HELIX ENERGY SOLUTIONS GROUP INC
Form 10-Q
April 30, 2010

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, 2010
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 27, 2010, 104,561,347 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, 2010 (Unaudited)	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 212,178	$ 270,673
Accounts receivable —		
Trade, net of allowance for uncollectible accounts of $918 and $5,172, respectively	159,704	145,519
Unbilled revenue	27,383	17,854
Costs in excess of billing	28	9,305
Other current assets	129,490	122,209
Total current assets	528,783	565,560
Property and equipment	4,402,651	4,352,109
Less — accumulated depreciation	(1,551,136)	(1,488,403)
	2,851,515	2,863,706
Other assets:		
Equity investments	186,944	189,411
Goodwill	77,771	78,643
Other assets, net	85,934	82,213
	$ 3,730,947	$ 3,779,533
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 135,985	$ 155,457
Accrued liabilities	202,481	200,607
Current maturities of long-term debt	11,834	12,424
Total current liabilities	350,300	368,488
Long-term debt	1,347,007	1,348,315
Deferred income taxes	431,147	442,607
Asset retirement obligations	178,371	182,399
Other long-term liabilities	4,789	4,262
Total liabilities	2,311,614	2,346,071
Convertible preferred stock	6,000	6,000
Commitments and contingencies		
Shareholders' equity:		
Common stock, no par, 240,000 shares authorized, 104,578 and 104,281 shares issued, respectively	907,362	907,691
Retained earnings	501,916	519,807

Accumulated other comprehensive loss	(18,978)	(22,241)
Total controlling interest shareholders’ equity	1,390,300	1,405,257
Noncontrolling interests	23,033	22,205
Total equity	1,413,333	1,427,462
	$ 3,730,947	$ 3,779,533

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, 2010	Three Months Ended March 31, 2009
Net revenues:		
Contracting services	$ 110,855	$ 410,794
Oil and gas	90,715	160,181
	201,570	570,975
Cost of sales:		
Contracting services	86,248	325,698
Oil and gas	89,466	84,067
	175,714	409,765
Gross profit	25,856	161,210
Gain on oil and gas derivative contracts	—	74,609
Gain on sale or acquisition of assets, net	6,247	454
Selling and administrative expenses	(40,501)	(41,353)
Income (loss) from operations	(8,398)	194,920
Equity in earnings of investments	5,055	7,503
Net interest expense and other	(21,193)	(22,195)
Income (loss) before income taxes	(24,536)	180,228
(Provision) benefit for income taxes	7,561	(64,919)
Income (loss) from continuing operations	(16,975)	115,309
Discontinued operations, net of tax	(27)	(2,554)
Net income (loss), including noncontrolling interests	(17,002)	112,755
Less: net income (loss) applicable to noncontrolling interests	(829)	(5,553)
Net income (loss) applicable to Helix	(17,831)	107,202
Preferred stock dividends	(60)	(313)
Preferred stock beneficial conversion charges	—	(53,439)
Net income (loss) applicable to Helix common shareholders	$ (17,891)	$ 53,450
Basic earnings (loss) per share of common stock:		
Continuing operations	$ (0.17)	$ 0.58
Discontinued operations	—	(0.03)
Net income (loss) per common share	$ (0.17)	$ 0.55
Diluted earnings (loss) per share of common stock:		
Continuing operations	$ (0.17)	$ 0.52
Discontinued operations	—	(0.02)
Net income (loss) per common share	$ (0.17)	$ 0.50

Weighted average common shares outstanding:		
Basic	103,090	95,052
Diluted	103,090	105,863

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, 2010	Three Months Ended March 31, 2009
Cash flows from operating activities:		
Net income (loss), including noncontrolling interests	$ (17,002)	$ 112,755
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by operating activities		
Depreciation and amortization	60,827	82,893
Asset impairment charge and dry hole expense	11,292	361
Equity in earnings of investments, net of distributions	—	320
Amortization of deferred financing costs	1,726	1,482
Loss from discontinued operations	27	2,554
Stock compensation expense	2,488	4,084
Amortization of debt discount	2,068	1,938
Deferred income taxes	(2,110)	43,699
Excess tax benefit from stock-based compensation	1,842	1,676
Gain on sale or acquisition of assets	(6,247)	(454)
Unrealized (gain) loss on derivative contracts	3,001	(55,420)
Changes in operating assets and liabilities:		
Accounts receivable, net	(23,823)	41,134
Other current assets	30,780	(2,448)
Income tax payable	(9,513)	54,518
Accounts payable and accrued liabilities	(22,027)	(51,713)
Other noncurrent, net	(14,865)	(73,889)
Cash provided by operating activities	18,464	163,490
Cash used in discontinued operations	(27)	(1,002)
Net cash provided by operating activities	18,437	162,488
Cash flows from investing activities:		
Capital expenditures	(68,428)	(133,663)
Investments in equity investments	—	(320)
Distributions from equity investments, net	965	2,477
Proceeds from sales of property	(4)	22,481
Net cash used in investing activities	(67,467)	(109,025)
Cash flows from financing activities:		
Repayment of Helix Term Loan	(1,082)	(1,082)
Repayments on Helix Revolver	—	(100,000)
Repayment of MARAD borrowings	(2,403)	(2,081)
Borrowings on CDI Revolver	—	100,000
Repayments on CDI Term Note	—	(20,000)

Deferred financing costs	(2,789)	—
Preferred stock dividends paid and other	(771)	(250)
Repurchase of common stock	(976)	(288)
Excess tax benefit from stock-based compensation	(1,842)	(1,676)
Net cash used in financing activities	(9,863)	(25,377)
Effect of exchange rate changes on cash and cash equivalents	398	(114)
Net (decrease) increase in cash and cash equivalents	(58,495)	27,972
Cash and cash equivalents:		
Balance, beginning of year	270,673	223,613
Balance, end of period	$ 212,178	$ 251,585

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

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. Until June 2009, Cal Dive International, Inc. (collectively with its subsidiaries referred to as "Cal Dive" or "CDI") was a majority-owned subsidiary of Helix. Helix sold substantially all its remaining ownership interest in Cal Dive during 2009 (see Note 4 below and Note 3 of our Annual Report on Form 10-K for the year ended December 31, 2009 ("2009 Form 10-K")). 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 2009 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 period ended March 31, 2010 are not necessarily indicative of the results that may be expected for the year ending December 31, 2010. Our balance sheet as of December 31, 2009 included herein has been derived from the audited balance sheet as of December 31, 2009 included in our 2009 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 2009 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.

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 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 almost 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 three disciplines: subsea construction, well operations and production facilities. We have disaggregated our contracting services operations into two continuing reportable segments: Contracting Services and Production Facilities. Our Contracting Services business primarily includes deepwater construction and well operation activities. Formerly, we had a third

Contracting Service segment, Shelf Contracting, which represented the assets of CDI. We sold substantially all our remaining ownership of CDI through various transactions in 2009 (Note 4). Our Production Facilities business includes our investments in Deepwater Gateway, L.L.C. (“Deepwater Gateway”), Independence Hub, LLC (“Independence Hub”) and Kommandor LLC (“Kommandor”).

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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 asset utilization of our contracting services business 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.

Discontinued Operations

In April 2009, we sold Helix Energy Limited ("HEL"), our former reservoir technology consulting business, to a subsidiary of Baker Hughes Incorporated for $25 million. As a result of the sale of HEL, which entity's operations were conducted by its wholly owned subsidiary, Helix RDS Limited ("Helix RDS"), we have presented the results of Helix RDS as discontinued operations in the accompanying condensed consolidated financial statements (Note 3). HEL and Helix RDS were previously components of our Contracting Services segment.

Business Strategy

We continue to focus on improving our balance sheet by increasing our liquidity through reductions in planned capital spending and potential additional dispositions of our non-core business assets. During 2009, we completed the following dispositions of non-core business assets:

- Sold five oil and gas properties for approximately $24 million;
- Sold a total of 15.2 million shares of CDI common stock held by us to CDI for $100 million in separate transactions in January and June 2009;
- Sold Helix RDS Limited, our subsurface reservoir consulting business for $25 million in April 2009; and
- Sold a total of 45.8 million shares of CDI common stock held by us to third parties in two separate public secondary offerings for approximately $404.4 million, net of underwriting fees in June 2009 and September 2009. For additional information regarding the sales of CDI common shares by us see Note 4.

In March 2010, we announced that we have engaged advisors to assist us with evaluating potential alternatives for the complete disposition of our oil and gas business. At the time of the filing of this Current Report on Form 10-Q we do not have an approved or definitive plan for such disposition of our oil and gas business.

Note 3 – Details of Certain Accounts

Other current assets consisted of the following as of March 31, 2010 and December 31, 2009:

	March 31, 2010	December 31, 2009
	(in thousands)	
Other receivables	$ 2,208	$ 7,990
Prepaid insurance	6,334	11,105
Other prepaids	13,100	21,819
Restricted cash (Notes 6 and 7)	10,000	—
Inventory	25,108	25,755
Current deferred tax assets	10,980	24,517
Hedging assets	30,491	6,214
Gas imbalance	7,289	7,655
Income tax receivable	17,201	8,492

Assets of discontinued operations	829	878
Other	5,950	7,784
	$ 129,490	$ 122,209

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Other assets, net, consisted of the following as of March 31, 2010 and December 31, 2009:

	March 31, 2010	December 31, 2009
	(in thousands)	
Restricted cash	$ 35,405	$ 35,409
Deferred drydock expenses, net	15,401	12,030
Deferred financing costs	31,228	30,061
Intangible assets with finite lives, net	754	768
Other	3,146	3,945
	$ 85,934	$ 82,213

Accrued liabilities consisted of the following as of March 31, 2010 and December 31, 2009:

	March 31, 2010	December 31, 2009
	(in thousands)	
Accrued payroll and related benefits	$ 18,291	$ 30,513
Royalties payable	10,179	5,717
Asset retirement obligation	76,804	65,729
Unearned revenue	3,617	3,672
Accrued interest	15,828	27,830
Billing in excess of cost	6,838	—
Deposit	25,542	25,542
Hedge liability	24,489	19,536
Liabilities of discontinued operations	176	451
Other	20,717	21,617
	$ 202,481	$ 200,607

Note 4 — Ownership of Cal Dive International, Inc.

In January 2009, we sold approximately 13.6 million shares of Cal Dive common stock to Cal Dive for $86 million. This transaction constituted a single transaction and was not part of any planned set of transactions that would result in us having a noncontrolling interest in Cal Dive, and reduced our ownership in Cal Dive to approximately 51%. Because we retained control of CDI immediately after the transaction, the loss of approximately $2.9 million on this sale was treated as a reduction of our equity.

In June 2009, we sold 22.6 million shares of Cal Dive common stock held by us pursuant to a secondary public offering ("Offering") and Cal Dive repurchased an additional 1.6 million shares from us of its common stock. Following the closing of these two transactions, our ownership of Cal Dive common stock was reduced to approximately 26%. Since we no longer held a controlling interest in Cal Dive, we ceased consolidating Cal Dive effective June 10, 2009, and subsequently accounted for our remaining ownership interest in Cal Dive under the equity method of accounting until September 2009, when we sold substantially all our remaining interest in Cal Dive.

We continue to own 0.5 million shares of Cal Dive common stock, representing less than 1% of the total outstanding shares of Cal Dive. Accordingly we now classify our remaining interest in Cal Dive as an investment available for sale pursuant to ASC Topic No. 320 "Investment - Debt and Equity Securities." As an investment available for sale, the value of our remaining interest will be marked-to-market at each period end with the corresponding change in value being reported as a component of other comprehensive income (loss) in the accompanying condensed consolidated balance sheets (Note 11). The value of our remaining investment in Cal Dive as of March 31, 2010 has decreased \$0.1 million since December 31, 2009 and \$1.3 million since our Cal Dive sales transaction in September 2009.

See Note 3 of our 2009 Form 10-K for additional information regarding our sale transactions involving Cal Dive common stock in 2009.

Note 5 – Convertible Preferred Stock

In January 2009, Fletcher International, Ltd. ("Fletcher") issued a redemption notice with respect to its $30 million of the Series A-2 Cumulative Convertible Preferred Stock, and, pursuant to such redemption, we issued and delivered 5,938,776 shares of our common stock to Fletcher. Accordingly, in the first quarter of 2009 we recognized a $29.3 million charge to reflect the terms this redemption, which was recorded as a reduction in our net income applicable to common shareholders. This beneficial conversion charge reflected the value associated with the additional 3,974,718 shares delivered over the original 1,964,058 shares that would have been contractually required to be issued upon a conversion but was limited to the $29.3 million of net proceeds we received from the issuance of the Series A-2 Cumulative Convertible Preferred Stock in June 2004.

In February 2009, the price of our common stock fell below $2.767 per share. Under terms of the agreement governing the issuance of the cumulative convertible preferred stock, we provided notice to Fletcher that with respect to the $25 million of Series A-1 Cumulative Convertible Preferred Stock the conversion price was reset to $2.767, the established minimum price per the agreement, and that Fletcher shall have no further rights to redeem the shares, and we have no further right to pay dividends in common stock. As a result of the reset of the conversion price, Fletcher would receive an aggregate of 9,035,056 shares in future conversion(s) into our common stock. In the event we elect to settle any future conversion in cash, Fletcher would receive cash in an amount approximately equal to the value of the shares it would receive upon a conversion, which could be substantially greater than the original face amount of the Series A-1 Cumulative Convertible Preferred Stock, and which would result in additional beneficial conversion charges in our statement of operations. Under the existing terms of our Senior Credit Facilities (Note 9) we are not permitted to deliver cash to the holder upon a conversion of the Convertible Preferred Stock.

In connection with the reset of the conversion price of the Series A-1 Cumulative Convertible Preferred Stock to $2.767, we were required to recognize a $24.1 million charge to reflect the value associated with the additional 7,368,388 shares that will be required to be delivered upon any future conversion(s) over the 1,666,668 shares that were to be delivered under the original contractual terms. This $24.1 million charge was recorded as a beneficial conversion charge reducing our net income applicable to common shareholders. The beneficial conversion charge for the Series A-1 Cumulative Convertible Preferred Stock is limited to the $24.1 million of net proceeds received upon its issuance in January 2003.

In the third quarter of 2009, Fletcher converted $19 million of its Series A-1 Cumulative Convertible Preferred Stock into 6,866,641 shares of our common stock. The remaining $6 million of the Series A-1 Cumulative Convertible Preferred Stock, which is convertible into 2,168,413 shares of our common stock, maintains its mezzanine presentation below liabilities but is not included as component of shareholders' equity, because we may, under certain instances be required to settle any future conversions in cash. Prior to any future conversion(s), the common shares issuable will be assessed for inclusion in our diluted earnings per share computations using the if converted method based on the applicable conversion price of $2.767 per share, meaning that for all periods in which we have positive earnings from continuing operations and our average stock price exceeds $2.767 per share we will have an assumed conversion of convertible preferred stock and the 2,168,413 shares will be included in our diluted shares outstanding amount.

Note 6 – Oil and Gas Properties

In March 2010, we announced that we engaged advisors to assist us with evaluating potential alternatives for the complete disposition of our oil and gas business. At the time of the filing of this Current Report on Form 10-Q we do not have an approved or definitive plan for such disposition of our oil and gas business.

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, 2010, we capitalized approximately $3.2 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, 2010 and 2009:

	Three Months Ended March 31,	
	2010	2009
	(in thousands)	
Delay rental and geological and geophysical costs	$ 346	$ 472
Dry hole expense	(180)	4
Total exploration expense	$ 166	$ 476

Impairments

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 three affected U.S. Gulf of Mexico properties comprising our impairment expense 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). There were no impairment charges in the first quarter of 2009. 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.

MMS Royalty Claims

We and other industry participants were involved in a dispute with the U.S. Department of the Interior Minerals Management Service (“MMS”) over royalties associated with production from certain deepwater oil and gas leases. As a result of this dispute, we recorded reserves for the disputed royalties (and any other royalties that may be claimed for production during 2005, 2006, 2007 and 2008) plus interest at 5% for our portion the MMS claim, which affected our Garden Banks Blocks 667, 668 and 669 (“Gunnison”) leases. The result of accruing these reserves since 2005 had reduced our oil and gas revenues. In the first quarter of 2009, following the decision of the United States Court of Appeals for the Fifth Circuit Court affirming the district court’s previous ruling in favor of the plaintiffs in that case, we reversed our previously accrued royalties ($73.5 million) to oil and gas revenues. On October 5, 2009, the United States Supreme Court denied the government’s petition for a writ of certiorari, and, based on this the MMS subsequently withdrew its orders to pay the royalty.

For additional information regarding our MMS royalty dispute and related litigation see Note 17 of our 2009 Form 10-K.

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 by agreeing to assume the obligations, most notably the asset retirement obligation, related to its 50% working interest in the field. The following table contains the fair value of

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the assets acquired and liabilities assumed in our acquisition of this third party and its 50% working interest in the Camelot field (in thousands):

Cash (a)	$ 10,156
Deferred tax asset	2,083
Accrued liabilities	(438)
Accrued reclamation obligation	(5,841)
Gain on acquisition of assets	$ 5,960

a) At March 31, 2010, $10.0 million of this amount remains held in an escrow account and is restricted for future use to fund the asset retirement costs associated with Camelot field. This amount is reflected in other current assets in the accompanying condensed consolidated balance sheet (Note 3). The current classification of both the restricted funds and the related asset retirement reflect the probable near-term of these activities occurring.

In connection with the valuation of assets acquired and liabilities assumed in 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 further expending the capital necessary to further develop the field and our plans are to abandon the field over the near term. As a result, we recorded a $4.1 million impairment charge to fully impair the property. Accordingly, in our future estimates of proved reserves we will no longer consider the reserves associated with this field as proved but rather deem them as probable reserves.

Property Sales

In the first quarter of 2009, we sold our interest in East Cameron Block 316 for gross proceeds of approximately $18 million. We recorded an approximate $0.7 million gain from the sale of East Cameron Block 316 which was partially offset by the loss on the sale of the remaining 10% of our interest in the Bass Lite field at Atwater Block 426 in January 2009.

Asset retirement obligations

The following table describes the changes in our asset retirement obligations (both long term and current) since December 31, 2009 (in thousands):

Asset retirement obligation at December 31, 2009	$ 248,128
Liability incurred during the period (a)	5,907
Liability settled during the period	(4,495)
Revision in estimated cash flows	1,704
Accretion expense (included in depreciation and amortization)	3,931
Asset retirement obligations at March 31 2010	$ 255,175

a) Amount primarily associated with the acquisition of the remaining 50% working interest in the Camelot field in February 2010 (see "United Kingdom Property" above).

Insurance

In September 2008, we sustained damage to certain of our oil and gas production facilities from Hurricanes Gustav and Ike. While we sustained some damage to our own production facilities from Hurricane Ike, the larger issue in terms of production recovery involved damage to third party pipelines and onshore processing facilities. 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 were recorded when the realization of the claim for recovery of a loss is deemed probable. In the first quarter of 2010, we incurred $2.1 million of hurricane-related repair costs compared to $12.7 million in the first quarter of 2009. The first quarter of 2009 costs were partially offset by reimbursements or approved reimbursements of $3.1 million. See Note 4 of our 2009 Form 10-K for information regarding our settlement with the insurance underwriters in June 2009.

Note 7 – 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 $45.4 million at March 31, 2010 and $35.4 million at December 31, 2009. The $10.0 million increase in our restricted cash from the year end 2009 amount reflects the escrowed funds we acquired in the Camelot acquisition in February 2010 (Note 6). This amount is reflected in other current assets in the accompanying condensed consolidated balance sheet at March 31, 2010. The remaining $35.4 million of restricted cash relates entirely to funds required to be escrowed to cover the future asset retirement obligations associated with our South Marsh Island 130 field. We have fully satisfied the escrow requirements under this agreement and may use the restricted cash for the future asset retirement costs of the related 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 months ended March 31, 2010 and 2009 (in thousands):

	Three Months Ended March 31,	
	2010	2009
Interest paid, net of capitalized interest(1)	$ 23,737	$ 33,372
Income taxes paid	$ 4,357	$ 30,928

Non-cash investing activities for the three-month periods ended March 31, 2010 and 2009 included $48.2 million and $88.4 million, respectively, of accruals for capital expenditures. The accruals have been reflected in the condensed consolidated balance sheet as an increase in property and equipment and accounts payable.

Note 8 – Equity Investments

As of March 31, 2010, we have the following material investments, both of which are included within our Production Facilities segment and are accounted for under the equity method of accounting:

· Deepwater Gateway, L.L.C. In June 2002, we, along with Enterprise Products Partners L.P. (”Enterprise”), formed Deepwater Gateway, L.L.C. (“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 $102.1 million and $103.3 million as of March 31, 2010 and December 31, 2009, respectively (including capitalized interest of $1.5 million at March 31, 2010 and December 31, 2009). Distributions from Deepwater Gateway, net to our interest, totaled $2.3 million in the first quarter of 2010.

· 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 $86.2 million and $86.1 million as of March 31, 2010 and December 31, 2009, respectively (including capitalized interest of $5.5 million and $5.6 million at March 31, 2010 and December 31, 2009, respectively). Distributions from Independence Hub, net to our interest, totaled $4.9 million in the first quarter of 2010.

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The following presents selected summarized unaudited operating results for our Deepwater Gateway and Independence Hub equity investments for the three month periods ended March 31, 2010 and 2009

	Deepwater Gateway		Independence Hub		Combined	
	2010	2009	2010	2009	2010	2009
Revenues	$4,318	$6,642	$29,182	$33,616	$33,500	$40,258
Operating income	2,238	3,623	25,610	30,025	27,848	33,648
Net income	2,238	3,631	25,610	30,037	27,848	33,668
Equity in earnings	$1,119	$1,816	$5,122	$6,007	$6,241	$7,823

See Note 16 for information about our consolidated Kommandor LLC joint venture, which represents the remainder of our Production Facilities segment.

In February 2010, we announced the formation of a joint venture 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. Services provided by the joint venture, named Clough Helix JV Co., will include subsea well intervention and well abandonment, SURF (subsea infrastructure, umbilical, riser and flowline installation), saturation and air diving and subsea inspection, repair and maintenance services. The Clough Helix joint venture will integrate our well intervention equipment with Clough's new 12 man saturation diving system, to enable both to be deployed from the 118 meter long DP2 multiservice vessel, Normand Clough, outfitted with a 250 ton active heave compensated crane. We recorded a $1.4 million loss associated with our 50% interest in the joint venture in the first quarter of 2010. The loss primarily represented the mobilization costs of transporting the Normand Clough from the Gulf of Mexico to Singapore where it is being prepared for the joint venture's initial project. This joint venture is part of our Contracting Services segment.

Note 9 – Long-Term Debt

Scheduled maturities of long-term debt and capital lease obligations outstanding as of March 31, 2010 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	$	$	$	$ 4,533	$ 2,975	$ 11,834
One to two years	4,326				4,760		9,086
Two to three years	4,326				4,997		9,323
Three to four years	400,707				5,247		405,954
Four to five years					5,508		5,508
Over five years			550,000	300,000	92,005		942,005
Total debt	413,685		550,000	300,000	117,050	2,975	1,383,710
Current maturities	(4,326)				(4,533)	(2,975)	(11,834)
Long-term debt, less current maturities	$409,359	$	$ 550,000	$ 300,000	$ 112,517	$	$1,371,876
Unamortized debt discount (3)				(24,869)			(24,869)

Long-term debt	$409,359	$	$ 550,000	$ 275,131	$ 112,517	$	$1,347,007

(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 not mature until March 2025.

(2) Represents the balance of the loan provided by Kommandor RØMØ to Kommandor LLC as March 31, 2010.

(3) Reflects debt discount resulting from adoption of new provisions of ASC Topic No. 470-20 “Convertible Debt and Other Options” on January 1, 2009. The notes will increase to $300 million face amount through accretion of non-cash interest charges through 2012.

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At March 31, 2010, unsecured letters of credit issued totaled approximately $49.5 million (see "Credit Agreement" below). These letters of credit primarily guaranty 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 months ended March 31, 2010 and 2009:

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
	(in thousands)	
Interest expense	$ 26,057	$ 29,850
Interest income	(1,906)	(264)
Capitalized interest	(8,516)	(7,620)
Interest expense, net	$ 15,635	$ 21,966

Included below is a summary of certain components of our indebtedness. At March 31, 2010 and December 31, 2009, we were in compliance with all debt covenants. For additional information regarding our debt see Note 10 of our 2009 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 Term Loan is scheduled to mature in July 1, 2013. 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 original maturity date of the Credit Agreement was July 1, 2011. 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 months ended March 31, 2010 and 2009 was approximately 2.8% and 5.0%, respectively, including the effects of our interest rate swaps.

As of December 31, 2009, the Credit Agreement had been amended twice since its inception, with the most recent amendment occurring in October 2009. Borrowing availability under the Revolving Credit facility was $435 million at December 31, 2009 (decreasing to $410 million beginning July 1, 2011 through November 30, 2012). The October amendment extended the maturity of the Revolving Credit Facility to November 30, 2012. The full amount of the Revolving Credit Facility may be used for issuances of letters of credit. At March 31, 2010, we had no amounts drawn on the Revolving Credit Facility and our availability under the Revolving Credit Facility totaled $385.5 million, net of $49.5 million of unsecured letters of credit issued. 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 and on whether the lender to whom interest is payable has extended the maturity of its portion of the Revolving Credit Facility to November 30, 2012. We did not have any borrowings under our Revolving Loans in the three months ended March 31, 2010. Our average interest rate on the Revolving Loans for the three months ended March 31, 2009 was approximately 3.4%.

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In February 2010, we again amended our Credit Agreement. This amendment:

- changed the consolidated leverage ratio that we are required to comply with. Through December 31, 2009, the maximum permitted leverage was 3.50 to 1.00. Beginning with the quarter ending March 31, 2010, the ratio is now as follows:

  - March 31, 2010 – 5.00 to 1.00
  - June 30, 2010 – 5.50 to 1.00
  - September 30, 2010 – 5.00 to 1.00
  - December 31, 2010 – 4.50 to 1.00
  - March 31, 2011 and thereafter – 4.00 to 1.00

- added a new Credit Agreement leverage ratio we are required to comply with beginning with the quarter ending March 31, 2010. This ratio is a measure of our senior funded indebtedness that is secured by a lien on our property against consolidated EBITDA for the trailing four quarters. The ratio will be as follows:

  - March 31 and June 30, 2010 – 2.50 to 1.00
  - September 30, 2010 – 2.25 to 1.00
  - December 31, 2010 and thereafter – 2.00 to 1.00

- increased the margin on Revolving Loans by 0.50% should our consolidated leverage ratio equal or exceed 4.50 to 1.00, and increased the margin on the Term Loan by 0.25% if our consolidated leverage ratio is less than 4.50 to 1.00 and by 0.50% if the consolidated leverage ratio is equal to or greater than 4.50 to 1.00.

As the rates for our Term Loan are subject to market influences and will vary over the term of the Credit Agreement, we entered 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 18).

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 balance sheet. No conversion triggers were met during the three-month period ended March 31, 2010. 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 10 of our 2009 Form 10-K). Effective

January 1, 2009 we adopted certain new required standards within ASC Topic No. 470-20 “Debt with Conversion and Other Options”, which required us to discount the principal amount of our Convertible Senior Notes (see Note 2 of our 2009 Form 10-K). Following adoption of these standards, the effective interest rate for the Convertible Senior Notes is 6.6%.

Our average share price for the both the first quarter of 2010 and 2009 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

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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 which began 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 and restrictions, including the maintenance of minimum net worth, working capital and debt-to-equity requirements. As of March 31, 2010, we were in compliance with these covenants and restrictions. The Senior Unsecured Notes and Credit Agreement contain provisions that limit our ability to incur certain types of additional indebtedness.

Deferred financing costs of $31.2 million and $30.1 million are included in other assets, net as of March 31, 2010 and December 31, 2009, respectively, and are being amortized over the life of the respective loan agreements.

Note 10 – Income Taxes

The effective tax rate for the three months ended March 31, 2010 was 30.8% compared with 36.0% for the three months ended March 31, 2009. The effective tax rate for the first quarter of 2010 decreased as a result of the deconsolidation of CDI in 2009 and the increased benefit derived from the effect of 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; therefore, our assessments can involve a series of complex judgments about future events and rely heavily on estimates and assumptions.

Note 11 – Comprehensive Income

The components of total comprehensive income for the three months ended March 31, 2010 and 2009 were as follows (in thousands):

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Net income (loss), including noncontrolling interests	$ (17,002)	$ 112,755
Other accumulated comprehensive income (loss), net of tax		
Foreign currency translation loss	(10,702)	(3,619)

Unrealized gain (loss) on hedges, net	14,040	(4,464)
Unrealized loss on investment available for sale	(75)	
Total accumulated comprehensive income (loss)	(13,739)	104,672
Less: Other accumulated comprehensive income (loss) applicable to noncontrolling interest		(5,546)
Total accumulated comprehensive income (loss) applicable to Helix	$ (13,739)	$ 99,126

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

	March 31, 2010	December 31, 2009
Cumulative foreign currency translation adjustment	$ (22,959)	$ (12,257)
Unrealized gain (loss) on hedges, net	4,943	(9,097)
Unrealized loss on investment available for sale	(962)	(887)
Accumulated other comprehensive loss	$ (18,978)	$ (22,241)

Note 12 – 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 this applicable 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.

Basic EPS 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 computation of basic and diluted EPS amounts for the three months ended March 31, 2010 and 2009 follows (in thousands):

	Three Months Ended March 31, 2010		Three Months Ended March 31, 2009	
	Income	Shares	Income	Shares
Basic:				
Net income (loss) applicable to common shareholders	$ (17,891)		$ 53,450	
Less: Undistributed net income allocable to participating securities			(884)	
Undistributed net income (loss) applicable to common shareholders	(17,891)		52,566	
(Income) loss from discontinued operations	27		2,554	
Income (loss) per common share – continuing operations	$ (17,864)	103,090	$ 55,120	95,052

	Three Months Ended March 31, 2010		Three Months Ended March 31, 2009	
	Income	Shares	Income	Shares
Diluted:				
Net income (loss) per common share –	$ (17,864)		$ 55,120	95,052

continuing operations – Basic				
Effect of dilutive securities:				
Stock options				
Undistributed earnings reallocated to participating securities			89	
Convertible Senior Notes				
Convertible preferred stock			313	10,811
Income (loss) per common share continuing operations	(17,864)		55,522	
Income (loss) per common share discontinued operations	(27)		(2,554)	
Net income (loss) per common share	$ (17,891)	103,090	$ 52,968	105,863

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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 months 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

There were no dilutive stock options in the three months ended March 31, 2009 as the option strike price was below the average market price for the period ($5.22 per share). The diluted EPS amount included the $0.1 million and $0.3 million of dividends and related costs associated with the assumed conversion of the convertible preferred stock for the three months ended March 31, 2010 and 2009, respectively. The cumulative $53.4 million of beneficial conversion charges that were realized and recorded during the first quarter of 2009 following the transaction affecting our convertible preferred stock (Note 5) are not included as a positive adjustment to earnings applicable to common stock for our diluted earnings per share calculation.

Note 13 – 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, 2010, there were approximately 1.3 million shares available for grant under our 2005 Incentive Plan.

During the three months ended March 31, 2010, we made the following restricted share or restricted stock unit grants to certain key executives, selected management employees and non-employee members of the board of directors under the 2005 incentive plan:

Date of Grant	Type	Shares	Market Value Per Share	Vesting Period
January 4, 2010	(1)	452,849	$ 11.75	20% per year over five years
January 4, 2010	(2)	23,569	11.75	20% per year over five years
January 4, 2010	(1)	1,197	11.75	100% on January 1, 2012

(1) Restricted shares
(2) Restricted stock units

There were no stock option grants in the three months ended March 31, 2010 and 2009.

Compensation cost is recognized over the respective vesting periods on a straight-line basis. There was no compensation cost associated with stock options for the three months ended March 31, 2010 as all outstanding stock options have vested. We recorded $0.1 million of compensation expense related to stock options in first quarter of 2009. For the three months ended March 31, 2010, $2.5 million was recognized as compensation expense related to restricted shares as compared with $4.0 million during the three months ended March 31, 2009, including $1.7 million related to CDI and its compensation plans.

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 will fluctuate based on the common stock's performance. This share based component is considered a liability plan under the guidance of ACS Topic No. 718 "Compensation – Stock

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Compensation" 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 $14.7 million in 2009, including $8.1 million for our executive officers, which vest over a five year period. In January 2010, $10.1 million was awarded under the 2009 LTI Plan to eligible employees, including $6.0 million to our executive officers and other members of senior management. Total compensation under 2009 the LTI plan totaled $1.9 million and $0.7 million for the three months ended March 31, 2010 and 2009, respectively.

For more information regarding our stock-based compensation plans, including our 2009 LTI Plan see Note 13 of our 2009 Form 10-K.

Note 14 – Business Segment Information

Our operations are conducted through the following lines of business: contracting services operations and oil and gas operations. We have disaggregated our contracting services operations into two continuing reportable segments in accordance with ASC Topic No 280 "Segment Reporting": Contracting Services and Production Facilities. As a result, our reportable segments consisted of the following: Contracting Services and Oil and Gas and Production Facilities. Contracting Services operations include deepwater pipelay, well operations and robotics. Formerly, we had a third contracting services business, Shelf Contracting, which consisted of CDI's operations, and which included all assets deployed primarily for diving-related activities and shallow water construction. On June 10, 2009, we ceased consolidating CDI when our remaining ownership interest decreased to below 50% following the sale of a portion of CDI common stock held by us (Note 4). We continued to disclose the results of Shelf Contracting business as a segment up to and through June 10, 2009. All material intercompany transactions between the segments have been eliminated.

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. The majority of our Production Facilities segment (Deepwater Gateway and Independence Hub) is accounted for under the equity method of accounting. We consolidate our investment in Kommandor and its results are included within our Production Facilities segment.

	Three Months Ended March 31,	
	2010	2009
	(in thousands)	
Revenues		
Contracting Services	$ 154,200	$ 230,855
Shelf Contracting		207,053
Oil and Gas (1)	90,715	160,181
Production Facilities	1,320	
Intercompany elimination	(44,665)	(27,114)
Total	$ 201,570	$ 570,975

	Three Months Ended March 31,	
	2010	2009
	(in thousands)	
Income (loss) from operations		

Contracting Services	$ 27,486	$ 39,748
Shelf Contracting		20,932
Production Facilities equity investments(2)	(37)	(134)
Oil and Gas (1)	(664)	145,183
Corporate (3)	(22,878)	(10,519)
Intercompany elimination	(12,305)	(290)
Total	$ (8,398)	$ 194,920
Equity in earnings of equity investments	$ 5,055	$ 7,503

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(1) Included $73.5 million of disputed accrued royalty payments that we reversed in first quarter of 2009 following a favorable court ruling (Note 6).
(2) Included selling and administrative expense of Production Facilities incurred by us.
(3) Includes $13.8 million settlement of third party claim against us in March 2010 (Note 16).

	March 31, 2010	December 31, 2009
	(in thousands)	
Identifiable Assets		
Contracting Services	$1,669,228	$ 1,738,005
Production Facilities	523,136	499,497
Oil and Gas	1,537,754	1,541,153
Assets of discontinued operations	829	878
Total	$3,730,947	$ 3,779,533

Intercompany segment revenues during the three months ended March 31, 2010 and 2009 were as follows:

	Three Months Ended March 31,	
	2010	2009
	(in thousands)	
Contracting Services	$ 43,741	$ 23,903
Production Facilities	924	
Shelf Contracting		3,211
Total	$ 44,665	$ 27,114

Intercompany segment profits during the three months ended March 31, 2010 and 2009 were as follows:

	Three Months Ended March 31,	
	2010	2009
	(in thousands)	
Contracting Services	$ 11,442	$ (104)
Production Facilities	880	
Shelf Contracting		394
Total	$ 12,322	$ 290

Note 15 – Related Party Transactions

In April 2000, we acquired a 20% working interest in Gunnison, a Deepwater Gulf of Mexico prospect. 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. 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. Production began in December 2003. Our payments to OKCD totaled $3.0 million and $2.7 million for the three months ended March 31, 2010 and 2009, respectively.

Note 16 – Commitments and Contingencies

Commitments

We completed the conversion of the Caesar (acquired in January 2006 for $27.5 million in cash) into a deepwater pipelay vessel. We are completing the final capital upgrades to the vessel. Total capitalized costs for the vessel when complete are estimated to range between $290 million and $300 million (including capitalized interest of approximately $25 million), of which approximately $273.1 million had been incurred, with an additional $4.9 million committed, at March 31, 2010. The Caesar is expected to join our fleet in the second quarter of 2010.

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Further, we, along with Kommandor Rømø, a Danish corporation, formed a joint venture company called Kommandor and converted a ferry vessel into a floating production unit, the Helix Producer I. The total cost of the ferry and the conversion was approximately $150 million. We provided $98.9 million in interim construction financing to the joint venture. During 2009, $58.8 million of this amount was converted to equity in our investment in Kommandor. Kommandor Rømø provided a $5.0 million loan to Kommandor, the remaining balance of which was $3.0 million at March 31, 2010.

Upon completion of the initial conversion, which occurred in April 2009, we chartered the Helix Producer I from Kommandor, and have installed, at 100% our cost, processing facilities and a disconnectable fluid transfer system on the Helix Producer I for use on our Phoenix field. The cost of these additional facilities is estimated to range between $200 million and $210 million (including capitalized interest of $17 million) and the work is expected to be completed in the second quarter of 2010. As of March 31, 2010, approximately $338 million of costs related to the purchase of the Helix Producer I ($20 million), conversion of the Helix Producer I and construction of the additional facilities had been incurred, with an additional $8.3 million committed. The total estimated cost of the vessel, initial conversion and the additional facilities will range approximately between $350 million and $360 million. We have consolidated Kommandor in all periods presented in the accompanying consolidated financial statements. The results of Kommandor are included within our Production Facilities segment.

As of March 31, 2010, we planned to spend approximately $16 million for additional capital improvements to the newly constructed Well Enhancer vessel and have committed to spend $67.0 million in additional capital expenditures for exploration, development and drilling costs related to our oil and gas properties.

Contingencies

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.

Litigation and Claims

In March 2009, we were notified of a third party's intention to terminate an international construction contract based on a claimed breach of that contract by one of our subsidiaries. Under the terms of the contract, our potential liability was generally capped for actual damages at approximately $27 million Australian dollars ("AUD") (approximately $24.3 million US dollars at December 31, 2009) and for liquidated damages at approximately $5 million AUD (approximately $4.5 million US dollars at December 31, 2009). We asserted a counterclaim that in the aggregate approximates $12 million U.S. dollars. On March 30, 2010, an out of court settlement of these claims was negotiated. On April 19, 2010, pursuant to the terms of the agreement, we paid the third party $15 million AUD to settle all their damage claims against us. We also agreed not to seek any further payment of our counter claims against them. Our results for the three months 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 general and administrative expenses in the accompanying condensed consolidated statements of operations.

See Note 6 for information updating the litigation involving certain disputed royalty payments, which were recognized as oil and gas revenues in the first quarter of 2009.

Note 17 – Fair Value Measurements and Recent Accounting Standards

Fair Value Measurements

We follow the provisions of the ASC 820, Fair Value Measurements and Disclosures, for financial assets and liabilities that are measured and reported at fair value on a recurring basis. ASC 820 establishes 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, 2010 (in thousands):

	Level 1	Level 2 (1)	Level 3	Total	Valuation Technique
Assets:					
Gas swaps and collars	$–	$30,491	$–	$30,491	(c)
Interest rate swaps	–	536		536	(c)
Investment in Cal Dive	3,665	–	–	3,665	(a)
Liabilities:					
Oil swaps and collars	–	22,449	–	22,449	(c)
Fair value of long term debt(2)	1,239,196	122,434		1,361,630	(a), (b)
Foreign currency forwards	–	833	–	833	(c)
Interest rate swaps	–	1,538	–	1,538	(c)
Total net liability	$1,235,531	$116,227	$–	$1,351,758	

(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 9 for additional information regarding our long term debt. The fair value of our long term debt at March 31. 2010 is as follows:

	Fair Value	Carrying Value

Term Loan (matures July 2013)	$	403,343	$	413,685
Revolving Credit Facility (matures November 2012)				
Convertible Senior Notes (matures March 2025)		271,878		275,131
Senior Unsecured Notes (matures January 2016)		561,000		550,000
MARAD Debt (matures August 2027) (a)		122,434		117,050
Loan Notes(b)		2,975		2,975
Total	$	1,361,630	$	1,358,841

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(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 maturing of the notes is current.

We account for long-lived assets in accordance with ASC 360-10-35, Impairment of Disposal of Long Lived Assets, and 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 6). The total amount of the impairment charges were $7.0 million, which reduced these properties to their aggregate fair value of $28.2 million.

Recent Accounting Pronouncements

In January 2010, the Financial Accounting Standard Board ("FASB") issued Accounting Standards Update ("ASU") No. 2010-06, "Improving Disclosures about Fair Value Measurements" an amendment to ASC Topic 820. This amendment requires an entity to: (i) disclose separately the amounts of significant transfers in and out of Level 1 and Level 2 fair value measurements and describe the reason for the transfers and (ii) present separate information for Level 3 activity pertaining to gross purchases, sales, issuances, and settlements. This amendment is effective interim and annual reporting periods beginning after December 15, 2009. We adopted this ASU effective January 1, 2010.

In June 2009, the FASB issued ASC Topic 810 (originally issued as Statement of Financial Accounting Standards No. 167, "Amendments to FASB Interpretation No. ("FIN") 46(R)"). Among other items, ASC 810 responds to concerns about an enterprise's application of certain key provisions of FIN 46(R), including those regarding the transparency of the enterprise's involvement with variable interest entities. ASC 810 is effective for calendar year-end companies beginning on January 1, 2010. We adopted the standard for the interim period ended March 31, 2010. There was no impact on the our financial position, results of operations, cash flows, or disclosures.

Note 18 – 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 our balance sheet at fair value unless otherwise noted, and do not contain credit-risk related or other contingent features that could cause accelerated payments when our derivative liabilities are in net liability positions.

We engage only 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, a component of shareholders' equity, until the hedged transactions occur and are recognized in

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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. Further, when we have obligations and receivables with the same counterparty, the fair value of the derivative liability and asset are presented at net value.

For additional information regarding our accounting for derivatives see Notes 2 and 22 of our 2009 Form 10-K.

Commodity Price Risks

We currently manage commodity price risks through various financial costless collars and swap instruments covering a portion of our anticipated oil and natural gas production for 2010. In the past, we have also utilized forward sales contracts that require physical delivery of oil and natural gas. All of our current commodity derivative contracts qualify for hedge accounting. However, due to disruptions in our production as a result of damages caused by the hurricanes in third quarter 2008, most of our financial commodity contracts in place at March 31, 2009 no longer qualified for hedge accounting. Our forward sales contracts were not within the scope of SFAS No. 133 as they qualified for the normal purchases and sales scope exception. However, due to disruptions in our production as a result of damages caused by the hurricanes, as mentioned above, they no longer qualified for the scope exception. As a result, both our oil and natural gas commodity contracts and our natural gas normal purchase and sale contracts were required to be mark-to-market effective March 31, 2009. At that time, there were no contracts related to 2010 anticipated production and no contracts related to 2010 anticipated production have been subject to mark-to-market adjustments as they have been effective since their inception.

As of March 31, 2010, we have the following volumes under derivative contracts related to our oil and gas producing activities totaling approximately 3.0 MMBbl of oil and 18.6 Bcf of natural gas:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:			(per barrel)
April 2010 — December 2010	Collar	100 MBbl	$62.50-$80.73
April 2010 — December 2010	Swap	99.4 MBbl	$77.12
April 2010 — June 2010	Swap	50 MBbl	$71.08
July 2010 — December 2010	Swap	175 MBbl	$80.80
Natural Gas:			(per Mcf)
April 2010 — December 2010	Swap	1,061.1 Mmcf	$5.82
April 2010 — December 2010	Collar	1,008.3 Mmcf	$6.00 — $6.70

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.

Variable Interest Rate Risks

As some of our long-term debt are subject to market influences and have 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 9). 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 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 and other.

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Foreign Currency Exchange Risks

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

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, 2010 and December 31, 2009. As required by ASC Topic No. 815 "Derivatives and Hedging", 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. As a result, the amounts below may not agree with the amounts presented on our condensed consolidated balance sheet and the fair value information presented for our derivative instruments (Note 17).

Derivatives designated as hedging instruments under ASC Topic No. 815:

	As of March 31, 2010		As of December 31, 2009	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
		(in thousands)		
Asset Derivatives:				
Oil contracts	Other current assets	$ —	Other current assets	$ —
Natural gas contracts	Other current assets	30,491	Other current assets	5,071
Interest rate swaps	Other assets, net	536	Other assets, net	—
		$ 31,027		$ 5,071

	As of March 31, 2010		As of December 31, 2009	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
		(in thousands)		
Liability Derivatives:				
Oil contracts	Accrued liabilities	$ 22,449	Accrued liabilities	$ 19,477
Natural gas contracts	Accrued liabilities	—	Accrued liabilities	59
Interest rate swaps	Accrued liabilities	1,538	Accrued liabilities	—
		$ 23,987		$ 19,536

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

	As of March 31, 2010	As of December 31, 2009

	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
		(in thousands)		
Asset Derivatives:				
Natural gas contracts	Other current assets	$ —	Other current assets	$ —
Foreign exchange forwards	Other current assets	—	Other current assets	1,143
Foreign exchange forwards	Other assets, net	—	Other assets, net	931
		$ —		$ 2,074
Liability Derivatives:				
Foreign exchange forwards	Accrued liabilities	502	Accrued liabilities	—
Foreign exchange forwards	Other liabilities	331	Other liabilities	—
		$ 833		$ —

The following tables present the impact the impact that derivative instruments designated as cash flow hedges had on our accumulated comprehensive income and our consolidated statements of operations for the three month periods ended March 31, 2010 and 2009.

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	Gain (Loss) Recognized in Accumulated OCI on Derivatives 2010	2009
	(in thousands)	
Oil and natural gas commodity contracts	$ 14,630	$ (4,267)
Foreign exchange forwards	—	(581)
Interest rate swaps	(590)	384
	$ 14,040	$ (4,464)

1) All unrealized gains (losses) related to our derivatives are expected to be reclassified into earnings within the next 12 months, except for amounts related to our interest swap contracts.

	Location of Gain (Loss) Reclassified from Accumulated OCI into Income	Gain (Loss) Recognized from Accumulated OCI into Income 2010	2009
		(in thousands)	
Oil and natural gas commodity contracts	Oil and gas revenue	$ 802	$9,586
Foreign exchange forwards	Net interest expense and other	—	—
Interest rate swaps	Net interest expense and other	(418)	(654)
		$ 384	$8,932

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, 2010 and 2009:

	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives 2010	2009
		(in thousands)	
Natural gas contracts	Gain on oil and gas derivative contracts	$ —	$ 74,609
Foreign exchange forwards	Net interest expense and other	(2,907)	646
Interest rate swaps	Net interest expense and other	—	(12)
		$ (2,907)	$ 75,243

Note 19 – Condensed Consolidated Guarantor and Non-Guarantor Financial Information

The payment of 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. (Cal Dive and its subsidies were never guarantors of the Senior Unsecured Notes). 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, 2010				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 197,601	$ 3,600	$ 10,977	$ —	$ 212,178
Accounts receivable, net	60,293	85,238	14,173	—	159,704
Unbilled revenue	8,970	261	18,180	—	27,411
Income taxes receivable	49,662	—	20,658	(53,119)	17,201
Other current assets	43,226	65,876	24,487	(21,300)	112,289
Total current assets	359,752	154,975	88,475	(74,419)	528,783
Intercompany	45,543	188,541	(167,317)	(66,767)	—
Property and equipment, net	245,233	1,906,769	704,709	(5,196)	2,851,515
Other assets:					
Equity investments	2,148,100	29,142	186,944	(2,177,242)	186,944
Goodwill	—	45,107	32,664	—	77,771
Other assets, net	50,403	40,097	29,175	(33,741)	85,934
Due from subsidiaries/parent	118,639	49,880	—	(168,519)	—
	$ 2,967,670	$ 2,414,511	$ 874,650	$ (2,525,884)	$ 3,730,947
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 64,111	$ 53,380	$ 18,494	$ —	$ 135,985
Accrued liabilities	68,796	111,037	22,683	(35)	202,481
Income taxes payable	—	66,903	—	(66,903)	—
Current maturities of long-term debt	4,326	—	28,395	(20,887)	11,834
Total current liabilities	137,233	231,320	69,572	(87,825)	350,300
Long-term debt	1,234,491	—	112,516	—	1,347,007
Deferred income taxes	142,686	211,410	87,087	(10,036)	431,147
Asset retirement obligations	—	178,371	—	—	178,371
Other long-term liabilities	985	2,987	740	77	4,789
Due to parent	—	—	144,124	(144,124)	—
Total liabilities	1,515,395	624,088	414,039	(241,908)	2,311,614

Convertible preferred stock	6,000	—	—	—	6,000
Total equity	1,446,275	1,790,423	460,611	(2,283,976)	1,413,333
	$ 2,967,670	$ 2,414,511	$ 874,650	$ (2,525,884)	$ 3,730,947

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

	As of December 31, 2009				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 258,742	$ 2,522	$ 9,409	$ —	$ 270,673
Accounts receivable, net	49,813	77,399	18,307	—	145,519
Unbilled revenue	9,425	480	17,254	—	27,159
Income taxes receivable	38,333	—	13,795	(43,636)	8,492
Other current assets	54,144	68,910	16,331	(25,668)	113,717
Total current assets	410,457	149,311	75,096	(69,304)	565,560
Intercompany	106,408	149,796	(190,729)	(65,475)	—
Property and equipment, net	220,408	1,919,412	729,131	(5,245)	2,863,706
Other assets:					
Equity investments in unconsolidated affiliates	—	—	189,411	—	189,411
Equity investments in affiliates	2,123,169	29,649	—	(2,152,818)	—
Goodwill, net	—	45,107	33,536	—	78,643
Other assets, net	48,822	41,669	22,919	(31,197)	82,213
Due from subsidiaries/parent	73,867	64,775	—	(138,642)	—
	$ 2,983,131	$ 2,399,719	$ 859,364	$ (2,462,681)	$ 3,779,533
LIABILITIES AND SHAREHOLDERS’ EQUITY					
Current liabilities:					
Accounts payable	$ 58,451	$ 79,128	$ 17,878	$ —	$ 155,457
Accrued liabilities	81,021	104,450	15,136	—	200,607
Income taxes payable	—	54,955	—	(54,955)	—
Current maturities of long-term debt	4,326	—	33,837	(25,739)	12,424
Total current liabilities	143,798	238,533	66,851	(80,694)	368,488
Long-term debt	1,233,504	—	114,811	—	1,348,315
Deferred income taxes	137,662	222,528	90,676	(8,259)	442,607
Asset retirement obligations	—	176,657	5,742	—	182,399
Other long-term liabilities	924	2,495	766	77	4,262

Due to parent	—	—	99,352	(99,352)	—
Total liabilities	1,515,888	640,213	378,198	(188,228)	2,346,071
Convertible preferred stock	6,000	—	—	—	6,000
Total equity	1,461,243	1,759,506	481,166	(2,274,453)	1,427,462
	$ 2,983,131	$ 2,399,719	$ 859,364	$ (2,462,681)	$ 3,779,533

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

	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 of assets	—	287	5,960	—	6,247
Selling and administrative expenses	(23,875)	(10,081)	(7,045)	500	(40,501)
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)	(6,238)	—	(21,193)
Income (loss) before income taxes	(18,708)	11,814	(7,253)	(10,389)	(24,536)
(Provision) benefit for income taxes	4,796	(4,215)	4,871	2,109	7,561
Income from continuing operations	(13,912)	7,599	(2,382)	(8,280)	(16,975)
Discontinued operations, net of tax	—	—	(27)	—	(27)
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)

	Three Months Ended March 31, 2009				
	Helix	Guarantors	Non-Guarantors		Consolidated

				Consolidating Entries	
Net revenues	$ 96,082	$ 236,257	$ 262,017	$ (23,381)	$ 570,975
Cost of sales	62,702	149,544	219,193	(21,674)	409,765
Gross profit	33,380	86,713	42,824	(1,707)	161,210
Gain on oil & gas derivative contracts	—	74,609	—	—	74,609
Gain on sale of assets	—	454	—	—	454
Selling and administrative expenses	(11,860)	(8,270)	(22,512)	1,289	(41,353)
Income (loss) from operations	21,520	153,506	20,312	(418)	194,920
Equity in earnings of investments	108,922	(3,804)	7,503	(105,118)	7,503
Net interest expense and other	(9,119)	(5,182)	(7,185)	(709)	(22,195)
Income (loss) before income taxes	121,323	144,520	20,630	(106,245)	180,228
(Provision) benefit for income taxes	(10,991)	(50,346)	(3,972)	390	(64,919)
Income from continuing operations	110,332	94,174	16,658	(105,855)	115,309
Discontinued operations, net of tax	(2,392)	—	(162)	—	(2,554)
Net income (loss) applicable to Helix	107,940	94,174	16,496	(105,855)	112,755
Less: net income applicable to noncontrolling interests	—	—	—	(5,553)	(5,553)
Preferred stock dividends	(313)	—	—	—	(313)
Preferred stock beneficial conversion charges	(53,439)	—	—	—	(53,439)
Net income (loss) applicable to Helix common shareholders	$ 54,188	$ 94,174	$ 16,496	$ (111,408)	$ 53,450

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

	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	(1,183)	(5,880)	35,466
Cash provided by (used in) continuing operations	(18,891)	50,746	(3,592)	(9,799)	18,464
Cash provided by (used in) discontinued operations	—	—	(27)	—	(27)
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 provided by (used in) investing activities	(29,067)	(34,505)	(3,895)	—	(67,467)
Cash flows from financing activities:					

Repayments of debt	(1,082)	—	(2,403)	—	(3,485)
Deferred financing costs	(2,789)	—	—	—	(2,789)
Preferred stock dividends paid and other	(60)	—	(711)	—	(771)
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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HELIX ENERGY SOLUTIONS GROUP, INC.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(in thousands)

	Three Months Ended March 31, 2009				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flow from operating activities:					
Net income (loss), including noncontrolling interests	$ 107,940	$ 94,174	$ 16,496	$ (105,855)	$ 112,755
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by (used in) operating activities:					
Equity in earnings of unconsolidated Affiliates	—	—	320	—	320
Equity in earnings of affiliates	(108,923)	3,804	—	105,119	—
Other adjustments	(46,976)	(29,523)	121,592	5,322	50,415
Cash provided by continuing operations	(47,959)	68,455	138,408	4,586	163,490
Cash provided by discontinued operations	—	—	(1,002)	—	(1,002)
Net cash provided by (used in) operating activities	(47,959)	68,455	137,406	4,586	162,488
Cash flows from investing activities:					
Capital expenditures	(4,573)	(64,829)	(64,261)	—	(133,663)
Investments in equity investments	—	—	(320)	—	(320)
Distributions from equity investments, net	—	—	2,477	—	2,477
Increases in restricted cash	—	—	—	—	—
Proceeds from sales of property	—	22,481	—	—	22,481
Proceeds from sales of subsidiary stock	86,000	—	—	(86,000)	—

Net cash provided by (used in) investing activities	81,427	(42,348)	(62,104)	(86,000)	(109,025)
Cash flows from financing activities:					
Borrowings on revolver	—	—	100,000	—	100,000
Repayments on revolver	(100,000)	—	—	—	(100,000)
Repayments of debt	—	—	—	—	—
Deferred financing costs	(1,082)	—	(22,081)	—	(23,163)
Preferred stock dividends paid	(250)	—	—	—	(250)
Repurchase of common stock	(288)	—	(86,000)	86,000	(288)
Excess tax benefit from stock-based compensation	(1,676)	—	—	—	(1,676)
Exercise of stock options, net	—	—	—	—	—
Intercompany financing	69,992	(30,115)	(35,291)	(4,586)	—
Net cash provided by (used in) financing activities	(33,304)	(30,115)	(43,372)	81,414	(25,377)
Effect of exchange rate changes on cash and cash equivalents	—	—	(114)	—	(114)
Net increase (decrease) in cash and cash equivalents	164	(4,008)	31,816	—	27,972
Cash and cash equivalents:					
Balance, beginning of year	148,704	4,983	69,926	—	223,613
Balance, end of year	$ 148,868	$ 975	$ 101,742	$ —	$ 251,585

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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 acquisition, exploration, development and/or production of oil and gas properties, prospects or other interests and any anticipated costs related thereto;
- statements related to environmental risks, exploration and development risks, or drilling and operating risks;
- statements relating to the construction or acquisition of vessels or equipment and any anticipated costs related thereto;
- statements that our proposed vessels, when completed, will have certain characteristics or the effectiveness of such characteristics;
- 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 any SEC or other governmental or regulatory inquiry or investigation;
- statements regarding anticipated legislative, governmental, regulatory, administrative or other public body actions, requirements, permits or decisions;
- statements regarding anticipated developments, industry trends, performance or industry ranking;
- statements regarding general economic or political conditions, whether international, national or in the regional and local market areas in which we do business;
- statements related to our ability to retain key members of our senior management and key employees;
-

statements related to the underlying assumptions related to any projection or forward-looking statement; and

- any other statements that relate to non-historical or future information.

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

- impact of the weak economic conditions and the future impact of such conditions on the oil and gas industry and the demand for our services;
- uncertainties inherent in the development and production of oil and gas and in estimating reserves;
- the geographic concentration of our 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 derivative 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 2009 Annual Report on Form 10-K ("2009 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

In December 2008, we announced the intention to focus and shape the future direction of the Company around our deepwater construction and well intervention services and that we intend to achieve this strategic focus by seeking and evaluating strategic opportunities to:

1) Divest all or a portion of our oil and gas assets;
2) Divest our ownership interests in one or more of our production facilities; and
3) Dispose of our remaining interest in our majority owned subsidiary, CDI.

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Since the announcement of our strategy to monetize certain of our non core business assets, we have:

- Sold five oil and gas properties for approximately $68 million in gross proceeds;
- Sold a total of 15.2 million shares of CDI common stock held by us to CDI for $100 million in separate transactions in January and June 2009 (Note 4);
- Sold Helix RDS Limited, our subsurface reservoir consulting business for $25 million in April 2009; and
- Sold a total of 45.8 million shares of CDI common stock held by us to third parties in two separate public secondary offerings for approximately $404.4 million, net of underwriting fees in June 2009 and September 2009.

In March 2010, we announced that we have engaged advisors to assist us with evaluating potential alternatives for the complete disposition of our oil and gas business. At the time of the filing of this Current Report on Form 10-Q we do not have an approved or definitive plan for such disposition of our oil and gas business. We are unable to be specific to a timetable for any disposition, which will be largely dependent on the evolving economic and financial market conditions.

Demand for our contracting services operations is primarily influenced by the condition of the oil and gas industry, and in particular, the willingness of oil and gas companies to make capital expenditures for offshore exploration, drilling and production operations. Generally, spending for our contracting services fluctuates directly with the direction of oil and natural gas prices. The performance of our 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.

Economic Outlook and Industry Influences

Although there have been some indicators that the U.S and global economies are stabilizing from the significant downturn experienced since late 2008, there remains a general weakness in the equity and credit capital markets that continues to generate a certain degree of uncertainty regarding the overall outlook of the global economy. Generally, the economic downturn has affected us through decreases in prices of both oil and natural gas. The decreases in oil and natural gas prices not only negatively affected the amount of revenues we receive from the sale of our own production of these commodities but also reduced the demand for our Contracting Services as some oil and gas companies curtailed their capital spending. The demand for our Contracting Services began to soften around mid-year 2009 and this weakening resulted in lower utilization for our Contracting Services assets and reduced margins for many of the services we perform. As a result, we initiated efforts to accelerate some of our internal projects to augment production from our oil and gas properties.

Currently, oil prices are above $80 per barrel, which is significantly higher than prices realized in late 2008 and the first half of 2009. Natural gas prices continue to range between approximately $3.00 and $5.00 per thousand cubic feet (Mcf) of gas, which remains towards the lower end of prices realized over the past five years. We believe that the stabilization in price for both oil and natural gas are contributing to increased energy services capital spending, which in turn could result in additional work opportunities for our Contracting Services business over the remainder of 2010, in particular over the second half of 2010.

Over the longer-term, the fundamentals for our business remain generally favorable as the need for the continual replenishment of oil and gas production should drive the demand for our services.

At March 31, 2010, we had cash on hand of $212.2 million and $385.5 million available for borrowing under our Revolving Credit Facilities. To stabilize the price we receive for our oil and natural gas production we have hedged a substantial portion of our anticipated 2010 production. Our capital expenditures for full year 2010 are expected to total approximately $220 million, which reflects the final construction payments for our Well Enhancer, Caesar and Helix Producer I vessels and the completion of two of our significant deepwater oil and gas properties expected to commence production in 2010 (one achieved first production in February 2010 and the other's initial production is expected in the second quarter of 2010). If we

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successfully implement our business plan, we believe we have sufficient liquidity without incurring additional indebtedness beyond the existing capacity under the Revolving Credit Facility.

Our business is substantially dependent upon the condition of the oil and natural gas industry and, in particular, the willingness of oil and natural gas companies to make capital expenditures for offshore exploration, drilling and production operations. The level of capital expenditures generally depends on the prevailing views of future oil and natural gas prices, which are influenced by numerous 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;
- 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.

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 in accordance with FASB Codification ("ASC") Topic No. 280 Segment Reporting. As a result, our reportable segments consist of the following: Contracting Services, Production Facilities and Oil and Gas. Formerly, we had a third contracting services segment, Shelf Contracting. In June 2009, we ceased consolidating our Shelf Contracting segment, which represented the results and operations of Cal Dive, following the sale of a substantial amount of our remaining ownership of Cal Dive (Note 4). Each line item within our consolidated statement of operations for the three months ended March 31, 2010 is impacted significantly when compared to the same period last year as a result of the deconsolidation of the Cal Dive results. We continued to disclose the operating results of the Shelf Contracting business as a segment through June 10, 2009. See Note 4 elsewhere in this Quarterly Report on Form 10-Q and Note 3 of our 2009 Form 10-K for additional disclosure regarding our transactions that substantially eliminated our ownership interest in Cal Dive.

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

Contracting Services Operations

We seek to provide services and methodologies that we believe are critical to finding and developing offshore reservoirs and maximizing production economics. The Contracting Services segment includes operations such as subsea construction, 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, 2010, our Contracting Services operations had backlog of approximately $314 million, including $268 million for 2010. At December 31, 2009, our Contracting Services backlog totaled approximately $251 million, including $217 million for 2010. 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 asset utilization of our contracting services business 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.

Discontinued Operations

In April 2009, we sold Helix RDS Limited to a subsidiary of Baker Hughes Incorporated for $25 million. Helix RDS is a provider of reservoir engineering, geophysical, production technology and associated specialized consulting services to the upstream oil and gas industry. We have presented the results of Helix RDS as discontinued operations in the accompanying condensed consolidated financial statements (Note 2). Helix RDS was previously a component of our Contracting Services business.

Comparison of Three Months Ended March 31, 2010 and 2009

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

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009	Increase/ (Decrease)
Revenues (in thousands) –			
Contracting Services	$ 154,200	$ 230,855	$ (76,655)
Shelf Contracting		207,053	(207,053)
Oil and Gas	90,715	160,181	(69,466)
Production Facilities	1,320		1,320
Intercompany elimination	(44,665)	(27,114)	(17,551)
	$ 201,570	$ 570,975	$ (369,405)
Gross profit (in thousands) –			
Contracting Services	$ 37,622	$ 47,253	$ (9,631)
Shelf Contracting		38,805	(38,805)
Oil and Gas	1,249	76,114	(74,865)
Production Facilities	21		21
Corporate	(714)	(672)	(42)
Intercompany elimination	(12,322)	(290)	(12,032)
	$ 25,856	$ 161,210	$ (135,354)
Gross Margin –			
Contracting Services	24 %	20 %	4 pts
Shelf Contracting	%	19 %	N/A
Oil and Gas	1 %	48 %	(47) pts
Total company	13 %	28 %	(15) pts
Number of vessels(1)/ Utilization(2) –			

Contracting Services:				
Construction vessels	7/83	%	8/79	%
Well operations	3/60	%	2/76	%
ROVs	47/59	%	46/64	%
Shelf Contracting	N/A		30/49	%

(1) Represents number of vessels as of the end of the period excluding acquired vessels prior to their in-service dates and vessels taken out of service prior to their disposition.

(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.

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Intercompany segment revenues during the three months ended March 31, 2010 and 2009 were as follows (in thousands):

	Three Months Ended March 31, 2010	2009	Increase/ (Decrease)
Contracting Services	$ 43,741	$ 23,903	$ 19,838
Production Facilities	924		924
Shelf Contracting		3,211	(3,211)
	$ 44,665	$ 27,114	$ 17,551

Intercompany segment profit during the three months ended March 31, 2010 and 2009 was as follows (in thousands):

	Three Months Ended March 31, 2010	2009	Increase/ (Decrease)
Contracting Services	$ 11,442	$ (104)	$ 11,546
Production Facilities	880		880
Shelf Contracting		394	(394)
	$ 12,322	$ 290	$ 12,032

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, 2010	2009	Increase/ (Decrease)
Oil and Gas information–			
Oil production volume (MBbls)	655	820	(165)
Oil sales revenue (in thousands)	$ 47,008	$ 47,391	$ (383)
Average oil sales price per Bbl (excluding hedges)	$ 75.69	$ 51.74	$ 23.95
Average realized oil price per Bbl (including hedges)	$ 71.82	$ 57.82	$ 14.00
Increase (decrease) in oil sales revenue due to:			
Change in prices (in thousands)	$ 11,474		
Change in production volume (in thousands)	(11,857)		
Total decrease in oil sales revenue (in thousands)	$ (383)		
Gas production volume (MMcf)	7,343	6,990	353
Gas sales revenue (in thousands)	$ 42,185	$ 37,431	$ 4,754
	$ 5.29	$ 5.30	$ (0.01)

Average gas sales price per mcf (excluding hedges)			
Average realized gas price per mcf (including hedges)	$ 5.75	$ 5.35	$ 0.40
Increase in gas sales revenue due to:			
Change in prices (in thousands)	$ 2,727		
Change in production volume (in thousands)	2,027		
Total increase in gas sales revenue (in thousands)	$ 4,754		
Total production (MMcfe)	11,270	11,908	(638)
Price per Mcfe	$ 7.91	$ 7.12	$ 0.79
Oil and Gas revenue information (in thousands)–			
Oil and gas sales revenue	$ 89,193	$ 84,822	$ 4,371
Other revenues(1)	1,522	75,359	(73,837)
	$ 90,715	$ 160,181	$ (69,466)

(1) Other revenues include fees earned under our process handling agreements. The amount in 2009 also included $73.5 million of previously accrued royalty payments involved in a legal dispute that were reversed in January 2009 following a favorable ruling by the Fifth District Court of Appeals, which rendered the probability of being required to make these payments remote (Note 6).

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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,			
	2010		2009	
	Total	Per Mcfe	Total	Per Mcfe
	(in thousands, except per Mcfe amounts)			
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$ 14,523	$ 1.29	$ 18,599	$ 1.56
Workover	11,613	1.03	780	0.07
Transportation	1,293	0.11	1,202	0.10
Repairs and maintenance	1,808	0.16	2,743	0.23
Overhead and company labor	1,925	0.17	1,462	0.12
	$ 31,162	$ 2.76	$ 24,786	$ 2.08
Depletion expense	$ 40,205	$ 3.57	$ 44,088	$ 3.70
Abandonment	765	0.07	745	0.06
Accretion expense	4,003	0.36	4,003	0.34
Net hurricane costs	2,055	0.18	9,610	0.81
Impairment	11,112	0.99	358	0.03
	58,140	5.17	58,804	4.94
Total	$ 89,302	$ 7.93	$ 83,590	$ 7.02

(1) Excludes exploration expense of $0.2 million and $0.5 million for the three months ended March 31, 2010 and 2009, respectively. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

The following table contains selected data extracted from our condensed consolidated statements of operations. This information is presented to the illustrate amounts associated with our Contracting Services and Oil and Gas businesses. The second table modifies the first table to illustrate the effect of deconsolidating the Shelf Contracting business (Cal Dive) had on our operating results (Note 4). These results are provided to facilitate the understanding of the variances in our results of operations for the comparative three-month periods ended March 31, 2010 and 2009:

	2010			2009		
	Contracting Services	Oil and Gas	Total	Contracting Services	Oil and Gas	Total
	(amounts in thousands)					
Revenues	$110,855	$90,715	$201,570	$410,794	$160,181	$570,975
Gross Profit	24,607	1,249	25,856	85,096	76,114	161,210
Gain on sale or acquisition of assets	-	6,247	6,247	-	454	454
Selling and administrative expenses	32,342	8,159	40,501	35,359	5,994	41,353
Equity in earnings of investment	5,055	-	5,055	7,503		7,503
Net interest expense and other	16,202	4,991	21,193	16,521	5,674	22,195

The following table modifies the preceding table to illustrate the effect that our now deconsolidated Shelf Contracting business (Cal Dive) had on our Contracting Services operating results in the first quarter of 2009 (Note 4). These results are provided to facilitate the understanding of the variances discussed below of our Contracting Services operations as reported on an continuing basis for the comparative three month periods ended March 31, 2009 and 2010 (amounts in thousands):

	2009			2010	
	Contracting Services as reported	Less Shelf Contracting	Continuing Contracting Services	Contracting Services	Variance Of Continuing Contracting Services
			(amounts in thousands)		
Revenues	$ 410,794	$ 207,053	$ 203,741	$ 110,855	$ (92,886)
Gross Profit	85,096	38,805	46,291	24,607	(21,684)
Gain on sale or acquisition of assets	-	-	-	-	-
Selling and administrative expenses	35,359	17,873	17,486	32,342	14,856
Equity in earnings of investment	7,503	-	7,503	5,055	(2,448)
Net interest expense and other	16,521	3,176	13,345	16,202	2,857

In following discussion of our results of operations discussion of our Contracting Services specifically refers to those businesses in which we continue to operate. We no longer have any Shelf Contracting operations. The preceding table provides the variances of our continuing Contracting Services that are discussed below.

Revenues. Our continuing Contracting Services revenues decreased 46% for the three months ended March 31, 2010 compared to the same period in 2009 reflecting the increased amount of internal vessel utilization to develop our oil and gas properties, decreased margins reflecting the continuation of generally soft industry conditions, a scheduled dry docking of our Seawell vessel and the completion of a large international construction project in the second quarter of 2009. Overall utilization levels for well operations and ROVs decreased while utilization for our subsea construction vessels increased. The decrease for our well operations vessels primary reflects the out-of-service days for the scheduled regulatory dry docking of the Seawell in February 2010.

Oil and Gas revenues decreased 43% during the three months ended March 31, 2010 as compared to the same period in 2009. The decrease is substantially attributed to the $73.5 million of previously accrued royalty payments that we recognized in the first quarter of 2009 following a favorable judicial ruling in the dispute over the lessee's responsibility to make these payments (Note 6). For additional information regarding the resolution of these previously disputed royalty payments see Note 17 of our 2009 Form 10-K. Excluding the effect of these royalty payments our oil and gas revenues increased by 5% primarily reflecting higher oil and natural gas prices. Our production was 0.6 billion cubic feet of natural gas equivalent (Bcfe) less in the first quarter of 2010 as compared to the same period in 2009. Our production in the first quarter of 2010 was adversely affected by well workover activities at our Noonan gas field at Garden Bank Block 506 and mechanical platform issues at our East Cameron Block 346 field. These issues have been resolved and both the Noonan gas field and the East Cameron Block 346 field, including our Danny oil field have resumed normal production rates. For the month of April our production rate approximated 136 MMcfe/d as compared to an approximate average of 125 MMcfe/d in the first quarter of 2010.

Gross Profit. Our Contracting Services gross profit decreased by 47% primarily reflecting the generally soft industry conditions, which contributed to lower vessel utilization and contracting rates as well as to our increased scope of internal work related to our oil and gas properties.

The Oil and Gas gross profit decrease of $74.9 million in first quarter 2010 as compared to the same period in 2009 was primarily attributable to the reversal of the disputed accrued royalties as previously discussed above. Excluding these royalty payments, gross profit between the comparable first quarter periods would have decreased $1.4 million, which reflects higher lease operating costs, including higher workover costs offset in part by increased revenues reflecting higher prices for both oil and natural gas received during the first quarter of 2010. Further, following decreases in natural gas prices from those in effect at year end 2009, in the first quarter of 2010 we were required to record $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 6).

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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 6). The sales in the first quarter of 2009 reflected the sale of East Cameron Block 316 for gross proceeds of $18 million ($0.7 million gain) and the remaining 10% of our interest in the Bass Lite field in January 2009.

Selling and Administrative Expenses. Selling and administrative expenses of $40.5 million for the first quarter of 2010 were $17.0 million higher than the $23.5 million incurred in the same prior year period after excluding our Shelf Contracting expense. The increase reflects the $17.5 million related to our settlement of litigation claims in Australia (Note 16) and approximately $1.9 million of charges related to the resignation of our former Executive Vice President-Oil and Gas (see Part II, Other Information - Item 6. Exhibits – Exhibit 10.1 for information regarding the resignation of this executive officer).

Equity in Earnings of Investments. Equity in earnings of investments decreased by $2.4 million during the three months ended March 31, 2010 as compared to the same prior year period. This decrease was mostly due to lower throughput at both our Deepwater Gateway and Independence facilities and the start-up costs related to the Helix Clough Joint Venture in Australia (Note 16).

Net Interest Expense and Other. We reported net interest and other expense of $21.2 million in first quarter 2010 as compared to $22.2 million in the same prior year period. Gross interest expense of $26.0 million during the three months ended March 31, 2010 was lower than the $29.9 million incurred in 2009 reflecting both lower interest rates and lower balances outstanding. Capitalized interest totaled $8.5 million for the three months ended March 31, 2010 compared with $7.6 million for the same period last year. Interest income totaled $1.9 million for the three months ended March 31, 2010 compared with $0.3 million in the comparable period in 2009. In the first quarter of 2010 we recorded losses on our foreign exchange forward contracts totaling $2.9 million compared to a gain of $0.6 million in the first quarter of 2009 (Note 18).

Provision for Income Taxes. Income taxes reflect a benefit of $7.6 million in the first quarter of 2010 compared to income tax expense of $64.9 million in the same period last year. The variance primarily reflects decreased profitability in the current year period and the deconsolidation of the CDI in 2009. The effective tax rate of 30.8% for the first quarter of 2010 was lower than the 36.0% effective tax rate for the first quarter of 2009 as a result of the deconsolidation of CDI in 2009 and the increased benefit derived from the effect of lower tax rates in certain foreign jurisdictions.

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, 2010	December 31, 2009
	(in thousands)	
Net working capital	$ 178,483	$ 197,072
Long-term debt(1)	1,347,007	1,348,315

(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 that was recorded effective with the adoption of a new accounting standards effective January 1, 2009 (see Note 2 of 2009 Form 10-K).

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The carrying amount of our debt, including current maturities as of March 31, 2010 and December 31, 2009 follow :

	March 31, 2010	December 31, 2009
	(in thousands)	
Term Loan (matures July 2013)	$ 413,685	$ 414,766
Revolving Credit Facility (matures November 2012)		
Convertible Senior Notes (matures March 2025) (1)	275,131	273,064
Senior Unsecured Notes (matures January 2016)	550,000	550,000
MARAD Debt (matures August 2027)	117,050	119,235
Loan Notes(2)	2,975	3,674
Total	$ 1,358,841	$ 1,360,739

(1) Net of the unamortized debt discount resulting from adoption of new provisions of ASC Topic No. 470-20 "Convertible Debt and Other Options" on January 1, 2009. The notes will increase to $300 million face amount through accretion of non-cash interest charges through 2012.

(2) Assumed to be current, represents the loan provided by Kommandor RØMØ to Kommandor LLC (Note 16).

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

	Three Months Ended March 31,	
	2010	2009
	(in thousands)	
Net cash provided by (used in):		
Operating activities	$ 18,437	$ 162,488
Investing activities	$ (67,467)	$ (109,025)
Financing activities	$ (9,863)	$ (25,377)

As of March 31, 2010, our liquidity totaled $597.7 million, including cash and cash equivalents of $212.2 million and $385.5 million of available borrowing capacity under our Revolving Credit Facility.

Our current requirements for cash primarily reflect the need to fund capital expenditures to allow the growth of our current lines of business and to service our existing debt. We also intend to repay debt with any additional free cash flow from operations and/or cash received from any dispositions of our non core business assets. Historically, we have funded our capital program, including acquisitions, with cash flow from operations, borrowings under credit facilities and use of project financing along with other debt and equity alternatives.

We continue to focus on improving our balance sheet by increasing our liquidity through reductions in planned capital spending and potential additional dispositions of our non-core business assets. 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 for 2010. We believe that internally generated cash flow and available borrowing capacity under our amended Revolving Credit Facility (Note 9) will be sufficient to fund our operations. In the first half of 2009, we repaid the remaining $349.5 million of borrowing under our revolving credit facility.

In accordance with our Credit Agreement, Senior Unsecured Notes, the 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. As of March 31, 2010 and December 31, 2009, we were in compliance with these covenants and restrictions.

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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.

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, it could lead to an event of default, the possible acceleration of our repayment of outstanding debt and the exercise of certain remedies by the lenders, including foreclosure on our pledged collateral.

The Convertible Senior Notes can be converted prior to the 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 balance sheet. No conversion triggers were met during either the first quarter of 2010 or 2009.

As discussed above, we amended our Credit Agreement in October 2009 and again in February 2010. 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 for periods beginning on or after March 31, 2010. See Note 9 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 decreased by $144.1 million in the three months ended March 31, 2010 as compared to the same period in 2009. This decrease includes the effect of recognizing $73.5 million of previously disputed cash royalty payments that we had been deferring until January 2009 (Note 6), the deconsolidation of Cal Dive in June 2009, our increased internal utilization of vessels for developing our oil and gas properties and a decrease in our working capital cash flows.

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 of oil and gas properties and investments in our production facilities. Significant sources (uses) of cash associated with investing activities for the three months ended March 31, 2010 and 2009 were as follows:

	Three Months Ended March 31,	
	2010	2009
	(in thousands)	
Capital expenditures:		
Contracting Services	$ (14,978)	$ (65,745)

Shelf Contracting		(27,275)
Production Facilities	(29,325)	(11,712)
Oil and Gas	(24,125)	(28,931)
Investments in production facilities		(320)
Distributions from equity investments, net(1)	965	2,477
Proceeds from sale of properties and other	(4)	22,481
Cash (used in) provided by investing activities	$ (67,467)	$ (109,025)

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

Restricted Cash

As of March 31, 2010 and December 31, 2009, we had $45.4 million and $35.4 million of restricted cash. The $10.0 million increase in our restricted cash since year end 2009 reflects the escrowed funds we acquired in the Camelot acquisition in February 2010 (Note 6). This amount is reflected in other current assets in the accompanying condensed consolidated balance sheet at March 31, 2010. The remaining $35.4 million of restricted cash at March 31, 2010 and December 31, 2009, respectively, relates entirely to the funds contractually required to be escrowed to cover the asset retirement obligations associated with the 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 made the following contributions to our equity investments during the three months ended March 31, 2010 and 2009 (in thousands):

	Three Months Ended March 31,	
	2010	2009
	(in thousands)	
Independence	$	$
Other		320
Total	$	$ 320

We received the following distributions from our equity investments during the three months ended March 31, 2010 and 2009:

	Three Months Ended March 31,	
	2010	2009
	(in thousands)	
Deepwater Gateway.	$ 2,250	$ 3,500
Independence	4,900	6,800
Other	268	
Total	$ 7,418	$ 10,300

Sale of Oil and Gas Properties

In the first quarter of 2009 we sold our remaining 10% interests in the Bass Lite field for $4.5 million and our interests in East Cameron Block 316 for $18 million.

Outlook

We anticipate capital expenditures for the remainder of 2010 will total between $150 million and $160 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 or inability to execute sales transactions related to our non core business assets. We believe internally generated cash flow, cash from future sales of our non-core business assets, and borrowings under our existing credit facilities will provide the capital necessary to fund our 2010 initiatives.

The following table summarizes our contractual cash obligations as of March 31, 2010 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	413,685	4,326	8,652	400,707	
MARAD debt	117,050	4,533	9,757	10,755	92,005
Revolving Credit Facility					
Loan notes	2,975	2,975			
Interest related to long-term debt	548,566	80,989	158,716	137,909	170,952
Drilling and development costs	67,063	67,063			
Property and equipment (3)	15,703	15,703			
Operating leases(4)	96,841	51,123	42,423	2,764	531
Total cash obligations	$2,111,883	$226,712	$219,548	$552,135	$1,113,488

(1) Excludes unsecured letters of credit outstanding at March 31, 2010 totaling $49.5 million. These letters of credit primarily guarantee various contract bidding, contractual obligations and insurance activities.

(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. 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, 2010, the conversion trigger was not met.

(3) Costs incurred as of March 31, 2010 and additional property and equipment commitments at March 31, 2010 consisted of the following (in thousands):

	Costs Incurred (a)	Costs Committed	Total Estimated Project Cost Range
Caesar conversion	$ 273,112	$ 4,882	$ 290,000 – 300,000
Well Enhancer construction	237,110	2,490	250,000 – 260,000

Helix Producer I(b)	337,954	8,331	350,000 – 360,000
Total	$ 848,176	$ 15,703	$ 890,000 – 920,000

(a) Includes capitalized interest.

(b) Represents 100% of the cost of the vessel, conversion and construction of additional facilities.

(4) Operating leases included facility leases and vessel charter leases. Vessel charter lease commitments at March 31, 2010 were approximately $83.5 million.

Contingencies

In March 2009, we were notified of a third party's intention to terminate an international construction contract based on a claimed breach of that contract by one of our subsidiaries. Under the terms of the contract, our potential liability was generally capped for actual damages at approximately $27 million Australian dollars ("AUD") (approximately $24.3 million US dollars at December 31, 2009) and for liquidated damages at approximately $5 million AUD (approximately $4.5 million US dollars at December 31, 2009). We asserted a counterclaim that in the aggregate approximates $12 million U.S. dollars. On March 30, 2010, an out of court settlement of these claims was negotiated. Under terms of the agreement, in April 2010 we paid the third party $15 million AUD to settle all their damage claims against us. We also agreed not to seek any further payment of our counter claims against them. Our condensed consolidated statement of operations for the three months ended March 31, 2010 includes 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. The charges were recorded as a component of our general and administrative expenses.

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CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our discussion and analysis of our financial condition and results of operations are based upon our 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 2009 Form 10-K.

RECENT ACCOUNTING STANDARDS

In January 2010, the Financial Accounting Standard Board ("FASB") issued Accounting Standards Update ("ASU") No. 2010-06, "Improving Disclosures about Fair Value Measurements" an amendment to ASC Topic 820. This amendment requires an entity to: (i) disclose separately the amounts of significant transfers in and out of Level 1 and Level 2 fair value measurements and describe the reason for the transfers and (ii) present separate information for Level 3 activity pertaining to gross purchases, sales, issuances, and settlements. This amendment is effective interim and annual reporting periods beginning after December 15, 2009, We adopted this ASU effective January 1, 2010.

In June 2009, the FASB issued ASC Topic 810 (originally issued as Statement of Financial Accounting Standards No. 167, "Amendments to FASB Interpretation No. ("FIN") 46(R)"). Among other items, ASC 810 responds to concerns about an enterprise's application of certain key provisions of FIN 46(R), including those regarding the transparency of the enterprise's involvement with variable interest entities. ASC 810 is effective for calendar year-end companies beginning on January 1, 2010. We adopted the standard for the interim period ended March 31, 2010. There was no impact on the our financial position, results of operations, cash flows, or disclosures.

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, 2010, we had the following volumes under derivative contracts related to our oil and gas producing activities totaling approximately 3.0 MMBbl of oil and 18.6 Bcf of natural gas:

Production Period	Instrument Type	Average Monthly Volumes		Weighted Average Price
Crude Oil:				(per barrel)
April 2010 — December 2010	Collar	100	MBbl	\$62.50-\$80.73
April 2010 — December 2010	Swap	99.4	MBbl	\$77.12
April 2010 — June 2010	Swap	50	MBbl	\$71.08
July 2010 — December 2010	Swap	175	MBbl	\$80.80

Natural Gas:			(per Mcf)
April 2010 — December 2010	Swap	1,061.1 Mmcf	$5.82
April 2010 — December 2010	Collar	1,008.3 Mmcf	$6.00 — $6.70

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 18).

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Item 4. Controls and Procedures

(a) Evaluation of disclosure controls and procedures. Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Exchange Act) as of the end of the fiscal quarter ended March 31, 2010. 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, 2010 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, 2010.

Part II. OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Note 16 to the Condensed Consolidated Financial Statements, which is incorporated herein by reference.

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

Issuer Purchases of Equity Securities

Period	(a) Total number of shares purchased	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced program	(d) Maximum value of shares that may yet be purchased under the program
January 1 to January 31, 2010(1)	54,001	$ 11.75		451,569
February 1 to February 28, 2010(1)	1,464	11.51		451,569
March 1 to March 31, 2010(1)	23,590	13.84		451,569
	79,055	$ 12.37		451,569

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

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Item 6. Exhibits

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 Robert P. Murphy effective March 8, 2010. Incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed by registrant with Securities and Exchange Commission on March 8, 2010.
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

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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 30, 2010	By: /s/ Owen Kratz Owen Kratz President and Chief Executive Officer (Principal Executive Officer)
Date: April 30, 2010	By: /s/ Anthony Tripodo Anthony Tripodo Executive Vice President and Chief Financial Officer (Principal Financial Officer)

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