HELIX ENERGY SOLUTIONS GROUP INC
Form 10-Q
April 27, 2011

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

Form 10-Q

[X] Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended March 31, 2011

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, or a non-accelerated filer. See definition of “accelerated filer and large accelerated filer” in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer [√]	Accelerated filer [ ]	Non-accelerated filer [ ]

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

As of April 21, 2011, 106,011,182 shares of common stock were outstanding.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements.

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

	March 31, 2011 (Unaudited)	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 440,531	$ 391,085
Accounts receivable —		
Trade, net of allowance for uncollectible accounts of $4,445 and $4,527, respectively	190,859	177,293
Unbilled revenue	21,959	33,712
Costs in excess of billing	434	15,699
Other current assets	113,829	123,065
Total current assets	767,612	740,854
Property and equipment	4,535,834	4,486,077
Less — accumulated depreciation	(2,046,613)	(1,958,997)
	2,489,221	2,527,080
Other assets:		
Equity investments	186,831	187,031
Goodwill	62,956	62,494
Other assets, net	70,449	74,561
	$ 3,577,069	$ 3,592,020
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 126,364	$ 159,381
Accrued liabilities	199,479	198,237
Current maturities of long-term debt	9,638	10,179
Total current liabilities	335,481	367,797
Long-term debt	1,346,469	1,347,753
Deferred income taxes	415,312	413,639
Asset retirement obligations	168,014	170,410
Other long-term liabilities	5,301	5,777
Total liabilities	2,270,577	2,305,376
Convertible preferred stock	1,000	1,000
Commitments and contingencies		
Shareholders' equity:		
Common stock, no par, 240,000 shares authorized, 106,012 and 105,592 shares issued, respectively	908,632	906,957

Retained earnings	418,562	392,705
Accumulated other comprehensive loss	(47,510)	(39,058)
Total controlling interest shareholders’ equity	1,279,684	1,260,604
Noncontrolling interests	25,808	25,040
Total equity	1,305,492	1,285,644
	$ 3,577,069	$ 3,592,020

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

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

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
Net revenues:		
Contracting services	$ 122,748	$ 110,855
Oil and gas	168,859	90,715
	291,607	201,570
Cost of sales:		
Contracting services	106,907	86,248
Oil and gas	107,624	89,466
	214,531	175,714
Gross profit	77,076	25,856
Gain on sale or acquisition of assets, net	16	6,247
Selling, general and administrative expenses	(24,981)	(40,501)
Income (loss) from operations	52,111	(8,398)
Equity in earnings of investments	5,650	5,055
Net interest expense	(24,236)	(15,635)
Other income (expense)	2,660	(5,585)
Income (loss) before income taxes	36,185	(24,563)
Provision (benefit) for income taxes	9,550	(7,561)
Net income (loss), including noncontrolling interests	26,635	(17,002)
Less net income applicable to noncontrolling interests	(768)	(829)
Net income (loss) applicable to Helix	25,867	(17,831)
Preferred stock dividends	(10)	(60)
Net income (loss) applicable to Helix common shareholders	$ 25,857	$ (17,891)

Earnings (loss) per share of common stock:				
Basic	$	0.24	$	(0.17)
Diluted	$	0.24	$	(0.17)
Weighted average common shares outstanding:				
Basic		104,471		103,090
Diluted		104,903		103,090

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

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

	Three Months Ended March 31,	
	2011	2010
Cash flows from operating activities:		
Net income (loss), including noncontrolling interests	$ 26,635	$ (17,002)
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by operating activities		
Depreciation and amortization	92,143	60,827
Asset impairment charge and dry hole expense	—	11,292
Amortization of deferred financing costs	1,981	1,726
Stock compensation expense	2,953	2,488
Amortization of debt discount	2,207	2,068
Deferred income taxes	9,329	(2,110)
Excess tax benefit from stock-based compensation	969	1,842
Gain on investment in Cal Dive common stock	(753)	—
Gain on sale or acquisition of assets	(16)	(6,247)
Unrealized (gain) loss on derivative contracts	(318)	3,001
Changes in operating assets and liabilities:		
Accounts receivable, net	(381)	(23,823)
Other current assets	18,869	30,780
Income tax payable	(2,338)	(9,513)
Accounts payable and accrued liabilities	(58,747)	(22,027)
Oil and gas asset retirement costs	(8,160)	(12,541)
Other noncurrent, net	692	(2,324)
Net cash provided by operating activities	85,065	18,437
Cash flows from investing activities:		
Capital expenditures	(34,488)	(68,428)
Distributions from equity investments, net	480	965
Proceeds from sale of Cal Dive common stock	3,588	—
Decrease (increase) in restricted cash	613	(4)
Net cash used in investing activities	(29,807)	(67,467)

Cash flows from financing activities:		
Repayment of Helix Term Loan	(1,082)	(1,082)
Repayment of MARAD borrowings	(2,294)	(2,403)
Loan notes repayment	(660)	(711)
Deferred financing costs	—	(2,789)
Preferred stock dividends paid	(10)	(60)
Repurchases of common stock	(927)	(976)
Excess tax benefit from stock-based compensation	(969)	(1,842)
Exercise of stock options, net	600	—
Net cash used in financing activities	(5,342)	(9,863)
Effect of exchange rate changes on cash and cash equivalents	(470)	398
Net increase (decrease) in cash and cash equivalents	49,446	(58,495)
Cash and cash equivalents:		
Balance, beginning of year	391,085	270,673
Balance, end of period	$ 440,531	$ 212,178

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

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 2010 Annual Report on Form 10-K (“2010 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, results of operations, and cash flows, as applicable. The operating results for the three-month period ended March 31, 2011 are not necessarily indicative of the results that may be expected for the year ending December 31, 2011. Our balance sheet as of December 31, 2010 included herein has been derived from the audited balance sheet as of December 31, 2010 included in our 2010 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 2010 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, including reclassifying the previously recorded results associated with our discontinued operations. The discontinued operations results are now reflected as a component of other income (expense) in the accompanying condensed consolidated statement of operations as such amounts are immaterial for all the periods presented in this Quarterly Report on Form 10-Q.

Note 2 – Company Overview

We are an international offshore energy company that provides reservoir development solutions and other contracting services to the energy market as well as to our own oil and gas properties. Our Contracting Services segment utilizes our vessels, offshore equipment and methodologies to deliver services that may reduce finding and development costs and encompass the complete lifecycle of an offshore oil and gas field. Our Contracting Services are located primarily in Gulf of Mexico, North Sea, Asia Pacific and West Africa regions. Our Oil and Gas segment engages in exploration, development and production activities. Our oil and gas operations are exclusively located in the Gulf of Mexico.

Contracting Services Operations
We seek to provide services and methodologies which we believe are critical to finding and developing offshore reservoirs and maximizing production economics. Our “life of field” services are segregated into four disciplines: subsea construction, well operations, robotics and production facilities. We have disaggregated our contracting services operations into two reportable segments: Contracting Services and Production Facilities. Our Contracting Services business primarily includes subsea construction, deepwater pipelay, well operations and robotics

activities. Our Production Facilities business includes our investments in Deepwater Gateway, L.L.C. (“Deepwater Gateway”) and Independence Hub, LLC (“Independence Hub”) as well as our majority ownership of the Helix Producer I (“HP I”) vessel. We recently developed a response system that may be utilized in future oil spill containment efforts in Gulf of Mexico (see “Events in Gulf of Mexico” below).

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Oil and Gas Operations

We began our oil and gas operations to provide a more efficient solution to offshore abandonment, to expand our off-season utilization of our contracting services assets and to achieve incremental returns. We have evolved this business model to include not only mature oil and gas properties but also proved and unproved reserves yet to be developed and explored. This has led to the assembly of services that allows us to create value at key points in the life of a reservoir from exploration through development, life of field management and operating through abandonment.

Business 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 March 31, 2011, our cash on hand totaled $440.5 million and our liquidity was $836.7 million. Our capital expenditures for full year 2011 are expected to total approximately $250 million, which primarily reflects development of certain of our oil and gas properties (but is exclusive of expenditures related to our asset retirement obligations). We believe that we have sufficient liquidity to successfully implement our business plan in 2011 without incurring additional indebtedness beyond the existing capacity under the Revolving Credit Facility.

In March 2010, we announced the engagement of advisors to assist us with evaluating potential alternatives for the disposition of our oil and gas business. Since that time, we have had intervening events, such as the Macondo well oil spill (discussed below in “Events in Gulf of Mexico”) and the subsequent regulatory effects associated with that event, which has resulted in a challenging environment for the sale of our entire oil and gas business. Furthermore, given the favorable commodity price environment and its positive impact on our financial condition, our focus has recently transitioned from a sale of our entire oil and gas business to building value through development of a number of our existing oil and gas properties. In 2011, our plan is to pursue development of a portion of our significant proved undeveloped reserves portfolio and to explore certain of our existing exploration prospects with a focus on crude oil prospects to generate higher cash flow. We will continue to evaluate the potential sale of properties as opportunities arise and may pursue those opportunities that we deem to be in our best interests in terms of economic returns and/or risk mitigation.

Events in Gulf of Mexico

In April 2010, an explosion occurred on the Deepwater Horizon drilling rig located on the site of the Macondo well at Mississippi Canyon Block 252. The resulting events included loss of life, the complete destruction of the drilling rig and an oil spill, the magnitude of which was unprecedented in U.S. territorial waters. In May 2010, the U.S. Department of Interior (“DOI”) announced a total moratorium on new drilling in the Gulf of Mexico. The drilling moratorium was partially lifted in late May 2010 (for drilling of prospects in less than 500 feet of water). In October 2010, the DOI lifted the drilling moratorium and instructed the Bureau of Ocean Energy Management, Regulation and Enforcement (“BOEMRE”) that it could resume issuing drilling permits conditioned on the requesting company’s compliance with all revised drilling, safety and environmental requirements. No deepwater drilling permits were issued in the period from October 2010 through late February 2011. In late February 2011, the BOEMRE commenced issuing deepwater permits. At the time of this filing 11 deepwater permits have been issued, six of which were issued using the Helix Fast Response System as further discussed below.

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 for the HFRS became effective April 1, 2011 and will be a component of our Production Facilities business segment. A total of six permits have been granted to CGA participants for deepwater drilling operations identifying the HFRS to fulfill the BOERME requirement to have a spill response solution included in the submitted permit applications.

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Note 3 – Details of Certain Accounts

Other current assets consisted of the following as of March 31, 2011 and December 31, 2010:

	March 31, 2011	December 31, 2010
	(in thousands)	
Other receivables	$ 4,674	$ 1,247
Prepaid insurance	6,602	12,375
Other prepaids	12,076	11,623
Spare parts inventory	23,742	25,333
Current deferred tax assets	46,789	49,200
Hedging assets	3,466	5,472
Gas imbalance	5,900	6,001
Income tax receivable	7,497	6,099
Investment held for sale (a)	—	2,835
Other	3,083	2,880
	$ 113,829	$ 123,065

a. In the first quarter of 2011, we sold our remaining 500,000 shares of Cal Dive common stock. These sales transactions resulted in net proceeds of approximately $3.6 million and a pre-tax gain of $0.8 million. In the fourth quarter of 2010, we had recognized a $2.2 million other than temporary loss on our investment in Cal Dive common shares (see Notes 2 and 3 of our 2010 Form 10-K for additional information regarding our former Investment in Cal Dive common stock)

Other assets, net, consisted of the following as of March 31, 2011 and December 31, 2010:

	March 31, 2011	December 31, 2010
	(in thousands)	
Restricted cash	$ 34,726	$ 35,339
Deferred drydock expenses, net	9,478	11,086
Deferred financing costs, net	23,812	25,697
Intangible assets with finite lives, net	628	636
Other	1,805	1,803
	$ 70,449	$ 74,561

Accrued liabilities consisted of the following as of March 31, 2011 and December 31, 2010:

	March 31, 2011	December 31, 2010
	(in thousands)	
Accrued payroll and related benefits	$ 26,023	$ 38,026
Royalties payable	18,817	15,008
Current asset retirement obligations	64,398	64,526
Unearned revenue	9,594	4,094
Billing in excess of cost	5,842	3,869
Accrued interest	15,248	27,308
Hedge liability	45,022	30,606

Other		14,535		14,800
	$	199,479	$	198,237

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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.

Depletion expense is determined on a field-by-field basis using the units-of-production method, with depletion rates for leasehold acquisition costs based on estimated total remaining proved reserves. Depletion rates for well and related facility costs are based on estimated total remaining proved developed reserves associated with each individual field. The depletion rates are changed whenever there is an indication of the need for a revision but, at a minimum, are evaluated annually. Any such revisions are accounted for prospectively as a change in accounting estimate.

Exploration and Other

As of March 31, 2011, we capitalized approximately $3.4 million of costs associated with ongoing exploration and/or appraisal activities. 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 months ended March 31, 2011 and 2010:

	Three Months Ended March 31,	
	2011	2010
	(in thousands)	
Delay rental and geological and geophysical costs	$ 355	$ 346
Dry hole expense	(9)	(180)
Total exploration expense	$ 346	$ 166

Impairments

No property impairments were recorded in the first quarter of 2011. In the first quarter of 2010, we recorded $7.0 million of impairment charges primarily resulting from natural gas price declines since year end 2009. The impairment charges affected three of our U.S. Gulf of Mexico properties that produce primarily natural gas. Separately, we also recorded a $4.1 million impairment charge for our only non-domestic oil and gas property (see “United Kingdom Property” below). Impairment expense is recorded as a component of depletion expense, which is reflected as cost of sales in the accompanying condensed consolidated statements of operations.

United Kingdom Property

Since 2006, we have maintained an ownership interest in the Camelot field, located offshore in the North Sea. In 2007, we sold half of our 100% working interest in Camelot to a third party with whom we agreed to jointly pursue future development and production of the field. In February 2010, we acquired this third party, including its $10.2 million of cash and thereby assumed the obligations, most notably the asset retirement obligation, related to its 50%

working interest in the field. We recorded an approximate $6.0 million gain on the acquisition of the remaining working interest in Camelot (see Note 5 of 2010 Form 10-K).

Also in connection with this acquisition, we reassessed the fair value associated with our original 50% interest in the field. Based on these evaluations, it was concluded that Camelot was impaired based on the unlikely probability of our expending the additional capital necessary to further develop the field and our plans are to abandon the field in 2011 in accordance with applicable United Kingdom regulations. As a result, we recorded a $4.1 million impairment charge to fully impair the property in the first quarter of 2010.

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Asset retirement obligations

The following table describes the changes in our asset retirement obligations (both long term and current) since December 31, 2010 (in thousands):

Asset retirement obligation at December 31, 2010	$ 234,936
Liability incurred during the period	511
Liability settled during the period	(7,328)
Revision in estimated cash flows	507
Accretion expense (included in depreciation and amortization)	3,786
Asset retirement obligations at March 31, 2011	$ 232,412

Insurance

In September 2008, we sustained damage to certain of our oil and gas production facilities from Hurricanes Gustav and Ike. We carried comprehensive insurance on all of our operated and non-operated producing and non-producing properties. We record our hurricane-related costs as incurred. Insurance reimbursements are recorded when the realization of the claim for recovery of a loss is deemed probable. In the first quarter of 2011, we incurred $0.2 million of hurricane-related repair costs compared to $2.1 million in the first quarter of 2010. The first quarter of 2011 costs were offset by approved insurance reimbursements of $3.8 million. Expense related to our hurricane catastrophic bond windstorm coverage was immaterial for all periods presented in this Quarterly Report on Form 10-Q. See Note 4 of our 2010 Form 10-K for information regarding our settlement with the insurance underwriters in June 2009.

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 $34.7 million at March 31, 2011 and $35.3 million at December 31, 2010, all of which was related to 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 the future asset retirement costs of the field. These amounts are reflected in other assets, net in the accompanying condensed consolidated balance sheets.

The following table provides supplemental cash flow information for the three-month periods ended March 31, 2011 and 2010 (in thousands):

	Three Months Ended March 31,	
	2011	2010
Interest paid, net of capitalized interest	$ 32,093	$ 23,737
Income taxes paid	$ 3,785	$ 4,357

Non-cash investing activities for the three-month periods ended March 31, 2011 and 2010 included $36.0 million and $48.2 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 and accounts payable.

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Note 6 – Equity Investments

As of March 31, 2011, we have three investments that we account for using the equity method of accounting: Deepwater Gateway, Independence Hub, and the Clough Helix Joint Venture Pty Ltd. (“Clough Helix JV”). Deepwater Gateway and Independence Hub are included in our Production Facilities segment while the Clough Helix joint venture is a component of our Contracting Services 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 (“TLP”) production hub primarily for Anadarko Petroleum Corporation's Marco Polo field in the Deepwater Gulf of Mexico. Our investment in Deepwater Gateway totaled $99.0 million and $99.8 million as of March 31, 2011 and December 31, 2010, respectively (including capitalized interest of $1.5 million at both March 31, 2011 and December 31, 2010). Our net distributions from Deepwater Gateway totaled $1.8 million in the first quarter of 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. First production through the facility commenced in July 2007. Our investment in Independence Hub was $82.1 million and $82.4 million as of March 31, 2011 and December 31, 2010, respectively (including capitalized interest of $5.2 million at March 31, 2011 and December 31, 2010). Our net distributions from Independence Hub totaled $4.4 million in the first quarter of 2011.

- Clough Helix JV. In February 2010, we announced the formation of the Clough Helix JV with Australian-based engineering and construction company, Clough Projects Australia Pty Ltd (“Clough”), to provide a range of subsea services to offshore operators in the Asia Pacific region. The Clough Helix JV combines our well intervention equipment with Clough’s 12-man saturation diving system, which are deployed from the 118 meter long DP2 multiservice vessel, Normand Clough. In the first quarter of 2011, the Clough Helix JV commenced an approximate six to nine month day rate project located offshore China. Our 50% share of the earnings from the Clough Helix JV totaled $0.4 million for the three-month period ended March 31, 2011 as compared to a $1.4 million loss in the first quarter of 2010. The loss in the first quarter of 2010 primarily represented the mobilization costs of transporting the Normand Clough from the Gulf of Mexico to Singapore. Our investment in the Clough Helix JV was $5.7 million at March 31, 2011 and $4.9 million at December 31, 2010.

Note 7 – Long-Term Debt

Scheduled maturities of long-term debt and capital lease obligations outstanding as of March 31, 2011 were as follows (in thousands):

	Helix Term Loan	Helix Revolving Loans	Senior Unsecured Notes	Convertible Senior Notes (1)	MARAD Debt	Other(2)	Total
Less than one year	$ 4,326	$	$	$	$ 4,759	$ 553	$ 9,638
One to two years	4,326				4,997		9,323
Two to three years	400,707				5,247		405,954
					5,508		5,508

Three to four years							
Four to five years			550,000		5,783		555,783
Over five years				300,000	86,222		386,222
Total debt	409,359		550,000	300,000	112,516	553	1,372,428
Current maturities	(4,326)				(4,759)	(553)	(9,638)
Long-term debt, less current maturities	$405,033	$	$ 550,000	$ 300,000	$ 107,757	$	$1,362,790
Unamortized debt discount (3)				(16,321)			(16,321)
Long-term debt	$405,033	$	$ 550,000	$ 283,679	$ 107,757	$	$1,346,469

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(1) Beginning in December 2012, the holders may require us to repurchase the notes or we may at our own option elect to repurchase notes. Notes will mature in March 2025.
(2) Represents the balance of the loan provided by Kommandor RØMØ to Kommandor LLC as of March 31, 2011.
(3) The notes will increase to the $300 million face amount through accretion of non-cash interest charges through 2012.

At March 31, 2011, unsecured letters of credit issued totaled approximately $38.8 million (see "Credit Agreement" below). These letters of credit primarily guarantee various contract bidding, contractual performance, including asset retirement obligations, and insurance activities. The following table details our interest expense and capitalized interest for the three-month periods ended March 31, 2011 and 2010:

	Three Months Ended March 31,	
	2011	2010
	(in thousands)	
Interest expense	$ 24,767	$ 24,349
Interest income	(476)	(198)
Capitalized interest	(55)	(8,516)
Interest expense, net	$ 24,236	$ 15,635

Included below is a summary of certain components of our indebtedness. We were in compliance with all debt covenants and restrictions at March 31, 2011 and December 31, 2010. For additional information regarding our debt see Note 9 of our 2010 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. We used the proceeds from the Senior Unsecured Notes to repay outstanding indebtedness under our Credit Agreement (see below).

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 initially 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 three times, most recently in February 2010, to address certain issues with regard to covenants, maturity and the borrowing limits under the Revolving Credit Facility. For additional information regarding the current terms of our credit facility see Note 9 of our 2010 Form 10-K.

The proceeds from the Term Loan were used to fund the cash portion of the acquisition of Remington Oil and Gas Corporation in July 2006. The Term Loan currently bears interest either at the one-, three- or six-month LIBOR at our election plus a margin of between 2.25% and 2.5% depending on current leverage ratios. Our average interest rate on the Term Loan for the three-month periods ended March 31, 2011 and 2010 was approximately 3.0% and 2.8%, respectively, including the effects of our interest rate swaps (Note 16). The Term Loan is currently scheduled to mature on July 1, 2013.

The original maturity date of the Revolving Credit Facility was July 1, 2011. In the fourth quarter of 2009, we increased the Revolving Credit Facility and extended its maturity date to November 30, 2012. As a consequence of the foregoing, the borrowing limit under the Revolving Credit Facility was increased by amendment to $435 million, effective December 31, 2009. This limit will decrease to $410 million beginning July 1, 2011 and will stay at that level through the maturity of the Revolving Credit Facility on November 30, 2012. The full amount of the Revolving Credit Facility may be used for issuances of letters of credit. At March 31, 2011, we had no amounts drawn on the Revolving Credit Facility and our availability under the Revolving Credit Facility totaled $396.2 million, net of $38.8 million of letters of credit issued.

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The Revolving Loans bear interest based on one-, three- or six-month LIBOR rates or on Base Rates at our election plus an applicable margin. The margin ranges from 1.0% to 4.5%, depending on our consolidated leverage ratio. We have not borrowed any amounts under the Revolving Loans since we repaid the outstanding amount in the second quarter of 2009.

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 (Note 16).

Convertible Senior Notes

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

The Convertible Senior Notes can be converted prior to the stated maturity (March 2025) under certain triggering events specified in the indenture governing the Convertible Senior Notes. To the extent we do not have long-term financing secured to cover the conversion, the Convertible Senior Notes would be classified as a current liability in the accompanying condensed consolidated balance sheet. No conversion triggers were met during the three-month period ended March 31, 2011. The first dates for early redemption of the Convertible Senior Notes are in December 2012, with the holders of the Convertible Senior Notes being able to put them to us on December 15, 2012 and our being able to call the Convertible Senior Notes at any time after December 20, 2012 (see Note 9 of our 2010 Form 10-K).   Effective January 1, 2009 we adopted certain new required accounting standards that required us to discount the principal amount of our Convertible Senior Notes. Following adoption of these accounting standards, the effective interest rate for the Convertible Senior Notes is 6.6%.

Our average share price for the both the first quarter of 2011 and 2010 was below the $32.14 per share conversion price. As a result of our share price being lower than the $32.14 per share conversion price for these periods there are no shares included in our diluted earnings per share calculation associated with the assumed conversion of our Convertible Senior 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 on conversion. The Convertible Senior Notes are convertible into a maximum 13,303,770 shares of our common stock.

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).

Other

In accordance with our Credit Agreement and our Senior Unsecured Notes, Convertible Senior Notes and MARAD Debt agreements, we are required to comply with certain covenants, including the maintenance of minimum net worth, working capital and debt-to-equity requirements, and restrictions that limit our ability to incur certain types of additional indebtedness. As of March 31, 2011, we were in compliance with these covenants and restrictions.

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Deferred financing costs of $23.8 million and $25.7 million are included in other assets, net as of March 31, 2011 and December 31, 2010, respectively, and are being amortized over the life of the respective loan agreements.

Note 8 – Income Taxes

The effective tax rate for the three-month period ended March 31, 2011 was 26.4% as compared with 30.8% for the three-month period ended March 31, 2010. The effective tax rate for the first quarter of 2011 resulted from of the increased benefit derived from lower tax rates in certain foreign jurisdictions.

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.

Note 9 – Comprehensive Income (Loss)

The components of total comprehensive income (loss) for the three-month periods ended March 31, 2011 and 2010 were as follows (in thousands):

	Three Months Ended March 31,	
	2011	2010
Net income (loss), including noncontrolling interests	$ 26,635	$ (17,002)
Other accumulated comprehensive income (loss), net of tax		
Foreign currency translation gain (loss)	2,115	(10,702)
Unrealized (loss) gain on hedges, net	(10,567)	14,040
Unrealized loss on investment available for sale	—	(75)
Total accumulated comprehensive income (loss)	$ 18,183	$ (13,739)

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

	March 31, 2011	December 31, 2010
Cumulative foreign currency translation adjustment	$ (20,147)	$ (22,262)
Unrealized loss on hedges, net	(27,363)	(16,796)
Accumulated other comprehensive loss	$ (47,510)	$ (39,058)

Note 10 – Earnings Per Share

We have shares of restricted stock issued and outstanding, some of which remain subject to certain 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.

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

	Three Months Ended March 31, 2011		Three Months Ended March 31, 2010	
	Income	Shares	Income	Shares
Basic:				
Net income (loss) applicable to common shareholders	$ 25,857		$ (17,891)	
Less: Undistributed net income allocable to participating securities	(338)			
Net income (loss) applicable to common shareholders	$ 25,519	104,471	$ (17,891)	103,090

	Three Months Ended March 31, 2011		Three Months Ended March 31, 2010	
	Income	Shares	Income	Shares
Diluted:				
Net income (loss) per common share - Basic	$ 25,519	104,471	$ (17,891)	103,090
Effect of dilutive securities:				
Stock options		71		
Undistributed earnings reallocated to participating securities	1			
Convertible Senior Notes				
Convertible preferred stock	10	361		
Net income (loss) per common share - Diluted	$ 25,530	104,903	$ (17,891)	103,090

We had a net loss from continuing operations during the three-month period ended March 31, 2010. Accordingly, we had no dilutive securities during this reporting period as their inclusion would have an anti-dilutive effect on our EPS calculation, meaning it would increase our reported EPS amount. The following table provides the effect the excluded securities would have had on our diluted shares calculation for the three-month period ended March 31, 2010 assuming we had earnings from continuing operations (in thousands):

Diluted shares (as reported)	103,090
Stock options	194
Convertible preferred stock	2,168
Total	105,452

Note 11 – Stock-Based Compensation Plans

We have two stock-based compensation plans: the 1995 Long-Term Incentive Plan, as amended (the "1995 Incentive Plan") and the 2005 Long-Term Incentive Plan, as amended (the "2005 Incentive Plan"). As of March 31, 2011, there were 892,573 million shares available for grant under our 2005 Incentive Plan.

There were no stock option grants in the three-month periods ended March 31, 2011 and 2010.
During the three-month period ended March 31, 2011, we made the following restricted share grants to executive officers, selected management employees and non-employee members of the board of directors under the 2005 incentive plan:

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Date of Grant	Shares	Market Value Per Share	Vesting Period
January 4, 2011	475,804	$ 12.14	20% per year over five years
January 4, 2011	4,427	12.14	100% on January 1, 2013

Compensation cost is recognized over the respective vesting periods on a straight-line basis. For the three-month period ended March 31, 2011, $3.0 million was recognized as compensation expense related to restricted shares as compared with $2.5 million during the three-month period ended March 31, 2010.

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 over a five year vesting period. However, some of the cash awards are indexed to our Company common stock and the payment amount at each vesting date will fluctuate based on the common stock's performance. 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 appropriate.

The total awards made under the 2009 LTI Plan totaled $10.2 million in 2010 and $4.0 million in 2011. These grant amounts include $6.0 million in 2010 and the entire grant in 2011 that is deemed to be within the liability plan component of the 2009 LTI Plan. Total compensation expense under the 2009 LTI plan totaled $3.0 million and $1.9 million for the three-month periods ended March 31, 2011 and 2010, respectively.

For more information regarding our stock-based compensation plans, including our 2009 LTI Plan see Note 12 of our 2010 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 consisted of the following: Contracting Services, Production Facilities and Oil and Gas. Contracting Services operations include subsea construction, deepwater pipelay, well operations and robotics. 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 income before income taxes of each segment. Segment assets are comprised of all assets attributable to the reportable segment. All material intercompany transactions between the segments have been eliminated.

	Three Months Ended March 31,	
	2011	2010
	(in thousands)	
Revenues		
Contracting Services	$ 131,537	$ 154,200
Production Facilities	15,570	1,320
Oil and Gas	168,859	90,715

Intercompany elimination	(24,359)	(44,665)
Total	$ 291,607	$ 201,570

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	Three Months Ended March 31, 2011	2010
	(in thousands)	
Income (loss) from operations		
Contracting Services	$ 3,266	$ 27,486
Production Facilities(1)	5,956	(37)
Oil and Gas	53,240	(664)
Corporate (2)	(10,441)	(22,878)
Intercompany elimination	90	(12,305)
Total	$ 52,111	$ (8,398)
Equity in earnings of equity investments	$ 5,650	$ 5,055

(1) In April 2009, Kommandor LLC commenced leasing the HP I to us under terms of a charter arrangement following the completion of the initial conversion of the vessel (Note 8 of our 2010 Form 10-K). The HP I was certified as a floating oil and gas production unit in June 2010 following the completion of installation of oil and gas processing facilities on the vessel.

(2) Includes $13.8 million settlement of third party claim against us in March 2010 (Note 14).

	March 31, 2011	December 31, 2010
	(in thousands)	
Identifiable Assets		
Contracting Services	$1,853,349	$1,856,016
Production Facilities	514,086	512,990
Oil and Gas	1,209,634	1,223,014
Total	$3,577,069	$3,592,020

Intercompany segment revenues during the three-month periods ended March 31, 2011 and 2010 were as follows:

	Three Months Ended March 31, 2011	2010
	(in thousands)	
Contracting Services	$ 12,869	$ 43,741
Production Facilities	11,490	924
Total	$ 24,359	$ 44,665

Intercompany segment profits during the three-month periods ended March 31, 2011 and 2010 were as follows:

	Three Months Ended March 31,	
	2011	2010
	(in thousands)	
Contracting Services	$ (24)	$ 11,442
Production Facilities	(66)	880
Total	$ (90)	$ 12,322

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Note 13 – Related Party Transactions

In April 2000, we acquired a 20% working interest in Gunnison, a deepwater Gulf of Mexico prospect, from a third party. Financing for the exploratory costs of approximately $20 million was provided by an investment partnership (OKCD Investments, Ltd. or "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 $2.3 million and $3.0 million for the three-month periods ended March 31, 2011 and 2010, respectively. Our Chief Executive Officer, Owen Kratz, through Class A limited partnership interests in OKCD, personally owns approximately 80.4% 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

Litigation and Claims

In March 2009, we were notified of a third party's intention to terminate an international construction contract with one of our subsidiaries based on a claimed breach of that contract. Under the terms of the contract, our potential liability was generally capped for actual damages at approximately $32 million Australian dollars ("AUD"). We asserted a counterclaim that in the aggregate approximated $12 million U.S. dollars. On March 30, 2010, an out of court settlement of these claims was reached. On April 19, 2010, pursuant to the terms of the settlement, we paid the third party $15 million AUD to settle all its damage claims against us. We also agreed not to seek any further payment of our counter claims against them. Our results for the three-month period ended March 31, 2010 included approximately $17.5 million in expenses associated with this settlement agreement, including $13.8 million for the litigation settlement payment and $3.7 million to write off our remaining trade receivable from the third party. These amounts were recorded as selling, general and administrative expenses in the accompanying condensed consolidated statements of operations.

Loss Contract

As discussed in Note 16 of the 2010 Form 10-K, in 2010 our Australian subsidiary contracted for a project to plug, abandon and salvage subsea wells in an oil and gas field located offshore China. As previously reported as of the year ended December 31, 2010, we had recorded an aggregate pre-tax loss of approximately $30 million related to this project which reflected the difficulty we had in plugging the wells because of certain structural issues, start-up issues with our recently repaired subsea intervention device and significant weather related delays. In the first quarter of 2011, this project ended and we recorded an additional pre-tax loss of approximately $0.2 million. Our remaining trade receivable related to this project is $6.7 million. We believe this amount is collectable, however, if we are unable to collect any of this amount any variance would increase the recorded loss for the project.

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 and claims 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 2010 Form 10-K). However, at the time of this filing no final commercial resolution of this matter has been reached.

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We have received value added tax (VAT) assessments from the State of Andhra Pradesh, India (the "State") in the amount of approximately $28 million related to our subsea and diving contract entered into in December 2006 in India for the tax years 2007, 2008, 2009, and 2010. 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 it relates 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.

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 and Recent Accounting Standards

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 in which there is little or no market data, which require the reporting entity to develop its own assumptions.

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

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

The following table provides additional information related to assets and liabilities measured at fair value on a recurring basis at March 31, 2011 (in thousands):

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	Level 1	Level 2 (1)	Level 3	Total	Valuation Technique
Assets:					
Natural gas contracts	$ –	$ 2,983	$ –	$ 2,983	(c)
Foreign currency forwards	–	584	–	584	(c)
Liabilities:					
Oil contracts	–	43,481	–	43,481	(c)
Fair value of long term debt(2)	1,289,897	118,254	–	1,408,151	(a), (b)
Natural gas contracts	–	529	–	529	(c)
Interest rate swaps	–	1,541	–	1,541	(c)
Total net liability	$1,289,897	$ 160,238	$ –	$1,450,135	

(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 can 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 March 31, 2011 is as follows:

	Fair Value	Carrying Value
Term Loan (matures July 2013)	$ 407,599	$ 409,359
Revolving Credit Facility (matures November 2012)		
Convertible Senior Notes (matures March 2025)	300,120	283,679
Senior Unsecured Notes (matures January 2016)	581,625	550,000
MARAD Debt (matures February 2027) (a)	118,254	112,516
Loan Notes(b)	553	553
Total	$ 1,408,151	$ 1,356,107

(a) The estimated fair value of all debt, other than MARAD Debt and Loan Notes, 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 market place with similar terms. The fair value of the MARAD debt was estimated using level 2 fair value inputs using the cost approach.

(b) The carrying value of the loan notes approximates fair value as the maturity of the notes is current.

We review long lived assets for impairment whenever events occur or changes in circumstances indicate that the carrying amount of assets may not be recoverable. In such evaluation, the estimated future undiscounted cash flows to be generated by the asset are compared with the carrying value of the asset to determine if an impairment may be required. For our oil and gas properties, the estimated future undiscounted cash flows are based on estimated crude oil and natural gas proved and probable reserves and published future market commodity prices, estimated operating costs and estimates of future capital expenditures. If the estimated undiscounted cash flows for a particular asset are not sufficient to cover the carrying value of the asset the asset is impaired and its carrying value is reduced to the current fair value. The fair value of these assets is determined using an income approach by calculating present value of future cash flows attributable to the asset based on market information (such as forward commodity prices), estimates of future costs and estimated proved and probable reserve quantities. These fair value measurements fall within Level 3 of the fair value hierarchy. In the first quarter of 2010, we impaired three of our natural gas producing properties following a significant drop in natural gas prices during the period (Note 4). The total amount of the impairment charges were $7.0 million, which reduced these properties to their then aggregate fair value of $28.2 million.

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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 rate exposure and foreign exchange currency fluctuations. All derivatives are reflected in the accompanying condensed consolidated balance sheets at fair value unless otherwise noted.

We engage solely in cash flow hedges. Hedges of cash flow exposure are entered into to hedge a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability. Changes in the derivative fair values that are designated as cash flow hedges are deferred to the extent that they are effective and are recorded as a component of accumulated other comprehensive income (loss), a component of shareholders' equity, until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge's change in fair value 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 2010 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 2011 and 2012. All of our current commodity derivative contracts qualify for hedge accounting.

As of March 31, 2011, we have the following volumes under derivative contracts related to our oil and gas producing activities totaling approximately 1.8 MMBbl of oil and 10.4 Bcf of natural gas:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:			(per barrel)
April 2011 — December 2011	Swap	192.2 MBbl	$82.35
April 2011 — December 2011	Collar	11.1 MBbl	$95.00 - $124.00
Natural Gas:			(per Mcf)
April 2011 — December 2011	Swap	825 Mmcf	$4.99
January 2012 — December 2012	Swap	250 Mmcf	$4.77

In April 2011, we entered into four additional costless collar financial hedging agreements. The first contract covers a total of 250 MBbls of oil over the second half of 2011 with a floor price of $95.00 and a ceiling price of $124.89. The second and third contracts cover a total 600 MBbls of oil with a floor price of $95.00 and an average ceiling price $117.10 from January to December 2012. The fourth contract covers 1 Bcf of natural gas with a floor price of $4.75 and a ceiling price of $5.28 from January to December 2012.

Changes in NYMEX oil and gas 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 prices.

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Variable Interest Rate Risks

As some of our long-term debt is subject to market influences and has variable interest rates, 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). These monthly contracts will mature in January 2012. Changes in the interest rate swap fair value are deferred to the extent the swap is effective and are recorded as a component of accumulated other comprehensive income (loss) until the anticipated interest payments occur and are recognized in interest expense. The ineffective portion of the interest rate swap, if any, will be recognized immediately in earnings within the line titled net interest expense.

Foreign Currency Exchange 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. The last of our existing monthly foreign currency swap contracts will settle in June 2012.

Quantitative Disclosures Related to Derivative Instruments

The following tables present the fair value and balance sheet classification of our derivative instruments as of March 31, 2011 and December 31, 2010. The fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements.

Derivatives designated as hedging instruments are as follows:

	As of March 31, 2011		As of December 31, 2010	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
		(in thousands)		
Asset Derivatives:				
Natural gas contracts	Other current assets	$ 2,983	Other current assets	$ 5,324
		$ 2,983		$ 5,324

	As of March 31, 2011		As of December 31, 2010	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
		(in thousands)		
Liability Derivatives:				
Oil contracts	Accrued liabilities	$ 43,481	Accrued liabilities	$ 28,855
Interest rate swaps	Accrued liabilities	1,541	Accrued liabilities	1,751
Gas contracts	Other long-term liabilities	529	Accrued liabilities	913
Interest rate swaps	Other long-term	—	Accrued liabilities	115

	liabilities			
		$ 45,551		$ 31,634

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

	As of March 31, 2011		As of December 31, 2010	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
		(in thousands)		
Asset Derivatives:				
Foreign exchange forwards	Other current assets	$ 483	Other current assets	$ 148
Foreign exchange forwards	Other assets, net	101	Other assets, net	42
		$ 584		$ 190
Liability Derivatives:		$ —		$ —

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The following tables present the impact that derivative instruments designated as cash flow hedges had on our accumulated comprehensive income (loss) and our consolidated statements of operations for the three-month periods ended March 31, 2011 and 2010. Most of our unrealized gains (losses) related to our derivatives are expected to be reclassified into earnings within the next 12 months; however, we do have some contracts that extend into 2012 (as discussed above).

	Gain (Loss) Recognized in Accumulated OCI on Derivatives	
	2011	2010
	(in thousands)	
Oil and natural gas commodity contracts	$ (10,778)	$ 14,630
Foreign exchange forwards	—	—
Interest rate swaps	211	(590)
	$ (10,567)	$ 14,040

	Location of Gain (Loss) Reclassified from Accumulated OCI into Income	Gain (Loss) Recognized from Accumulated OCI into Income	
		2011	2010
		(in thousands)	
Oil and natural gas commodity contracts	Oil and gas revenue	$ (6,325)	$ 802
Interest rate swaps	Net interest expense	(480)	(418)
		$ (6,805)	$ 384

The following tables present the impact that derivative instruments not designated as hedges had on our condensed consolidated income statement for the three months ended March 31, 2011 and 2010:

	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives	
		2011	2010
		(in thousands)	
Foreign exchange forwards	Other expense	$ 608	$ (2,907)
		$ 608	$ (2,907)

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

The payment of our obligations under the Senior Unsecured Notes is guaranteed by all of our restricted domestic subsidiaries ("Subsidiary Guarantors") except for Cal Dive I-Title XI, Inc. Each of these Subsidiary Guarantors is included in our 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 presented 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 related primarily to the elimination of investments in subsidiaries and associated intercompany balances and transactions.

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

	As of March 31, 2011				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 425,514	$ 2,473	$ 12,544	$ —	$ 440,531
Accounts receivable, net	62,735	106,559	21,565	—	190,859
Unbilled revenue	1,547	—	20,846	—	22,393
Income taxes receivable	46,442	—	12,167	(51,112)	7,497
Other current assets	44,066	56,385	10,268	(4,387)	106,332
Total current assets	580,304	165,417	77,390	(55,499)	767,612
Intercompany	4,447	287,466	(188,963)	(102,950)	—
Property and equipment, net	219,598	1,565,045	709,591	(5,013)	2,489,221
Other assets:					
Equity investments in unconsolidated affiliates	—	—	186,831	—	186,831
Equity investments	1,954,489	24,237	—	(1,978,726)	—
Goodwill	—	45,107	17,849	—	62,956
Other assets, net	42,135	37,198	20,808	(29,692)	70,449
Due from subsidiaries/parent	90,965	184,967	—	(275,932)	—
	$ 2,891,938	$ 2,309,437	$ 823,506	$ (2,447,812)	$ 3,577,069
LIABILITIES AND SHAREHOLDERS’ EQUITY					
Current liabilities:					
Accounts payable	$ 33,137	$ 69,424	$ 23,803	$ —	$ 126,364
Accrued liabilities	45,094	124,574	29,811	—	199,479
Income taxes payable	—	67,543	—	(67,543)	—
Current maturities of long-term debt	4,326	—	9,169	(3,857)	9,638
Total current liabilities	82,557	261,541	62,783	(71,400)	335,481
Long-term debt	1,238,712	—	107,757	—	1,346,469
Deferred income taxes	199,200	124,072	97,964	(5,924)	415,312
	—	168,014	—	—	168,014

Asset retirement obligations					
Other long-term liabilities	1,319	3,341	641	—	5,301
Due to parent	—	—	116,451	(116,451)	—
Total liabilities	1,521,788	556,968	385,596	(193,775)	2,270,577
Convertible preferred stock	1,000	—	—	—	1,000
Total equity	1,369,150	1,752,469	437,910	(2,254,037)	1,305,492
	$ 2,891,938	$ 2,309,437	$ 823,506	$ (2,447,812)	$ 3,577,069

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

	As of December 31, 2010				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 376,434	$ 3,294	$ 11,357	$ —	$ 391,085
Accounts receivable, net	61,846	91,659	23,788	—	177,293
Unbilled revenue	11,990	—	37,421	—	49,411
Income taxes receivable	19,334	—	7,195	(20,430)	6,099
Other current assets	63,306	49,557	12,889	(8,786)	116,966
Total current assets	532,910	144,510	92,650	(29,216)	740,854
Intercompany	1,906	263,920	(171,513)	(94,313)	—
Property and equipment, net	217,153	1,605,906	709,082	(5,061)	2,527,080
Other assets:					
Equity investments in unconsolidated affiliates	—	—	187,031	—	187,031
Equity investments in affiliates	1,998,289	29,899	—	(2,028,188)	—
Goodwill, net	—	45,107	17,387	—	62,494
Other assets, net	43,971	38,324	21,900	(29,634)	74,561
Due from subsidiaries/parent	95,398	105,434	—	(200,832)	—
	$ 2,889,627	$ 2,233,100	$ 856,537	$ (2,387,244)	$ 3,592,020
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 60,308	$ 56,107	$ 42,966	$ —	$ 159,381
Accrued liabilities	58,074	107,874	32,289	—	198,237
Income taxes payable	—	36,678	—	(36,678)	—
Current maturities of long-term debt	4,326	—	14,301	(8,448)	10,179
Total current liabilities	122,708	200,659	89,556	(45,126)	367,797
Long-term debt	1,237,587	—	110,166	—	1,347,753
Deferred income taxes	185,453	135,101	98,968	(5,883)	413,639
	—	170,410	—	—	170,410

Asset retirement obligations					
Other long-term liabilities	1,421	3,691	665	—	5,777
Due to parent	—	—	120,884	(120,884)	—
Total liabilities	1,547,169	509,861	420,239	(171,893)	2,305,376
Convertible preferred stock	1,000	—	—	—	1,000
Total equity	1,341,458	1,723,239	436,298	(2,215,351)	1,285,644
	$ 2,889,627	$ 2,233,100	$ 856,537	$ (2,387,244)	$ 3,592,020

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

	Three Months Ended March 31, 2011				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$ 15,582	$ 242,042	$ 57,876	$ (23,893)	$ 291,607
Cost of sales	16,593	165,231	56,278	(23,571)	214,531
Gross profit	(1,011)	76,811	1,598	(322)	77,076
Gain on sale or acquisition of assets	16	—	—	—	16
Selling, general and administrative expenses	(11,186)	(10,036)	(4,154)	395	(24,981)
Income (loss) from operations	(12,181)	66,775	(2,556)	73	52,111
Equity in earnings of investments	48,107	(5,662)	5,650	(42,445)	5,650
Net interest expense and other	(17,284)	(4,709)	417	—	(21,576)
Income (loss) before income taxes	18,642	56,404	3,511	(42,372)	36,185
Provision (benefit) for income taxes	(7,173)	21,741	(5,041)	23	9,550
Net income (loss) applicable to Helix	25,815	34,663	8,552	(42,395)	26,635
Less:net income applicable to noncontrolling interests	—	—	—	(768)	(768)
Preferred stock dividends	(10)	—	—	—	(10)
Net income (loss) applicable to Helix common shareholders	$ 25,805	$ 34,663	$ 8,552	$ (43,163)	$ 25,857

	Three Months Ended March 31, 2010				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$ 21,022	$ 169,723	$ 44,972	$ (34,147)	$ 201,570
Cost of sales	13,334	140,042	49,957	(27,619)	175,714
Gross profit	7,688	29,681	(4,985)	(6,528)	25,856
Gain on sale or acquisition of assets	—	287	5,960	—	6,247
	(23,875)	(10,081)	(7,045)	500	(40,501)

Selling, general and administrative expenses					
Income (loss) from operations	(16,187)	19,887	(6,070)	(6,028)	(8,398)
Equity in earnings of investments	4,868	(507)	5,055	(4,361)	5,055
Net interest expense and other	(7,389)	(7,566)	(6,265)	—	(21,220)
Income (loss) before income taxes	(18,708)	11,814	(7,280)	(10,389)	(24,563)
Provision (benefit) for income taxes	(4,796)	4,215	(4,871)	(2,109)	(7,561)
Net income (loss) applicable to Helix	(13,912)	7,599	(2,409)	(8,280)	(17,002)
Less:net income applicable to noncontrolling interests	—	—	—	(829)	(829)
Preferred stock dividends	(60)	—	—	—	(60)
Net income (loss) applicable to Helix common shareholders	$ (13,972)	$ 7,599	$ (2,409)	$ (9,109)	$ (17,891)

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

	Three Months Ended March 31, 2011				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flow from operating activities:					
Net income (loss), including noncontrolling interests	$ 25,815	$ 34,663	$ 8,552	$ (42,395)	$ 26,635
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by (used in) operating activities:					
Equity in earnings of affiliates	(48,107)	5,662	—	42,445	—
Other adjustments	(16,484)	74,174	4,644	(3,904)	58,430
Net cash provided by (used in) operating activities	(38,776)	114,499	13,196	(3,854)	85,065
Cash flows from investing activities:					
Capital expenditures	(7,143)	(18,200)	(9,145)	—	(34,488)
Distributions from equity investments, net	—	—	480	—	480
Proceeds from sale of Cal Dive common stock	3,588	—	—	—	3,588
Deceases in restricted cash	—	613	—	—	613
Net cash used in investing activities	(3,555)	(17,587)	(8,665)	—	(29,807)
Cash flows from financing activities:					
Repayments of debt	(1,082)	—	(2,954)	—	(4,036)
Preferred stock dividends paid and other	(10)	—	—	—	(10)
Repurchases of common stock	(927)	—	—	—	(927)
Excess tax benefit from stock-based compensation	(969)	—	—	—	(969)

Exercise of stock options, net	600	—	—	—	600
Intercompany financing	93,799	(97,733)	80	3,854	—
Net cash provided by (used in) financing activities	91,411	(97,733)	(2,874)	3,854	(5,342)
Effect of exchange rate changes on cash and cash equivalents	—	—	(470)	—	(470)
Net increase (decrease) in cash and cash equivalents	49,080	(821)	1,187	—	49,446
Cash and cash equivalents:					
Balance, beginning of year	376,434	3,294	11,357	—	391,085
Balance, end of year	$425,514	$ 2,473	$ 12,544	$ —	$ 440,531

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

	Three Months Ended March 31, 2010				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flow from operating activities:					
Net income (loss), including noncontrolling interests	$ (13,912)	$ 7,599	$ (2,409)	$ (8,280)	$ (17,002)
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by (used in) operating activities:					
Equity in earnings of affiliates	(4,868)	507	—	4,361	—
Other adjustments	(111)	42,640	(1,210)	(5,880)	35,439
Net cash provided by (used in) operating activities	(18,891)	50,746	(3,619)	(9,799)	18,437
Cash flows from investing activities:					
Capital expenditures	(29,067)	(34,501)	(4,860)	—	(68,428)
Distributions from equity investments, net	—	—	965	—	965
Increases in restricted cash	—	(4)	—	—	(4)
Net cash used in investing activities	(29,067)	(34,505)	(3,895)	—	(67,467)
Cash flows from financing activities:					
Repayments of debt	(1,082)	—	(3,114)	—	(4,196)
Deferred financing costs	(2,789)	—	—	—	(2,789)
Preferred stock dividends paid	(60)	—	—	—	(60)
Repurchase of common stock	(976)	—	—		(976)
Excess tax benefit from stock-based compensation	(1,842)	—	—	—	(1,842)
Intercompany financing	(6,434)	(15,163)	11,798	9,799	—
Net cash provided by (used in) financing activities	(13,183)	(15,163)	8,684	9,799	(9,863)

Effect of exchange rate changes on cash and cash equivalents	—	—	398	—	398
Net increase (decrease) in cash and cash equivalents	(61,141)	1,078	1,568	—	(58,495)
Cash and cash equivalents:					
Balance, beginning of year	258,742	2,522	9,409	—	270,673
Balance, end of year	$197,601	$ 3,600	$ 10,977	$ —	$ 212,178

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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," "plan," "project," "propose," "strategy," "predict," "envision," "hope," "intend," "will," "continue," "may," "potent and similar 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;
- 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 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:

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- 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;
- 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 new regulations on the offshore Gulf of Mexico oil and gas operations;
- uncertainties regarding our ability to replace depletion;
- 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 or reduce 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 or other risks associated with marine operations;
- 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 2010 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 reservoir development solutions and other contracting services to the energy market as well as to our own oil and gas properties. Our oil and gas business is a prospect generation, exploration, development and production company. Employing our own key services and methodologies, we seek to lower finding and development costs, relative to industry norms.

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 March 31, 2011, our cash on hand totaled $440.5 million and our liquidity was $836.7 million. Our capital expenditures for full year 2011 are expected to total approximately $250 million, primarily reflecting the development plan 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 business plan in 2011 without incurring additional indebtedness beyond the existing capacity under the Revolving Credit Facility.

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In March 2010, we announced the engagement of advisors to assist us with evaluating potential alternatives for the disposition of our oil and gas business. Since that time, we have had intervening events, such as the Macondo well oil spill (discussed below in "Events in Gulf of Mexico") and the subsequent regulatory effects associated with that event, which has resulted in a challenging environment for the sale of our entire oil and gas business. Furthermore, given the favorable commodity price environment and its positive impact on our financial condition, our focus has recently transitioned from a sale of our entire oil and gas business to building value through development of a number of our oil and gas properties. In 2011, our plan is to pursue development of a portion of our significant proved undeveloped reserves portfolio and to explore certain of our existing exploration prospects with a focus on crude oil prospects to generate higher cash flow. We will continue to evaluate the potential sale of properties as opportunities arise and may pursue those opportunities that we deem to be in our best interests in terms of economic returns and/or risk mitigation.

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. 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 excess capacity, geopolitical issues, weather, and several other factors, including but not limited to:

- worldwide economic activity, including available access to global capital and capital markets;
- demand for oil and natural gas, especially in the United States, Europe, China and India;
- economic and political conditions in the Middle East and other oil-producing regions;
- the effect of new regulations on the offshore Gulf of Mexico oil and gas operations;
- actions taken by the Organization of Petroleum Exporting Countries ("OPEC") ;
- the availability and discovery rate of new oil and natural gas reserves in offshore areas;
- the 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.

Oil prices increased significantly in the first quarter of 2011 (the average WTI price was $94.10 per barrel in the first quarter of 2011). The increased oil price can be primarily attributed to recent political events in the Middle East region, including the escalation of hostilities in Libya. The NYMEX Henry Hub natural gas price averaged $4.11 per

Mmbtu in the first quarter of 2011. Prices for natural gas have decreased significantly from the record highs in mid 2008 primarily reflecting the increased supply from non-traditional sources of natural gas such as production from shale formations and tight sands as well as decreased demand following the economic downturn that commenced in mid-to-late 2008. Although there have been signs that the economy is improving, most economists believe the recovery will be slow and will take time to recover to levels previously achieved. 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 more recent uncertainties concerning increased government regulation of the industry in the United States (as further discussed below).

In April 2010, an explosion occurred on the Deepwater Horizon drilling rig located on the site of the Macondo well at Mississippi Canyon Block 252 (Note 1). The resulting events included loss of life, the complete destruction of the drilling rig and an oil spill, the magnitude of which was unprecedented in U.S. territorial waters. In May 2010, the U.S. Department of Interior ("DOI") announced a total moratorium on new drilling in the Gulf of Mexico. The drilling moratorium was partially lifted in late May 2010 (for drilling of prospects in less than 500 feet of water). In October 2010, the DOI lifted the drilling moratorium

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and instructed the Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE") that it could resume issuing drilling permits conditioned on the requesting company's compliance with all revised drilling, safety and environmental requirements. No deepwater drilling permits were issued in the period from October 2010 through late February 2011. In late February 2011, the BOEMRE commenced issuing deepwater permits. At the time of this filing 11 deepwater permits have been issued, six of which were issued using the Helix Fast Response System (see below).

While we did not have plans to drill any additional deepwater wells during the period covered by the drilling moratorium, our contracting services businesses rely heavily on industry investment in the Gulf of Mexico and the results of the moratorium and subsequent delay in the drilling permit process has adversely affected our results of operations and financial position. Although our contracting services activities during 2010 remained substantially unaffected, delays in restarting drilling in the deepwater of the Gulf of Mexico, due to the failure to issue permits or otherwise, have resulted in a deferral or cancellation of portions of our contracted backlog and have decreased opportunities for future contracts for work in the Gulf of Mexico. Furthermore, the impact of the deepwater drilling moratorium, continuing delays in the permitting process and any subsequent related developments in the Gulf of Mexico could require us to pursue relocation of our vessels located in the Gulf of Mexico to other international locations, such as the North Sea, West Africa, Southeast Asia, Brazil and Mexico.

Although we are still feeling the effects of the recent global recession and are beginning to experience the consequences of the additional regulatory requirements resulting from the aftermath of the oil spill in the Gulf of Mexico, we believe that the long-term industry fundamentals are positive based on the following factors: (1) long term increasing world demand for oil and natural gas requires the need for continual replenishment of oil and gas production; (2) peaking global production rates; (3) globalization of the natural gas market; (4) increasing number of mature and small reservoirs; (5) increasing global offshore activity, particularly in deepwater; and (6) increasing number of subsea developments. Our strategy of combining contracting services operations and oil and gas operations allows us to focus on trends (4) through (6) in that we pursue long-term sustainable growth by applying specialized subsea services to the broad external offshore market but with a complementary focus on marginal fields and new reservoirs in which we currently have an equity stake.

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 will be a component of our Production Facilities business segment. A total of six permits have been granted to CGA participants for deepwater drilling operations identifying the HFRS to fulfill the BOERME requirement to have a spill response solution included in the submitted permit applications.

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.

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Contracting Services Operations

We seek to provide services and methodologies that we believe are critical to finding and developing offshore reservoirs and maximizing production economics. The Contracting Services segment includes operations such as subsea construction, deepwater pipelay, well operations and robotics. Our Contracting Services business operates primarily in the Gulf of Mexico, the North Sea, Asia Pacific and West Africa regions, with services that cover the lifecycle of an offshore oil or gas field. As of March 31, 2011, our Contracting Services operations had backlog of approximately $336.1 million, including $251.3 million for 2011. At December 31, 2010, our Contracting Services backlog totaled approximately $267.3 million, including $218.8 million for 2011. These backlog contracts are cancellable 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 provide a more efficient solution to offshore abandonment, to expand our off-season utilization of our contracting services assets and to achieve incremental returns. We have evolved this business model to include not only mature oil and gas properties but also 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 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 industries, to analyze and evaluate financial and strategic planning decisions regarding future operating 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 covenant requirements. We believe our measure of EBITDAX provides useful information to the public regarding our ability to service debt and fund capital expenditures and it may help our investors understand our operating performance and make it easier to 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 oil and gas property impairment charges, which if not material would be reflected as a component of our depreciation, depletion and amortization expense. Because such impairment charges are material for most of the periods presented, we have reported them as a separate line item in the accompanying consolidated statements of operations. Non cash impairment charges related to goodwill are also added back if applicable.

In our reconciliation of income (loss) including noncontrolling interests, we provide amounts as reflected in our accompanying condensed consolidated financial statements, unless otherwise footnoted. This means such amounts are at 100% even if we do not own 100% of all of our subsidiaries. Accordingly, to arrive at our measure of Adjusted EBITDAX, we deduct the non-controlling interests related to the adjustment components of EBITDAX, the adjustment components of EBITDAX of any discontinued operations, the gain or loss on the sale of assets, and the portion of our asset impairment charges that are considered cash-related charges. Asset impairment charges that are considered cash are those that affect future cash outflows most notably those related to adjustment to our asset retirement obligations.

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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 (loss) attributable to common shareholders but used as a supplement to that GAAP financial measure. A reconciliation of our net income (loss) attributable to common shareholders to EBITDAX is as follows:

	Three Months Ended March 31,	
	2011	2010
Income (loss), including noncontrolling interests	$ 26,635	$ (17,002)
Adjustments:		
Income tax provision (benefit)	9,550	(7,561)
Net interest expense and other	21,576	21,220
Depreciation, depletion and amortization expense	92,143	60,827
Asset impairment charges	—	11,112
Exploration expenses	346	166
EBITDAX	150,250	68,762
Adjustments:		
Non-controlling interest Kommandor LLC	(1,015)	(1,095)
Discontinued operations	—	(15)
Gain on sales of assets	(16)	(6,247)
ADJUSTED EBITDAX	$ 149,219	$ 61,405

Comparison of Three Months Ended March 31, 2011 and 2010

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

	Three Months Ended March 31,		
	2011	2010	Increase/ (Decrease)
Revenues (in thousands) –			
Contracting Services	$ 131,537	$ 154,200	$ (22,663)
Production Facilities	15,570	1,320	14,250
Oil and Gas	168,859	90,715	78,144
Intercompany elimination	(24,359)	(44,665)	20,306
	$ 291,607	$ 201,570	$ 90,037
Gross profit (in thousands) –			
Contracting Services	$ 10,512	$ 37,622	$ (27,110)
Production Facilities	6,136	21	6,115
Oil and Gas	61,235	1,249	59,986
Corporate	(897)	(714)	(183)
Intercompany elimination	90	(12,322)	12,412

	$ 77,076	$ 25,856	$ 51,220
Gross Margin –			
Contracting Services	8%	24%	(16)pts
Production Facilities	39%	%	39 pts
Oil and Gas	36%	1%	35 pts
Total company	26%	13%	13 pts
Number of vessels(1)/ Utilization(2) –			
Contracting Services:			
Construction vessels	8/44%	7/83%	
Well operations	3/77%	3/60%	
ROVs	46/49%	47/59%	

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(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.

Intercompany segment revenues during the three-month periods ended March 31, 2011 and 2010 were as follows (in thousands):

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010	Increase/ (Decrease)
Contracting Services	$ 12,869	$ 43,741	$ (30,872)
Production Facilities	11,490	924	10,566
	$ 24,359	$ 44,665	$ (20,306)

Intercompany segment profit during the three-month periods ended March 31, 2011 and 2010 was as follows (in thousands):

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010	Increase/ (Decrease)
Contracting Services	$ (24)	$ 11,442	$ (11,466)
Production Facilities	(66)	880	(946)
	$ (90)	$ 12,322	$ (12,412)

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

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010	Increase/ (Decrease)
Oil and Gas information–			
Oil production volume (MBbls)	1,501	655	846
Oil sales revenue (in thousands)	$135,836	$ 47,008	$ 88,828
Average oil sales price per Bbl (excluding hedges)	$ 96.95	$ 75.69	$ 21.26
Average realized oil price per Bbl (including hedges)	$ 90.49	$ 71.82	$ 18.67
Increase in oil sales revenue due to:			
Change in prices (in thousands)	$ 12,225		
Change in production volume (in thousands)	76,603		
	$ 88,828		

Total increase in oil sales revenue (in thousands)			
Gas production volume (MMcf)	5,402	7,343	(1,941)
Gas sales revenue (in thousands)	$ 31,161	$ 42,185	$ (11,024)
Average gas sales price per mcf (excluding hedges)	$ 5.14	$ 5.29	$ (0.15)
Average realized gas price per mcf (including hedges)	$ 5.77	$ 5.75	$ 0.02
Increase (decrease) in gas sales revenue due to:			
Change in prices (in thousands)	$ 168		
Change in production volume (in thousands)	(11,192)		
Total decrease in gas sales revenue (in thousands)	$ (11,024)		
Total production (MMcfe)	14,409	11,270	3,139
Price per Mcfe	$ 11.59	$ 7.91	$ 3.68
Oil and Gas revenue information (in thousands)–			
Oil and gas sales revenue	$166,997	$ 89,193	$ 77,804
Other revenues(1)	1,862	1,522	340
	$168,859	$ 90,715	$ 78,144

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

Presenting the expenses of our Oil and Gas segment on a cost per Mcfe 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 converted to Mcfe at a ratio of one barrel of oil to six Mcf:

	Three Months Ended March 31,			
	2011		2010	
	Total	Per Mcfe	Total	Per Mcfe
	(in thousands, except per Mcfe amounts)			
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$ 30,660	$ 2.13	$ 14,523	$ 1.29
Workover	2,568	0.18	11,613	1.03
Transportation	2,411	0.17	1,293	0.11
Repairs and maintenance	2,267	0.16	1,808	0.16
Overhead and company labor	3,317	0.23	1,925	0.17
	$ 41,223	$ 2.87	$ 31,162	$ 2.76
Depletion expense	$ 65,713	$ 4.56	$ 40,205	$ 3.57
Abandonment	158	0.01	765	0.07
Accretion expense	3,786	0.26	4,003	0.36
Net hurricane (reimbursements) costs	(3,602)	(0.25)	2,055	0.18
Impairment	—	—	11,112	0.99
	66,055	4.58	58,140	5.17
Total	$ 107,278	$ 7.45	$ 89,302	$ 7.93

(1) Excludes exploration expense of $0.3 million and $0.2 million for the three-month periods ended March 31, 2011 and 2010, respectively. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

Revenues. Our Contracting Services revenues decreased by 15% for the three-month period ended March 31, 2011 as compared to the same period in 2010 reflecting the decreased subsea construction activity in the Gulf of Mexico, primarily attributable to delays in permitting of projects since the the Macondo oil spill in April 2010. Separately, in the first quarter of 2010 we performed a number of projects related to our oil and gas operations but we did not perform any substantive internal work in the first quarter of 2011. Overall utilization levels for subsea construction assets decreased significantly. Our ROV utilization rate decreased by approximately 10% from rates achieved during the first quarter of 2010. The decrease in our utilization rates for our pipelay and robotics support vessels and ROVs primarily reflects the lower number of projects with approved permits in the Gulf of Mexico region. Our well operations vessels utilization increased slightly as demand for these vessels remains strong. Our well operation utilization rates were somewhat reduced in the first quarter of 2011as a result of unplanned downtime for the Well Enhancer and Seawell as well as the Q4000. A portion of the Q4000 downtime was associated with making certain upgrades to the vessel related to its participation in the HFRS. In the first quarter of 2010 the Seawell was in regulatory drydock in February 2010.

Oil and Gas revenues increased 86% during the three-month period ended March 31, 2011 as compared to the same period in 2010, reflecting increased oil production and higher oil prices. Our production was 3.1 billion cubic feet of natural gas equivalent (Bcfe) more in the first quarter of 2011 as compared to the same period in 2010, primarily reflecting oil production from our Phoenix field at Green Canyon Blocks 236, 237, 238 and 282, which commenced production in October 2010. For the month of April our production rate approximated 140 MMcfe/d as compared to an approximate average of 160 MMcfe/d in the first quarter of 2011.

Our Production Facilities revenues increased substantially reflecting the HP I being placed in service in June 2010, following the final installation of its production processing facility upgrades and receipt of its certification by U.S. Coast Guard. The HP I is currently being utilized in the Phoenix field, where it is expected to remain until the field depletes (currently anticipated to be sometime in 2013, based on future successful development of existing proved reserves in the field).

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Gross Profit. Gross profit associated with our Contracting Services decreased by 72% in the first quarter of 2011 as compared to the same period last year. This decrease primarily reflected the weak subsea construction industry conditions in the Gulf of Mexico region, which contributed significantly to our lower pipelay and robotics support vessel and ROV utilization rates. Our contracting services rates in the first quarter of 2010 benefitted from our increased scope of internal work related to our oil and gas properties.

Oil and Gas gross profit increased by $60.0 million in the first quarter of 2011 as compared to the same period in 2010, which was primarily attributable to increased oil production and higher oil price realizations. The increase in our production is primarily related to the commencement of production from our Phoenix field in October 2010. In the first quarter of 2010, we recorded $7.0 million of impairment expense related to three of our U.S. Gulf of Mexico natural gas production fields and a $4.1 million impairment related to our only non-domestic (U.K.) oil and gas property (Note 4).

Gain on Sale or Purchase of Assets, Net. In the first quarter of 2010 our gain was primarily associated with the acquisition of the remaining 50% working interest related to the Camelot field in the United Kingdom (Note 4).

Selling, General and Administrative Expenses. Selling, general and administrative expenses of $25.0 million for the first quarter of 2011 were $15.5 million lower than the $40.5 million incurred in the same prior year period. The decrease primarily reflects the $17.5 million related to our settlement of litigation claims in Australia in the first quarter of 2010 (Note 14). In the first quarter of 2011, our selling, general and administrative expenses included $1.6 million of costs related to the resignation of our Executive Vice President and Chief Operating Officer; while the first quarter of 2010 amounts included approximately $1.9 million of charges related to the resignation of our former Executive Vice President-Oil and Gas.

Equity in Earnings of Investments. Equity in earnings of investments increased by $0.6 million during the three-month period ended March 31, 2011 as compared to the same prior year period. This increase was mostly due to the Clough Helix JV participating in its first contracted project, which is located offshore China, and has resulted in us recording $0.4 million of our 50% share of the net income for the three-month period ended March 31, 2011, as compared to a loss of $1.4 million in the first quarter of 2010 reflecting some of joint venture's start up costs. This increase was partially offset by lower throughput at both our Deepwater Gateway and Independence Hub facilities.

Net Interest Expense and Other. We reported net interest and other expense of $21.6 million in first quarter 2011 as compared to $21.2 million in the same prior year period. Gross interest expense of $24.8 million during the three-month period ended March 31, 2011 was higher than the $24.3 million incurred in 2010. Capitalized interest totaled $0.1 million for the three-month period ended March 31, 2011 as compared with $8.5 million for the same period last year reflecting completion of significant capital projects in 2010. Interest income totaled $0.5 million for the three-month period ended March 31, 2011 compared with $0.2 million in the first quarter of 2010 primarily reflecting our increased cash balances. In the first quarter of 2011 we recorded gains on our foreign exchange forward contracts totaling $0.6 million compared to losses of $2.9 million in the first quarter of 2010 (Note 16). In the first quarter of 2011, we also sold our remaining 0.5 million shares of Cal Dive common stock (see Note 3 of our 2010 Form 10-K) 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 $9.6 million in the first quarter of 2011 as compared to an income tax benefit of $7.6 million in the same period last year. The variance primarily reflects increased profitability in the current year period. The effective tax rate of 26.4% for the first quarter of 2011 was lower than the 30.8% effective tax rate for the first quarter of 2010 as a result of the increased benefit derived from the effect of lower tax rates in certain foreign jurisdictions.

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LIQUIDITY AND CAPITAL RESOURCES

Overview

The following tables present certain information useful in the analysis of our financial condition and liquidity for the periods presented:

	March 31, 2011	December 31, 2010
	(in thousands)	
Net working capital	$ 432,131	$ 373,057
Long-term debt(1)	1,346,469	1,347,753
Liquidity(2)	836,681	787,296

(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 Convertible Senior Notes (Note 7).
(2) Liquidity, as defined by us, is equal to cash and cash equivalents plus available capacity under our revolving credit facility.

The carrying amount of our debt, including current maturities as of March 31, 2011 and December 31, 2010 follow:

	March 31, 2011	December 31, 2010
	(in thousands)	
Term Loan (matures July 2013)	$ 409,359	$ 410,441
Revolving Credit Facility (matures November 2012)		
Convertible Senior Notes (matures March 2025) (1)	283,679	281,472
Senior Unsecured Notes (matures January 2016)	550,000	550,000
MARAD Debt (matures February 2027)	112,516	114,811
Loan Notes(2)	553	1,208
Total	$ 1,356,107	$ 1,357,932

(1) This amount is net of the unamortized debt discount of $16.3 million and $18.5 million, respectively. The notes will increase to $300 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).
(2) Assumed to be current, represents the loan provided by Kommandor RØMØ to Kommandor LLC.

The following table provides summary data from our consolidated statement of cash flows:

	Three Months Ended March 31, 2011	2010
	(in thousands)	
Net cash provided by (used in):		
Operating activities	$ 85,065	$ 18,437
Investing activities	$ (29,807)	$ (67,467)
Financing activities	$ (5,342)	$ (9,863)

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.

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We remain focused on maintaining a strong balance sheet and adequate liquidity. We may reduce planned capital spending and seek further additional dispositions of our non-core business assets (see "Executive Summary" above). We also have a reasonable basis for estimating our future cash flow supported by our remaining Contracting Services backlog and the significant hedged portion of our estimated oil and gas production through 2011 and into 2012. We believe that internally generated cash flow and available borrowing capacity under our amended Revolving Credit Facility will be sufficient to fund our operations throughout 2011. There have been no borrowings outstanding under the Revolving Credit Facility since we repaid the outstanding amount in the second quarter of 2009.

In accordance with our Credit Agreement, Senior Unsecured Notes, Convertible Senior Notes and the MARAD debt, we are required to comply with certain covenants and restrictions, including certain financial ratios (such as collateral coverage, interest coverage, consolidated leverage), 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 loans) secured by the underlying asset, provided that the 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. Such prepayments will be applied first to the Term Loan, and any excess will then be applied to the Revolving Loans. As of March 31, 2011 and December 31, 2010, 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.

Our Convertible Senior Notes can be converted prior to stated maturity under certain triggering events specified in the indenture governing the Convertible Senior Notes. To the extent we do not have long-term financing secured to cover the conversion, the Convertible Senior Notes would be classified as a current liability in the accompanying condensed consolidated balance sheet. No conversion triggers were met during the first quarter of 2011. The holders may redeem the Convertible Senior Notes beginning December 2012 (Note 7 as well as Note 9 of our 2010 Form 10-K).

In October 2009 the Credit Agreement was amended to, among other things, extend its maturity from July 2011 to November 2012. In February 2010, the Credit Agreement was once again amended, to among other things, modify the consolidated leverage ratio test and to include an additional senior secured debt leverage ratio test. See Note 9 of our 2010 Form 10-K for additional information related to our long-term debt, including more information regarding the recent amendments of 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 increased by $66.6 million in the three-month period ended March 31, 2011 as compared to the same period in 2010. This increase primarily reflects the effect of increased oil production as well as the substantially higher oil prices.

Investing Activities

Capital expenditures have consisted principally of strategic asset acquisitions related to the purchase or construction of dynamically positioned vessels, acquisition of select businesses, improvements to existing vessels, acquisition and development of oil and gas properties and investments in our production facilities. Significant sources (uses) of cash associated with investing activities for the three-month periods ended March 31, 2011 and 2010 were as follows:

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	Three Months Ended March 31, 2011	2010
	(in thousands)	
Capital expenditures:		
Contracting Services	$ (15,016)	$ (14,978)
Production Facilities	(6,638)	(29,325)
Oil and Gas	(12,834)	(24,125)
Distributions from equity investments, net(1)	480	965
Sales of shares of Cal Dive common stock	3,588	
Decrease (increase) in restricted cash	613	(4)
Cash (used in) provided by investing activities	$ (29,807)	$ (67,467)

(1) Distributions from equity investments are net of undistributed equity earnings from our equity investments. Gross distributions from our equity investments are detailed below.

Restricted Cash

As of March 31, 2011 and December 31, 2010, we had $34.7 million and $35.3 million of restricted cash, all of which was related to 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 the future asset retirement costs for this field. 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 three months ended March 31, 2011 and 2010:

	Three Months Ended March 31, 2011	2010
	(in thousands)	
Deepwater Gateway	$1,750	$ 2,250
Independence Hub	4,380	4,900
Other		268
Total	$6,130	$ 7,418

Outlook

We anticipate capital expenditures for the remainder of 2011 will total between $160 million and $200 million. The estimates for these capital expenditures may increase or decrease based on various economic factors. However, we may reduce the level of our planned capital expenditures given a prolonged economic downturn. We believe internally generated cash flow, cash from potential future sales of our non-core business assets, and borrowing availability under our existing credit facilities will provide the capital necessary to fund our 2011 initiatives.

The following table summarizes our contractual cash obligations as of March 31, 2011 and the scheduled years in which the obligations are contractually due:

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	Total (1)	Less Than 1 year	1-3 Years (in thousands)	3-5 Years	More Than 5 Years
Convertible Senior Notes(2)	$ 300,000	$	$	$	$300,000
Senior Unsecured Notes	550,000			550,000	
Term Loan	409,359	4,326	405,033		
MARAD debt	112,516	4,759	10,244	11,291	86,222
Revolving Credit Facility(3)					
Loan notes	553	553			
Interest related to long-term debt	473,751	84,262	151,132	123,845	114,512
Drilling and development costs	57,607	57,607			
Property and equipment	24,231	24,231			
Operating leases(4)	75,547	59,586	14,046	1,915	
Total cash obligations	$2,003,564	$235,324	$580,455	$687,051	$500,734

(1) Excludes unsecured letters of credit outstanding at March 31, 2011 totaling $38.8 million. These letters of credit primarily guarantee various contract bidding, insurance activities and shipyard commitments.

(2) Contractual maturity in 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. $38.56 per share) and under certain triggering events as specified in the indenture governing the Convertible Senior 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 Convertible Senior Notes would be classified as a current liability in the accompanying balance sheet. At March 31, 2011, the conversion trigger was not met.

(3) Our Revolver will mature on November 30, 2012.

(4) Operating leases included facility leases and vessel charter leases. Vessel charter lease commitments at March 31, 2011 were approximately $64.2 million.

Contingencies

In March 2009, we were notified of a third party's intention to terminate an international construction contract with one of our subsidiaries based on a claimed breach of that contract. Under the terms of the contract, our potential liability was generally capped for actual damages at approximately $32 million Australian dollars ("AUD"). We asserted a counterclaim that in the aggregate approximated $12 million U.S. dollars. On March 30, 2010, an out of court settlement of these claims was reached. On April 19, 2010, pursuant to the terms of the settlement, we paid the third party $15 million AUD to settle all its damage claims against us. We also agreed not to seek any further payment of our counter claims against them. Our results for the three-month period ended March 31, 2010 included approximately $17.5 million in expenses associated with this settlement agreement, including $13.8 million for the litigation settlement payment and $3.7 million to write off our remaining trade receivable from the third party. These amounts were recorded as selling, general and administrative expenses in the accompanying condensed consolidated statements of operations.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our discussion and analysis of our financial condition and results of operations are based upon our 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. Please read the following discussion in conjunction with our “Critical Accounting Policies and Estimates” as disclosed in our 2010 Form 10-K.

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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.

Commodity Price Risk. As of March 31, 2011, we had the following volumes under derivative contracts related to our oil and gas producing activities totaling approximately 1.8 MMBbl of oil and 10.4 Bcf of natural gas:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:			(per barrel)
April 2011 — December 2011	Swap	192.2 MBbl	$ 82.35
April 2011 — December 2011	Collar	11.1 MBbl	$ 95.00 - $124.00
Natural Gas:			(per Mcf)
April 2011 — December 2011	Swap	825 Mmcf	$ 4.99
January 2012 — December 2012	Swap	250 Mmcf	$ 4.77

In April 2011, we entered into four additional costless collar financial hedging agreements. The first contract covers a total of 250 MBbls of oil over the second half of 2011 with a floor price of $95.00 and a ceiling price of $124.89. The second and third contracts cover a total 600 MBbls of oil with a floor price of $95.00 and an average ceiling price $117.10 from January to December 2012. The fourth contract covers 1.0 Bcf of natural gas with a floor price of $4.75 and a ceiling price of $5.28 from January to December 2012.

All of commodity derivative contracts were designated as cash flow hedges and all remain effective and qualify for hedge accounting as of March 31, 2010 (Note 16).

Item 4. Controls and Procedures

(a) Evaluation of disclosure controls and procedures. Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Exchange Act) as of the end of the fiscal quarter ended March 31, 2011. Based on this evaluation, the principal executive officer and the principal financial officer have concluded that our disclosure controls and procedures were effective as of the end of the fiscal quarter ended March 31, 2011 to ensure that information that is required to be disclosed by us in the reports we file or submit under the Exchange Act is (i) recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms and (ii) accumulated and communicated to our management, as appropriate, to allow timely decisions regarding required disclosure.

(b) Changes in internal control over financial reporting. There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Exchange Act, in the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Resulting impacts on internal controls over financial reporting were evaluated and determined not to be significant for the fiscal quarter ended March 31, 2011.

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.

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

Issuer Purchases of Equity Securities

Period	(a) Total number of shares purchased	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced program	(d) Maximum value of shares that may yet be purchased under the program
January 1 to January 31, 2011(1)	75,131	$ 12.07		475,804(2)
February 1 to February 28, 2011(1)	1,246	14.91		
March 1 to March 31, 2011(1)				
	76,377	$ 12.11		

(1) Represents shares subject to restricted share awards withheld to satisfy tax obligations arising upon the vesting of restricted shares.

(2) In January 2011, we issued this amount of restricted shares to certain of our employees (Note 11). Under the terms of our stock repurchase program, these grants increase the amount of shares available for repurchase. For additional information regarding our stock repurchase program see Note 14 of the 2010 Form 10-K.

Item 6. Exhibits

The exhibits to this report are listed in the Exhibit Index beginning on Page 43 hereof.

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SIGNATURES

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

HELIX ENERGY SOLUTIONS GROUP, INC.
(Registrant)

Date: April 27, 2011	By: /s/ Owen Kratz Owen Kratz President and Chief Executive Officer (Principal Executive Officer)
Date: April 27, 2011	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.
10.1	Separation and Release Agreement by and between Helix Energy Solutions Group, Inc and Bart H. Heijermans dated January 21, 2011, incorporated by reference to Exhibit 10.1 to the January 24, 2011 Form 8-K.
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)
	(1) Filed herewith
	(2) Furnished herewith