HELIX ENERGY SOLUTIONS GROUP INC
Form 10-Q
April 24, 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 March 31, 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.)
400 North Sam Houston Parkway East Suite 400 Houston, Texas (Address of principal executive offices)	77060 (Zip Code)

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

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 April 19, 2013, 105,935,517 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)

	March 31, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 625,650	$ 437,100
Accounts receivable:		
Trade, net of allowance for uncollectible accounts of $5,154 and $5,152, respectively	142,793	152,233
Unbilled revenue	29,392	26,992
Costs in excess of billing	5,438	6,848
Other current assets	61,189	96,934
Current assets of discontinued operations	—	84,000
Total current assets	864,462	804,107
Property and equipment	2,115,321	2,051,796
Less accumulated depreciation	(582,594)	(565,921)
Property and equipment, net	1,532,727	1,485,875
Other assets:		
Equity investments	165,452	167,599
Goodwill	61,732	62,935
Other assets, net	41,958	49,837
Non-current assets of discontinued operations	—	816,227
Total assets	$ 2,666,331	$ 3,386,580
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 100,553	$ 92,398
Accrued liabilities	122,024	161,514
Income tax payable	35,797	—
Current maturities of long-term debt	10,247	16,607
Current liabilities of discontinued operations	—	182,527
Total current liabilities	268,621	453,046
Long-term debt	687,461	1,002,621
Deferred tax liabilities	290,102	359,237
Other non-current liabilities	14,976	5,025
Non-current liabilities of discontinued operations	—	147,237
Total liabilities	1,261,160	1,967,166
Commitments and contingencies		
Shareholders' equity:		
	935,463	932,742

Common stock, no par, 240,000 shares authorized, 105,939 and 105,763 shares issued, respectively		
Retained earnings	477,925	476,310
Accumulated other comprehensive loss	(33,986)	(15,667)
Total controlling interest shareholders' equity	1,379,402	1,393,385
Noncontrolling interest	25,769	26,029
Total equity	1,405,171	1,419,414
Total liabilities and shareholders' equity	$ 2,666,331	$ 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 March 31, 2013	Three Months Ended March 31, 2012
Net revenues	$ 197,429	$ 229,842
Cost of sales	144,862	157,359
Gross profit	52,567	72,483
Loss on commodity derivative contracts	(14,113)	—
Selling, general and administrative expenses	(23,216)	(22,415)
Income from operations	15,238	50,068
Equity in earnings of investments	610	407
Net interest expense	(10,323)	(14,477)
Loss on early extinguishment of long-term debt	(2,882)	(17,127)
Other income (expense), net	(3,684)	70
Other income – oil and gas	2,818	—
Income before income taxes	1,777	18,941
Income tax provision	443	1,278
Income from continuing operations	1,334	17,663
Income from discontinued operations, net of tax	1,058	48,853
Net income, including noncontrolling interests	2,392	66,516
Less net income applicable to noncontrolling interests	(777)	(789)
Net income applicable to Helix	$ 1,615	$ 65,727
Basic earnings per share of common stock:		
Continuing operations	$ 0.01	$ 0.16
Discontinued operations	0.01	0.46
Net income per common share	$ 0.02	$ 0.62
Diluted earnings per share of common stock:		
Continuing operations	$ 0.01	$ 0.16
Discontinued operations	0.01	0.46
Net income per common share	$ 0.02	$ 0.62
Weighted average common shares outstanding:		
Basic	105,032	104,530
Diluted	105,165	104,989

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 March 31, 2013	Three Months Ended March 31, 2012
Net income, including noncontrolling interests	$ 2,392	$ 66,516
Other comprehensive income (loss), net of tax:		
Unrealized loss on hedges arising during the period	(11,285)	(21,318)
Reclassification adjustments for loss included in net income	150	84
Income taxes on unrealized losses on hedges	3,897	7,432
Unrealized loss on hedges, net of tax	(7,238)	(13,802)
Foreign currency translation gain (loss)	(11,081)	4,152
Other comprehensive loss, net of tax	(18,319)	(9,650)
Comprehensive income (loss)	(15,927)	56,866
Less comprehensive income applicable to noncontrolling interests	(777)	(789)
Comprehensive income (loss) applicable to Helix	$ (16,704)	$ 56,077

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)

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Cash flows from operating activities:		
Net income, including noncontrolling interests	$ 2,392	$ 66,516
Adjustments to reconcile net income, including noncontrolling interests to net cash provided by operating activities:		
Income from discontinued operations	(1,058)	(48,853)
Depreciation and amortization	24,380	24,649
Amortization of deferred financing costs	1,472	1,611
Stock-based compensation expense	3,353	1,838
Amortization of debt discount	1,278	2,355
Deferred income taxes	16,784	(2,673)
Excess tax from stock-based compensation	(617)	340
Loss on early extinguishment of debt	2,882	17,127
Unrealized loss and ineffectiveness on derivative contracts, net	969	114
Changes in operating assets and liabilities:		
Accounts receivable, net	3,714	6,835
Other current assets	12,577	10,483
Income tax payable	(20,283)	23,233
Accounts payable and accrued liabilities	(48,765)	(35,987)
Oil and gas asset retirement costs	(240)	(5,367)
Other noncurrent, net	(7,005)	(4,056)
Net cash provided by (used in) operating activities	(8,167)	58,165
Net cash provided by (used in) discontinued operations	(30,503)	75,640
Net cash provided by (used in) operating activities	(38,670)	133,805
Cash flows from investing activities:		
Capital expenditures	(36,455)	(82,962)
Distributions from equity investments, net	2,050	5,943
Net cash provided by (used in) investing activities	(34,405)	(77,019)
Net cash provided by (used in) discontinued operations	582,965	(17,860)
Net cash provided by (used in) investing activities	548,560	(94,879)
Cash flows from financing activities:		
Early extinguishment of Senior Unsecured Notes	—	(209,500)
Borrowings under revolving credit facility	2,573	100,000
Repayment of revolving credit facility	(24,473)	—
Issuance of Convertible Senior Notes due 2032	—	200,000
Repurchase of Convertible Senior Notes due 2025	(3,487)	(143,945)
Proceeds from Term Loan	—	100,000
Repayment of Term Loans	(294,882)	(750)
Repayment of MARAD borrowings	(2,529)	(2,409)
Deferred financing costs	(41)	(6,337)

Distributions to noncontrolling interest	(1,037)	—
Repurchases of common stock	(1,473)	(991)
Excess tax from stock-based compensation	617	(340)
Exercise of stock options, net and other	174	381
Net cash provided by (used in) financing activities	(324,558)	36,109
Effect of exchange rate changes on cash and cash equivalents	3,218	(1,051)
Net increase in cash and cash equivalents	188,550	73,984
Cash and cash equivalents:		
Balance, beginning of year	437,100	546,465
Balance, end of period	$ 625,650	$ 620,449

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 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 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 ("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 reflected 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-month period ended March 31, 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. 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").

In December 2011, the FASB issued ASU No. 2011-11, "Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities" ("ASU 2011-11"). Offsetting, otherwise known as netting, is the presentation of assets and liabilities as a single net amount in the statement of financial position (balance sheet). U.S. GAAP allows companies the option to present net in their balance sheets derivatives that are subject to a legally enforceable netting arrangement with the same party where rights of set-off are only available in the event of default or bankruptcy. ASU 2011-11 requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. An entity is required to apply the amendments for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. An entity should provide the disclosures required by those amendments retrospectively for all comparative periods presented. The adoption of ASU 2011-11 did not have any material impact on our consolidated financial statements.

In February 2013, the FASB issued ASU No. 2013-02, "Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income" ("ASU 2013-02"). ASU 2013-02 requires companies to provide information about the amounts that are reclassified out of accumulated other comprehensive income either by the respective line items of net income or by cross-reference to other required disclosures. This guidance is effective prospectively for fiscal years beginning after December 15, 2012. We adopted ASU 2013-02 on January 1, 2013. The adoption of this guidance did not have any material impact on our consolidated financial statements. We have presented the information required by the guidance in Note 16.

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Note 2 — Company Overview

We are an international offshore energy company that provides specialty services to the offshore energy industry, with a focus on growing well intervention and robotics operations. In February 2013, we completed the sale of ERT, our former wholly-owned subsidiary that conducted our oil and gas operations in the U.S., 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. We used $318.4 million of the sales proceeds to reduce our indebtedness under our Credit Agreement (Note 7) and we are using the remainder in our continuing operations, including supporting the expansion of our well intervention and robotics operations.

Contracting Services 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. We have disaggregated our contracting services operations into two reportable segments: Contracting Services and Production Facilities. Our Contracting Services segment includes well intervention, robotics and subsea construction operations (see below for disclosure regarding the planned dispositions of our remaining subsea construction vessels and related assets). Our Production Facilities business 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 Express and the Caesar, and other related pipelay equipment for a total sales price of $238.3 million, of which we have received a $50 million deposit that is only refundable in very limited circumstances. The sales of these vessels are expected to close in July 2013 following the completion of each vessel's backlog of work.

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 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.

Note 3 — Details of Certain Accounts

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

	March 31, 2013	December 31, 2012
Other receivables	$ 737	$ 1,086
Prepaid insurance	4,337	11,999
Other prepaids	12,545	11,751
Spare parts inventory	2,589	2,480
Income tax receivable	—	14,201
Current deferred tax assets	34,397	43,942

Derivative assets		—		5,946
Other		6,584		5,529
Total other current assets	$	61,189	$	96,934

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

	March 31, 2013	December 31, 2012
Deferred dry dock expenses, net	$ 19,689	$ 22,704
Deferred financing costs, net	19,620	24,338
Intangible assets with finite lives, net	469	491
Other	2,180	2,304
Total other assets, net	$ 41,958	$ 49,837

Accrued liabilities consist of the following (in thousands):

	March 31, 2013	December 31, 2012
Accrued payroll and related benefits	$ 34,721	$ 51,561
Current asset retirement obligations	4,048	2,898
Unearned revenue	6,964	6,137
Billing in excess of cost	4,625	6,445
Accrued interest	7,699	17,451
Derivative liability (Note 16)	2,008	16,266
Taxes payable excluding income tax payable	5,788	5,164
Pipelay assets sale deposit (Note 2)	50,000	50,000
Other	6,171	5,592
Total accrued liabilities	$ 122,024	$ 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:

	Three Months Ended March 31,	
	2013 (1)	2012
Revenues	$ 48,847	$ 178,085
Costs:		
Production (lifting) costs	16,017	37,020
Exploration expenses	3,514	754
Depreciation, depletion, amortization and accretion	1,226	47,843
Proved property impairment and abandonment charges (credits)	(152)	3,241
Loss on sale of oil and gas properties	—	1,478
Loss on commodity derivative contracts	—	2,339
Selling, general and administrative expenses	1,229	3,281
Net interest expense and other (2)	2,732	7,277
Total costs	24,566	103,233

Pretax income from discontinued operations		24,281		74,852
Income tax provision		8,499		25,999
Income from operations of discontinued operations		15,782		48,853
Loss on sale of business, net of tax		(14,724)		—
Income from discontinued operations, net of tax	$	1,058	$	48,853

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(1) Results for the first quarter of 2013 were through February 6, 2013 when ERT was sold.

(2) Net interest expense of $2.7 million and $7.2 million for the three-month periods ended March 31, 2013 and 2012, respectively, was allocated to ERT primarily based on 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 paid upon the disposition of ERT.

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):

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Interest paid, net of interest capitalized	$ 20,164	$ 32,554
Income taxes paid	$ 4,521	$ 6,725

Total non-cash investing activities for the three-month periods ended March 31, 2013 and 2012 included $23.3 million and $21.0 million, respectively, of accruals for property and equipment capital expenditures.

Note 6 — Equity Investments

As of March 31, 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 $90.2 million and $91.4 million as of March 31, 2013 and December 31, 2012, respectively (including capitalized interest of $1.3 million and $1.3 million at March 31, 2013 and December 31, 2012, respectively).

Independence Hub, LLC. In December 2004, we acquired a 20% interest in Independence Hub, an affiliate of Enterprise. Independence Hub owns the "Independence Hub" platform located in Mississippi Canyon Block 920 in a water depth of 8,000 feet. Our investment in Independence Hub was $75.3 million and $76.2 million as of March 31, 2013 and December 31, 2012, respectively (including capitalized interest of $4.5 million and $4.6 million at March 31, 2013 and December 31, 2012, respectively).

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

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Deepwater Gateway	$ 1,500	$ 2,150
Independence Hub	1,160	4,200
Total	$ 2,660	$ 6,350

As disclosed in our 2012 Form 10-K, in the first quarter of 2012, we recorded losses totaling $3.8 million associated with our investment in an Australian joint venture, including a $3.0 million fee paid in connection with our exit from the joint venture. In April 2012, we paid this fee and received approximately $3.7 million of proceeds for our pro rata portion (50%) of the value of certain of the net assets on hand at the time of our exit. We are no longer a participant in this joint venture.

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The summarized aggregated financial information related to the subsidiaries we record using the equity method is as follows (in thousands):

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Revenues	$ 9,025	$ 23,018
Operating income	3,296	17,379
Net income	3,296	17,379

	March 31, 2013	December 31, 2012
Current assets	$ 16,776	$ 16,682
Total assets	531,749	537,251
Current liabilities	635	706
Total liabilities	5,322	5,320

Note 7 — Long-Term Debt

Scheduled maturities of long-term debt outstanding as of March 31, 2013 are as follows (in thousands):

	Term Loan (1)	Revolving Credit Facility (1)	Senior Unsecured Notes	MARAD Debt	2032 Notes (2)	Total
Less than one year	$5,000	$—	$—	$5,247	$—	$10,247
One to two years	5,000	—	—	5,508	—	10,508
Two to three years	62,299	78,100	274,960	5,783	—	421,142
Three to four years	—	—	—	6,072	—	6,072
Four to five years	—	—	—	6,375	—	6,375
Over five years	—	—	—	73,774	200,000	273,774
Total debt	72,299	78,100	274,960	102,759	200,000	728,118
Current maturities	(5,000)	—	—	(5,247)	—	(10,247)
Long-term debt, less current maturities	67,299	78,100	274,960	97,512	200,000	717,871
Unamortized debt discount (3)	—	—	—	—	(30,410)	(30,410)
Long-term debt	$67,299	$78,100	$274,960	$97,512	$169,590	$687,461

(1) Amounts reflect our remaining Term Loan debt. In February 2013, we repaid $293.9 million of our Term Loan debt and $24.5 million under our Revolving Credit Facility with the after-tax proceeds from the sale of ERT.

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

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

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

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Senior Unsecured Notes

In December 2007, we issued $550 million of 9.5% Senior Unsecured Notes due 2016 ("Senior Unsecured Notes"). Interest on the Senior Unsecured Notes is payable semi-annually in arrears on each January 15 and July 15, commencing July 15, 2008. The Senior Unsecured Notes are fully and unconditionally guaranteed by substantially all of our existing restricted domestic subsidiaries, except for Cal Dive I-Title XI, Inc. In addition, any future restricted domestic subsidiaries that guarantee any of our indebtedness and/or our restricted subsidiaries' indebtedness are required to guarantee the Senior Unsecured Notes. Our foreign subsidiaries are not guarantors of the notes. Prior to 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%

In March 2012, we purchased a portion of these Senior Unsecured Notes which resulted in an early extinguishment of $200.0 million of our outstanding balance. In these transactions we paid an aggregate amount of $213.5 million, including $200.0 million in principal, a $9.5 million premium and $4.0 million of accrued interest. We also recorded a $2.0 million charge to accelerate a pro rata portion of the deferred financing costs associated with the original issuance of the Senior Unsecured Notes. The loss on the early extinguishment of these Senior Unsecured Notes totaled $11.5 million and is reflected as a component of "Loss on early extinguishment of long-term debt" in the accompanying condensed consolidated statements of operations. We had $275.0 million of Senior Unsecured Notes outstanding at March 31, 2013 and December 31, 2012.

Credit Agreement

In July 2006, we entered into a credit agreement (the "Credit Agreement") under which we borrowed $835 million in a term loan (the "Term Loan B") and were able to borrow up to $300 million (the "Revolving Loans") under a revolving credit facility (the "Revolving Credit Facility"). The Credit Agreement has been amended eight times, with the most recent amendment occurring in February 2013. These amendments address certain issues with regard to covenants, maturity and the borrowing limits under the Term Loan and the Revolving Loans. The February 2013 amendment was entered into to waive certain year end oil and gas reporting requirements and covenant compliance as a result of the sale of ERT.

In February 2013, we repaid $293.9 million of our Term Loan debt (including the entire outstanding balance of the Term Loan B) and $24.5 million under our Revolving Credit Facility with the after-tax proceeds from the sale of ERT. At March 31, 2013, the remaining balance of our Term Loan debt was $72.3 million. In connection with the repayment of 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 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.

Our Term Loan debt currently bears interest at the one-, two-, three- or six-month LIBOR or on Base Rates at our current election plus an applicable margin between 2.25% and 3.5% depending on our consolidated leverage ratio. The average interest rates on our Term Loan debt were 3.3% for the three-month period ended March 31, 2013 and 4.0% (including the effects of our interest rate swaps) for the same period last year. The Term Loan is currently scheduled to mature on July 1, 2015 but could be extended to January 1, 2016 if our Senior Unsecured Notes are fully repaid or refinanced by July 1, 2015.

As amended, our Revolving Credit Facility provides for $600 million in borrowing capacity. The full amount of the Revolving Credit Facility may be used for issuances of letters of credit. These letters of credit guarantee items such as various contract bidding, contractual performance, insurance activities and shipyard commitments. The Revolving Loans bear interest based on one-, two-, three- or six-month LIBOR rates or on Base Rates at our current election, plus an applicable margin. The margin ranges from 1.5% to 3.5%, depending on our consolidated leverage ratio. Fees associated with outstanding letters of credit range from 2.0% to 3.0%, depending on our consolidated leverage ratio. We also pay a fixed commitment fee of 0.5%

on the unused portion of our Revolving Credit Facility. We had $78.1 million and $100.0 million drawn on the Revolving Credit Facility at March 31, 2013 and December 31, 2012, respectively. At March 31, 2013, our availability under the Revolving Credit Facility totaled $513.9 million, net of $8.0 million of letters of credit issued. The average interest rate for the outstanding balance under the Revolving Credit Facility totaled 3.0% during the three-month period ended March 31, 2013.

We may elect to prepay amounts outstanding under the Term Loan without penalty, but may not reborrow any amounts paid. We may repay amounts outstanding under the Revolving Loans without penalty, and may reborrow amounts paid prior to maturity. In addition, upon the occurrence of certain dispositions or the issuance or incurrence of certain types of indebtedness, we may be required to repay a portion of the Term Loan debt and borrowings under the Revolving Credit Facility equal to the amount of proceeds received from such occurrences (in the event of a disposition of assets comprising collateral, 60% of the after-tax proceeds). Such payments would be applied to the Term Loan and the Revolving Credit Facility on a pro rata basis.

The Credit Agreement contains various covenants regarding, among other things, collateral, capital expenditures, investments, dispositions, indebtedness and financial performance that are customary for this type of financing and for companies in our industry.

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 (“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 the 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 on early extinguishment 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 by the holders in December 2012.

Convertible Senior Notes Due 2032

In March 2012, we completed the public offering and sale of $200.0 million in aggregate principal amount of 3.25% Convertible Senior Notes due 2032 (“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 above) in separate, privately negotiated transactions. The remaining net proceeds were used for general corporate purposes, including the repayment of other indebtedness.

The registered 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 by us. 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 of the 2032 Notes (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. The initial conversion price represents a conversion premium of 35.0% over the closing price of our common stock on March 6, 2012, which was $18.53 per share.

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Prior to March 20, 2018, the 2032 Notes will not be 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. 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.

MARAD Debt

This U.S. government guaranteed financing ("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 25 years from such date. The MARAD Debt is collateralized by the Q4000, is guaranteed 50% by us, and initially bore interest at a floating rate which approximated AAA Commercial Paper yields plus 20 basis points. As provided for in the MARAD Debt agreements, in September 2005, we fixed the interest rate on the debt through the issuance of a 4.93% fixed-rate note with the same maturity date (February 2027).

Other

In accordance with our Credit Agreement, Senior Unsecured Notes, 2032 Notes and MARAD Debt agreements, we are required to comply with certain covenants, including the maintenance of minimum net worth, working capital and debt-to-equity requirements, and restrictions that limit our ability to incur certain types of additional indebtedness. As of March 31, 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 being amortized over the life of the respective debt agreements. The following table reflects the components of our deferred financing costs (in thousands):

	March 31, 2013			December 31, 2012		
	Gross Carrying Amount	Accumulated Amortization	Net	Gross Carrying Amount	Accumulated Amortization	Net
Term Loans (mature July 2015)	$ 15,325	$ (14,669)	$ 656	$ 15,318	$ (11,595)	$ 3,723
Revolving Credit Facility (matures July 2015)	20,046	(13,225)	6,821	20,021	(12,466)	7,555

2025 Notes (mature December 2025)	—	—	—	8,189	(8,189)	—
2032 Notes (mature March 2032)	3,759	(687)	3,072	4,251	(534)	3,717
Senior Unsecured Notes (mature January 2016)	10,643	(8,402)	2,241	10,643	(8,252)	2,391
MARAD Debt (matures February 2027)	12,200	(5,370)	6,830	12,200	(5,248)	6,952
Total deferred financing costs	$ 61,973	$ (42,353)	$ 19,620	$ 70,622	$ (46,284)	$ 24,338

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The following table details our interest expense and capitalized interest (in thousands):

	Three Months Ended March 31,	
	2013	2012
Interest expense	$ 12,578	$ 15,244
Interest income	(316)	(288)
Capitalized interest	(1,939)	(479)
Interest expense, net	$ 10,323	$ 14,477

Note 8 — Income Taxes

The effective tax rates for the three-month periods ended March 31, 2013 and 2012 were 24.9% and 6.7%, respectively. 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 which are allowed as deductions for federal and foreign income tax reporting purposes, but not for book purposes. The primary differences between the statutory rate and our effective rate from continuing operations are as follows:

	Three Months Ended March 31,	
	2013	2012
Statutory rate	35.0 %	35.0 %
Foreign provision	(10.7)	(26.5)
Other	0.6	(1.8)
Effective rate	24.9 %	6.7 %

Note 9 — Accumulated Other Comprehensive Loss

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

	March 31, 2013	December 31, 2012
Cumulative foreign currency translation adjustment	$ (26,748)	$ (15,667)
Unrealized loss on hedges, net (1)	(7,238)	—
Accumulated other comprehensive loss	$ (33,986)	$ (15,667)

(1) Amount at March 31, 2013 is related to foreign currency hedges for the Grand Canyon, Grand Canyon II and Grand Canyon III and is net of deferred income taxes totaling $3.9 million.

Note 10 — Earnings Per Share

We have shares of restricted stock issued and outstanding, some of 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

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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 March 31, 2013		Three Months Ended March 31, 2012	
	Income	Shares	Income	Shares
Basic:				
Continuing operations:				
Net income applicable to Helix	$1,615		$65,727	
Less: Income from discontinued operations, net of tax	(1,058)		(48,853)	
Income from continuing operations	557		16,874	
Less: Undistributed income allocable to participating securities – continuing operations	(5)		(174)	
Income applicable to common shareholders – continuing operations	$552	105,032	$16,700	104,530
Discontinued operations:				
Income from discontinued operations, net of tax	$1,058		$48,853	
Less: Undistributed income allocable to participating securities – discontinued operations	(8)		(503)	
Income applicable to common shareholders – discontinued operations	$1,050	105,032	$48,350	104,530

	Three Months Ended March 31, 2013		Three Months Ended March 31, 2012	
	Income	Shares	Income	Shares
Diluted:				
Continuing operations:				
Income applicable to common shareholders – continuing operations	$552	105,032	$16,700	104,530
Effect of dilutive securities:				
Share-based awards other than participating securities	—	133	—	98
Undistributed income reallocated to participating securities	—	—	1	—
Convertible preferred stock	—	—	10	361
Income applicable to common shareholders – continuing operations	$552	105,165	$16,711	104,989
Discontinued operations:				

Income from discontinued operations, net of tax	1,058	105,165	48,853	104,989

No diluted shares were included for the 2032 Notes for the three-month periods ended March 31, 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). There were no diluted shares associated with our 2025 Convertible Senior Notes as the conversion price of $32.14 (and conversion trigger of $38.57 per share) was not met in the three-month periods ended March 31, 2013 and 2012.

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Note 11 — Employee Benefit Plans

Stock-Based Compensation Plan

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 (the "2005 Incentive Plan"). As of March 31, 2013, there were 6.4 million shares available for issuance under the amended and restated 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-month periods ended March 31, 2013 and 2012. During the three-month period ended March 31, 2013, the following grants of share-based awards were made to executive officers and non-employee members of our Board of Directors under the amended and restated 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

(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 one of our directors.

Compensation cost is recognized over the respective vesting periods on a straight-line basis. For the three-month periods ended March 31, 2013 and 2012, $3.4 million and $1.8 million, respectively, were recognized as stock-based compensation expense related to share-based awards. Additionally during the three-month period ended March 31, 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. This share-based component is considered a liability plan and as such is re-measured to fair value each reporting period with corresponding changes being recorded as a charge to earnings as deemed appropriate.

The cash awards made under the LTI Plans totaled $5.9 million in 2013 and $4.2 million in 2012. Such 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 $2.5 million ($1.6 million related to our executive officers) and $2.4 million ($2.0 million related to our executive officers) for the three-month periods ended March 31, 2013 and 2012, respectively. The liability balance for the cash

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awards issued under the LTI Plans was $8.3 million at March 31, 2013 and $13.0 million at December 31, 2012, including $7.5 million at March 31, 2013 and $11.7 million at December 31, 2012 associated with the variable portion of the cash awards issued under the LTI plans.

Employee Stock Purchase Plan

In May 2012, the shareholders approved the Helix Energy Solutions Group, Inc. Employee Stock Purchase Plan (the "ESPP"). The ESPP has 1.5 million shares authorized for issuance. 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 (which administers the ESPP) 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 for the three-month period ended March 31, 2013.

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 of our 2012 Form 10-K.

Note 12 — Business Segment Information

In 2012, our operations were conducted through the following lines of business: contracting services and oil and gas. We have disaggregated our contracting services operations into two reportable segments: Contracting Services and Production Facilities. Our Contracting Services segment includes well intervention, robotics and subsea construction operations (see Note 2 for disclosures regarding the planned dispositions of our remaining subsea construction vessels and related assets). 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 of accounting. 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.

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 March 31, 2013	Three Months Ended March 31, 2012
Revenues —		
Contracting Services	$ 198,054	$ 244,544
Production Facilities	20,393	20,022
Intercompany elimination	(21,018)	(34,724)
Total	$ 197,429	$ 229,842

Income (loss) from operations —						
Contracting Services	$	39,304		$	59,124	
Production Facilities		11,185			10,049	
Corporate		(33,531	)		(16,085	)
Intercompany elimination		(1,720	)		(3,020	)
Total	$	15,238		$	50,068	
Equity in earnings of equity investments	$	610		$	407	

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Intercompany segment revenues are as follows (in thousands):

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Contracting Services	$ 16,345	$ 23,201
Production Facilities	4,673	11,523
Total	$ 21,018	$ 34,724

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

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Contracting Services	$ 1,764	$ 3,064
Production Facilities	(44)	(44)
Total	$ 1,720	$ 3,020

Segment assets are comprised of all assets attributable to each reportable segment. The following table reflected total assets by reportable segment (in thousands):

	March 31, 2013	December 31, 2012
Contracting Services	$ 2,141,930	$ 1,974,763
Production Facilities	496,986	503,531
Corporate and other	27,415	8,059
Discontinued operations	—	900,227
Total	$ 2,666,331	$ 3,386,580

Note 13 — Related Party Transactions

In April 2000, we acquired a 20% working interest in Gunnison, a deepwater Gulf of Mexico prospect, from a third party. Financing for the exploratory costs of approximately $20 million was provided by an investment partnership, OKCD Investments, Ltd. ("OKCD"), the investors of which include current and former Helix management, in exchange for a revenue interest that is an overriding royalty interest of 25% of Helix's working interest. Production began in December 2003. Our payments to OKCD totaled $0.6 million and $1.7 million in the three-month periods ended March 31, 2013 and 2012, respectively. Our Chief Executive Officer, Owen Kratz, through Class A limited partnership interests in OKCD, personally owns approximately 83% of the partnership. In 2000, OKCD also awarded Class B income participations to key Helix employees who are required to maintain their employment status with Helix in order to retain such income participations. The royalty agreement with OKCD was assumed by the purchaser of ERT following the sale of ERT in February 2013.

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 March 31, 2013, our total investment in the Q5000 was $142.6 million, including $115.9 million of scheduled payments made to the shipyard.

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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 currently undergoing upgrades and modifications in Singapore to render it suitable for use as a well intervention vessel. At March 31, 2013, our investment in the acquisition and subsequent upgrades to and modifications of the Helix 534 totaled $147.9 million, including related well control equipment.

In January 2013, we contracted to charter the Rem Installer for use in our robotics operations. The term of the charter will be three years from the delivery date, which is expected to be around mid-2013.

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.

Contingencies and Claims

Under terms of the ERT equity purchase agreement, we have required the buyer to provide bonding in a sufficient amount as determined by the Bureau of Ocean Energy Management ("BOEM") to replace and allow for a full discharge of our existing guaranty to the BOEM for ERT's lease obligations. The BOEM is in the process of reevaluating its decommissioning assessments for ERT's deepwater lease properties in the Gulf of Mexico and as such it is currently uncertain as to the amount of bonding that will be required, and thus also the amount of collateral that the buyer will be required to post to its surety/ies to secure such bonding. To the extent that the purchaser is required to post bonding collateral in an amount greater than $100 million to obtain bonds in the aggregate amount required by the BOEM in order for the BOEM to release our guaranty of ERT's lease obligations, we have agreed to provide incremental collateral above that amount, if and to the extent required, to the surety/ies providing bonding for ERT's deepwater properties (the Bushwood and Phoenix fields) in the form of letter(s) of credit, up to the next $50 million of required collateral, for a period not to exceed one year from issuance of the letter(s) of credit, after which the purchaser would then be required to provide all collateral associated with the bonding requirements with respect to our former oil and gas properties. We anticipate that the BOEM will determine its assessments of decommissioning costs for our former deepwater fields in the near term and that the bonding amounts, and therefore the bonding collateral requirements, to obtain a release of our guaranty with respect to ERT's lease obligations will be known. At the time of this filing it is uncertain whether the amount of collateral will exceed the $100 million threshold so as to require any incremental bonding collateral on our part.

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. However, 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 assessed this VAT tax and has no foundation for the assessment and 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 this assessment and our potential liability from it, if any, cannot be determined at this time. If the current assessment is upheld, it may have a material negative effect on our consolidated results of operations while also impacting our financial position.

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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.

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).

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The following table provides additional information related to other financial instruments measured at fair value on a recurring basis at March 31, 2013 (in thousands):

	Level 1	Level 2 (1)	Level 3	Total	Valuation Technique
Liabilities:					
Fair value of long-term debt (2)	681,558	117,597	—	799,155	(a)
Foreign currency forwards	—	11,958	—	11,958	(c)
Total liability	$681,558	$129,555	$—	$811,113	

(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.

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

	March 31, 2013	
	Carrying Value	Fair Value
Term Loan (mature July 2015) (a)	$ 72,299	$ 73,022
Revolving Credit Facility (matures July 2015) (a)	78,100	78,100
2032 Notes (mature March 2032) (b)	200,000	246,540
Senior Unsecured Notes (mature January 2016)	274,960	283,896
MARAD Debt (matures February 2027) (c)	102,759	117,597
Total debt	$ 728,118	$ 799,155

(a) In February 2013, we repaid $293.9 million of our Term Loans and $24.5 million under our Revolving Credit Facility with the after-tax proceeds from the sale of ERT.

(b) Carrying value excludes the related unamortized debt discount of $30.4 million at March 31, 2013.

(c) 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.

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For additional information regarding our accounting for derivatives, see Notes 2 and 17 of our 2012 Form 10-K.

Interest Rate Risk

As some of our long-term debt has variable interest rates, we historically entered into interest rate swaps to stabilize cash flows related to a portion of our Term Loan debt. We de-designated all of our outstanding interest rate swaps as hedging instruments in December 2012 following the announcement of the sale of ERT. We cash settled all outstanding interest rate swap contracts in February 2013.

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.

In January 2013, we entered into foreign currency exchange contracts to hedge the foreign currency exposure to potential variability in cash flows 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 being 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 outstanding oil and natural gas derivative contracts as hedging instruments. In addition, under the terms of our Credit Agreement (Note 7), we are required to use at a minimum 60% of the after-tax proceeds from the sales of the Caesar, the Express and ERT to make payments to reduce our Term Loan debt and borrowings under the Revolving Credit Facility. Because of the probability that the Term Loan debt would be totally repaid before the expiration of our interest rate swaps, we also concluded that the swaps no longer qualified as cash flow hedges. In February 2013, we settled all of our outstanding commodity derivative contracts and 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 March 31, 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 forwards	Other current assets	—	Other current assets	146
		$—		$5,946
Liability Derivatives:				
Oil contracts	Accrued liabilities	$—	Accrued liabilities	$15,777
Interest rate swaps	Accrued liabilities	—	Accrued liabilities	489

Foreign exchange forwards	Accrued liabilities	821	Accrued liabilities	—
Interest rate swaps	Other long-term liabilities	—	Other long-term liabilities	32
Foreign exchange forwards	Other long-term liabilities	2	Other long-term liabilities	—
		$823		$16,298

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As of March 31, 2013, our only derivative instruments designated as cash flow hedges were foreign currency exchange contracts related to the Grand Canyon, Grand Canyon II and Grand Canyon III charter payments. The fair value of these hedging instruments as of March 31, 2013 totaled $11.1 million, $1.2 million of which is reflected in “Accrued liabilities” and the remaining $9.9 million of which is reflected in “Other long-term liabilities” in the accompanying condensed consolidated balance sheet. The last of these contracts will settle in February 2020.

Ineffectiveness associated with our foreign exchange 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 comprehensive income (loss) and our condensed consolidated statements of operations (in thousands).

	Loss Recognized in OCI on Derivatives (Effective Portion) Three Months Ended March 31, 2013	2012
Foreign exchange forwards	$ (7,238)	$ —
Oil and natural gas commodity contracts	—	(13,555)
Interest rate swaps	—	(247)
	$ (7,238)	$ (13,802)

	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 March 31, 2013	2012
Oil and natural gas commodity contracts	Income from discontinued operations, net of tax	$ —	$ 109
Interest rate swaps	Net interest expense	—	(193)
Foreign exchange forwards	Cost of sales	(150)	—
		$ (150)	$ (84)

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

	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives Three Months Ended March 31, 2013	2012
Oil and natural gas commodity contracts	Loss on commodity derivative contracts	$ (14,113)	$ —
Interest rate swaps	Other income (expense), net	(86)	—
Foreign exchange forwards	Other income (expense), net	(1,244)	233
		$ (15,443)	$ 233

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Note 17 — Condensed Consolidated Guarantor and Non-Guarantor Financial Information

The payment of our obligations under the Senior Unsecured Notes is guaranteed by all of our restricted domestic subsidiaries ("Subsidiary Guarantors") except for Cal Dive I-Title XI, Inc. Each of these Subsidiary Guarantors is included in our condensed consolidated financial statements and has fully and unconditionally guaranteed the Senior Unsecured Notes on a joint and several basis. As a result of these guaranty arrangements, we are required to present the following condensed consolidating financial information. The accompanying guarantor financial information is reported based on the equity method of accounting for all periods presented. Under this method, investments in subsidiaries are recorded at cost and adjusted for our share in the subsidiaries' cumulative results of operations, capital contributions and distributions and other changes in equity. Elimination entries primarily relate to the elimination of investments in subsidiaries and associated intercompany balances and transactions.

HELIX ENERGY SOLUTIONS GROUP, INC.
CONDENSED CONSOLIDATING BALANCE SHEETS
(UNAUDITED)
(in thousands)

	As of March 31, 2013				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$551,596	$7,274	$66,780	$ —	$ 625,650
Accounts receivable, net	75,490	30,366	36,937	—	142,793
Unbilled revenue	8,179	386	26,265	—	34,830
Income taxes receivable	—	—	3,402	(3,402)	—
Other current assets	40,566	4,946	15,742	(65)	61,189
Total current assets	675,831	42,972	149,126	(3,467)	864,462
Intercompany	(116,440)	334,709	(130,205)	(88,064)	—
Property and equipment, net	224,594	353,969	960,461	(6,297)	1,532,727
Other assets:					
Equity investments in unconsolidated affiliates	—	—	165,452	—	165,452
Equity investments in affiliates	1,240,653	47,066	—	(1,287,719)	—
Goodwill	—	45,107	16,625	—	61,732
Other assets, net	39,678	136	31,507	(29,363)	41,958
Due from subsidiaries/parent	319,941	—	—	(319,941)	—
Total assets	$2,384,257	$823,959	$1,192,966	$ (1,734,851)	$ 2,666,331
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$55,165	$16,824	$28,564	$ —	$ 100,553
Accrued liabilities	94,783	13,532	13,709	—	122,024
Income taxes payable	35,149	19,953	—	(19,305)	35,797
Current maturities of long-term debt	5,000	—	5,247	—	10,247
Total current liabilities	190,097	50,309	47,520	(19,305)	268,621
Long-term debt	589,948	—	97,513	—	687,461
Deferred tax liabilities	171,543	11,454	112,606	(5,501)	290,102

Other long-term liabilities	4,559	9,950	467	—	14,976
Due to parent	—	52,582	345,426	(398,008)	—
Total liabilities	956,147	124,295	603,532	(422,814)	1,261,160
Total equity	1,428,110	699,664	589,434	(1,312,037)	1,405,171
Total liabilities and shareholders' equity	$2,384,257	$823,959	$1,192,966	$ (1,734,851)	$ 2,666,331

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HELIX ENERGY SOLUTIONS GROUP, INC.
CONDENSED CONSOLIDATING BALANCE SHEETS
(in thousands)

	As of December 31, 2012				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$381,599	$4,436	$51,065	$ —	$ 437,100
Accounts receivable, net	39,203	37,378	75,652	—	152,233
Unbilled revenue	13,959	875	19,006	—	33,840
Income taxes receivable	24,611	—	306	(10,716)	14,201
Other current assets	54,588	16,418	11,696	31	82,733
Current assets of discontinued operations	—	84,000	—	—	84,000
Total current assets	513,960	143,107	157,725	(10,685)	804,107
Intercompany	(154,756)	352,210	(125,889)	(71,565)	—
Property and equipment, net	208,190	351,746	930,556	(4,617)	1,485,875
Other assets:					
Equity investments in unconsolidated affiliates	—	—	167,599	—	167,599
Equity investments in affiliates	1,762,359	53,461	—	(1,815,820)	—
Goodwill	—	45,107	17,828	—	62,935
Other assets, net	47,355	130	34,848	(32,496)	49,837
Due from subsidiaries/parent	294,461	485,096	—	(779,557)	—
Non-current assets of discontinued operations	—	816,227	—	—	816,227
Total assets	$2,671,569	$2,247,084	$1,182,667	$ (2,714,740)	$ 3,386,580
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$45,784	$17,229	$29,385	$ —	$ 92,398
Accrued liabilities	117,902	26,019	17,593	—	161,514
Income taxes payable	—	26,618	—	(26,618)	—
Current maturities of long-term debt	11,487	—	5,120	—	16,607
Current liabilities of discontinued operations	—	182,527	—	—	182,527
Total current liabilities	175,173	252,393	52,098	(26,618)	453,046
Long-term debt	902,453	—	100,168	—	1,002,621
Deferred tax liabilities	168,688	86,925	109,171	(5,547)	359,237
Other long-term liabilities	1,453	3,086	486	—	5,025
Due to parent	—	—	323,049	(323,049)	—
Non-current liabilities of discontinued operations	—	147,237	—	—	147,237
Total liabilities	1,247,767	489,641	584,972	(355,214)	1,967,166
Total equity	1,423,802	1,757,443	597,695	(2,359,526)	1,419,414
Total liabilities and shareholders' equity	$2,671,569	$2,247,084	$1,182,667	$ (2,714,740)	$ 3,386,580

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

	Three Months Ended March 31, 2013				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$20,394	$102,063	$91,126	$ (16,154)	$ 197,429
Cost of sales	16,589	74,370	70,100	(16,197)	144,862
Gross profit	3,805	27,693	21,026	43	52,567
Loss on commodity derivative contracts	(2,337)	(11,776)	—	—	(14,113)
Selling, general and administrative expenses	(15,790)	(3,909)	(3,517)	—	(23,216)
Income (loss) from operations	(14,322)	12,008	17,509	43	15,238
Equity in earnings of investments	33,146	(6,395)	610	(26,751)	610
Net interest expense and other	(8,780)	(1,149)	(4,142)	—	(14,071)
Income (loss) before income taxes	10,044	4,464	13,977	(26,708)	1,777
Income tax provision (benefit)	(6,268)	3,805	2,891	15	443
Income (loss) from continuing operations	16,312	659	11,086	(26,723)	1,334
Income (loss) from discontinued operations, net of tax	(14,724)	15,782	—	—	1,058
Net income (loss), including noncontrolling interest	1,588	16,441	11,086	(26,723)	2,392
Less net income applicable to noncontrolling interests	—	—	—	(777)	(777)
Net income (loss) applicable to Helix	$1,588	$16,441	$11,086	$ (27,500)	$ 1,615
Total comprehensive income (loss) applicable to Helix	$1,588	$9,203	$5	$ (27,500)	$ (16,704)

	Three Months Ended March 31, 2012				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$20,022	$107,603	$125,900	$ (23,683)	$ 229,842
Cost of sales	16,621	75,735	88,445	(23,442)	157,359
Gross profit (loss)	3,401	31,868	37,455	(241)	72,483
Selling, general and administrative expenses	(11,272)	(6,596)	(4,834)	287	(22,415)
Income (loss) from operations	(7,871)	25,272	32,621	46	50,068
Equity in earnings of investments	93,250	2,625	407	(95,875)	407
Net interest expense and other	(30,557)	67	(1,044)	—	(31,534)
Income (loss) before income taxes	54,822	27,964	31,984	(95,829)	18,941
Income tax provision (benefit)	(10,874)	8,882	3,255	15	1,278
Income (loss) from continuing operations	65,696	19,082	28,729	(95,844)	17,663

Income from discontinued operations, net of tax	—	48,853	—	—	48,853
Net income (loss), including noncontrolling interest	65,696	67,935	28,729	(95,844)	66,516
Less net income applicable to noncontrolling interests	—	—	—	(789)	(789)
Net income (loss) applicable to Helix	$65,696	$67,935	$28,729	$ (96,633)	$ 65,727
Total comprehensive income (loss) applicable to Helix	$65,450	$54,380	$32,884	$ (96,637)	$ 56,077

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

	Three Months Ended March 31, 2013				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flows from operating activities:					
Net income (loss), including noncontrolling interests	$1,588	$16,441	$11,086	$ (26,723)	$ 2,392
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by (used in) operating activities:					
Equity in earnings of affiliates	(33,146)	6,395	—	26,751	—
Other adjustments	31,324	(46,931)	21,420	(16,372)	(10,559)
Cash provided by (used in) operating activities	(234)	(24,095)	32,506	(16,344)	(8,167)
Cash used in discontinued operations	—	(30,503)	—	—	(30,503)
Net cash provided by (used in) operating activities	(234)	(54,598)	32,506	(16,344)	(38,670)
Cash flows from investing activities:					
Capital expenditures	166	(6,486)	(30,135)	—	(36,455)
Distributions from equity investments, net	—	—	2,050	—	2,050
Cash provided by (used in) investing activities	166	(6,486)	(28,085)	—	(34,405)
Cash provided by discontinued operations	—	582,965	—	—	582,965
Net cash provided by (used in) investing activities	166	576,479	(28,085)	—	548,560
Cash flows from financing activities:					
Borrowings of debt	2,573	—	—	—	2,573
Repayments of debt	(322,842)	—	(2,529)	—	(325,371)
Deferred financing costs	(41)	—	—	—	(41)
Distributions to noncontrolling interests	—	—	(1,037)	—	(1,037)
Repurchases of common stock	(1,473)	—	—	—	(1,473)
Excess tax from stock-based compensation	617	—	—	—	617
Exercise of stock options, net and other	174	—	—	—	174
Intercompany financing	491,057	(519,043)	11,642	16,344	—
Net cash provided by (used in) financing activities	170,065	(519,043)	8,076	16,344	(324,558)
Effect of exchange rate changes on cash and cash equivalents	—	—	3,218	—	3,218
Net increase in cash and cash equivalents	169,997	2,838	15,715	—	188,550
Cash and cash equivalents:					
Balance, beginning of year	381,599	4,436	51,065	—	437,100

Balance, end of period	551,596	7,274	66,780	—	625,650

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

	Three Months Ended March 31, 2012				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flows from operating activities:					
Net income (loss), including noncontrolling interests	$65,696	$67,935	$28,729	$ (95,844)	$ 66,516
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by (used in) operating activities:					
Equity in earnings of affiliates	(93,250)	(2,625)	—	95,875	—
Other adjustments	15,695	(6,751)	(14,792)	(2,503)	(8,351)
Cash provided by (used in) operating activities	(11,859)	58,559	13,937	(2,472)	58,165
Cash provided by discontinued operations	—	75,640	—	—	75,640
Net cash provided by (used in) operating activities	(11,859)	134,199	13,937	(2,472)	133,805
Cash flows from investing activities:					
Capital expenditures	(896)	(75,858)	(6,208)	—	(82,962)
Distributions from equity investments, net	—	—	5,943	—	5,943
Cash used in investing activities	(896)	(75,858)	(265)	—	(77,019)
Cash used in discontinued operations	—	(17,860)	—	—	(17,860)
Net cash used in investing activities	(896)	(93,718)	(265)	—	(94,879)
Cash flows from financing activities:					
Borrowings of debt	400,000	—	—	—	400,000
Repayments of debt	(354,195)	—	(2,409)	—	(356,604)
Deferred financing costs	(6,337)	—	—	—	(6,337)
Repurchases of common stock	(991)	—	—	—	(991)
Excess tax from stock-based compensation	(340)	—	—	—	(340)
Exercise of stock options, net and other	381	—	—	—	381
Intercompany financing	45,040	(40,417)	(7,095)	2,472	—
Net cash provided by (used in) financing activities	83,558	(40,417)	(9,504)	2,472	36,109
Effect of exchange rate changes on cash and cash equivalents	—	—	(1,051)	—	(1,051)
Net increase in cash and cash equivalents	70,803	64	3,117	—	73,984
Cash and cash equivalents:					
Balance, beginning of year	495,484	2,434	48,547	—	546,465
Balance, end of period	566,287	2,498	51,664	—	620,449

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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 is subject to change;
- the timing of the closing of our pipelay vessel sales in 2013;
- 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 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 weak 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 third quarter of 2013), the Q5000 (expected in 2015), the Grand Canyon II (expected in 2014) and the Grand Canyon III (expected in 2015);
- delays, costs and difficulties related to the pipelay vessel sales in 2013;
- 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;

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- the effectiveness of our current and future hedging activities;
- the availability (or lack thereof) of capital (including any financing) to fund our business strategy and/or operations, and the terms of any such financing;
- the 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

We are an international offshore energy company that provides specialty services to the offshore energy industry, with a focus on growing well intervention and robotics operations. In February 2013, we completed the sale of ERT, our former wholly-owned subsidiary that conducted our oil and gas operations in the U.S., 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. We used $318.4 million of the sales proceeds to reduce our indebtedness under our Credit Agreement (Note 7) and we will use the remainder to continue to support the expansion of our well intervention and robotics operations.

Our Strategy

We have improved our balance sheet and increased our liquidity since 2008 through dispositions of non-core business assets, related repayment of a significant portion of our indebtedness as well as the reduction in our capital spending through 2011. With this goal substantially accomplished with the sale of ERT in February 2013 and the expected mid-year 2013 sales of our remaining pipelay vessels and related equipment, we are now positioned to expand and grow our core operations.

Our current focus is to expand our Contracting Services capabilities by growing our well intervention and robotics operations. 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 a newbuild semi-submersible vessel, the Q5000, acquiring the Discoverer 534 drillship (renamed the Helix 534) which is currently undergoing upgrades and modifications in Singapore to render it suitable for use as a well intervention vessel, and chartering the Skandi Constructor for use in 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. During the first quarter of 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 contracted to charter the Rem Installer, which is expected to be delivered to us by mid-2013

Economic Outlook and Industry Influences

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

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- the effect of regulations on offshore Gulf of Mexico oil and gas operations;
- actions taken by the Organization of the Petroleum Exporting Countries ("OPEC");
- the availability and discovery rate of new oil and natural gas reserves in offshore areas;
- the exploration and production of shale oil and natural gas;
- the cost of offshore exploration for and production and transportation of oil and gas;
- the ability of oil and natural gas companies to generate funds or otherwise obtain external capital for exploration, development and production operations;
- the sale and expiration dates of offshore leases in the United States and overseas;
- technological advances affecting energy exploration production transportation and consumption;
- weather conditions;
- environmental and other governmental regulations; and
- tax policies.

Despite strong financial market performances in recent months, overall indicators of growth and confidence remain well below their normal levels for a recovery. The International Monetary Fund has recently lowered its forecast for global economic growth in 2013 and 2014 largely as a result of government spending cuts in the United States and continued struggles of the eurozone. Weak economic data in these advanced economies could continue to affect the global equity and commodity markets as well as effectively hampering normal business activities. The slowdown in many emerging economies is set to continue. This is evidenced by the slower than expected growth in China during the first quarter of 2013. 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) increasing number of mature and small reservoirs; (5) increasing offshore activity, particularly in deepwater; and (6) 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 presently 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. When the original set of agreements expired on March 31, 2013, a new set of substantially similar agreements were entered into 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. These new contracts covering the HFRS were signed in the first quarter of 2013 and provide for a four-year term commencing April 1, 2013.

RESULTS OF OPERATIONS

We have disaggregated our contracting services operations into two reportable segments: Contracting Services and Production Facilities. Previously, we had a third business segment, Oil and Gas. In December 2012, we announced a definitive agreement for the sale of ERT. In February 2013, the sale of ERT closed. 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. The Contracting Services segment includes well intervention, robotics and subsea construction operations (see Note 2 regarding the planned dispositions of our remaining subsea construction vessels and related assets). Our Contracting Services business operates 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 contracting services operations as contracts may be added, cancelled and in many cases modified while in progress. As of March 31, 2013, our Contracting Services segment had backlog of approximately $924.9 million, including $438.0 million expected to be performed over the remainder of 2013. Subsequently in early April, 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.

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, a new 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 will also pay us a variable throughput fee. We currently anticipate that the total combined fees will approximate at least 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).

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 under 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 (loss) 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:

	Three Months Ended March 31,	
	2013	2012
Net income from continuing operations	$ 1,334	$ 17,663
Adjustments:		
Income tax provision	443	1,278
Net interest expense and other	14,007	14,407
Loss on extinguishment of long-term debt	2,882	17,127
Depreciation and amortization	24,380	24,649
EBITDA from continuing operations	43,046	75,124
Adjustments:		
Noncontrolling interest Kommandor LLC	(1,015)	(1,026)
ADJUSTED EBITDA from continuing operations	$ 42,031	$ 74,098
ADJUSTED EBITDA from continuing operations	$ 42,031	$ 74,098
ADJUSTED EBITDAX from discontinued operations (1)	31,754	134,543
ADJUSTED EBITDAX	$ 73,785	$ 208,641

(1) Amounts relate to ERT which was sold in February 2013 (Notes 2 and 4).

Comparison of Three Months Ended March 31, 2013 and 2012

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

	Three Months Ended March 31,		Increase/
	2013	2012	(Decrease)
Revenues (in thousands) —			
Contracting Services	$198,054	$244,544	$(46,490)
Production Facilities	20,393	20,022	371
Intercompany elimination	(21,018)	(34,724)	13,706
	$197,429	$229,842	$(32,413)
Gross profit (in thousands) —			
Contracting Services	$45,287	$66,512	$(21,225)

Production Facilities	11,349	10,190	1,159
Corporate and other	(2,349)	(1,199)	(1,150)
Intercompany elimination	(1,720)	(3,020)	1,300
	$52,567	$72,483	$(19,916)

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	Three Months Ended March 31, 2013	2012
Gross Margin —		
Contracting Services	23%	27%
Production Facilities	56%	51%
Total company	27%	32%
Number of vessels (1) / Utilization (2)		
Contracting Services:		
Construction vessels	7/75%	9/93%
Well intervention	3/100%	3/84%
ROVs	55/55%	47/68%

(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 March 31, 2013	2012	Increase/ (Decrease)
Contracting Services	$16,345	$23,201	$(6,856)
Production Facilities	4,673	11,523	(6,850)
	$21,018	$34,724	$(13,706)

Intercompany segment profit is as follows (in thousands):

	Three Months Ended March 31, 2013	2012	Increase/ (Decrease)
Contracting Services	$1,764	$3,064	$(1,300)
Production Facilities	(44)	(44)	—
	$1,720	$3,020	$(1,300)

In the following disclosures regarding our results of operations, please refer to the tables above and Note 12 for supplemental information regarding our business segment results. Our disclosures specifically refer to our Contracting Services and Production Facilities segments. Disclosures regarding our former Oil and Gas segment are presented under “Discontinued Operations — Oil and Gas” below and in Note 4.

Revenues. Our Contracting Services revenues decreased by 19% for the three-month period ended March 31, 2013 as compared to the same period in 2012 reflecting significantly lower revenues associated with our subsea construction vessels, which were adversely affected by permitting delays related to the two remaining projects to be serviced by the Express prior to its planned sale and significant reductions in the utilization for our robotics vessels and

ROVs. Typically the first quarter is affected by seasonal weather patterns in the North Sea and thus robotics activities generally decrease in the winter months. However, over the past few years we benefitted from robotics activities in the first quarter, including a number of North Sea trenching projects in early 2012. These decreases were partially offset by full utilization of our three well intervention vessels during the first quarter of 2013 as compared to 84% utilization in the first quarter of 2012. In 2012, the Q4000 underwent required regulatory dry dock, which resulted in the vessel being out of service for 28 days during the first quarter of 2012.

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Our Production Facilities revenues increased by 2% for the three-month period ended March 31, 2013 as compared to the same period in 2012, which reflects a slight increase in our total revenues under the new HP I contract for processing of production from the Phoenix field (see "Contracting Services Operations" above). The quarterly HFRS retainer fees will increase effective April 1, 2013 as a result of new contracts covering the HFRS which were signed in the first quarter of 2013 and provide for a four-year term (see "Helix Fast Response System" above).

Gross Profit. Our Contracting Services gross profit decreased by 32% for the three-month period ended March 31, 2013 as compared to the same period in 2012. This decrease was primarily attributed to both our robotics and subsea construction vessels seeking lower margin work to reduce vessel idle time during first quarter of 2013. Gross profit benefitted from full utilization of all three well intervention vessels during the first quarter of 2013 as compared to 84% utilization in same period last year. However, some of the Q4000 work was at low margins because of problems with its well control system. These problems, which have been remediated, resulted in an aggregate reduction of $1.8 million of day rate revenues associated with the vessel.

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 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 cash settle our remaining open commodity derivative contracts.

Selling, General and Administrative Expenses. Our selling, general and administrative expenses increased by $0.8 million for the three-month period ended March 31, 2013 as compared to the same period in 2012. In the first quarter of 2013, our selling, general and administrative expenses included severance related costs of approximately $1.6 million.

Equity in Earnings of Investments. Equity in earnings of investments increased by $0.2 million for the three-month period ended March 31, 2013 as compared to the same period in 2012. The increase was primarily due to higher throughput at both the Deepwater Gateway and Independence Hub facilities, partially offset by the expiration in March 2012 of the supplemental demand fee to the major customers using Independence Hub.

Net Interest Expense. Our net interest expense totaled $10.3 million for the three-month period ended March 31, 2013 as compared to $14.5 million for the same period in 2012. The decrease in interest expense primarily reflects a $200.0 million reduction of our Senior Unsecured Notes indebtedness in the first quarter of 2012. The Senior Unsecured Notes bear a 9.5% interest rate which is greater than the 6.2% weighted average interest rate of our total indebtedness as of March 31, 2013. Capitalized interest totaled $1.9 million for the first quarter of 2013 as compared to $0.5 million for the first quarter of 2012. Generally, our capitalized interest will be increasing as we progress the construction of the Q5000 and the upgrades to and modifications of the Helix 534. Interest income totaled $0.3 million for the first quarter of 2013 and 2012.

Loss on Early Extinguishment of Long-term Debt. The $2.9 million loss in the first quarter of 2013 was associated with the acceleration of deferred financing fees related to the repayment of a substantial portion of our existing Term Loan debt (Note 7). The $17.1 million of charges in the first quarter of 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.

Other Income (Expense), Net. We reported net other expenses of $3.7 million for the three-month period ended March 31, 2013 as compared to net other income of $0.1 million for the same period in 2012. These amounts primarily reflect foreign exchange fluctuations in our non U.S. dollar functional currencies. We recorded foreign exchange losses of approximately $3.7 million in the first quarter of 2013 as compared to gains of $0.1 million in the first quarter of 2012. 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 $1.2 million of losses and $0.2 million of gains related to our foreign exchange forward contracts in the first quarters of 2013 and 2012, respectively (Note 16).

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Other Income – Oil and Gas. The $2.8 million income for the three-month period ended March 31, 2013 represents cash payments related to services we provided to our former oil and gas business following the sale of ERT. In future periods, the majority of these cash proceeds will be associated with our overriding royalty interests in ERT's Wang well, which is expected to commence production in the near term.

Income Tax Provision. Income taxes reflected expenses of $0.4 million in the first quarter of 2013 as compared to $1.3 million in the same period last year. The variance primarily reflects decreased profitability in the current year period. The effective tax rate of 24.9% for the first quarter of 2013 was higher than the 6.7% effective tax rate for the first quarter of 2012 as a result of projected year over year increases in profitability in the United States.

Discontinued Operations — Oil and Gas

Comparison of Three Months Ended March 31, 2013 and 2012

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

	Three Months Ended March 31,		Increase/
	2013 (1)	2012	(Decrease)
Oil and Gas information —			
Oil production volume (MBbls)	409	1,426	(1,017)
Oil sales revenue (in thousands)	$44,371	$155,744	$(111,373)
Average oil sales price per Bbl (excluding hedges)	$108.40	$111.61	$(3.21)
Average realized oil price per Bbl (including hedges)	$108.40	$109.18	$(0.78)
Increase (decrease) in oil sales revenue due to:			
Change in prices (in thousands)	$(1,121)		
Change in production volume (in thousands)	(110,252)		
Total decrease in oil sales revenue (in thousands)	$(111,373)		
Gas production volume (MMcf)	992	3,568	(2,576)
Gas sales revenue (in thousands)	$3,890	$20,757	$(16,867)
Average gas sales price per mcf (excluding hedges)	$3.92	$4.50	$(0.58)
Average realized gas price per mcf (including hedges)	$3.92	$5.82	$(1.90)
Decrease in gas sales revenue due to:			
Change in prices (in thousands)	$(6,766)		
Change in production volume (in thousands)	(10,101)		
Total decrease in gas sales revenue (in thousands)	$(16,867)		
Total production (MBOE)	575	2,021	(1,446)
Price per BOE	$83.97	$87.32	$(3.35)
Oil and Gas revenue information (in thousands) —			
Oil and gas sales revenue	$48,261	$176,501	$(128,240)
Other revenues	586	1,584	(998)
	$48,847	$178,085	$(129,238)

(1) Results for the first quarter of 2013 were through February 6, 2013 when ERT was sold.

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The following table highlights certain relevant expense items in total (in thousands) and on a cost per barrel of production basis (natural gas converted to barrel of oil equivalent at a ratio of six Mcf of natural gas to each barrel of oil):

	Three Months Ended March 31,			
	2013 (1)		2012	
	Total	Per barrel	Total	Per barrel
Oil and Gas operating expenses:				
Direct operating expenses (2)	$12,299	$21.40	$28,325	$14.02
Workover	1,197	2.08	2,080	1.03
Transportation	682	1.19	1,857	0.92
Repairs and maintenance	1,389	2.42	1,849	0.92
Overhead and company labor	450	0.78	2,909	1.44
	$16,017	$27.87	$37,020	$18.33
Depletion expense	$—	$—	$44,404	$21.97
Abandonment	(152)	(0.26)	3,241	1.60
Accretion expense	1,226	2.13	3,439	1.70
	1,074	1.87	51,084	25.27
Total	$17,091	$29.74	$88,104	$43.60

(1) Expenses in the first quarter of 2013 were through February 6, 2013 when ERT was sold.

(2) Includes production taxes and net hurricane (reimbursements) costs.

All of our oil and gas assets sold in February 2013 were located in the U.S. Gulf of Mexico. 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 its abandonment activities.

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

	March 31, 2013	December 31, 2012
Net working capital	$ 595,841	$ 351,061
Long-term debt (1)	$ 687,461	$ 1,002,621
Liquidity (2)	$ 1,139,508	$ 924,688

(1) Long-term debt does not include the current maturities portion of the long-term debt as such 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 (see table below). See Note 7 for disclosures 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 sale of ERT. Over the remainder of 2013, we anticipate a reduction in liquidity as a result of capital expenditures to expand our well intervention fleet as well as payments to reduce our existing debt and to fund other capital expenditures (see "Outlook" below). As of March 31, 2013, our liquidity included cash and cash equivalents of $625.6 million and $513.9 million of available borrowing capacity

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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 Revolving Credit Facility.

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

	March 31, 2013	December 31, 2012
Term Loans (mature July 2015) (1)	$ 72,299	$ 367,181
Revolving Credit Facility (matures July 2015) (1)	78,100	100,000
2025 Notes (mature December 2025) (2)	—	3,487
2032 Notes (mature March 2032) (3)	169,590	168,312
Senior Unsecured Notes (mature January 2016)	274,960	274,960
MARAD Debt (matures February 2027)	102,759	105,288
Total debt	$ 697,708	$ 1,019,228

(1) Represents earliest date debt would mature; see Note 7 for conditions that could extend the maturity date. In February 2013, we repaid $293.9 million of our Term Loan debt and $24.5 million under our Revolving Credit Facility with the after-tax proceeds from the sale of ERT.

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

(3) These amounts are net of the unamortized debt discount of $30.4 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.

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

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Cash provided by (used in):		
Operating activities	$ (8,167)	$ 58,165
Investing activities	$ (34,405)	$ (77,019)
Financing activities	$ (324,558)	$ 36,109
Discontinued operations (1)	$ 552,462	$ 57,780

(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 expect to further reduce our existing debt following the closing of the sales of our remaining pipelay vessels and related equipment in 2013. We may also repay debt with any additional free cash flow from operations. 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, Senior Unsecured Notes, 2032 Notes and MARAD debt, we are required to comply with certain covenants and restrictions, including certain financial ratios such as collateral coverage, interest coverage and consolidated indebtedness leverage, as well as the maintenance of minimum net worth, working capital and debt-to-equity requirements. Our Credit Agreement and Senior Unsecured Notes also contain provisions that limit our ability to incur certain types of additional indebtedness. These provisions effectively prohibit us from incurring any additional secured indebtedness or indebtedness guaranteed by the Company. The 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 loan) secured by the underlying asset, provided that such indebtedness is not guaranteed by us. Upon the occurrence of certain dispositions or the issuance or incurrence of certain types of indebtedness, we may be required to repay a portion of the Term Loan debt and borrowings under the Revolving Credit Facility equal to the amount of proceeds received from such occurrences (in the event of a disposition of assets comprising collateral, 60% of the after-tax proceeds). Such payments would be applied to the Term Loan (see below) and the Revolving Credit Facility on a pro rata basis. As of March 31, 2013 and December 31, 2012, we were in compliance with all of our debt covenants and restrictions. In February 2013, we repaid $293.9 million of our Term Loan debt (including the entire outstanding balance of the Term Loan B) and $24.5 million under our Revolving Credit Facility with the after-tax proceeds from the sale of ERT.

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.

The 2032 Notes can be converted prior to their stated maturity under certain triggering events specified in the respective indentures governing each series of such 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 notes. 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-month periods ended March 31, 2013 and 2012. 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 by the holders in December 2012.

In July 2006, we borrowed $835 million in a term loan (the “Term Loan B”) under our Credit Agreement. In June 2011, we amended our Credit Agreement to, among other things, extend its maturity to at least July 1, 2015 and increase the availability under our Revolving Credit Facility to $600 million. In February 2012, we entered into another amendment to our Credit Agreement. Under terms of this amendment, the lenders provided us with $100 million in additional proceeds under a term loan (the “Term Loan”). The terms of the Term Loan are the same as those governing the Revolving Credit Facility, with the Term Loan requiring a $5 million annual payment of the principal balance. The Term Loan funded in late March 2012 and we used these proceeds and $100 million of borrowings under our Revolving Credit Facility to redeem $200 million of our Senior Unsecured Notes outstanding. In September 2012, we amended our Credit Agreement to (i) permit investments in certain non-guarantor, non-pledged subsidiaries and joint ventures, (ii) increase the debt basket for certain foreign subsidiaries from $200 million to $400 million, and (iii) remove EBITDA, interest charges and indebtedness related to certain secured assets from the calculation of financial covenants. See Note 7 for additional information related to our long-term debt, including more information regarding the recent amendments to our Credit Agreement and our requirements and obligations under the debt agreements including our covenants and collateral security.

Working Capital

Total cash flows from operating activities decreased by $172.5 million in the three-month period ended March 31, 2013 as compared to the same period in 2012. This decrease primarily reflects the sale of ERT on February 6, 2013, the related settlement of our commodity derivative and interest rate swap contracts, and lower utilization of our robotics and subsea construction vessels and related equipment.

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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):

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Capital expenditures:		
Contracting Services	$(36,402)	$(82,238)
Production Facilities	(53)	(724)
Distributions from equity investments, net (1)	2,050	5,943
Net cash used in investing activities – continuing operations	(34,405)	(77,019)
Oil and Gas capital expenditures	(31,855)	(18,782)
Proceeds from sale of assets, net of related transaction costs	614,820	—
Other	—	922
Net cash provided by (used in) investing activities – discontinued operations	582,965	(17,860)
Net cash provided by (used in) investing activities	$548,560	$(94,879)

(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 contracting services business primarily include our Q5000 construction related payments (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 March 31, 2013, our total investment in the Q5000 was $142.6 million, including $115.9 million of scheduled payments made to the shipyard. We plan to spend approximately $135 million on the Q5000 during the remainder of 2013, including scheduled shipyard payments of $115.9 million. 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 currently undergoing upgrades and modifications in Singapore to render it suitable for use as a well intervention vessel. At March 31, 2013, our investment in the acquisition and subsequent upgrades to and modifications of the Helix 534 totaled $147.9 million, including related well control equipment. We estimate that an additional $45 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 the third quarter of 2013.

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 $365 million. These estimates may increase or decrease based on various economic factors and/or the existence of additional investment opportunities as well as the timing and shipyard activities associated with the H534. However, we may reduce the level of our planned future capital expenditures given any prolonged economic downturn.

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We believe that internally-generated cash flows, cash from the planned dispositions of our remaining subsea construction vessels and related assets, and availability under our existing credit facilities will provide the capital necessary to fund our 2013 initiatives.

Contractual Obligations and Commercial Commitments

The following table summarizes our contractual cash obligations as of March 31, 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
Senior Unsecured Notes	274,960	—	—	274,960	—
Term Loan (3)	72,299	5,000	67,299	—	—
MARAD debt	102,759	5,247	11,291	12,447	73,774
Revolving Credit Facility (4)	78,100	—	78,100	—	—
Interest related to debt	182,143	24,597	26,505	21,131	109,910
Property and equipment (5)	332,444	177,858	154,586	—	—
Operating leases (6)	655,259	107,068	268,230	178,796	101,165
Total cash obligations	$1,897,964	$319,770	$606,011	$487,334	$484,849

(1) Excludes unsecured letters of credit outstanding at March 31, 2013 totaling $8.0 million. These letters of credit guarantee items such as various contract bidding, insurance activities and shipyard commitments.

(2) Contractual maturity in 2032. The 2032 Notes can be converted prior to their stated maturity if the closing price of Helix's common stock for at least 20 days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter exceeds 130% of its issuance price on that 30th trading day (i.e., $32.53 per share). At March 31, 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 regarding these 2032 Notes.

(3) Our Term Loan will mature on July 1, 2015 but may extend to January 1, 2016 if our Senior Unsecured Notes are either refinanced or repaid in full by July 1, 2015 (Note 7). We repaid $293.9 million of our Term Loan debt in February 2013 following the sale of ERT.

(4) Our Revolving Credit Facility will mature on July 1, 2015 but may extend to January 1, 2016 if our Senior Unsecured Notes are either refinanced or repaid in full by July 1, 2015 (Note 7). We repaid $24.5 million under our Revolving Credit Facility in February 2013 following the sale of ERT.

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

(6) Operating leases included facility leases and vessel charter leases. At March 31, 2013, our vessel charter and ROV lease commitments totaled approximately $615.6 million.

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 March 31, 2013, $150.4 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. 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 $0.5 million in interest expense for the three-month period ended March 31, 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 risks 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 three-month period ended March 31, 2013, we recognized losses of $2.5 million related to foreign currency transactions in "Other income (expense), net" in the 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 kroner. In January 2013, we entered into foreign currency exchange contracts to hedge the foreign currency exposure to potential variability in cash flows 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 forwards that were not designated for hedge accounting totaled $1.0 million for the three-month period ended March 31, 2013.

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 March 31, 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 March 31, 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. Resulting impacts on internal controls over financial reporting were evaluated and determined not to be significant for the fiscal quarter ended March 31, 2013.

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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	(d) Maximum number of shares that may yet be purchased under the program (2) (3)
January 1 to January 31, 2013	71,315	$ 21.16	—	178,658
February 1 to February 28, 2013	—	—	—	178,658
March 1 to March 31, 2013	24,039	23.80	—	178,658
	95,354	$ 21.83	—	178,658

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

(2) In January 2013, we issued share-based awards to our executives (Note 11). Under the terms of our stock repurchase program, these grants increase the number of shares available for repurchase by a corresponding amount. For additional information regarding our stock repurchase program, see Note 11 of the 2012 Form 10-K.

(3) In April 2013, through the date of this filing, we repurchased 145,000 shares in open market transactions totaling $3.3 million for an average price of $22.93 per share under our stock repurchase program.

Item 5. Other Information

On April 24, 2013, a separation and release agreement was signed between the Company and Lloyd A. Hajdik, our Senior Vice President— Finance and former Chief Accounting Officer. See Exhibit 10.3 of this Quarterly Report on Form 10-Q for additional information regarding the agreement.

Item 6. Exhibits

The exhibits to this report are listed in the Exhibit Index beginning on Page 46 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: April 24, 2013	By: /s/ Owen Kratz Owen Kratz President and Chief Executive Officer (Principal Executive Officer)
Date: April 24, 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)
4.1	Amendment No. 8 to Credit Agreement dated February 19, 2013 by and among Helix Energy Solutions Group, Inc., as borrower, Bank of America, N.A., as administrative agent, and the lenders named thereto.	Exhibit 4.9 to the 2012 Form 10-K filed on February 22, 2013 (001-32936)
10.1	Amendment No. 1 to Equity Purchase Agreement dated January 27, 2013, between Helix Energy Solutions Group, Inc. and Talos Production LLC.	Exhibit 10.1 to the Current Report on Form 8-K filed on January 28, 2013 (001-32936)
10.2	Amendment No. 2 to Equity Purchase Agreement dated February 6, 2013, between Helix Energy Solutions Group, Inc. and Talos Production LLC.	Exhibit 10.1 to the Current Report on Form 8-K filed on February 12, 2013 (001-32936)
10.3 *	Separation and Release Agreement dated April 24, 2013, between Helix Energy Solutions Group, Inc. and Lloyd A. Hajdik.	Filed herewith
31.1	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Owen Kratz, Chief Executive Officer.	Filed herewith
31.2	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Anthony Tripodo, Chief Financial Officer.	Filed herewith
32.1	Certification of Helix's Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes — Oxley Act of 2002.	Furnished herewith
101.INS	XBRL Instance Document.	Furnished herewith
101.SCH	XBRL Schema Document.	Furnished herewith
101.CAL	XBRL Calculation Linkbase Document.	Furnished herewith
101.PRE	XBRL Presentation Linkbase Document.	Furnished herewith
101.DEF	XBRL Definition Linkbase Document.	Furnished herewith
101.LAB	XBRL Label Linkbase Document.	Furnished herewith

* Management contract or compensatory plan or arrangement