HELIX ENERGY SOLUTIONS GROUP INC
Form 10-Q
October 24, 2012

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

Form 10-Q

[X] Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended September 30, 2012

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 October 19, 2012, 105,338,962 shares of common stock were outstanding.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

	September 30, 2012 (Unaudited)	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$ 583,794	$ 546,465
Accounts receivable:		
Trade, net of allowance for uncollectible accounts of $4,844 and $4,067, respectively	198,046	238,781
Unbilled revenue	33,928	24,338
Costs in excess of billing	15,671	13,037
Other current assets	131,897	121,621
Total current assets	963,336	944,242
Property and equipment	4,378,185	4,391,064
Less accumulated depreciation	(1,946,358)	(2,059,737)
Property and equipment, net	2,431,827	2,331,327
Other assets:		
Equity investments	169,318	175,656
Goodwill	62,769	62,215
Other assets, net	84,707	68,907
Total assets	$ 3,711,957	$ 3,582,347
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 164,110	$ 147,043
Accrued liabilities	196,289	239,963
Income tax payable	—	1,293
Current maturities of long-term debt	13,120	7,877
Total current liabilities	373,519	396,176
Long-term debt	1,159,958	1,147,444
Deferred tax liabilities	455,266	417,610
Asset retirement obligations	136,293	161,208
Other long-term liabilities	8,336	9,368
Total liabilities	2,133,372	2,131,806
Convertible preferred stock	1,000	1,000
Commitments and contingencies		
Shareholders' equity:		
Common stock, no par, 240,000 shares authorized, 105,333 and 105,530 shares issued, respectively	929,397	908,776
Retained Earnings	647,877	522,644

Accumulated other comprehensive loss	(25,956)	(10,017)
Total controlling interest shareholders' equity	1,551,318	1,421,403
Noncontrolling interest	26,267	28,138
Total equity	1,577,585	1,449,541
Total liabilities and shareholders' equity	$ 3,711,957	$ 3,582,347

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 AND COMPREHENSIVE INCOME
(UNAUDITED)
(in thousands, except per share amounts)

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011
Net revenues:		
Contracting services	$217,110	$213,278
Oil and gas	119,124	159,218
Total net revenues	336,234	372,496
Cost of sales:		
Contracting services	148,731	147,614
Contracting services impairments	4,422	—
Oil and gas	97,324	102,587
Total cost of sales	250,477	250,201
Gross profit	85,757	122,295
Loss on sale of assets, net	(12,933)	—
Hedge ineffectiveness and non-hedge gain on commodity derivative contracts	(9,427)	—
Selling, general and administrative expenses	(28,022)	(22,082)
Income from operations	35,375	100,213
Equity in earnings of investments	1,392	4,906
Net interest expense	(18,211)	(24,114)
Loss on early extinguishment of long-term debt	—	(2,354)
Other income (expense), net	2,086	(8,360)
Income before income taxes	20,642	70,291
Provision for income taxes	4,967	23,465
Net income, including noncontrolling interests	15,675	46,826
Less net income applicable to noncontrolling interests	(800)	(800)
Net income applicable to Helix	14,875	46,026
Preferred stock dividends	(10)	(10)
Net income applicable to Helix common shareholders	$14,865	$46,016
Earnings per share of common stock:		
Basic	$0.14	$0.43
Diluted	$0.14	$0.43
Weighted average common shares outstanding:		
Basic	104,256	104,700
Diluted	104,729	105,154
Total comprehensive income (loss) applicable to Helix common shareholders (Note 9)	$(1,266)	$81,492

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 AND COMPREHENSIVE INCOME
(UNAUDITED)
(in thousands, except per share amounts)

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Net revenues:		
Contracting services	$644,413	$501,887
Oil and gas	447,142	500,535
Total net revenues	1,091,555	1,002,422
Cost of sales:		
Contracting services	452,855	371,042
Contracting services impairments	19,012	—
Oil and gas	278,996	320,238
Oil and gas property impairments	—	11,573
Total cost of sales	750,863	702,853
Gross profit	340,692	299,569
Loss on sale of assets, net	(14,647)	(6)
Hedge ineffectiveness and non-hedge gain on commodity derivative contracts	(1,697)	—
Selling, general and administrative expenses	(78,289)	(70,821)
Income from operations	246,059	228,742
Equity in earnings of investments	7,547	16,443
Net interest expense	(58,598)	(73,628)
Loss on early extinguishment of long-term debt	(17,127)	(2,354)
Other income (expense), net	480	(4,447)
Income before income taxes	178,361	164,756
Provision for income taxes	50,720	49,186
Net income, including noncontrolling interests	127,641	115,570
Less net income applicable to noncontrolling interests	(2,378)	(2,354)
Net income applicable to Helix	125,263	113,216
Preferred stock dividends	(30)	(30)
Net income applicable to Helix common shareholders	$125,233	$113,186
Earnings per share of common stock:		
Basic	$1.19	$1.07
Diluted	$1.18	$1.06
Weighted average common shares outstanding:		
Basic	104,450	104,616
Diluted	104,897	105,061
Total comprehensive income applicable to Helix common shareholders (Note 9)	$109,294	$159,764

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

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

	Nine Months Ended September 30,	
	2012	2011
Cash flows from operating activities:		
Net income, including noncontrolling interests	$127,641	$115,570
Adjustments to reconcile net income, including noncontrolling interests to net cash provided by operating activities:		
Depreciation and amortization	198,626	239,540
Asset impairment charge and dry hole expense	19,101	21,588
Amortization of deferred financing costs	4,990	7,197
Stock-based compensation expense	5,561	6,835
Amortization of debt discount	7,253	6,693
Deferred income taxes	26,495	31,707
Excess tax benefit from stock-based compensation	1,151	805
Gain on investment in Cal Dive common stock	—	(753)
Loss on sale of assets, net	14,647	6
Loss on early extinguishment of debt	17,127	2,354
Unrealized gain and ineffectiveness on derivative contracts, net	2,130	433
Changes in operating assets and liabilities:		
Accounts receivable, net	33,988	(24,205)
Other current assets	(6,774)	(11,100)
Income tax payable	(12,591)	9,129
Accounts payable and accrued liabilities	(16,828)	(28,668)
Oil and gas asset retirement costs	(94,623)	(34,836)
Other noncurrent, net	(19,742)	8,836
Net cash provided by operating activities	308,152	351,131
Cash flows from investing activities:		
Capital expenditures	(305,344)	(167,849)
Distributions from equity investments, net	6,174	738
Proceeds from sale of assets	14,500	—
Proceeds from sale of Cal Dive common stock	—	3,588
Decrease in restricted cash	2,698	703
Net cash used in investing activities	(281,972)	(162,820)
Cash flows from financing activities:		
Early extinguishment of Senior Unsecured Notes	(209,500)	(77,394)
Borrowings under revolving credit facility	100,000	109,400
Repayment of revolving credit facility	—	(109,400)
Issuance of Convertible Senior Notes due 2032	200,000	—
Repurchase of Convertible Senior Notes due 2025	(143,945)	—
Proceeds from Term Loan A	100,000	—
Repayment of Term Loan	(10,585)	(111,941)
Repayment of MARAD borrowings	(4,877)	(4,645)
Deferred financing costs	(7,766)	(9,224)

Distributions to noncontrolling interest	(4,249)	—
Repurchases of common stock	(7,510)	(1,072)
Excess tax benefit from stock-based compensation	(1,151)	(805)
Exercise of stock options, net and other	1,264	773
Net cash provided by (used in) financing activities	11,681	(204,308)
Effect of exchange rate changes on cash and cash equivalents	(532)	267
Net increase (decrease) in cash and cash equivalents	37,329	(15,730)
Cash and cash equivalents:		
Balance, beginning of year	546,465	391,085
Balance, end of period	$583,794	$375,355

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 and are consistent in all material respects with those applied in our 2011 Annual Report on Form 10-K (“2011 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 and comprehensive income, and statements of cash flows, as applicable. The operating results for the three- and nine-month periods ended September 30, 2012 are not necessarily indicative of the results that may be expected for the year ending December 31, 2012. Our balance sheet as of December 31, 2011 included herein has been derived from the audited balance sheet as of December 31, 2011 included in our 2011 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 2011 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.

In June 2011, the Financial Accounting Standards Board (“FASB”) issued amendments to disclosure requirements for presentation of comprehensive income. This guidance, effective retrospectively for the interim and annual periods beginning on or after December 15, 2011, requires presentation of total comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In December 2011, the FASB issued an amendment that deferred the presentation of reclassification adjustments for each component of accumulated other comprehensive income in both net income and other comprehensive income on the face of the financial statements. The implementation of the amended accounting guidance did not have a material impact on our consolidated financial position or results of operations.

Note 2 – Company Overview

We are an international offshore energy company that provides specialty services to the offshore energy industry, with a focus on our growing well intervention and robotics businesses. We also own an oil and gas business that is a prospect generation, exploration, development and production company. We utilize cash flow generated from our oil and gas production to support expansion of our well intervention and robotics businesses. Our contracting services operations are located primarily in the Gulf of Mexico, North Sea, Asia Pacific, and West Africa regions. Our oil and gas operations are located in the Gulf of Mexico.

Contracting Services Operations

We seek to provide services and methodologies which we believe are critical to developing offshore reservoirs and maximizing production economics. Our "life of field" services are segregated into four disciplines: well operations, 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 business includes the well operations, robotics and subsea construction activities (see Note 17 for disclosures regarding the announced sale of a large portion of our subsea

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construction 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"). It also includes the Helix Fast Response System ("HFRS"), which includes access to our Q4000 and HP I vessels. 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 for a two-year term to certain CGA participants who have executed utilization agreements with us. In addition to the agreement with CGA, we currently have separate utilization agreements with 24 CGA participant member companies. These agreements specify the day rates to be charged should the HFRS be deployed in connection with a well control incident. The retainer fee for the HFRS became effective April 1, 2011.

Oil and Gas Operations

We began our oil and gas operations to achieve incremental returns, to expand our off-season utilization of our contracting services assets, and to provide a more efficient solution to offshore abandonment for industry participants. We have evolved this business model to include not only mature oil and gas properties but also unproved and proved reserves yet to be explored and developed.

Note 3 – Details of Certain Accounts

Other current assets consisted of the following as of September 30, 2012 and December 31, 2011 (in thousands):

	September 30, 2012	December 31, 2011
Other receivables	$ 568	$ 5,096
Prepaid insurance	19,830	12,701
Other prepaids	15,861	13,271
Spare parts inventory	15,324	18,066
Current deferred tax assets	48,447	41,449
Hedging assets (Note 16)	7,510	21,579
Gas and oil imbalance	3,740	5,134
Income tax receivable	10,135	—
Assets held for sale (Note 14)	5,000	—
Other	5,482	4,325
Total other current assets	$ 131,897	$ 121,621

Other assets, net, consisted of the following as of September 30, 2012 and December 31, 2011 (in thousands):

	September 30, 2012	December 31, 2011
Restricted cash	$ 31,043	$ 33,741
Deferred dry dock expenses, net (1)	23,756	5,381
Deferred financing costs, net	26,091	26,483
Intangible assets with finite lives, net	471	531
Other	3,346	2,771
Total other assets, net	$ 84,707	$ 68,907

(1) The increase subsequent to December 31, 2011 reflects the costs associated with the regulatory dry docks for our Q4000, Seawell and Well Enhancer vessels during 2012.

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Accrued liabilities consisted of the following as of September 30, 2012 and December 31, 2011 (in thousands):

	September 30, 2012	December 31, 2011
Accrued payroll and related benefits	$ 54,147	$ 49,599
Royalties payable	13,061	19,391
Current asset retirement obligations (Note 4)	67,302	93,183
Unearned revenue	8,264	7,654
Billing in excess of cost	7,317	28,839
Accrued interest	9,292	24,028
Hedging liability (Note 16)	20,333	1,247
Gas and oil imbalance	3,167	4,177
Taxes payable excluding income tax payable	5,689	3,761
Other	7,717	8,084
Total accrued liabilities	$ 196,289	$ 239,963

Note 4 – Oil and Gas Properties

We follow the successful efforts method of accounting for our interests in oil and gas properties. Under the successful efforts method, the costs of successful wells and leases containing productive reserves are capitalized. Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized. Costs incurred relating to unsuccessful exploratory wells are charged to expense in the period in which the drilling is determined to be unsuccessful.

Exploration and Other

As of September 30, 2012, we capitalized approximately $10.5 million of costs associated with ongoing exploration and/or appraisal activities, including $8.1 million associated with our Wang exploratory well that will commence drilling in the fourth quarter of 2012 and $2.3 million for our T-6 well that we expect to drill in 2013. Both of these wells are located at Green Canyon Block 237 within our Phoenix field. Such capitalized costs may be charged against earnings in future periods if management determines that commercial quantities of hydrocarbons have not been discovered or that future appraisal drilling or development activities are not likely to occur.

The following table details the components of exploration expense for the three- and nine-month periods ended September 30, 2012 and 2011:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Delay rental and geological and geophysical costs	$623	$522	$2,380	$2,176
Impairment of unproved properties (1)	—	1,028	144	7,668
Dry hole expense	—	(1)	(55)	(11)
Total exploration expense	$623	$1,549	2,469	9,833

(1) Included in the nine-month period ended September 30, 2011 were costs of $6.6 million associated with a deepwater lease, the term of which expired during the second quarter of 2011.

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Danny II

We hold a 50% interest in the Danny II prospect at Garden Banks Block 506 in our Bushwood field. The Danny II exploration well was drilled to a total depth of approximately 14,750 feet, in water depths of approximately 2,800 feet. The well encountered hydrocarbon pay and is expected to be predominately an oil producer. The well is currently in the final stages of being developed via a subsea tie back system to our 70% owned and operated East Cameron Block 381 platform.

Impairments

We did not record any oil and gas property impairments during the nine-month period ended September 30, 2012. During the nine-month period ended September 30, 2011, we recorded impairment charges totaling $11.6 million to reduce the carrying value of five of our Gulf of Mexico oil and gas properties to their estimated fair value of $2.9 million.

Asset retirement obligations

The following table describes the changes in our asset retirement obligations (both current and long-term) since December 31, 2011 (in thousands):

Asset retirement obligation at December 31, 2011	$254,391
Liability incurred during the period	1,110
Liability settled during the period	(108,729)
Other revisions in estimated cash flows (1)	47,080
Accretion expense (included in depreciation and amortization)	9,743
Asset retirement obligations at September 30, 2012	$203,595

(1) The increased amount of these liabilities includes revisions to both non-producing and producing oil and gas properties. Increases to liabilities associated with non-producing properties ($24.9 million) include a corresponding charge to cost of sales within our condensed consolidated statements of operations and comprehensive income while changes in estimates for producing properties are recorded as an increase to property and equipment carrying costs of the related oil and gas properties within our condensed consolidated balance sheets.

During the nine-month period ended September 30, 2012, we recorded $13.0 million of expense charges related to our only non-domestic oil and gas property, Camelot, which is located in the North Sea. The charges reflect an increase in our estimated costs to complete our abandonment activities at this non-producing field. These activities are substantially complete. During the nine-month period ended September 30, 2011, we recorded $13.5 million of expense charges to increase our asset retirement obligations related to seven non-producing fields, including $4.1 million related to Camelot.

Insurance

On June 30, 2012, we obtained a hurricane catastrophic bond for the period from July 1, 2012 to June 30, 2013 and made a payment of $10.6 million. We charged approximately $8.4 million of this payment to insurance expense in the third quarter of 2012 and we will record a $2.0 million charge in the fourth quarter of 2012 based upon the bond's contractual intrinsic value at the end of each of these quarterly periods.

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 less than three months. We had restricted cash totaling $31.0 million at September 30, 2012 and $33.7 million at December 31, 2011, all of which consisted of funds required to be escrowed to cover the future asset retirement obligations associated with our South Marsh Island Block 130 field. We have fully satisfied the escrow requirements under the escrow agreement and may use the restricted cash for reclamation activities at the field, which activities may occur over many years. These escrowed funds are reflected in "Other assets, net" in the accompanying condensed consolidated balance sheets.

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The following table provides supplemental cash flow information for the nine-month periods ended September 30, 2012 and 2011 (in thousands):

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Interest paid, net of capitalized interest	$ 61,637	$ 73,096
Income taxes paid	$ 39,011	$ 9,575

Non-cash investing activities for the nine-month periods ended September 30, 2012 and 2011 included $33.1 million and $34.8 million, respectively, of accruals for capital expenditures. The accruals have been reflected in the accompanying condensed consolidated balance sheets as an increase in “Property and equipment” as well as “Accounts payable”.

Note 6 – Equity Investments

As of September 30, 2012, 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 $92.3 million and $96.0 million as of September 30, 2012 and December 31, 2011, respectively (including capitalized interest of $1.4 million at September 30, 2012 and December 31, 2011). Our net distributions from Deepwater Gateway totaled $3.4 million and $6.8 million for the three- and nine-month periods ended September 30, 2012, respectively, compared to $2.2 million and $5.7 million for the respective comparable periods in 2011.

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 $77.0 million and $79.7 million as of September 30, 2012 and December 31, 2011, respectively (including capitalized interest of $4.7 million and $4.9 million at September 30, 2012 and December 31, 2011, respectively). Our net distributions from Independence Hub totaled $2.1 million and $6.9 million in the three- and nine-month periods ended September 30, 2012, respectively, compared to $4.6 million and $14.2 million for the respective comparable periods in 2011.

As disclosed in our 2011 Form 10-K, we invested in an Australian joint venture that engaged in well intervention operations in the Southeast Asia region. At December 31, 2011, we fully impaired our investment in that joint venture (Note 7 of 2011 Form 10-K). In the first quarter of 2012, we recorded additional losses totaling $3.8 million, including a $3.0 million negotiated exit fee. In April 2012, we paid this fee and exited the joint venture. In connection with our exit, we were entitled to 50% of certain of the net assets on hand at the time of our departure. We received approximately $3.7 million of proceeds for our pro rata portion of those certain net assets of the joint venture, which was recorded as income in “Equity in earnings of investments” during the second quarter of 2012. We are no longer a participant in this Australian joint venture.

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Note 7 – Long-Term Debt

Scheduled maturities of long-term debt outstanding as of September 30, 2012 were as follows (in thousands):

	Term Loan (1)	Revolving Credit Facility	Senior Unsecured Notes	2025 Notes (2)	MARAD Debt	2032 Notes (3)	Total
Less than one year	$8,000	$—	$—	$—	$5,120	$—	$13,120
One to two years	8,000	—	—	—	5,376	—	13,376
Two to three years	353,165	100,000	—	—	5,644	—	458,809
Three to four years	—	—	274,960	—	5,926	—	280,886
Four to five years	—	—	—	—	6,222	—	6,222
Over five years	—	—	—	157,830	77,000	200,000	434,830
Total debt	369,165	100,000	274,960	157,830	105,288	200,000	1,207,243
Current maturities	(8,000)	—	—	—	(5,120)	—	(13,120)
Long-term debt, less current maturities	$361,165	$100,000	$274,960	$157,830	$100,168	$200,000	$1,194,123
Unamortized debt discount (4)	—	—	—	(1,241)	—	(32,924)	(34,165)
Long-term debt	$361,165	$100,000	$274,960	$156,589	$100,168	$167,076	$1,159,958

(1) Amounts reflect both our Term Loan and Term Loan A.

(2) Beginning in December 2012, 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 2025.

(3) 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 the notes. These notes will mature in March 2032.

(4) The notes will increase to their principal amount through accretion of non-cash interest charges through December 2012 for the Convertible Senior Notes due 2025 and 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 9 of our 2011 Form 10-K.

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 semiannually 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. 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, in any, thereon to the applicable redemption date.

Year	Redemption Price
2012	104.750%
2013	102.375%
2014 and thereafter	100.000%

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At December 31, 2010, we had $550.0 million of Senior Unsecured Notes outstanding. During the third quarter of 2011, we purchased a portion of our Senior Unsecured Notes that resulted in the early extinguishment of an aggregate $75.0 million of those notes. In these transactions we paid an aggregate amount of $77.4 million, including the $75.0 million in principal and $2.4 million in premium for the repurchased Senior Unsecured Notes. We also paid the accrued interest on these Senior Unsecured Notes totaling $0.8 million and we recorded a $0.9 million charge to interest expense to accelerate a pro rata portion of the deferred financing costs associated with the issuance of the Senior Unsecured Notes in 2007.

At December 31, 2011, we had $475.0 million of Senior Unsecured Notes outstanding. In March 2012, we purchased a portion of these Senior Unsecured Notes that resulted in an early extinguishment of $200.0 million of our balance outstanding. In these transactions we paid an aggregate amount of $213.5 million, including $200.0 million in principal, a $9.5 million premium for the repurchased Senior Unsecured Notes 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 related 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 and comprehensive income.

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") 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 seven times, with the most recent amendment occurring in September 2012. These amendments address certain issues with regard to covenants, maturity and the borrowing limits under the Term Loans and the Revolving Credit Facility. For additional information regarding the current terms of our credit facility, see Note 9 of our 2011 Form 10-K.

In September 2012, we amended the credit agreement to primarily:

- permit investments in (i) non-guarantor, non-pledged subsidiaries and (ii) joint ventures provided that after giving effect to each such investment, a minimum consolidated liquidity requirement of $400 million is met on a pro forma basis;
- increase the debt basket for foreign subsidiaries (other than specified foreign subsidiaries that currently are excepted from this debt basket) from $200 million to $400 million provided that such indebtedness is non-recourse to us and our other subsidiaries (the "Foreign Subsidiary Debt Basket"); and
- remove, to the extent they otherwise would be included in the calculation of financial covenants, EBITDA, interest charges and indebtedness related to assets secured by, or otherwise subject to, the indebtedness permitted by the Foreign Subsidiary Debt Basket.

In February 2012, we entered into a separate amendment to our Credit Agreement. Under the terms of this amendment, the participating lenders agreed to loan us $100.0 million pursuant to an additional term loan (the "Term Loan A"). The terms of Term Loan A are the same as those governing the Revolving Credit Facility, with the Term Loan A requiring a $5 million annual payment of its principal balance. The Term Loan A was funded in late March 2012 and we used the borrowings under the Term Loan A to repurchase a portion of our Senior Unsecured Notes.

The Term Loan 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 for the nine-month periods ended September 30, 2012 and 2011 were approximately 3.7% and 3.6%, respectively, including the effects of our interest rate swaps (Note 16). The Term Loan is currently scheduled to mature on July 1, 2015 but could be extended to July 1, 2016 if our Senior Unsecured

Notes are fully repaid or refinanced by July 1, 2015.

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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. In late March 2012, we borrowed $100.0 million under our Revolving Credit Facility to repurchase a portion of our Senior Unsecured Notes. Accordingly, at September 30, 2012, we had $100.0 million drawn on the Revolving Credit Facility and our availability under the Revolving Credit Facility totaled $455.7 million, net of $44.3 million of letters of credit issued. There were no borrowings outstanding at December 31, 2011.

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. The average interest rate under the Revolving Credit Facility totaled 3.0% for the period in which we had borrowings outstanding during the nine-month period ended September 30, 2012.

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.

As the rates for our Term Loan are subject to market influences and will vary over the term of the Credit Agreement, we may enter into various cash flow hedging interest rate swaps to stabilize cash flows relating to a portion of our interest payments for our Term Loan. In January 2010, we entered into $200 million, two-year interest rate swaps to stabilize cash flows relating to a portion of our interest payments on our Term Loan, which extended to January 2012. In August 2011, we entered into additional two-year interest rate swap contracts to assist in stabilizing cash flows related to our interest payments for $200 million of our Term Loan debt from January 2012 through January 2014 (Note 16).

Convertible Senior Notes

In March 2005, we issued $300 million of our 3.25% Convertible Senior Notes at 100% of the principal amount to certain qualified institutional buyers (the "2025 Notes"). The 2025 Notes are convertible into cash and, if applicable, shares of our common stock based on the specified conversion rate, subject to adjustment.

The 2025 Notes can be converted prior to the stated maturity (March 2025) under certain triggering events specified in the indenture governing the 2025 Notes. No conversion triggers were met during the nine-month periods ended September 30, 2012 and 2011. The first dates for early redemption of the 2025 Notes are in December 2012, with the holders of the 2025 Notes being able to put them to us on December 15, 2012 and our being able to call the 2025 Notes at any time after December 20, 2012 (see Note 9 of our 2011 Form 10-K). To the extent we do not have long-term financing secured to cover such conversion and/or redemption, the 2025 Notes would be classified as a current liability in the accompanying consolidated balance sheet. As the holders have the option to require us to redeem the 2025 Notes on December 15, 2012, we assessed whether or not this indebtedness was required to be classified as a current liability at September 30, 2012 and concluded that it still qualified as a long-term debt because a) we possess enough borrowing capacity under our Revolving Credit Facility (see "Credit Agreement" above) to settle the notes in full and b) it is our current intent to utilize our Revolving Credit Facility borrowings or other alternative financing proceeds to settle the remaining balance of our 2025 Notes, if and when the holders exercise their redemption option.

In association with the issuance of additional Convertible Senior Notes (see "2032 Notes" below), we repurchased $142.2 million in aggregate principal of our 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 on these repurchased 2025 Notes. The loss on the early extinguishment of these related 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 and comprehensive income. The loss on early extinguishment includes the acceleration of $3.5 million of related 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 these 2025 Notes. The remaining balance of our 2025 Notes was $157.8 million at September 30, 2012.

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The effective interest rate for the 2025 Notes is 6.6% after considering the effect of the accretion of the related debt discount that represented the equity component of the Convertible Notes at their inception.

Our average share price was below the $32.14 per share conversion price for all of the periods presented in this Quarterly Report on Form 10-Q. As a result, there are no shares included in our diluted earnings per share calculation associated with the assumed conversion of our 2025 Notes. In the event our average share price exceeds the conversion price, there would be a premium, payable in shares of common stock, in addition to the principal amount, which is paid in cash, and such shares would be issued upon conversion.

2032 Notes

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 (the “2032 Notes”). The net proceeds from the issuance of the 2032 Notes were $195.0 million, after deducting the underwriter’s discounts and commissions and estimated offering expenses. We used the net proceeds to repurchase and retire $142.2 million of aggregate principal amount of our 2025 Notes (see above), in separate, privately negotiated transactions, and intend to use the remaining net proceeds for other general corporate purposes, including the repayment of other indebtedness.

The registered 2032 Notes bear interest at a rate of 3.25% per annum, 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 of $18.53 per share.

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 of the 2032 Notes to be redeemed 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.

In connection with the issuance of our 2032 Notes, we recorded a discount of $35.4 million as required under existing accounting requirements. To arrive at this discount amount, we estimated the fair value of the liability component of the 2032 Notes as of the date of their issuance (March 12, 2012) using an income approach. To determine this estimated fair value, we used borrowing rates of similar market transactions involving comparable liabilities at the time of issuance and an expected life of 6.0 years. In selecting the expected life, we selected the earliest date that the holder 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 which is 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, with us guaranteeing 50% of the debt, 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).

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Other

In accordance with our Credit Agreement, Senior Unsecured Notes, 2025 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 September 30, 2012, we were in compliance with these covenants and restrictions.

Deferred financing costs of $26.1 million and $26.5 million were included in “Other assets, net” as of September 30, 2012 and December 31, 2011, respectively, and are being amortized over the life of the respective financing agreements.

At September 30, 2012, our unsecured letters of credit totaled approximately $44.3 million (see “Credit Agreement” above). These letters of credit primarily guarantee asset retirement obligations as well as various contract bidding, contractual performance, insurance activities and shipyard commitments. The following table details our interest expense and capitalized interest for the three- and nine-month periods ended September 30, 2012 and 2011 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Interest expense	$19,878	$25,175	$62,634	$75,971
Interest income	(460)	(600)	(1,352)	(1,575)
Capitalized interest	(1,207)	(461)	(2,684)	(768)
Interest expense, net	$18,211	$24,114	$58,598	$73,628

Note 8 – Income Taxes

The effective tax rates for the three- and nine-month periods ended September 30, 2012 were 24.1% and 28.4%, respectively. The effective tax rates for the three- and nine-month periods ended September 30, 2011 were 33.4% and 29.9%, respectively. The variance of the comparable year-over-year periods is primarily attributable to increased profitability in certain foreign jurisdictions with lower income tax rates. Our effective tax rate decreased in the third quarter of 2012, primarily reflecting the tax benefit of a reduction in the U.K. statutory tax rate.

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 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Statutory rate	35.0 %	35.0 %	35.0 %	35.0 %
Foreign provision	(3.8)	0.7	(5.3)	(3.7)
Change in U.K. tax rate	(7.6)	(1.9)	(0.9)	(0.8)
Other	0.5	(0.4)	(0.4)	(0.6)

Effective rate	24.1 %	33.4 %	28.4 %	29.9 %

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Note 9 – Comprehensive Income and Accumulated Other Comprehensive Loss

The components of total comprehensive income for the three- and nine-month periods ended September 30, 2012 and 2011 were as follows (in thousands):

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Net income, including noncontrolling interests	$15,675	$46,826	$127,641	$115,570
Other comprehensive income, net of tax				
Foreign currency translation gain	3,905	1,588	5,219	2,287
Unrealized gain (loss) on hedges, net	(20,036)	33,888	(21,158)	44,291
Total other comprehensive income (loss)	(16,131)	35,476	(15,939)	46,578
Total comprehensive income (loss)	(456)	82,302	111,702	162,148
Less comprehensive income applicable to noncontrolling interests	(800)	(800)	(2,378)	(2,354)
Total comprehensive income (loss) applicable to Helix	(1,256)	81,502	109,324	159,794
Preferred stock dividends	(10)	(10)	(30)	(30)
Total comprehensive income (loss) applicable to Helix common shareholders	$(1,266)	$81,492	$109,294	$159,764

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

	September 30, 2012	December 31, 2011
Cumulative foreign currency translation adjustment	$ (17,739)	$ (22,958)
Unrealized gain (loss) on hedges, net	(8,217)	12,941
Accumulated other comprehensive loss	$ (25,956)	$ (10,017)

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 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 and comprehensive income 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 and comprehensive income were as follows (in thousands):

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	Three Months Ended September 30, 2012		Three Months Ended September 30, 2011	
	Income	Shares	Income	Shares
Basic:				
Net income applicable to Helix common shareholders	$ 14,865		$ 46,016	
Less: Undistributed net income allocable to participating securities	(150)		(549)	
Net income applicable to Helix common shareholders	$ 14,715	104,256	$ 45,467	104,700
Diluted:				
Net income per common share - Basic	$ 14,715	104,256	$ 45,467	104,700
Effect of dilutive securities:				
Share-based awards other than participating securities	—	112	—	93
Undistributed earnings reallocated to participating securities	1	—	2	—
Convertible preferred stock	10	361	10	361
Net income per common share - Diluted	$ 14,726	104,729	$ 45,479	105,154

	Nine Months Ended September 30, 2012		Nine Months Ended September 30, 2011	
	Income	Shares	Income	Shares
Basic:				
Net income applicable to Helix common shareholders	$ 125,233		$ 113,186	
Less: Undistributed net income allocable to participating securities	(1,260)		(1,403)	
Net income applicable to Helix common shareholders	$ 123,973	104,450	$ 111,783	104,616
Diluted:				
Net income per common share - Basic	$ 123,973	104,450	$ 111,783	104,616
Effect of dilutive securities:				
Share-based awards other than participating securities	—	86	—	84
Undistributed earnings reallocated to participating securities	5	—	6	—
Convertible preferred stock	30	361	30	361
Net income per common share - Diluted	$ 124,008	104,897	$ 111,819	105,061

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 either of the three- or nine-month periods ended September 30, 2012 and 2011. Also, no diluted shares were included for our 2032 Notes for the three- or nine-month periods ended September 30, 2012 as the conversion price of $25.02 (and conversion trigger of $32.53 per share) was not met and we have the right to settle any such future conversions in cash at our sole discretion.

Note 11 – Employee Benefit Plans

We have two stock-based compensation plans: the 1995 Long-Term Incentive Plan, as amended (the “1995 Incentive Plan”) and the 2005 Long-Term Incentive Plan, as amended (the “2005 Incentive Plan”). In May 2012, the shareholders approved an amendment to and restatement of the 2005 Incentive Plan to: (i) authorize 4.3 million additional shares for issuance pursuant to our equity incentive compensation strategy, (ii) authorize incentive stock options, stock appreciation rights, cash awards and performance awards to be made pursuant to the amended and restated 2005 Incentive Plan, and (iii) include performance criteria for awards that may be made contingent upon the achievement of one or more performance measures, as well as limits on individual awards, in accordance with the requirements for performance-based compensation under Section 162(m) of the Internal Revenue Code. As of September 30, 2012, there were 6.7 million shares available for issuance under the amended and restated 2005 Incentive Plan, which includes a

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maximum of 2.0 million shares that may be granted as incentive stock options. There were no stock option grants in the three- and nine-month periods ended September 30, 2012 and 2011. During the nine-month period ended September 30, 2012, the following grants of share-based awards (restricted shares, restricted stock units and performance share units ("PSUs")) were made to executive officers, selected management employees 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 3, 2012	272,153	$ 15.80	33% per year over three years
January 3, 2012 (1)	132,910	23.68	100% on January 1, 2015
January 3, 2012	1,958	15.80	100% on January 1, 2014
April 1, 2012	1,879	17.80	100% on January 1, 2014
July 2, 2012	1,885	16.41	100% on January 1, 2014
August 23, 2012	3,539	18.84	20% per year over five years

(1) Reflects the grant of PSUs to certain of 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. See Note 12 of 2011 Form 10-K.

Compensation cost is recognized over the respective vesting periods on a straight-line basis. For the three- and nine-month periods ended September 30, 2012, $1.8 million and $5.5 million, respectively, were recognized as compensation expense related to share-based awards as compared with $1.9 million and $6.8 million during the three- and nine-month periods ended September 30, 2011.

Long-Term Incentive Compensation Plan

In January 2009, we adopted the 2009 Long-Term Incentive Cash Plan (the "2009 LTI Plan") to provide long-term cash-based compensation to eligible employees. Under the terms of the 2009 LTI Plan, the majority of the cash awards are fixed sum amounts payable (the vesting period is five years for awards granted before January 1, 2012 and three years thereafter). However, some of the cash awards are indexed to our common stock and the payment amount at each vesting date will fluctuate based on the performance of our common stock. 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 awards made under the 2009 LTI Plan totaled $4.2 million in 2012 and $5.2 million in 2011. Total compensation expense associated with the 2009 LTI Plan was $2.5 million and $6.1 million, respectively, for the three- and nine-month periods ended September 30, 2012. For the three- and nine-month periods ended September 30, 2011, compensation expense under the 2009 LTI Plan totaled $0.4 million and $5.0 million, respectively. The liability balance under the 2009 LTI Plan was $10.5 million at September 30, 2012 and $9.9 million at December 31, 2011, including $9.5 million at September 30, 2012 and $8.5 million at December 31, 2011 associated with the variable portion of the 2009 LTI plan.

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

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trading day of the purchase period. The first purchase period under the ESPP began on September 1, 2012. Share-based compensation expense with respect to the ESPP was $0.1 million for the three- and nine-month periods ended September 30, 2012.

For more information regarding our employee benefit plans, including our stock-based compensation plans and our 2009 LTI Plan, see Note 12 of our 2011 Form 10-K.

Note 12 – Business Segment Information

Our operations are conducted through the following lines of business: contracting services and oil and gas. We have disaggregated our contracting services operations into two reportable segments. As a result, our reportable segments consist of the following: Contracting Services, Production Facilities and Oil and Gas. Contracting Services operations include well operations, robotics and subsea construction (see Note 17 for disclosures regarding the announced sale of a large portion of our subsea construction 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.

We evaluate our performance based on operating income of each segment. The following table details revenues and income (loss) from operations by reportable segment (in thousands). All material intercompany transactions between the segments have been eliminated.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Revenues —				
Contracting Services	$221,491	$229,967	$675,592	$532,857
Production Facilities	20,024	19,986	60,009	56,101
Oil and Gas	119,124	159,218	447,142	500,535
Intercompany elimination	(24,405)	(36,675)	(91,188)	(87,071)
Total	$336,234	$372,496	$1,091,555	$1,002,422
Income (loss) from operations —				
Contracting Services	$33,012	$47,363	$111,359	$81,194
Production Facilities	10,180	10,983	30,111	28,859
Oil and Gas	5,540	48,622	142,924	144,926
Corporate	(13,396)	(6,227)	(35,452)	(25,780)
Intercompany elimination	39	(528)	(2,883)	(457)
Total	$35,375	$100,213	$246,059	$228,742
Equity in earnings of equity investments	$1,392	$4,906	$7,547	$16,443

Intercompany segment revenues during the three- and nine-month periods ended September 30, 2012 and 2011 were as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Contracting Services	12,896	25,410	56,635	52,574

Production Facilities	11,509	11,265	34,553	34,497
Total	$24,405	$36,675	$91,188	$87,071

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Intercompany segment profits (losses) during the three- and nine-month periods ended September 30, 2012 and 2011 were as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Contracting Services	5	606	3,014	645
Production Facilities	(44)	(78)	(131)	(188)
Total	$(39)	$528	$2,883	$457

Segment assets are comprised of all assets attributable to each reportable segment. The following table reflected total assets by reportable segment as of September 30, 2012 and December 31, 2011 (in thousands):

	September 30, 2012	December 31, 2011
Contracting Services	$ 2,215,076	$ 2,006,065
Production Facilities	509,468	534,776
Oil and Gas	987,413	1,041,506
Total	$ 3,711,957	$ 3,582,347

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"), the investors of which include current and former Helix senior management, in exchange for a revenue interest that is an overriding royalty interest of 25% of Helix's 20% working interest. Production began in December 2003. Our payments to OKCD totaled $1.8 million and $5.6 million for the three- and nine-month periods ended September 30, 2012, respectively, and $2.3 million and $7.3 million for the three- and nine-month periods ended September 30, 2011, respectively. Our Chief Executive Officer, Owen Kratz, through Class A limited partnership interests in OKCD, personally owns approximately 81% 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.

Note 14 – Commitments and Contingencies and Other Matters

Commitments Related to Expansion of Well Intervention Fleet

In March 2012, we executed a shipyard contract for the construction of a newbuild semisubmersible 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. We made the first scheduled payment under the contract in the amount of $57.8 million in March 2012. Under the terms of this contract, the payments will be made in fixed amounts on contractually scheduled dates. The next payment of $58.1 million is scheduled to be made in December 2012.

In July 2012, we contracted to charter the Skandi Constructor for use in our North Sea well intervention operations. The initial term of the charter will be three years once the vessel is delivered to us in the first half of 2013.

In August 2012, we acquired the Discoverer 534 drillship from Transocean Ltd. for $85 million. The vessel, renamed the Helix 534, is currently undergoing modifications in Singapore to convert it into a well intervention vessel.

Contingencies and Claims

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 number of factors associated with the ongoing negotiations with the prime contractor, in 2010 we established an allowance against our trade receivable balance that reduces its balance to an amount we believe is ultimately realizable (see Notes 16 and 18 of our 2011 Form 10-K). 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 2007, 2008, 2009 and 2010 related to a subsea construction and diving contract we entered into in December 2006 in India. The State claims 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.

Impairment and Sale of the Intrepid

As a result of diminished work opportunities for the Intrepid, formerly one of our subsea construction vessels, we deferred its scheduled regulatory dry dock and placed the vessel in cold-stack mode in the third quarter of 2012. When this decision was made in the second quarter of 2012, we recorded a $14.6 million impairment charge to reduce the vessel's carrying cost to its estimated fair value of $35.0 million at that time. In September 2012, we sold the Intrepid for $14.5 million in cash, which resulted in an additional $12.9 million charge to expense. This amount is reflected in the accompanying condensed consolidated statements of operations and comprehensive income in the line item titled "Loss on sale of assets, net".

Impairment of Well Intervention Assets in Australia

During the third quarter of 2012, we decided to cease our well intervention operations in Australia. In connection with the closure of these operations, we recorded $1.7 million of severance for our former employees. We also recorded a $4.4 million expense charge to reduce our well intervention assets in Australia to their estimated fair value of $5.0 million. The asset impairment charge was reflected in "Contracting services impairments" in the accompanying condensed consolidated statements of operations and comprehensive income while the fair value of these assets was included as assets held for sale (Note 3) in "Other current assets" in the accompanying condensed consolidated balance sheets. The sale of these assets will close in the fourth quarter of 2012.

Litigation

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, City of Sterling Heights Police & Fire Retirement System v. Owen Kratz, et al., a description of which is included in our 2011 Form 10-K. We have filed a motion to stay, motion to dismiss, special exceptions, plea to the jurisdiction and an original answer asserting that: (i) the suit should be stayed in favor of a first-filed federal derivative case; (ii) the plaintiff has not pled specific facts showing wrongful refusal of demand; (iii) the plaintiff has not

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demonstrated he continually owned shares during the complained of action; and (iv) the plaintiff has not stated a claim. 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.

On June 20, 2012, we were named as a defendant in a claim filed in the Western District of Virginia by an individual, Charles Adams, who claims that he invented the capping stack used to plug the BP Gulf of Mexico Macondo well. Mr. Adams alleges that we obtained some drawings and other intellectual property from an engineer named Richard Haun and/or Mr. Haun's company, Equipment Design & Manufacturing Group, LLC, d/b/a ED&M Deepwater Engineering (collectively "ED&M", and also a named defendant), and that we and ED&M then engaged Cameron International Corporation (which is also a named defendant) to manufacture the capping stack and realize the Plaintiff's invention. Mr. Adams sought at least $150 million in compensatory damages, treble damages under a Virginia statute, punitive damages, attorney's fees and costs, as well as temporary and permanent injunctions against the defendants in relation to his claimed intellectual property. When this lawsuit was filed against us, we believed that we were named in error because, among other things, we did not invent, manufacture or provide the capping stack that was used to plug the Macondo well, and although we did have a working relationship with ED&M, that work had nothing to do with the Macondo (or any other) capping stack. The plaintiff dismissed this lawsuit on September 7, 2012.

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 assets and liabilities measured at fair value on a recurring basis at September 30, 2012 (in thousands):

	Level 1	Level 2 (1)	Level 3	Total	Valuation Technique
Assets:					
Natural gas contracts	$ —	$4,325	$ —	$4,325	(c)
Oil contracts	—	4,411	—	4,411	(c)
Foreign currency forwards	—	116	—	116	(c)
Liabilities:					
Oil contracts	—	23,074	—	23,074	(c)
Fair value of long term debt (2)	1,139,814	122,397	—	1,262,211	(a)
Interest rate swaps	—	634	—	634	(c)
Total net liability	$1,139,814	$137,253	$ —	$1,277,067	

(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. 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 long-term debt at September 30, 2012 is as follows:

	Fair Value	Carrying Value
Term Loans (mature July 2015)	$ 370,157	$ 369,165
Revolving Credit Facility (matures July 2015)	100,000	100,000
2025 Notes (mature March 2025)	159,408	157,830 (a)
2032 Notes (mature March 2032)	222,228	200,000 (b)
Senior Unsecured Notes (mature January 2016)	288,021	274,960
MARAD Debt (matures February 2027) (c)	122,397	105,288
Total	$ 1,262,211	$ 1,207,243

(a) Amount excludes the related unamortized debt discount of $1.2 million.

(b) Amount excludes the related unamortized debt discount of $32.9 million.

(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

We are currently exposed to market risk in three major areas: commodity prices, interest rates and foreign currency exchange rates. Our risk management activities involve the use of derivative financial instruments to hedge the impact of market price risk exposures primarily related to our oil and gas production, variable interest rates and foreign exchange currency fluctuations. All derivatives are reflected in the accompanying condensed consolidated balance sheets at fair value, unless otherwise noted.

We engage primarily in cash flow hedges. Hedges of cash flow exposure are entered into to hedge a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability. Changes in the fair value of derivatives that are designated as cash flow hedges are deferred to the extent that the hedges are effective. These fair value changes are recorded in accumulated other comprehensive income (loss), a component of shareholders' equity, until the hedged transactions occur and

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are recognized in earnings. The ineffective portion of changes in the fair value of cash flow hedges is recognized immediately in earnings. In addition, any change in the fair value of a derivative that does not qualify for hedge accounting is recorded in earnings in the period in which the change occurs.

For additional information regarding our accounting for derivatives, see Notes 2 and 20 of our 2011 Form 10-K.

Commodity Price Risks

We currently manage commodity price risk through various financial costless collars and swap instruments covering a portion of our anticipated oil and natural gas production for 2012 and 2013. All of our oil derivative contracts qualify for hedge accounting. All of our natural gas derivative contracts for 2013 qualify for hedge accounting while some of our natural gas contracts for 2012 were recently de-designated as hedge contracts (as discussed below).

As of September 30, 2012, we had the following volumes under derivative contracts related to our oil and gas producing activities totaling approximately 3.4 million barrels of oil and 8.7 Bcf of natural gas:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price (1)
Crude Oil:			(per barrel)
October 2012 — December 2012	Collar	75.0 MBbl	$ 96.67 — $118.57 (2)
October 2012 — December 2012	Collar	80.3 MBbl	$ 99.77 — $118.71
October 2012 — December 2012	Swap	103.7 MBbl	$92.15
January 2013 — December 2013	Swap	88.9 MBbl	$95.28
January 2013 — December 2013	Collar	133.3 MBbl	$ 98.44 — $115.85
Natural Gas:			(per Mcf)
October 2012 — December 2012	Swap	776.7 Mmcf	$4.31
October 2012 — December 2012	Collar	130.0 Mmcf	$4.75 — $5.13
January 2013 — December 2013	Swap	500.0 Mmcf	$4.09

(1) The prices quoted in the table above are NYMEX Henry Hub for natural gas. Our oil contracts are indexed to the Brent crude oil price unless otherwise indicated.

(2) This contract is priced using NYMEX West Texas Intermediate for crude oil.

Changes in NYMEX oil and gas and Brent crude oil strip prices would, assuming all other things being equal, cause the fair value of these instruments to increase or decrease inversely to the change in NYMEX or Brent prices, respectively.

Variable Interest Rate Risks

As some of our long-term debt has variable interest rates and therefore is subject to market influences, in January 2010 we entered into various interest rate swaps to stabilize cash flows relating to interest payments for $200 million of our Term Loan debt under our Credit Agreement (Note 7). The last of these monthly contracts matured in January 2012. In August 2011, we entered into additional interest rate swap contracts to fix the interest rate on $200 million of our Term Loan debt. These monthly contracts began in January 2012 and extend through January 2014. Changes in the fair value of an interest rate swap are deferred to the extent the swap is effective. These changes are recorded as a component of accumulated other comprehensive income (loss) until the anticipated interest payments occur and are recognized in interest expense. The ineffective portion of the interest rate swap, if any, will be recognized immediately in earnings within the line titled "Net interest expense". The amount of ineffectiveness associated with our interest rate swap contracts was immaterial for all periods presented in this Quarterly Report on Form 10-Q.

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Foreign Currency Exchange Risks

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 denominated in British pounds. We did not designate any of our existing foreign exchange contracts as hedge contracts at their inception. The last of our existing monthly foreign currency swap contracts will settle in November 2012.

Quantitative Disclosures Related to Derivative Instruments

The following tables present the fair value and balance sheet classification of our derivative instruments as of September 30, 2012 and December 31, 2011.

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

	As of September 30, 2012		As of December 31, 2011	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Asset Derivatives:				
Natural gas contracts	Other current assets	$2,824	Other current assets	$12,957
Oil contracts	Other current assets	3,184	Other current assets	8,567
Oil contracts	Other assets	1,227	Other assets	—
Natural gas contracts	Other assets	115	Other assets	857
Interest rate swaps	Other assets	—	Other assets	327
		$7,350		$22,708

	As of September 30, 2012		As of December 31, 2011	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Liability Derivatives:				
Oil contracts	Accrued liabilities	$19,840	Accrued liabilities	$886
Interest rate swaps	Accrued liabilities	493	Accrued liabilities	202
Oil contracts	Other long-term liabilities	3,234	Other long-term liabilities	1,711
Interest rate swaps	Other long-term liabilities	141	Other long-term liabilities	—
		$23,708		$2,799

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

	As of September 30, 2012		As of December 31, 2011	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Asset Derivatives:				
Natural gas contracts	Other current assets	$1,386	Other current assets	$ —
Foreign exchange forwards	Other current assets	116	Other current assets	55
		$1,502		$55

	As of September 30, 2012		As of December 31, 2011	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value

Liability Derivatives:				
Foreign exchange forwards	Accrued liabilities	$ —	Accrued liabilities	$159
		$ —		$159

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As a result of recent natural gas production declines for our properties, including the effects Hurricane Isaac had on our properties in August 2012, sales of certain of our natural gas producing properties and the continued deferral of initiating production from our Nancy well in the Bushwood field, we de-designated four of our natural gas derivative contracts as hedging instruments. We concluded that these contracts no longer qualified for hedge accounting treatment because we could no longer forecast that we would have the necessary production volumes to cover the contractual volumes in these contracts. All four of these contracts will have final settlements by December 31, 2012. The mark to market adjustments associated with these contracts are recorded as a component of "Hedge ineffectiveness and non-hedge gain on commodity derivative contracts" in the accompanying condensed consolidated statements of operations and comprehensive income.

The following tables present the impact that derivative instruments designated as cash flow hedges had on our accumulated comprehensive income (loss) and our consolidated condensed statements of operations and comprehensive income for the three- and nine-month periods ended September 30, 2012 and 2011 (in thousands). The hedge ineffectiveness related to some of our crude oil contracts totaled $10.0 million and $2.3 million for the three- and nine-month periods ended September 30, 2012. The amount of any ineffectiveness associated with our oil contracts was immaterial for the three- and nine-month periods ended September 30, 2011. These amounts are reflected as a separate line item titled "Hedge ineffectiveness and non-hedge gain on commodity derivative contracts" in the accompanying condensed consolidated statements of operations and comprehensive income. Ineffectiveness associated with our interest rate swaps was immaterial for all periods presented. At September 30, 2012, most of our remaining unrealized gains (losses) related to our derivative contracts are expected to be reclassified into earnings within the next 12 months, including $(6.6) million for our oil and natural gas contracts and $(0.3) million related to our interest rate swap contracts. All unrealized gains (losses) related to our derivative contracts are expected to be reclassified to earnings by no later than December 31, 2013. The last of our interest rate swaps will be settled in January 2014.

	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Oil and natural gas commodity contracts	$(19,868)	$33,432	$(20,664)	$43,373
Interest rate swaps	(168)	456	(494)	918
	$(20,036)	$33,888	$(21,158)	$44,291

	Location of Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2012	2011	2012	2011
Oil and natural gas commodity contracts	Oil and gas revenue	$414	$(1,287)	$8,546	$(19,473)
Interest rate swaps	Net interest expense	(121)	(522)	(434)	(1,513)
		$293	$(1,809)	$8,112	$(20,986)

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The following table presents the impact that derivative instruments not designated as hedges had on our condensed consolidated statement of operations and comprehensive income for the three- and nine-month periods ended September 30, 2012 and 2011 (in thousands):

	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2012	2011	2012	2011
Natural gas commodity contracts	Hedge ineffectiveness and non-hedge gain on commodity derivative contracts	$633	$ —	$633	$ —
Foreign exchange forwards	Other income (expense)	217	(381)	381	(234)
		$850	$(381)	$1,014	$(234)

Note 17 - Subsequent Event

On October 15, 2012, we entered into an agreement to sell our two remaining pipelay vessels, the Express and the Caesar and other related equipment to Coastal Trade Limited. The total sales price is $238.3 million, of which we have received a $50 million deposit that is only refundable in limited circumstances. The final sale of these vessels will close and fund in two stages in 2013 following the completion of each vessel's existing backlog of work. Currently, we anticipate the Express sale will close in February 2013 and we expect the Caesar sale will close in July 2013. In the fourth quarter of 2012, we expect to record an impairment charge of approximately $160 million primarily related to the Caesar.

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Note 18 – 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
(in thousands)
(Unaudited)

	As of September 30, 2012				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 513,938	$ 8,367	$ 61,489	$ —	$ 583,794
Accounts receivable, net	68,808	86,348	42,890	—	198,046
Unbilled revenue	12,633	213	36,753	—	49,599
Income taxes receivable	25,557	—	—	(15,422)	10,135
Other current assets	68,422	33,325	20,013	2	121,762
Total current assets	689,358	128,253	161,145	(15,420)	963,336
Intercompany	(14,878)	226,890	(130,679)	(81,333)	—
Property and equipment, net	219,244	1,446,593	770,651	(4,661)	2,431,827
Other assets:					
Equity investments in unconsolidated affiliates	—	—	169,318	—	169,318
Equity investments in affiliates	2,015,444	56,263	—	(2,071,707)	—
Goodwill, net	—	45,107	17,662	—	62,769
Other assets, net	53,657	33,132	35,414	(37,496)	84,707
Due from subsidiaries/parent	40,754	598,407	—	(639,161)	—
	$ 3,003,579	$ 2,534,645	$ 1,023,511	$ (2,849,778)	$ 3,711,957
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 41,754	$ 88,304	$ 34,052	$ —	$ 164,110

Accrued liabilities	60,873	114,528	20,888	—	196,289
Income taxes payable	—	29,588	1,736	(31,324)	—
Current maturities of long-term debt	8,000	—	5,120	—	13,120
Total current liabilities	110,627	232,420	61,796	(31,324)	373,519
Long-term debt	1,059,790	—	100,168	—	1,159,958
Deferred tax liabilities	239,026	115,150	106,582	(5,492)	455,266
Asset retirement obligations	—	136,293	—	—	136,293
Other long-term liabilities	1,548	6,281	507	—	8,336
Due to parent	—	—	74,384	(74,384)	—
Total liabilities	1,410,991	490,144	343,437	(111,200)	2,133,372
Convertible preferred stock	1,000	—	—	—	1,000
Total equity	1,591,588	2,044,501	680,074	(2,738,578)	1,577,585
	$ 3,003,579	$ 2,534,645	$ 1,023,511	$ (2,849,778)	$ 3,711,957

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

	As of December 31, 2011				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 495,484	$ 2,434	$ 48,547	$ —	$ 546,465
Accounts receivable, net	79,290	117,767	41,724	—	238,781
Unbilled revenue	10,530	155	26,690	—	37,375
Income taxes receivable	80,388	—	—	(80,388)	—
Other current assets	68,627	48,661	10,159	(5,826)	121,621
Total current assets	734,319	169,017	127,120	(86,214)	944,242
Intercompany	(147,187)	315,821	(102,826)	(65,808)	—
Property and equipment, net	230,946	1,422,326	682,899	(4,844)	2,331,327
Other assets:					
Equity investments in unconsolidated affiliates	—	—	175,656	—	175,656
Equity investments in affiliates	1,952,392	37,239	—	(1,989,631)	—
Goodwill, net	—	45,107	17,108	—	62,215
Other assets, net	53,425	36,453	16,809	(37,780)	68,907
Due from subsidiaries/parent	64,655	430,496	—	(495,151)	—
	$ 2,888,550	$ 2,456,459	$ 916,766	$ (2,679,428)	$ 3,582,347
LIABILITIES AND SHAREHOLDERS’ EQUITY					
Current liabilities:					
Accounts payable	$ 39,280	$ 82,750	$ 25,013	$ —	$ 147,043
Accrued liabilities	115,921	97,692	26,350	—	239,963
Income taxes payable	—	97,692	217	(96,616)	1,293
Current maturities of long-term debt	3,000	—	10,377	(5,500)	7,877
Total current liabilities	158,201	278,134	61,957	(102,116)	396,176
Long-term debt	1,042,155	—	105,289	—	1,147,444
Deferred tax liabilities	231,255	88,625	103,552	(5,822)	417,610
Asset retirement obligations	—	161,208	—	—	161,208
Other long-term liabilities	4,150	4,647	571	—	9,368
Due to parent	—	—	98,285	(98,285)	—
Total liabilities	1,435,761	532,614	369,654	(206,223)	2,131,806

Convertible preferred stock	1,000	—	—	—	1,000
Total equity	1,451,789	1,923,845	547,112	(2,473,205)	1,449,541
	$ 2,888,550	$ 2,456,459	$ 916,766	$ (2,679,428)	$ 3,582,347

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

	Three Months Ended September 30, 2012				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$ 20,024	$ 219,661	$ 118,896	$ (22,347)	$ 336,234
Cost of sales	22,668	157,490	92,211	(21,892)	250,477
Gross profit	(2,644)	62,171	26,685	(455)	85,757
Loss on sale of assets, net	—	(12,933)	—	—	(12,933)
Hedge ineffectiveness and non-hedge gain on commodity derivative contracts	—	(9,427)	—	—	(9,427)
Selling, general and administrative expenses	(13,853)	(8,426)	(6,213)	470	(28,022)
Income (loss) from operations	(16,497)	31,385	20,472	15	35,375
Equity in earnings of investments	20,289	12,729	1,392	(33,018)	1,392
Net interest expense and other	(9,686)	(6,927)	488	—	(16,125)
Income (loss) before income taxes	(5,894)	37,187	22,352	(33,003)	20,642
Provision (benefit) for income taxes	(15,268)	14,469	5,751	15	4,967
Net income (loss) applicable to Helix	9,374	22,718	16,601	(33,018)	15,675
Less: net income applicable to noncontrolling interests	—	—	—	(800)	(800)
Preferred stock dividends	(10)	—	—	—	(10)
Net income (loss) applicable to Helix common shareholders	$ 9,364	$ 22,718	$ 16,601	$ (33,818)	$ 14,865
Total comprehensive income (loss) applicable to Helix common shareholders	$ 9,196	$ 2,850	$ 20,507	$ (33,819)	$ (1,266)

	Three Months Ended September 30, 2011				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated

Net revenues	$ 19,986	$ 266,447	$ 109,780	$ (23,717)	$ 372,496
Cost of sales	15,698	182,259	75,643	(23,399)	250,201
Gross profit	4,288	84,188	34,137	(318)	122,295
Loss on sale of assets, net	—	—	—	—	—
Selling, general and administrative expenses	(6,752)	(9,551)	(6,105)	326	(22,082)
Income (loss) from operations	(2,464)	74,637	28,032	8	100,213
Equity in earnings of investments	60,831	7,277	4,906	(68,108)	4,906
Net interest expense and other	(17,612)	(8,016)	(9,200)	—	(34,828)
Income (loss) before income taxes	40,755	73,898	23,738	(68,100)	70,291
Provision (benefit) for income taxes	(5,266)	24,419	4,309	3	23,465
Net income (loss) applicable to Helix	46,021	49,479	19,429	(68,103)	46,826
Less:net income applicable to noncontrolling interests	—	—	—	(800)	(800)
Preferred stock dividends	(10)	—	—	—	(10)
Net income (loss) applicable to Helix common shareholders	$ 46,011	$ 49,479	$ 19,429	$ (68,903)	$ 46,016
Total comprehensive income (loss) applicable to Helix common shareholders	$ 46,467	$ 82,911	$ 21,018	$ (68,904)	$ 81,492

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

	Nine Months Ended September 30, 2012				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$ 60,009	$ 760,229	$ 340,428	$ (69,111)	$ 1,091,555
Cost of sales	65,373	500,520	253,165	(68,195)	750,863
Gross profit	(5,364)	259,709	87,263	(916)	340,692
Loss on sale of assets, net	—	(14,647)	—	—	(14,647)
Hedge ineffectiveness and non-hedge gain on commodity derivative contracts	—	(1,697)	—	—	(1,697)
Selling, general and administrative expenses	(36,783)	(27,222)	(15,304)	1,020	(78,289)
Income (loss) from operations	(42,147)	216,143	71,959	104	246,059
Equity in earnings of investments	177,985	19,024	7,547	(197,009)	7,547
Net interest expense and other	(49,830)	(21,211)	(4,204)	—	(75,245)
Income (loss) before income taxes	86,008	213,956	75,302	(196,905)	178,361
Provision (benefit) for income taxes	(33,696)	73,492	10,878	46	50,720
Net income (loss) applicable to Helix	119,704	140,464	64,424	(196,951)	127,641
Less: net income applicable to noncontrolling interests	—	—	—	(2,378)	(2,378)
Preferred stock dividends	(30)	—	—	—	(30)
Net income (loss) applicable to Helix common shareholders	$ 119,674	$ 140,464	$ 64,424	$ (199,329)	$ 125,233
Total comprehensive income (loss) applicable to Helix common shareholders	$ 119,180	$ 119,800	$ 69,646	$ (199,332)	$ 109,294

	Nine Months Ended September 30, 2011				
	Helix	Guarantors	Non-Guarantors		Consolidated

				Consolidating Entries	
Net revenues	$ 56,113	$ 756,344	$ 260,582	$ (70,617)	$ 1,002,422
Cost of sales	47,414	521,387	203,651	(69,599)	702,853
Gross profit	8,699	234,957	56,931	(1,018)	299,569
Loss on sale of assets, net	(6)	—	—	—	(6)
Selling, general and administrative expenses	(27,512)	(29,502)	(14,917)	1,110	(70,821)
Income (loss) from operations	(18,819)	205,455	42,014	92	228,742
Equity in earnings of investments	167,867	5,809	16,443	(173,676)	16,443
Net interest expense and other	(53,139)	(18,615)	(8,675)	—	(80,429)
Income (loss) before income taxes	95,909	192,649	49,782	(173,584)	164,756
Provision (benefit) for income taxes	(17,229)	66,479	(95)	31	49,186
Net income (loss) applicable to Helix	113,138	126,170	49,877	(173,615)	115,570
Less:net income applicable to noncontrolling interests	—	—	—	(2,354)	(2,354)
Preferred stock dividends	(30)	—	—	—	(30)
Net income (loss) applicable to Helix common shareholders	$ 113,108	$ 126,170	$ 49,877	$ (175,969)	$ 113,186
Total comprehensive income (loss) applicable to Helix common shareholders	$ 114,026	$ 169,543	$ 52,175	$ (175,980)	$ 159,764

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

	Nine Months Ended September 30, 2012				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flow from operating activities:					
Net income (loss), including noncontrolling interests	$ 119,704	$ 140,464	$ 64,424	$ (196,951)	$ 127,641
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by (used in) operating activities:					
Equity in earnings of affiliates	(177,985)	(19,024)	—	197,009	—
Other adjustments	50,771	141,899	(2,365)	(9,794)	180,511
Net cash provided by (used in) operating activities	(7,510)	263,339	62,059	(9,736)	308,152
Cash flows from investing activities:					
Capital expenditures	(1,368)	(196,481)	(107,495)	—	(305,344)
Distributions from equity investments, net	—	—	6,174	—	6,174
Proceeds from sale of assets	—	14,500	—	—	14,500
Decreases in restricted cash	—	2,698	—	—	2,698
Net cash used in investing activities	(1,368)	(179,283)	(101,321)	—	(281,972)
Cash flows from financing activities:					
Borrowings of debt	400,000	—	—	—	400,000
Repayments of debt	(364,030)	—	(4,877)	—	(368,907)
Deferred financing costs	(7,766)	—	—	—	(7,766)
Distributions to noncontrolling interest	—	—	(4,249)	—	(4,249)
Repurchases of common stock	(7,510)	—	—	—	(7,510)
	(1,151)	—	—	—	(1,151)

Excess tax benefit from stock-based compensation					
Exercise of stock options, net and other	1,264	—	—	—	1,264
Intercompany financing	6,525	(78,123)	61,862	9,736	—
Net cash provided by (used in) financing activities	27,332	(78,123)	52,736	9,736	11,681
Effect of exchange rate changes on cash and cash equivalents	—	—	(532)	—	(532)
Net increase in cash and cash equivalents	18,454	5,933	12,942	—	37,329
Cash and cash equivalents:					
Balance, beginning of year	495,484	2,434	48,547	—	546,465
Balance, end of year	$ 513,938	$ 8,367	$ 61,489	$ —	$ 583,794

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

	Nine Months Ended September 30, 2011				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flow from operating activities:					
Net income (loss), including noncontrolling interests	$ 113,138	$ 126,170	$ 49,877	$ (173,615)	$ 115,570
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by (used in) operating activities:					
Equity in earnings of affiliates	(167,867)	(5,809)	—	173,676	—
Other adjustments	19,125	218,602	2,578	(4,744)	235,561
Net cash provided by (used in) operating activities	(35,604)	338,963	52,455	(4,683)	351,131
Cash flows from investing activities:					
Capital expenditures	(18,240)	(129,535)	(20,074)	—	(167,849)
Distributions from equity investments, net	—	—	738	—	738
Proceeds from sale of Cal Dive common stock	3,588	—	—	—	3,588
Decreases in restricted cash	—	703	—	—	703
Net cash used in investing activities	(14,652)	(128,832)	(19,336)	—	(162,820)
Cash flows from financing activities:					
Repayments of debt	(189,335)	—	(4,645)	—	(193,980)
Deferred financing costs	(9,224)	—	—	—	(9,224)
Repurchases of common stock	(1,072)	—	—	—	(1,072)
Excess tax benefit from stock-based compensation	(805)	—	—	—	(805)
Exercise of stock options, net and other	1,988	—	(1,215)	—	773
Intercompany financing	207,333	(212,365)	349	4,683	—

Net cash provided by (used in) financing activities	8,885	(212,365)	(5,511)	4,683	(204,308)
Effect of exchange rate changes on cash and cash equivalents	—	—	267	—	267
Net increase (decrease) in cash and cash equivalents	(41,371)	(2,234)	27,875	—	(15,730)
Cash and cash equivalents:					
Balance, beginning of year	376,434	3,294	11,357	—	391,085
Balance, end of year	$ 335,063	$ 1,060	$ 39,232	$ —	$ 375,355

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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," "co terms and phrases, are forward-looking statements. Included in forward-looking statements are, among other things:

- statements regarding our business strategy, including the potential sale of assets and/or other investments in our subsidiaries and facilities, 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;
- statements regarding our anticipated production volumes, results of exploration, exploitation, development, acquisition or operations expenditures, and current or prospective reserve levels with respect to any oil and gas property or well;
- statements related to commodity prices for oil and gas or with respect to the supply of and demand for oil and gas;
- statements relating to our proposed exploration, development and/or production of oil and gas properties, prospects or other interests and any anticipated costs related thereto;
- statements related to environmental risks, exploration and development risks, or drilling and operating risks;
- statements relating to the construction or acquisition of vessels or equipment and any anticipated costs related hereto;
- 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 the weak economic conditions and the future impact of such conditions on the oil and gas industry and the demand for our services;
- Delays, costs and difficulties related to the pipelay vessel sales;
- uncertainties inherent in the development and production of oil and gas and in estimating reserves;
- the geographic concentration of our oil and gas operations;
- the effect of regulations on the offshore Gulf of Mexico oil and gas operations;
- uncertainties regarding our ability to replace depletion;

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- unexpected future capital expenditures (including the amount and nature thereof);
- impact of oil and gas price fluctuations and the cyclical nature of the oil and gas industry;
- 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 effectiveness of our hedging activities;
- the results of our continuing efforts to control costs, and improve performance;
- the success of our risk management activities;
- the effects of competition;
- the availability (or lack thereof) of capital (including any financing) to fund our business strategy and/or operations and the terms of any such financing;
- 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, including exposure of our oil and gas operations to tropical storm activity in the Gulf of Mexico;
- the impact of operational disruptions affecting the Helix Producer I vessel which is crucial to producing oil and natural gas from our Phoenix field;
- the effect of environmental liabilities that are not covered by an effective indemnity or insurance;
- 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 2011 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 our growing well intervention and robotics businesses. We also own an oil and gas business that is a prospect generation, exploration, development and production company. We utilize cash flow generated from our oil and gas production to support expansion of our well intervention and robotics businesses.

Our Strategy

Over the past few years, we have focused on improving our balance sheet by increasing our liquidity through disposition of non-core business assets and reductions in our planned capital spending. At September 30, 2012, our cash on hand totaled $583.8 million and our liquidity was $1.0 billion. Our capital expenditures for full year 2012 are expected to total approximately $545 million, primarily reflecting construction costs associated with our new semi-submersible well intervention vessel, the Q5000, costs related to the purchase and conversion of the Discoverer 534 drillship, which we subsequently renamed the Helix 534, into a well intervention vessel, and the exploration and development costs for certain of our oil and gas properties (excluding costs related to our asset retirement obligations). We believe that we have sufficient liquidity to successfully implement our near term business plan without incurring additional indebtedness beyond the existing capacity under the Revolving Credit Facility.

Announced Sale of Pipelay Vessels

On October 15, 2012, we entered into an agreement to sell our two remaining pipelay vessels, the Express and the Caesar and other related equipment to Coastal Trade Limited. The total sales price is $238.3 million, of which we have received a $50 million deposit that is only refundable in limited circumstances. The final sale of these vessels will close and fund in two stages in 2013 following the completion of each vessel’s existing backlog of work. Currently, we anticipate the Express sale will close in February 2013 and we expect the Caesar sale will close in July 2013. In the fourth quarter of 2012, we expect to record an impairment charge of approximately $160 million (approximately $100 million after tax) to reduce the carrying cost of the Caesar and other related pipelay equipment to their respective fair value. In the first quarter of 2013, we expect to record a pre-tax gain of approximately $14 million (approximately $9 million after tax) related to the sale of the Express. We will be required to use a portion of the proceeds from the sale of these vessels to reduce our Term Loan debt pursuant to the terms of our Credit Agreement and for reinvestment into our well intervention and robotics businesses.

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. However, some of our contracting services will often lag drilling operations by a period of 6 to 18 months, meaning that even if there were a sudden increase in deepwater permitting and subsequent drilling in the Gulf of Mexico, it probably would still be some time before we would start securing any awarded projects in this region. The performance of our oil and gas 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 equity markets;
- demand for oil and natural gas, especially in the United States, Europe, China and India;
- economic and political conditions in the Middle East and other oil-producing regions;
- the effect of regulations on offshore Gulf of Mexico oil and gas operations;
- actions taken by OPEC;
- the availability and discovery rate of new oil and natural gas reserves in offshore areas;
- 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.

During the third quarter of 2012, oil prices slightly decreased from levels realized in the previous three months. The average NYMEX West Texas Intermediate ("WTI") crude oil price was $92.22 per barrel in the third quarter of 2012 compared to $93.49 per barrel in the second quarter of 2012 and $102.93 per barrel in the first quarter of 2012. In 2011, the price that we received for the majority of our crude oil sales volumes started to increase significantly over the WTI market price. Historically the price we received for most of our crude oil, as priced using a number of Gulf Coast crude oil price indexes, closely correlated with the then-current market prices of WTI crude oil; however, because of a substantial increase in crude oil inventories at Cushing, Oklahoma the price of Gulf Coast crude has been substantially higher than WTI. Currently the price we receive for our crude oil more closely correlates with the Brent crude oil price in the North Sea. The premium we received for our oil sales was anywhere from $8 - $27 per barrel greater than the given WTI price during the past twelve months and was approximately $13 per barrel greater than the WTI price in the first nine months of 2012. We do not know how long the price variance of our crude oil and the WTI will continue but most analysts believe this premium will continue at least through the remainder of 2012.

Although the market environment for natural gas improved in the third quarter of 2012, in general natural gas prices remain weak, reflecting the unusually mild conditions during the past winter season over the majority of the United States and the continued increase in supply of natural gas derived primarily from non-traditional sources of natural gas such as production from shale formations and tight sands located throughout the United States. A combination of these factors has decreased the NYMEX Henry Hub price of natural gas to below $2.00 per Mcf during April 2012, reflecting the lowest prices for natural gas in approximately 10 years. At September 30, 2012, the NYMEX Henry Hub price of natural gas was $3.08 per Mcf.

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Worries about the “fiscal cliff” have taken center stage in recent months. The “fiscal cliff” as a result of the end of tax breaks and the steep federal spending cuts set to take effect at the start of 2013 is believed to pose a serious risk to the economy. Long-term uncertainties surrounding the European sovereign debt crisis are expected to continue despite the European Central Bank’s recent announcement of the unlimited bond purchase program aimed at bringing stability to financial markets. This could continue to affect the global equity and commodity markets as well as effectively hampering normal business activities. For the seventh consecutive quarter, growth slowed in China, which may also signal a global economic slowdown. A series of recently released key economic data suggest that the economic recovery in the United States continues to be slow-paced. 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.

Helix Fast Response System

We developed the Helix Fast Response System (“HFRS”) as a culmination of our experience as a responder in the Macondo oil spill response 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 oil spill response 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 for a two-year term to certain CGA participants who have executed utilization agreements with us. In addition to the agreement with CGA, we currently have signed separate utilization agreements with 24 CGA participant member companies specifying the day rates to be charged should the HFRS solution be deployed in connection with a well control incident. The retainer fee associated with HFRS was effective April 1, 2011 and is a component of our Production Facilities business segment.

RESULTS OF OPERATIONS

Our operations are conducted through two lines of business: contracting services and oil and gas. We have disaggregated our contracting services operations into two continuing reportable segments Contracting Services and Production Facilities. Our third business segment is Oil and Gas.

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

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 operations, robotics and subsea construction services (see Note 17 for disclosures regarding the announced sale of a large portion of our subsea construction 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. As of September 30, 2012, our Contracting Services segment had backlog of approximately $697.7 million, including $177.2 million expected to be performed over the remainder of 2012. 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). Backlog for the HP I totaled approximately $24.4 million at September 30, 2012, including $8.4 million expected to be serviced over the remainder of 2012. At December 31, 2011, our combined backlog for both Contracting Services and the HP I totaled $539.7 million, including $505.1 million for 2012. These backlog contracts are cancelable without penalty in many cases. Backlog is not a reliable indicator of total annual revenue for our

Contracting Services businesses as contracts may be added, cancelled and in many cases modified while in progress.

Oil and Gas Operations

We began our oil and gas operations to achieve incremental returns, to expand off-season utilization of our Contracting Services assets, and to provide a more efficient solution to offshore abandonment for industry participants. We have evolved this business model to include not only mature oil and gas properties but also

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proved and unproved reserves yet to be developed and explored. By owning oil and gas reservoirs and prospects, we are able to utilize the services we otherwise provide to third parties to create value at key points in the life of our own reservoirs including during the exploration and development stages, the field management stage, and the abandonment stage. It is also a feature of our business model to opportunistically monetize part of the created reservoir value, through sales of working interests, in order to help fund field development and reduce gross profit deferrals from our Contracting Services operations. Therefore the reservoir value we create is realized through oil and gas production and/or monetization of working interest stakes.

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 generally accepted accounting principles ("GAAP"). We measure our operating performance based on EBITDAX, a non-GAAP financial measure that is commonly used in the oil and natural gas industry but is not a recognized accounting term under GAAP. We use EBITDAX 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 EBITDAX 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 EBITDAX as income (loss) from continuing operations plus income taxes, net interest expense and other, depreciation, depletion and amortization expense and exploration expenses. We separately disclose our non-cash asset impairment charges, which, if not material, would be reflected as a component of our depreciation, depletion and amortization expense. Loss on early extinguishment of long-term debt is considered equivalent to additional interest expense.

In our reconciliation of income, including noncontrolling interests, 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 EBITDAX, when applicable, we deduct the noncontrolling interests related to the adjustment components of EBITDAX, the gain or loss on the sale of assets, the hedge ineffectiveness on commodity derivative contracts.

Other companies may calculate their measures of EBITDAX and Adjusted EBITDAX differently than we do, which may limit its usefulness as a comparative measure. Because EBITDAX is not a financial measure calculated in accordance with GAAP, it should not be considered in isolation or as a substitute for net income attributable to common shareholders, but used as a supplement to that GAAP financial measure. A reconciliation of our net income, including noncontrolling interests to EBITDAX and Adjusted EBITDAX is as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net income, including noncontrolling interests	$15,675	$46,826	$127,641	$115,570
Adjustments:				
Income tax provision	4,967	23,465	50,720	49,186

Net interest expense and other	16,125	32,474	58,118	78,075
Loss on extinguishment of long-term debt	—	2,354	17,127	2,354
Depreciation and amortization	63,666	72,370	198,626	239,540
Asset impairment charges	4,422	—	19,012	11,573
Exploration expenses	623	1,549	2,469	9,833
EBITDAX	105,478	179,038	473,713	506,131
Adjustments:				
Non-controlling interest Kommandor LLC	(1,037)	(1,036)	(3,089)	(3,076)
Hedge ineffectiveness on commodity derivative contracts	10,060	—	2,330	—
Loss on sale of assets	12,933	—	14,647	6
ADJUSTED EBITDAX	$127,434	$178,002	$487,601	$503,061

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Comparison of Three Months Ended September 30, 2012 and 2011

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

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Increase/ (Decrease)
Revenues (in thousands) —			
Contracting Services	$221,491	$229,967	$(8,476)
Production Facilities	20,024	19,986	38
Oil and Gas	119,124	159,218	(40,094)
Intercompany elimination	(24,405)	(36,675)	12,270
	$336,234	$372,496	$(36,262)
Gross profit (in thousands) —			
Contracting Services	$54,494	$55,799	$(1,305)
Production Facilities	10,300	11,072	(772)
Oil and Gas	21,800	56,631	(34,831)
Corporate	(876)	(679)	(197)
Intercompany elimination	39	(528)	567
	$85,757	$122,295	$(36,538)
Gross Margin —			
Contracting Services	25%	24%	
Production Facilities	51%	55%	
Oil and Gas	18%	36%	
Total company	26%	33%	
Number of vessels (1) / Utilization (2)			
Contracting Services:			
Construction vessels	9/97%	8/86%	
Well operations	3/81%	3/99%	
ROVs	53/73%	46/67%	

(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 this category generated revenues by the total number of calendar days in the applicable period. Utilization statistics for construction vessels excluded the Intrepid in the third quarter of 2012 as this asset had been in cold-stack mode during the quarter and was sold in September 2012.

Intercompany segment revenues during the three-month periods ended September 30, 2012 and 2011 were as follows (in thousands):

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Increase/ (Decrease)

Contracting Services	$12,896	$25,410	$(12,514)
Production Facilities	11,509	11,265	244
	$24,405	$36,675	$(12,270)

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Intercompany segment profit during the three-month periods ended September 30, 2012 and 2011 was as follows (in thousands):

	Three Months Ended September 30, 2012	2011	Increase/ (Decrease)
Contracting Services	$5	$606	$(601)
Production Facilities	(44)	(78)	34
	$(39)	$528	$(567)

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

	Three Months Ended September 30, 2012	2011	Increase/ (Decrease)
Oil and Gas information —			
Oil production volume (MBbls)	1,058	1,343	(285)
Oil sales revenue (in thousands)	$104,285	$135,590	$(31,305)
Average oil sales price per Bbl (excluding hedges)	$101.82	$103.20	$(1.38)
Average realized oil price per Bbl (including hedges)	$98.57	$100.93	$(2.36)
Decrease in oil sales revenue due to:			
Change in prices (in thousands)	$(3,169)		
Change in production volume (in thousands)	(28,136)		
Total decrease in oil sales revenue (in thousands)	$(31,305)		
Gas production volume (MMcf)	2,481	3,617	(1,136)
Gas sales revenue (in thousands)	$14,109	$22,244	$(8,135)
Average gas sales price per mcf (excluding hedges)	$4.13	$5.66	$(1.53)
Average realized gas price per mcf (including hedges)	$5.69	$6.15	$(0.46)
Decrease in gas sales revenue due to:			
Change in prices (in thousands)	$(1,674)		
Change in production volume (in thousands)	(6,461)		
Total decrease in gas sales revenue (in thousands)	$(8,135)		
Total production (MBOE)	1,471	1,946	(475)
Price per BOE	$80.46	$81.10	$(0.64)
Oil and Gas revenue information (in thousands) —			
Oil and gas sales revenue	$118,394	$157,834	$(39,440)
Other revenues (1)	730	1,384	(654)
	$119,124	$159,218	$(40,094)

(1) Other revenues include fees earned under our process handling agreements.

Presenting the expenses of our Oil and Gas segment on a cost per barrel of production basis normalizes for the impact of production gains/losses and provides a measure of expense control efficiencies. 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):

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	Three Months Ended September 30, 2012		2011	
	Total	Per barrel	Total	Per barrel
Oil and gas operating expenses (1):				
Direct operating expenses (2)	$33,810	$22.98	$38,022	$19.54
Workover	6,595	4.48	3,737	1.92
Transportation	1,447	0.98	1,816	0.93
Repairs and maintenance	2,202	1.50	2,369	1.22
Overhead and company labor	3,045	2.07	2,709	1.39
	$47,099	$32.01	$48,653	$25.00
Depletion expense	$35,808	$24.34	$46,008	$23.64
Abandonment	10,640	7.23	3,028	1.56
Accretion expense	2,889	1.96	3,622	1.86
Net hurricane (reimbursements) costs	265	0.18	(272)	(0.14)
	49,602	33.71	52,386	26.92
Total	$96,701	$65.72	$101,039	$51.92

(1) Excludes exploration expense of $0.6 million and $1.5 million for the three-month periods ended September 30, 2012 and 2011, respectively. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

Revenues. Our Contracting Services revenues decreased by 4% for the three-month period ended September 30, 2012 as compared to the same period in 2011. The decrease reflects lower utilization of our well intervention vessels which primarily reflect the Well Enhancer undergoing a regulatory dry dock for 52 days during the third quarter of 2012. The effect of this dry docking was largely offset by higher utilization associated with our robotics operations, which reflects the increased number of assets for that business as well as higher utilization of our chartered vessels and owned ROVs.

Oil and Gas revenues decreased 25% during the three-month period ended September 30, 2012 as compared to the same period in 2011, reflecting a 24% reduction in production volumes. The decline in production volumes was impacted by weather-related downtime resulting from Hurricane Isaac for all of our producing fields in August 2012 for a period of approximately 10 days, normal oil production declines, and decreased natural gas production reflecting the disposition of certain natural gas fields subsequent to September 30, 2011. For the month of October (through October 21, 2012) our production rate approximated 14.0 MBOE/d as compared to an approximate average of 16.0 MBOE/d in the third quarter of 2012.

Our Production Facilities revenues remained consistent for the three-month period ended September 30, 2012 as compared to the same period in 2011.

Gross Profit. Gross profit associated with Contracting Services decreased by approximately 2% in the third quarter of 2012 as compared to the same period last year. Our gross profit was negatively impacted by regulatory dry docking of the Well Enhancer in the third quarter of 2012. The margins for the remainder of our well intervention fleet as well as those for our robotics and construction vessels were strong during the third quarter of 2012, and the relatively high utilization of all said vessels allowed us to almost completely offset the lost profit associated with the dry dock of the Well Enhancer. We anticipate high utilization for all of our vessels for the remainder of 2012.

Oil and Gas gross profit decreased by 62% in the third quarter of 2012 as compared to the same period in 2011, primarily reflecting lower production volumes and slightly reduced oil price realizations. Our gross profit was also adversely affected by $10.6 million of asset retirement obligation overruns, $6.0 million of which related to the final decommissioning of our offshore U.K. property, Camelot.

Loss on Sale of Assets, Net. The $12.9 million loss on the disposition of assets in the third quarter of 2012 reflects the sale of the Intrepid in September 2012 (Note 14).

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Hedge Ineffectiveness and Non-hedge Gain on Commodity Derivative Contracts. The $9.4 million loss on commodity derivative contracts reflects $10.0 million of unrealized ineffectiveness associated with our oil derivative contracts that were designated as hedging contracts offset in part by $0.6 million of gains associated with our natural gas contracts that no longer qualified for hedge accounting (Note 16).

Selling, General and Administrative Expenses. Our selling, general and administrative expenses increased by $5.9 million in the third quarter of 2012 as compared to the same period in 2011. The variance is primarily associated with the timing of accruing certain performance bonuses and the increase in long-term incentive compensation. The increase in long-term incentive compensation resulted primarily from the amortization of awards granted in 2012 being over a vesting period of three years (as compared to the previous five-year vesting period for all long-term incentive awards granted prior to 2012) (Note 11). Also included in the third quarter of 2012 are approximately $1.5 million of costs associated with winding down of our Australian well intervention business as well as $0.7 million of identified bad debts including those associated with ceased Australian operations.

Equity in Earnings of Investments. Equity in earnings of investments was $1.4 million in the third quarter of 2012 as compared to $4.9 million in the third quarter of 2011. This decrease was primarily due to Independence Hub receiving lower fees from major customers of the facility following expiration of a five-year supplemental monthly demand fee in March 2012 and lower throughput at both the Deepwater Gateway and Independence Hub facilities.

Net Interest Expense. Our net interest expense totaled $18.2 million for the three-month period ended September 30, 2012 as compared to $24.1 million in the same period last year. The decrease in interest expense primarily reflects a general reduction of our Senior Unsecured Notes indebtedness since the second quarter of 2011, including the early extinguishment of approximately $275 million of our Senior Unsecured Notes during the third quarter of 2011 ($75 million) and the first quarter of 2012 ($200 million). The Senior Unsecured Notes bear a 9.5% interest rate which is greater than the 5.2% weighted average interest rate of our total indebtedness as of September 30, 2012. Capitalized interest totaled $1.2 million for the three-month period ended September 30, 2012 as compared to $0.5 million for the same period in 2011. Interest income totaled $0.5 million for the third quarter of 2012 as compared with $0.6 million in the third quarter of 2011.

Other Income (Expense), net. We reported other income of $2.1 million in the third quarter of 2012 as compared to other expense of $8.4 million in the same prior year period. These amounts primarily reflect foreign exchange fluctuations in our non U.S. dollar functional currencies. The foreign exchange losses in 2011 were attributed to the strengthening of the U.S. dollar against other global currencies. Included in these foreign exchange gains or losses were $0.2 million of gains and $0.4 million of losses related to our foreign exchange forward contracts for the three-month periods ended September 30, 2012 and 2011, respectively (Note 16).

Provision for Income Taxes. Income taxes reflected expense of $5.0 million in the third quarter of 2012 as compared to $23.5 million in the same period last year. The variance primarily reflects decreased profitability in the current year period. The effective tax rate of 24.1% for the third quarter of 2012 was lower than the 33.4% effective tax rate for the third quarter of 2011 as a result of projected increases in profitability in certain foreign jurisdictions with lower income tax rates.

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Comparison of Nine Months Ended September 30, 2012 and 2011

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

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011	Increase/ (Decrease)
Revenues (in thousands) —			
Contracting Services	$675,592	$532,857	$142,735
Production Facilities	60,009	56,101	3,908
Oil and Gas	447,142	500,535	(53,393)
Intercompany elimination	(91,188)	(87,071)	(4,117)
	$1,091,555	$1,002,422	$89,133
Gross profit (in thousands) —			
Contracting Services	$147,344	$104,360	$42,984
Production Facilities	30,507	29,278	1,229
Oil and Gas	168,146	168,724	(578)
Corporate	(2,422)	(2,336)	(86)
Intercompany elimination	(2,883)	(457)	(2,426)
	$340,692	$299,569	$41,123
Gross Margin —			
Contracting Services	22 %	20 %	
Production Facilities	51 %	52 %	
Oil and Gas	38 %	34 %	
Total company	31 %	30 %	
Number of vessels (1) / Utilization (2)			
Contracting Services:			
Construction vessels	9/92 %	8/70 %	
Well operations	3/78 %	3/88 %	
ROVs	53/69 %	46/57 %	

(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 this category generated revenues by the total number of calendar days in the applicable period. Utilization statistics for construction vessels excluded the Intrepid in the third quarter of 2012 as this asset had been in cold-stack mode during the quarter and was sold in September 2012.

Intercompany segment revenues during the nine-month periods ended September 30, 2012 and 2011 were as follows (in thousands):

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011	Increase/ (Decrease)

Contracting Services	$56,635	$52,574	$4,061
Production Facilities	34,553	34,497	56
	$91,188	$87,071	$4,117

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Intercompany segment profit during the nine-month periods ended September 30, 2012 and 2011 was as follows (in thousands):

	Nine Months Ended September 30, 2012	2011	Increase/ (Decrease)
Contracting Services	$3,014	$645	$2,369
Production Facilities	(131)	(188)	57
	$2,883	$457	$2,426

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

	Nine Months Ended September 30, 2012	2011	Increase/ (Decrease)
Oil and Gas information —			
Oil production volume (MBbls)	3,716	4,275	(559)
Oil sales revenue (in thousands)	$392,454	$416,500	$(24,046)
Average oil sales price per Bbl (excluding hedges)	$107.28	$103.69	$3.59
Average realized oil price per Bbl (including hedges)	$105.61	$97.43	$8.18
Increase (decrease) in oil sales revenue due to:			
Change in prices (in thousands)	$34,956		
Change in production volume (in thousands)	(59,002)		
Total decrease in oil sales revenue (in thousands)	$(24,046)		
Gas production volume (MMcf)	8,784	13,094	(4,310)
Gas sales revenue (in thousands)	$50,627	$78,527	$(27,900)
Average gas sales price per mcf (excluding hedges)	$4.08	$5.44	$(1.36)
Average realized gas price per mcf (including hedges)	$5.76	$6.00	$(0.24)
Decrease in gas sales revenue due to:			
Change in prices (in thousands)	$(3,059)		
Change in production volume (in thousands)	(24,841)		
Total decrease in gas sales revenue (in thousands)	$(27,900)		
Total production (MBOE)	5,180	6,457	(1,277)
Price per BOE	$85.53	$76.66	$8.87
Oil and Gas revenue information (in thousands) —			
Oil and gas sales revenue	$443,081	$495,027	$(51,946)
Other revenues (1)	4,061	5,508	(1,447)
	$447,142	$500,535	$(53,393)

(1) Other revenues include fees earned under our process handling agreements.

Presenting the expenses of our Oil and Gas segment on a cost per barrel of production basis normalizes for the impact of production gains/losses and provides a measure of expense control efficiencies. 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):

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	Nine Months Ended September 30, 2012		2011	
	Total	Per barrel	Total	Per barrel
Oil and gas operating expenses (1):				
Direct operating expenses (2)	$89,687	$17.31	$98,072	$15.19
Workover	14,826	2.86	8,541	1.32
Transportation	5,280	1.02	5,618	0.86
Repairs and maintenance	6,186	1.20	7,616	1.18
Overhead and company labor	9,029	1.74	9,322	1.44
	$125,008	$24.13	$129,169	$19.99
Depletion expense	$116,526	$22.50	$160,247	$24.82
Abandonment	24,899	4.81	14,561	2.25
Accretion expense	9,743	1.88	11,252	1.74
Net hurricane (reimbursements) costs	351	0.07	(4,824)	(0.76)
Impairment	—	—	11,573	1.79
	151,519	29.26	192,809	29.84
Total	$276,527	$53.39	$321,978	$49.83

(1) Excludes exploration expense of $2.5 million and $9.8 million for the nine-month periods ended September 30, 2012 and 2011, respectively. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

Revenues. Our Contracting Services revenues increased by 27% for the nine-month period ended September 30, 2012 as compared to the same period in 2011. The increase reflects significantly higher utilization for our subsea construction vessels, which benefited from an increase in activity in the Gulf of Mexico in the first quarter of 2012, the continued deployment of the Caesar on an accommodation project in Mexico and the Express working offshore Israel and in the North Sea for most of the second and third quarters of 2012. The increase in our robotics revenues reflects the high utilization of our chartered vessels and owned ROVs, the utilization of a number of additional spot market vessels for much of the nine-month period ended September 30, 2012, and the performance of a number of North Sea trenching projects in early 2012 (which activities are not normally conducted during the first quarter in large part because of seasonal weather patterns). Our well operations activities reflected slightly increased revenues despite the Q4000 (70 days), Seawell (52 days) and Well Enhancer (52 days) all being in regulatory dry dock in 2012. The lost days associated with the regulatory dry docks were more than offset by increasing rates reflecting the high demand for our well intervention services and vessels.

Oil and Gas revenues decreased 11% during the nine-month period ended September 30, 2012 as compared to the same period in 2011, reflecting lower production volumes offset in part by higher oil prices. Our production decreased by 20% for the nine-month period ended September 30, 2012 as compared to the same period in 2011, primarily reflecting much lower natural gas production, normal oil production declines, and the weather-related downtime affecting all of our fields in August 2012 due to Hurricane Isaac and certain of our fields in June 2012. The decrease in the production of natural gas primarily reflects the disposition of certain oil and gas properties subsequent to September 30, 2011, most notably the sale of eight natural gas producing fields in the Main Pass area in January 2012.

Our Production Facilities revenues increased by 7% for the nine-month period ended September 30, 2012 as compared to the same period in 2011. The increase in revenues primarily reflects the quarterly HFRS retainer fee, which commenced on April 1, 2011.

Gross Profit. Gross profit associated with our Contracting Services increased by approximately 41% for the nine-month period ended September 30, 2012 as compared to the same period last year. This increase reflects the high margins achieved on many of our Contracting Services projects as well as the increased number and much higher utilization of our construction vessels and ROVs. Gross profit was negatively impacted for the nine-month period ended September 30, 2012 because of the extended regulatory dry docks

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for the Q4000, Seawell and Well Enhancer vessels. In 2012, we also recorded a $14.6 million asset impairment charge following our decision to place the Intrepid in cold-stack mode (Note 14) and a $4.4 million expense charge to reduce our well intervention assets in Australia to their estimated fair value following our decision to cease our well intervention operations in that region and sell these assets (Note 14). We expect high utilization for our well operations and robotics vessels for the remainder of 2012.

Oil and Gas gross profit was flat for the comparable nine-month periods ended September 30, 2012 and 2011. We were able to achieve these comparable gross profit margins despite lower production volumes as discussed in "Revenues" above, primarily due to the realization of higher oil prices and the absence of any property impairment in 2012 as compared with a total of $11.6 million of producing property impairments during the nine-month period ended September 30, 2011. Our gross profit was also adversely affected by $24.9 million of asset retirement obligation overruns, $13.0 million of which related to the final decommissioning of our offshore U.K. property, Camelot.

Loss on Sale of Assets, Net. The $14.6 million loss on the disposition of assets for the nine-month period ended September 30, 2012 reflects the $12.9 million related to the sale of the Intrepid in September 2012 (Note 14) and $1.7 million primarily related to the disposition of eight of our non-operated oil and gas properties located in the Main Pass area of the Gulf of Mexico in January 2012.

Hedge Ineffectiveness and Non-hedge Gain on Commodity Derivative Contracts. The $1.7 million loss on commodity derivative contracts primarily reflects the amount of unrealized ineffectiveness associated with our oil derivative contracts designated as hedging contracts.

Selling, General and Administrative Expenses. Our selling, general and administrative expenses increased by $7.5 million for the nine-month period ended September 30, 2012 as compared to the same period in 2011. The increase is primarily associated with the timing of recording certain accrued performance bonuses and the increase in long-term incentive compensation. The increase in long-term incentive compensation resulted primarily from the amortization of awards granted in 2012 being over a vesting period of three years (as compared to the previous five-year vesting period for all long-term incentive awards granted prior to 2012) (Note 11). The 2012 amount also includes $0.7 million of identified bad debts and approximately $1.5 million of costs associated with our decision to cease our Australian well intervention operations. Our selling, general and administrative expenses in the nine-month period ended September 30, 2011 included $1.6 million of severance costs related to the resignation of our Executive Vice President and Chief Operating Officer.

Equity in Earnings of Investments. Equity in earnings of investments decreased by $8.9 million during the nine-month period ended September 30, 2012 as compared to the same prior year period. The decrease was primarily due to Independence Hub receiving lower fees from major customers of the facility following expiration of a five-year supplemental monthly demand fee in March 2012 and lower throughput at both the Deepwater Gateway and Independence Hub facilities, reflecting both storm related disruptions and normal production declines for the fields using the facilities.

Net Interest Expense. Our net interest expense totaled $58.6 million for the nine-month period ended September 30, 2012 as compared to $73.6 million in the same period last year. The decrease in interest expense primarily reflects a general reduction of our Senior Unsecured Notes indebtedness since the second quarter of 2011, including the early extinguishment of approximately $275 million of our Senior Unsecured Notes during the third quarter of 2011 ($75 million) and the first quarter of 2012 ($200 million). The Senior Unsecured Notes bear a 9.5% interest rate which is greater than the 5.2% weighted average interest rate of our total indebtedness as of September 30, 2012. Capitalized interest totaled $2.7 million for the nine-month period ended September 30, 2012 as compared to $0.8 million for the same period in 2011. Generally, our capitalized interest will be increasing as we progress the construction of our

Q5000 and Helix 534 vessels. Interest income totaled $1.4 million for the nine-month period ended September 30, 2012 as compared with $1.6 million for the comparable period in 2011.

Loss on early extinguishment of long-term debt. The charges of $17.1 million in 2012 were associated with the early extinguishment of portions of our debt in the first quarter of 2012, including $11.5 million related to our repurchase of $200 million of our Senior Unsecured Notes and $5.6 million related to our repurchase of $142.2 million of our 2025 Notes (Note 7). The $2.4 million charges in 2011 were related to premiums we paid to repurchase approximately $75 million of our Senior Unsecured Notes during the third quarter of 2011.

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Other Income (Expense), net. We reported other income of $0.5 million for the nine-month period ended September 30, 2012 as compared to other expense of $4.4 million in the same prior year period. These amounts primarily reflect foreign exchange fluctuations in our non U.S. dollar functional currencies. We recorded gains of $0.5 million in the nine-month period ended September 30, 2012 as compared to losses totaling $5.2 million for the nine-month period ended September 30, 2011. The foreign exchange losses in 2011 were attributed to the strengthening of the U.S. dollar against other global currencies. Included in these foreign exchange gains or losses were $0.4 million of gains and $0.2 million of losses related to our foreign exchange forward contracts for the nine-month periods ended September 30, 2012 and 2011, respectively (Note 16). In the nine-month period ended September 30, 2011, we also sold our remaining 0.5 million shares of Cal Dive common stock for net proceeds of approximately $3.6 million. Our gain on the sale of these remaining Cal Dive common shares was approximately $0.8 million.

Provision for Income Taxes. Income taxes reflected expense of $50.7 million in the nine-month period ended September 30, 2012 as compared to $49.2 million in the same period last year. The variance primarily reflects increased profitability in the current year period. The effective tax rate of 28.4% for the nine-month period ended September 30, 2012 was lower than the 29.9% effective tax rate for the same period in 2011 as a result of projected increases in profitability in certain foreign jurisdictions with lower income tax rates.

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

	September 30, 2012	December 31, 2011
Net working capital	$ 589,817	$ 548,066
Long-term debt (1)	1,159,958	1,147,444
Liquidity (2)	1,039,492	1,105,065

(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 our 2025 Notes and 2032 Notes (Note 7).

(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. Over the remainder of 2012, we anticipate a significant reduction in our liquidity reflecting capital expenditures to expand our well intervention fleet as well as expected cash outlays to reduce our existing debt and to fund other capital expenditures (see “Outlook” below).

The carrying amount of our debt, including current maturities, as of September 30, 2012 and December 31, 2011 was as follows (in thousands):

	September 30, 2012	December 31, 2011
Term Loans (mature July 2015) (1)	$ 369,165	$ 279,750
Revolving Credit Facility (matures July 2015) (1)	100,000	—
2025 Notes (mature March 2025) (2)	156,589	290,445

2032 Notes (mature March 2032) (3)		167,076		—
Senior Unsecured Notes (mature January 2016)		274,960		474,960
MARAD Debt (matures February 2027)		105,288		110,166
Total	$	1,173,078	$	1,155,321

(1) Represents earliest date debt would mature; see Note 7 for conditions that would extend the maturity date.

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(2) These amounts are net of the unamortized debt discount of $1.2 million and $9.6 million, respectively. The notes will increase to $157.8 million face amount through accretion of non-cash interest charges through 2012. Notes may be redeemed by the holders beginning in December 2012 (Note 7).

(3) This amount is net of the unamortized debt discount of $32.9 million. The notes will increase to the $200 million face amount through accretion of non-cash interest charges through March 2018, which is the period in which the holders of the notes may first require us to redeem the notes.

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

	Nine Months Ended September 30,	
	2012	2011
Net cash provided by (used in):		
Operating activities	$308,152	$351,131
Investing activities	$(281,972)	$(162,820)
Financing activities	$11,681	$(204,308)

Our current requirements for cash primarily reflect the need to fund capital expenditures to allow the growth of our current lines of business and to service our existing debt. We also intend to repay debt with any additional free cash flow from operations and/or cash received from any dispositions of our non-core business assets. Historically, we have funded our capital program, including acquisitions, with cash flow 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 flow supported by our remaining Contracting Services backlog and the hedged portion of our estimated oil and gas production through 2013. We believe that internally generated cash flow and available borrowing capacity under our Revolving Credit Facility will be sufficient to fund our operations over at least the next twelve months. Separately, under certain circumstances or conditions, we may reduce our planned capital spending and seek further additional dispositions of our non-core business assets to the extent satisfactory economic opportunities exist.

In accordance with our Credit Agreement, Senior Unsecured Notes, 2025 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. The 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 prepay a portion of the Term Loan equal to the amount of proceeds received from such occurrences (or at least 60% of the proceeds from the disposition of certain assets). Such prepayments will be applied first to the Term Loan, and any excess will then be applied to the Term Loan A and the Revolving Credit Facility. As of September 30, 2012 and December 31, 2011, we were in compliance with all of our debt covenants and restrictions.

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

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Our 2025 Notes and 2032 Notes can be converted prior to stated maturity under certain triggering events specified in the respective indentures governing each series of Convertible Senior Notes. To the extent we do not have cash on hand or long-term financing secured to cover the conversion, the 2025 Notes and 2032 Notes would be classified as a current liability in the accompanying condensed consolidated balance sheet. No conversion triggers were met during the nine-month period ended September 30, 2012. The holders may redeem the 2025 Notes beginning December 2012 (Note 7 as well as Note 9 of our 2011 Form 10-K). As the holders have this option, we assessed whether or not this debt was required to be classified as a current liability at September 30, 2012 but concluded this debt still qualified as a long-term debt because a) we possess enough borrowing capacity under our Revolving Credit Facility (matures July 2015) to settle the Convertible Senior Notes in full and b) it is our current intent to utilize our borrowing capacity under the Revolving Credit Facility or other alternative financing proceeds to settle our 2025 Notes, if and when the holders exercise their redemption option.

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 (Term Loan A). The terms of the Term Loan A are the same as those governing the Revolving Credit Facility, with the Term Loan A requiring a $5 million annual payment of the principal balance. The Term Loan A 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 as well as Note 9 of our 2011 Form 10-K 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

Cash flow from operating activities decreased by $43.0 million in the nine-month period ended September 30, 2012 as compared to the same period in 2011. This decrease primarily reflects decreased oil and natural gas production and the effect of some of our vessels being in dry dock in the nine-month period ended September 30, 2012. These decreases were partially offset by increased level of Contracting Services activity and the substantially higher oil prices realized during the nine-month period ended September 30, 2012.

Investing Activities

Capital expenditures have consisted principally of the purchase or construction of dynamically positioned vessels, strategic acquisitions of select businesses, improvements 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 for the nine-month periods ended September 30, 2012 and 2011 were as follows (in thousands):

	Nine Months Ended September 30,	
	2012	2011
Capital expenditures:		
Contracting Services	$(216,120)	$(62,202)
Production Facilities	(831)	(16,963)
Oil and Gas	(88,393)	(88,684)

Distributions from equity investments, net (1)	6,174	738
Proceeds from sale of assets	14,500	—
Proceeds from sale of Cal Dive common stock	—	3,588
Decrease in restricted cash	2,698	703
Cash used in investing activities	$(281,972)	$(162,820)

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(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 payments, the $85 million acquisition of the Helix 534 (see below) and the construction of additional ROVs and trenchers related to our robotics business.

In August 2012, we acquired the Discoverer 534 drillship from Transocean Ltd. for $85 million. The vessel, renamed the Helix 534, is currently undergoing modifications in Singapore to convert it into a well intervention vessel. Expected cost for the conversion of the Helix 534 into a well intervention vessel is approximately $95 million. At September 30, 2012, our total investment in the acquisition and subsequent modifications of the Helix 534 totaled $94.0 million. The vessel is expected to join our well intervention fleet in the Gulf of Mexico in mid-2013.

As disclosed in the "Executive Summary" above, in October 2012, we announced the sale of our remaining pipelay vessels and related equipment for $238.3 million. The transaction will close and fund over the next 10 months. Our oil and gas capital expenditures included costs associated with the exploration activities at our Danny II prospect at Garden Banks Block 506 in our Bushwood field. We hold a 50% working interest in the Danny II exploration well that was drilled to a total depth of approximately 14,750 feet, in water depths of approximately 2,800 feet. The well encountered more than 70 feet of high quality net pay. The well, expected to be predominately an oil producer, is currently in the final stages of being developed via a subsea tie back system to our 70% owned and operated East Cameron Block 381 platform. First production from Danny II is expected in the fourth quarter of 2012. Our oil and gas capital expenditures also included costs associated with ongoing exploration and/or appraisal activities related to our Wang exploratory well that will commence drilling in the fourth quarter of 2012 and our T-6 well that we expect to drill in 2013. Both of these wells are located at Green Canyon Block 237 within our Phoenix field.

Restricted Cash

As of September 30, 2012 and December 31, 2011, we had $31.0 million and $33.7 million of restricted cash, all of which consisted of funds required to be escrowed to cover the future asset retirement obligations associated with our South Marsh Island Block 130 field. We have fully satisfied our escrow requirements and may use the restricted cash for future asset retirement costs for this field. We have used a small portion of these escrowed funds to pay for the initial reclamation activities at the South Marsh Island Block 130 field. Reclamation activities at the field will occur over many years and will be funded with these escrowed amounts. These amounts are reflected in other assets, net in the accompanying condensed consolidated balance sheets.

Equity Investments

We received the following distributions from our equity investments during the nine-month periods ended September 30, 2012 and 2011 (in thousands):

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Deepwater Gateway	$ 6,807	$ 5,700
Independence Hub	6,913	14,180
Total	$ 13,720	$ 19,880

Outlook

We anticipate that our capital expenditures will total approximately $545 million for 2012, excluding asset retirement expenditures. These estimates may increase or decrease based on various economic factors and/or existence of additional investment opportunities. However, we may reduce the level of our planned future capital expenditures given any prolonged economic downturn or our inability to execute disposition transactions related to our remaining non-core business assets, most notably all or a portion of our oil and gas business assets. We believe that internally-generated cash flow, cash from future sales of

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our non-core business assets, and availability under our existing credit facilities will provide the capital necessary to fund our remaining 2012 initiatives.

The following table summarizes our contractual cash obligations as of September 30, 2012 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
2025 Notes (2)	$ 157,830	$ —	$ —	$ —	$ 157,830
2032 Notes (3)	200,000	—	—	—	200,000
Senior Unsecured Notes	274,960	—	—	274,960	—
Term Loans (4)	369,165	8,000	361,165	—	—
MARAD debt	105,288	5,120	11,020	12,148	77,000
Revolving Credit Facility (5)	100,000	—	100,000	—	—
Interest related to debt	312,164	59,218	108,730	29,153	115,063
Drilling and development costs	57,990	57,990	—	—	—
Property and equipment (6)	375,650	163,035	212,615	—	—
Operating leases (7)	470,516	69,321	209,459	150,321	41,415
Total cash obligations	$2,423,563	$ 362,684	$1,002,989	$ 466,582	$ 591,308

(1) Excludes unsecured letters of credit outstanding at September 30, 2012 totaling $44.3 million. These letters of credit primarily guarantee asset retirement obligations as well as various contract bidding, insurance activities and shipyard commitments.

(2) Contractual maturity in 2025 (2025 Notes can be redeemed by us or we may be required to purchase them beginning in December 2012). Notes can be converted prior to stated maturity if closing sale 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 120% of the closing price on that 30th trading day (i.e., $38.57 per share) and under certain triggering events as specified in the indenture governing the 2025 Notes. Upon the occurrence of a triggering event, to the extent we do not have alternative long-term financing secured to cover the conversion, the 2025 Notes would be classified as a current liability in the accompanying balance sheet. At September 30, 2012, the conversion trigger was not met.

(3) Contractual maturity in 2032. The 2032 Notes have the same triggering mechanisms as noted in the 2025 Notes in (2) above except its issuance price is $25.02 per share and the stock price would have to exceed 130% of its issuance price on that 30th trading day (i.e., $32.53 per share). At September 30, 2012, the conversion trigger was not met. The first date that the holders of these notes may require us to redeem the notes is in March 2018. See Note 7 for additional information regarding these 2032 Notes.

(4) Our Term Loans will mature on July 1, 2015 but may extend to July 1, 2016 (January 1, 2016 with regards to Term Loan A) if our Senior Unsecured Notes are either refinanced or repaid in full by July 1, 2015 (Note 7).

(5) 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).

(6) Primarily reflects the costs related to construction of our new semi-submersible well intervention vessel, the Q5000, and expected costs associated with the modifications to convert the Helix 534 into a well intervention vessel (Note 14).

(7) Operating leases included facility leases and vessel charter leases. Vessel charter lease commitments at September 30, 2012 were approximately $462.2 million.

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CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our discussion and analysis of our financial condition and results of operations are based upon our condensed consolidated financial statements. We prepare these financial statements in conformity with accounting principles generally accepted in the United States. As such, we are required to make certain estimates, judgments and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods presented. We base our estimates on historical experience, available information and various other assumptions we believe to be reasonable under the circumstances. These estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. For additional information regarding our critical accounting policies and estimates, please read our "Critical Accounting Policies and Estimates" as disclosed in our 2011 Form 10-K.

Item 3. Quantitative and Qualitative Disclosure about Market Risk

We are currently exposed to market risk in three major areas: interest rates, commodity prices and foreign currency exchange rates.

Interest Rate Risk. As of September 30, 2012, $469.2 million of our outstanding debt was subject to floating rates. The interest rate applicable to our variable rate debt may rise, increasing our interest expense and related cash outlay. To reduce the impact of this market risk, in January 2010, we entered into two-year cash flow hedging interest rate swaps to stabilize cash flows relating to interest payments on $200 million of our Term Loan. In August 2011, we entered into additional interest rate swap contracts to fix the interest rate on $200 million of our Term Loan. These swap contracts, which are settled monthly, begin in January 2012 and extend through January 2014. The impact of market risk is estimated using a hypothetical increase in interest rates by 100 basis points for our variable rate long-term debt that is not hedged. Based on this hypothetical assumption, we would have incurred an additional $1.6 million in interest expense for the nine-month period ended September 30, 2012.

Our financial instruments that are potentially sensitive to changes in interest rates also include our Term Loans, 2025 Notes, 2032 Notes, Senior Unsecured Notes and MARAD Debt. The following table reflects the fair value of these debt instruments as compared to their respective carrying value as of September 30, 2012 (in thousands):

	Fair Value	Carrying Value
Term Loans (mature July 2015) (a)	$ 370,157	$ 369,165
2025 Notes (mature March 2025) (a)	159,408	157,830 (b)
2032 Notes (mature March 2032) (a)	222,228	200,000 (c)
Senior Unsecured Notes (mature January 2016) (a)	288,021	274,960
MARAD Debt (matures February 2027) (d)	122,397	105,288
Total	$ 1,162,211	$ 1,107,243

(a) The fair values of these instruments were based on quoted market prices as of September 30, 2012.

(b) Amount excludes the related unamortized debt discount of $1.2 million.

(c) Amount excludes the related unamortized debt discount of $32.9 million.

(d) 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.

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Commodity Price Risk. As of September 30, 2012, we had the following volumes under derivative contracts related to our oil and gas producing activities totaling approximately 3.4 million barrels of oil and 8.7 Bcf of natural gas:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price (1)
Crude Oil:			(per barrel)
October 2012 — December 2012	Collar	75.0 MBbl	$ 96.67 — $118.57 (2)
October 2012 — December 2012	Collar	80.3 MBbl	$ 99.77 — $118.71
October 2012 — December 2012	Swap	103.7 MBbl	$92.15
January 2013 — December 2013	Swap	88.9 MBbl	$95.28
January 2013 — December 2013	Collar	133.3 MBbl	$ 98.44 — $115.85
Natural Gas:			(per Mcf)
October 2012 — December 2012	Swap	776.7 Mmcf	$4.31
October 2012 — December 2012	Collar	130.0 Mmcf	$4.75 — $5.13
January 2013 — December 2013	Swap	500.0 Mmcf	$4.09

(a) The prices quoted in the table above are NYMEX Henry Hub for natural gas. Our oil contracts are indexed to the Brent crude oil price unless otherwise noted.

(b) This contract is priced using NYMEX West Texas Intermediate for crude oil.

Changes in NYMEX oil and gas and Brent crude oil strip prices would, assuming all other things being equal, cause the fair value of these instruments to increase or decrease inversely to the change in NYMEX or Brent prices, respectively.

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 a) currencies other than the U.S. dollar, which is our functional currency or b) 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 nine-month period ended September 30, 2012, we recognized foreign exchange gains of $0.1 million in “Other income (expense), net” in the condensed consolidated statements of income and comprehensive income. We also entered into various foreign currency forward purchase contracts to stabilize expected cash outflows relating to certain vessel charters denominated in British pounds. The gain resulting from changes in the fair value of our foreign exchange forwards that were not designated for hedge accounting totaled $0.4 million for the nine-month period ended September 30, 2012.

Item 4. Controls and Procedures.

(a) Evaluation of disclosure controls and procedures. Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Exchange Act) as of the end of the fiscal quarter ended September 30, 2012. Based on this evaluation, the principal executive officer and the principal financial officer have concluded that our disclosure controls and procedures were effective as of the end of the fiscal quarter ended September 30, 2012 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 September 30, 2012.

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	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced program (1)	(d) Maximum number of shares that may yet be purchased under the program (1)
July 1 to July 31, 2012	—	$ —	—	—
August 1 to August 31, 2012	—	—	—	—
September 1 to September 30, 2012	—	—	—	—
	—	$ —	—	—

(1) Under the terms of our stock repurchase program, the issuance of shares to our employees increases the amount of shares available for repurchase. Currently we have no availability to repurchase any shares under our share repurchase program. For additional information regarding our stock repurchase program, see Note 14 of the 2011 Form 10-K.

Item 6. Exhibits

The exhibits to this report are listed in the Exhibit Index beginning on Page 57 hereof.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

HELIX ENERGY SOLUTIONS GROUP, INC.
(Registrant)

Date: October 24, 2012	By: /s/ Owen Kratz Owen Kratz President and Chief Executive Officer (Principal Executive Officer)
Date: October 24, 2012	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.

3.1	2005 Amended and Restated Articles of Incorporation, as amended, of registrant, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by registrant with the Securities and Exchange Commission on March 1, 2006.
3.2	Second Amended and Restated By-Laws of Helix, as amended, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on September 28, 2006.
4.1	Amendment No. 7 to Credit Agreement dated September 26, 2012 by and among Helix Energy Solutions Group, Inc., as borrower, Bank of America, N.A., as administrative agent, and the lenders named thereto, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by registrant with the Securities and Exchange Commission on October 1, 2012.
10.1	The MODU Sale Agreement between Helix Energy Solutions Group, Inc. and Transocean Discoverer 534 LLC dated July 23, 2012, incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q filed by the registrant with the Securities and Exchange Commission on July 25, 2012.
10.2	The Pipelay Asset Sale Agreement between Helix Energy Solutions Group, Inc. and Coastal Trade Limited dated October 15, 2012, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by the registrant with the Securities and Exchange Commission on October 16, 2012.
15.1	Independent Registered Public Accounting Firm's Acknowledgement Letter (1)
31.1	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Owen Kratz, Chief Executive Officer (1)
31.2	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Anthony Tripodo, Chief Financial Officer (1)
32.1	Certification of Helix's Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes – Oxley Act of 2002 (2)
99.1	Report of Independent Registered Public Accounting Firm (1)
101.INS	XBRL Instance Document (2)
101.SCH	XBRL Schema Document (2)
101.CAL	XBRL Calculation Linkbase Document (2)
101.PRE	XBRL Presentation Linkbase Document (2)
101.DEF	XBRL Definition Linkbase Document (2)
101.LAB	XBRL Label Linkbase Document (2)

(1) Filed herewith
(2) Furnished herewith