91,188)	39,841
	$649,724	$644,413	$5,311
Gross profit (in thousands) —			
Well Intervention	$101,887	$65,937	$35,950
Robotics	38,000	57,740	(19,740)
Subsea Construction	15,439	23,667	(8,228)
Production Facilities	40,420	30,507	9,913
Corporate and other	(3,687)	(16,128)	12,441
Intercompany elimination	(2,538)	(2,883)	345
	$189,521	$158,840	$30,681
Gross Margin —			
Well Intervention	32%	24%	
Robotics	16%	24%	
Subsea Construction	22%	15%	
Production Facilities	59%	51%	
Total company	29%	25%	
Number of vessels (1) / Utilization (2)			
Contracting Services:			
Well Intervention vessels	4/91%	3/78%	
ROVs	57/61%	53/69%	
Robotics vessels	5/89%	7/94%	
Subsea Construction vessels	0/92%	2/86%	

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

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

Intercompany segment revenues are as follows (in thousands):

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012	Increase/ (Decrease)

Well Intervention	$15,052	$18,231	$(3,179)
Robotics	31,305	34,684	(3,379)
Subsea Construction	317	3,720	(3,403)
Production Facilities	4,673	34,553	(29,880)
	$51,347	$91,188	$(39,841)

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Intercompany segment profit is as follows (in thousands):

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012	Increase/ (Decrease)
Well Intervention	$(91)	$1,259	$(1,350)
Robotics	2,602	98	2,504
Subsea Construction	158	1,657	(1,499)
Production Facilities	(131)	(131)	—
	$2,538	$2,883	$(345)

In reviewing the discussion below of our results of operations, please refer to the tables above and Note 12 for supplemental information regarding our business segment results. This discussion specifically refers to our Well Intervention, Robotics and Production Facilities segments. We recently sold our remaining Subsea Construction vessels and related equipment (Note 2). Information regarding our former Oil and Gas segment is presented under "Discontinued Operations — Oil and Gas" below and in Note 4.

Revenues. Our total revenues increased by 1% for the nine-month period ended September 30, 2013 as compared to the same period in 2012. The increase in revenues primarily reflects the increases in our Well Intervention revenues and all of our Production Facilities revenues becoming third party revenues following the sale of ERT in February 2013. This revenue increase was negatively affected by the sales of our pipelay vessels and related equipment in June and July 2013 (Note 2).

Our Well Intervention revenues increased by 17% for the nine-month period ended September 30, 2013 as compared to the same period in 2012 reflecting the addition of one chartered vessel, the Skandi Constructor, and the higher utilization of our other three well intervention vessels. During the nine-month period ended September 30, 2012, the Q4000, the Seawell and the Well Enhancer vessels all underwent required regulatory dry docks, resulting in a larger number of idle days in the prior year period as compared to the current year period.

Robotics revenues increased by 2% during the nine-month period ended September 30, 2013 primarily reflecting an increased number of ROVs and higher ROVDrill revenues. This revenue increase was adversely affected by a decrease in the number of spot market vessels being utilized, a reduction in utilization rates resulting from larger seasonal declines in the North Sea in early 2013, and lower period-over-period trenching activities associated with the deferral of many previously anticipated 2013 trenching projects in the North Sea region until the end of 2013 or into 2014.

Our Production Facilities revenues increased by 15% for the nine-month period ended September 30, 2013 as compared to the same period in 2012, which reflects a substantial increase in our total revenues under the new fee arrangement with ERT for processing of production from the Phoenix field. The quarterly HFRS retainer fees also increased effective April 1, 2013 as a result of new four-year agreements.

Gross Profit. Our total gross profit increased by 19% for the nine-month period ended September 30, 2013 as compared to the same period in 2012. The gross profit associated with our Well Intervention segment increased by 55% for the nine-month period ended September 30, 2013 as compared to the same period in 2012 reflecting the addition of the Skandi Constructor to our well intervention fleet in 2013 and improved utilization rates primarily resulting from regulatory dry docks for our three other well intervention vessels during the nine-month period ended September 30, 2012.

The gross profit associated with our Robotics segment decreased 34% for the nine-month period ended September 30, 2013 as compared to the same period in 2012 reflecting the performance of a high volume of lower gross profit margin work as an effort to reduce the idle time of our robotics assets. The increased pressure on this business reflected a tight market in the North Sea region in early 2013 and an unusually tight trenching market throughout 2013 following a year with good activity in 2012. We believe that the trenching market will improve in 2014 and some of the deferred projects will be awarded and performed.

Loss on Commodity Derivative Contracts. In December 2012, following the announcement of the sale of ERT, we de-designated our oil and gas commodity derivative contracts and interest rate swap contracts as hedging instruments (Note 16). The $14.1 million loss on commodity derivative contracts

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reflects the net loss on our oil and gas commodity derivative contracts during the first quarter of 2013. In February 2013, we paid approximately $22.5 million to settle our remaining open commodity derivative contracts.

Gain (Loss) on Sale of Assets. The $14.7 million gain on sale of assets for the nine-month period ended September 30, 2013 primarily reflects a $1.1 million loss on the sale of the Caesar in June 2013 and a $15.6 million gain on the sale of the Express in July 2013 (Note 2). The $12.9 million loss for the nine-month period ended September 30, 2012 reflects the sale of the Intrepid in September 2012.

Selling, General and Administrative Expenses. Our selling, general and administrative expenses decreased by $3.7 million for the nine-month period ended September 30, 2013 as compared to the same period in 2012. The decrease reflects the reduction in the size of our organization following the sale of ERT in February 2013, the winding up of our subsea construction operations, and the related effect of these transactions on the level of our corporate staffing. This decrease in our selling, general and administrative expenses was partially offset by severance related costs of approximately $1.9 million for the nine-month period ended September 30, 2013 and a $2.1 million increase in our allowance for uncollectible accounts in the third quarter of 2013.

Equity in Earnings of Investments. Equity in earnings of investments decreased by $5.4 million for the nine-month period ended September 30, 2013 as compared to the same period in 2012. The decrease primarily reflects the expiration in March 2012 of the supplemental demand fee to the major customers using Independence Hub. The decrease also reflects lower throughput at the Deepwater Gateway and Independence Hub facilities.

Net Interest Expense. Our net interest expense totaled $28.3 million for the nine-month period ended September 30, 2013 as compared to $37.4 million for the same period in 2012. The decrease reflects a reduction in interest expense and increases in capitalized interest and interest income. The decrease in interest expense from $40.7 million in 2012 to $36.0 million in 2013 reflects the substantial reduction in our indebtedness, including the $318.4 million repayment of debt in February 2013 following the sale of ERT, the early redemption of $200 million of our Senior Unsecured Notes in March 2012 and our redemption in July 2013 of the remaining $275 million of 9.5% Senior Unsecured Notes outstanding. Capitalized interest totaled $6.8 million for the nine-month period ended September 30, 2013 as compared to $2.7 million for the same period in 2012. Generally, our capitalized interest will be increasing as the construction of the Q5000 and the Q7000 and the upgrades to and modifications of the Helix 534 progress. Interest income totaled $0.9 million for the nine-month period ended September 30, 2013 as compared to $0.6 million for the same period in 2012.

Loss on Early Extinguishment of Long-term Debt. The $12.1 million loss in the nine-month period ended September 30, 2013 included the $8.6 million loss on our redemption in July 2013 of the remaining $275 million Senior Unsecured Notes outstanding and the acceleration of the remaining deferred financing fees related to the term loan component of our former credit agreement following the repayments of indebtedness and the related termination of the facility. The $17.1 million of charges in the nine-month period ended September 30, 2012 were associated with the early extinguishment of portions of our debt, including $11.5 million related to our repurchase of $200.0 million of our Senior Unsecured Notes and $5.6 million related to our repurchase of $142.2 million of the 2025 Notes. See Note 7 for information regarding our debt repayments.

Other Income (Expense), Net. We reported net other expense of $1.9 million for the nine-month period ended September 30, 2013 as compared to net other income of $0.5 million for the same period in 2012. These amounts primarily reflect foreign exchange fluctuations in our non-U.S. dollar functional currencies. The foreign exchange losses were attributed to the strengthening of the U.S. dollar against other global currencies. Included in these foreign exchange gains or losses were $0.7 million of losses and $0.4 million of gains related to our foreign exchange forward contracts in the nine-month period ended September 30, 2013 and 2012, respectively (Note 16).

Other Income – Oil and Gas. The $5.8 million income for the nine-month period ended September 30, 2013 represents cash payments related to services we provided to ERT following its sale to a third party and the initial proceeds associated with our overriding royalty interests in ERT's Wang well, which commenced production in late-April 2013. The Wang well is currently shut in while the HP I is undergoing its scheduled mandatory regulatory dry dock.

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Income Tax Provision (Benefit). Income taxes reflected an expense of $16.1 million in the nine-month period ended September 30, 2013 as compared to a benefit of $1.4 million in the same period last year. The variance primarily reflects increased profitability in the current year period. The effective tax rate of 17.7% for the nine-month ended September 30, 2013 was less favorable than the tax benefit that was recorded for the same period in 2012 as a result of projected year-over-year increases in profitability in the United States.

Discontinued Operations — Oil and Gas

All of our oil and gas assets sold in February 2013 were located in the U.S. Gulf of Mexico. See our Quarterly Report on Form 10-Q for the three-month period ended March 31, 2013 for the operating results of our discontinued oil and gas operations during 2013. Our operating results for the three- and nine-month periods ended September 30, 2012 are presented in Note 4. Our continuing operations include one property located offshore of the United Kingdom (“U.K.”). During the first quarter of 2013, we recorded a $1.6 million charge reflecting the estimated final costs to complete our U.K. property’s abandonment activities. We have completed the reclamation activities for this offshore property, including removing and appropriately disposing of all the related structures, and the plugging and abandoning of all the wells associated with the property. Our operating results for oil and gas operations were immaterial for the second and third quarters of 2013.

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

	September 30, 2013	December 31, 2012
Net working capital	$ 541,156	$ 351,061
Long-term debt (1)	$ 548,204	$ 1,002,621
Liquidity (2)	$ 1,073,624	$ 924,688

(1) Long-term debt does not include the current maturities portion of the long-term debt as that amount is included in net working capital. It is also net of unamortized debt discount on the 2032 Notes. We repaid $318.4 million of our outstanding indebtedness in February 2013 following the sale of ERT, and $150.4 million in June 2013 with proceeds from the sale of the Caesar and cash generated from operations (see table below). See Note 7 for information related to our existing debt.

(2) Liquidity, as defined by us, is equal to cash and cash equivalents plus available capacity under our Revolving Credit Facility, which capacity is reduced by current letters of credit drawn against the facility. The increase in our liquidity reflects proceeds from the sales of ERT, the Caesar and the Express. As of September 30, 2013, our liquidity included cash and cash equivalents of $480.2 million and $593.4 million of available borrowing capacity under our Revolving Credit Facility (Note 7). As of December 31, 2012, our liquidity included cash and cash equivalents of $437.1 million and $487.6 million of available borrowing capacity under our former revolving credit facility.

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The carrying amount of our debt, including current maturities is as follows (in thousands):

	September 30, 2013	December 31, 2012
Term Loans (mature July 2015) (1)	$ —	$ 367,181
Revolving Credit Facility (matures July 2015) (1)	—	100,000
Term Loan (matures June 2018)	296,250	—
2025 Notes (mature December 2025) (2)	—	3,487
2032 Notes (mature March 2032) (3)	172,162	168,312
Senior Unsecured Notes (mature January 2016) (4)	—	274,960
MARAD Debt (matures February 2027)	100,168	105,288
Total debt	$ 568,580	$ 1,019,228

(1) In February 2013, we repaid $293.9 million of our former term loan debt and $24.5 million under our former revolving credit facility with the proceeds from the sale of ERT. In June 2013, we used $150.4 million of the proceeds from the sale of the Caesar as well as cash generated from operations to repay the remaining amounts outstanding under our former credit agreement (Note 7).

(2) This amount represents the remaining 2025 Notes that we repurchased in February 2013 (Note 7).

(3) These amounts are net of the unamortized debt discount of $27.8 million and $31.7 million, respectively. The notes will increase to the $200 million face amount through accretion of non-cash interest charges through March 15, 2018, which is the date on which the holders of the notes may first require us to repurchase the notes.

(4) In July 2013, we redeemed the remaining Senior Unsecured Notes.

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

	Nine Months Ended September 30, 2013	2012
Cash provided by (used in):		
Operating activities	$ 50,309	$ 55,463
Investing activities	$ (80,771)	$ (196,277)
Financing activities	$ (477,623)	$ 11,681
Discontinued operations (1)	$ 552,462	$ 166,994

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

Our current requirements for cash primarily reflect the need to fund capital expenditures to allow the growth of our current lines of business and to service our existing debt. We also may repay debt with any additional free cash flow from operations and proceeds from the expected sale of our spoolbase in Ingleside, Texas. Historically, we have funded our capital program, including acquisitions, with cash flows from operations, borrowings under credit facilities and use of project financing along with other debt and equity alternatives.

We remain focused on maintaining a strong balance sheet and adequate liquidity. We have a reasonable basis for estimating our future cash flows supported by our existing and expanding backlog. We believe that internally generated cash flows and available borrowing capacity under our Revolving Credit Facility will be sufficient to fund our operations over at least the next twelve months.

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In accordance with our Credit Agreement, 2032 Notes and MARAD debt, we are required to comply with certain covenants and restrictions, including certain financial ratios such as consolidated interest coverage ratio and consolidated leverage ratio, as well as the maintenance of minimum net worth, working capital and debt-to-equity requirements. Our Credit Agreement also contains provisions that limit our ability to incur certain types of additional indebtedness. These provisions effectively prohibit us from incurring any additional secured indebtedness or indebtedness guaranteed by us. The Credit Agreement does permit us to incur certain unsecured indebtedness, and also provides for our subsidiaries to incur project financing indebtedness (such as our MARAD debt) secured by the underlying asset, provided that such indebtedness is not guaranteed by us. The Credit Agreement also permits our Unrestricted Subsidiaries to incur indebtedness provided that it is not guaranteed by us or any of our Restricted Subsidiaries. As of September 30, 2013 and December 31, 2012, we were in compliance with all of our then existing debt covenants and restrictions.

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

Under the terms of our Credit Agreement, we borrowed $300 million under a term loan in July 2013 in connection with our early redemption of the remaining $275 million Senior Unsecured Notes outstanding. We may also borrow up to $600 million under our revolving credit facility. The revolving credit facility also permits us to obtain letters of credit up to the full amount of the credit facility. Subject to customary conditions, we may request aggregate commitments with respect to the revolving credit facility be increased by, or additional term loans be made of, or a combination thereof, up to $200 million. See Note 7 for additional information related to our long-term debt, including more information regarding our current and former credit agreements, including covenants and collateral.

The 2032 Notes can be converted prior to their stated maturity upon certain triggering events specified in the Indenture governing the notes. Beginning on 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 three- and nine-month periods ended September 30, 2013 and 2012. Our 2025 Notes were extinguished when the holders exercised their option for us to repurchase their notes in December 2012 ($154.3 million) and in February 2013 when we repurchased the remaining $3.5 million of the 2025 Notes that were not put to us by the holders in December 2012.

Working Capital

Total cash flows from operating activities decreased by $288.3 million in the nine-month period ended September 30, 2013 as compared to the same period in 2012. This decrease primarily reflects the sale of ERT on February 6, 2013, the sales of our subsea construction vessels and related equipment, the related settlement of our commodity derivative and interest rate swap contracts, payment of income taxes, and lower utilization of our robotics assets.

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Investing Activities

Capital expenditures have consisted principally of the purchase or construction of dynamically positioned vessels; improvements and modifications to existing vessels; acquisition, exploration and development of oil and gas properties; and investments in our production facilities. Significant sources (uses) of cash associated with investing activities are as follows (in thousands):

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Capital expenditures:		
Well Intervention	$(245,105)	$(174,168)
Robotics	(29,514)	(40,486)
Production Facilities	(504)	(831)
Other	(812)	(1,466)
Distributions from equity investments, net (1)	6,110	6,174
Proceeds from sale of assets	189,054	14,500
Net cash used in investing activities – continuing operations	(80,771)	(196,277)
Oil and Gas capital expenditures	(31,855)	(88,393)
Proceeds from sale of ERT, net of related transaction costs	614,820	—
Other	—	2,698
Net cash provided by (used in) investing activities – discontinued operations	582,965	(85,695)
Net cash provided by (used in) investing activities	$502,194	$(281,972)

(1) Distributions from equity investments are net of undistributed equity earnings from our equity investments. Gross distributions from our equity investments are detailed in “Equity Investments” below.

Capital expenditures associated with our business primarily include the payments associated with the construction of the Q5000 and the Q7000 (see below), payments in connection with the acquisition and subsequent upgrades to and modifications of the Helix 534 (see below), and costs incurred in the construction of additional ROVs and trenchers related to our robotics operations.

In March 2012, we executed a contract with a shipyard in Singapore for the construction of a newbuild semi-submersible well intervention vessel, the Q5000. This $386.5 million shipyard contract represents the majority of the expected costs associated with the construction of the Q5000. Under the terms of this contract, payments are made in a fixed percentage of the contract price, together with any variations, on contractually scheduled dates. At September 30, 2013, our total investment in the Q5000 was $207.6 million, including $173.8 million of scheduled payments made to the shipyard. We plan to spend approximately $6 million on the Q5000 during the remainder of 2013. The next milestone payment to the shipyard will occur in the first half of 2014. The vessel is expected to be completed and placed in service in 2015.

In August 2012, we acquired the Discoverer 534 drillship from a subsidiary of Transocean Ltd. for $85 million. The vessel, renamed the Helix 534, is undergoing upgrades and modifications to render it suitable for use as a well intervention vessel. At September 30, 2013, our investment in the acquisition and subsequent upgrades to and modifications of the Helix 534 totaled $184.7 million, including related well control equipment. We estimate that an additional $32 million will be invested before the vessel is ready to be placed in service. The vessel is expected to join our well intervention fleet in the Gulf of Mexico in December 2013.

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

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At September 30, 2013, our total investment in the Q7000 was $74.4 million, including $69.2 million paid to the shipyard upon signing the contract.

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

Outlook

We anticipate that our capital expenditures in 2013 will total approximately $400 million. These estimates may increase or decrease based on various economic factors and/or the existence of additional investment opportunities. However, we may reduce the level of our planned future capital expenditures given any prolonged economic downturn. We believe that our cash on hand, internally-generated cash flows, and availability under our new credit facility will provide the capital necessary to continue funding our 2013 initiatives.

Contractual Obligations and Commercial Commitments

The following table summarizes our contractual cash obligations as of September 30, 2013 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
2032 Notes (2)	$200,000	$—	$—	$—	$200,000
Term Loan (3)	296,250	15,000	48,750	232,500	—
MARAD debt	100,168	5,376	11,570	12,754	70,468
Interest related to debt	210,364	23,663	44,947	36,944	104,810
Property and equipment (4)	558,190	174,600	383,590	—	—
Operating leases (5)	615,174	115,273	274,494	146,375	79,032
Total cash obligations	$1,980,146	$333,912	$763,351	$428,573	$454,310

(1) Excludes unsecured letters of credit outstanding at September 30, 2013 totaling $6.6 million. These letters of credit guarantee items such as various contractual obligations, contract bidding and insurance activities.

(2) Contractual maturity 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 its issuance price on that 30th trading day (i.e. $32.53 per share). At September 30, 2013, 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 7 for additional information.

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

(4) Primarily reflects the costs related to construction of our new semi-submersible well intervention vessels, the Q5000 and the Q7000, and costs associated with the upgrades and modifications to render the Helix 534 suitable for use as a well intervention vessel.

(5) Operating leases included facility leases and vessel charter leases. At September 30, 2013, our vessel charter and ROV lease commitments totaled approximately $573.9 million, including two vessels that will not be delivered to us until 2014 and 2015, respectively.

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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 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 2012 Form 10-K.

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 September 30, 2013, $296.3 million of our outstanding debt was subject to floating rates. The interest rate applicable to our variable rate debt may rise, increasing our interest expense and related cash outlay. To reduce the impact of this market risk, in September 2013, we entered into interest rate swap contracts to fix the interest rate on $148.1 million of our Term Loan debt. These swap contracts, which are settled monthly, begin in October 2013 and extend through October 2016. The impact of market risk is estimated using a hypothetical increase in interest rates by 100 basis points for our variable rate long-term debt that is not hedged. Based on this hypothetical assumption, we would have incurred an additional $1.5 million in interest expense for the nine-month period ended September 30, 2013.

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 U.K. and Australian operations). As such, our earnings are subject to movements in foreign currency exchange rates when transactions are denominated in (i) currencies other than the U.S. dollar, which is our functional currency, or (ii) the functional currency of our subsidiaries, which is not necessarily the U.S. dollar. In order to mitigate the effects of exchange rate risk in areas outside the United States, we generally pay a portion of our expenses in local currencies and a substantial portion of our contracts provide for collections from customers in U.S. dollars. During the nine-month period ended September 30, 2013, we recognized losses of $1.2 million related to foreign currency transactions in "Other expense, net" in our condensed consolidated statement of operations.

We also entered into various foreign currency forward purchase contracts to stabilize expected cash outflows relating to certain vessel charters denominated in British pounds and Norwegian kroners. In January 2013, we entered into foreign currency exchange contracts to hedge the foreign currency exposure associated with the Grand Canyon charter payments ($104.6 million) denominated in Norwegian kroner (NOK591.3 million), through September 2017. In February 2013, we entered into similar foreign currency exchange contracts for the Grand Canyon II and Grand Canyon III charter payments ($100.4 million and $98.8 million) denominated in Norwegian kroner (NOK594.7 million and NOK595.0 million), through July 2019 and February 2020, respectively. These contracts currently qualify for hedge accounting treatment. The loss resulting from changes in the fair value of our foreign exchange contracts that were not designated for hedge accounting totaled $0.6 million for the nine-month period ended September 30, 2013.

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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, evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Exchange Act) as of the end of the fiscal quarter ended September 30, 2013. Based on this evaluation, the principal executive officer and the principal financial officer have concluded that our disclosure controls and procedures were effective as of the end of the fiscal quarter ended September 30, 2013 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, as defined in Rule 13a-15(f) of the Exchange Act, in the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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Part II. OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Note 14 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 (1)	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced program (2)	(d) Maximum number of shares that may yet be purchased under the program (2)
July 1 to July 31, 2013	—	$ —	—	—
August 1 to August 31, 2013	—	—	—	—
September 1 to September 30, 2013	—	—	—	—
	—	$ —	—	

(1) Includes shares delivered to the Company by employees in satisfaction of minimum withholding taxes upon vesting of restricted shares.

(2) Under the terms of our stock repurchase program, the issuance of shares to our employees increases the amount of shares available for repurchase. Currently we have no availability to repurchase any shares under our share repurchase program. For additional information regarding our stock repurchase program, see Note 11 to our 2012 Form 10-K.

Item 6. Exhibits

The exhibits to this report are listed in the Exhibit Index beginning on Page 48 hereof.

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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: October 23, 2013

By: /s/ Owen Kratz
Owen Kratz
President and Chief Executive Officer
(Principal Executive Officer)

Date: October 23, 2013

By: /s/ Anthony Tripodo
Anthony Tripodo
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)

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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 registrant.	Exhibit 3.1 to the Current Report on Form 8-K filed on March 1, 2006 (000-22739)
3.2	Second Amended and Restated By-Laws of Helix, as amended.	Exhibit 3.1 to the Current Report on Form 8-K filed on September 28, 2006 (001-32936)
10.1	Construction Contract dated as of September 11, 2013 between Helix Q7000 Vessel Holdings S.à r.l. and Jurong Shipyard Pte Ltd.	Exhibit 10.1 to the Current Report on Form 8-K filed on September 13, 2013 (001-32936)
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