HELIX ENERGY SOLUTIONS GROUP INC
Form 10-Q
May 11, 2009

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, 2009

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):
[√] Accelerated filer [ ] [ ]

Large 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 30, 2009, 98,379,842 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, 2009 (Unaudited)	December 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 251,585	$ 223,613
Accounts receivable —		
Trade, net of allowance for uncollectible accounts of $6,203 and $5,904, respectively	385,090	427,856
Unbilled revenue	43,795	42,889
Costs in excess of billing	67,927	74,361
Other current assets	200,269	172,089
Net assets of discontinued operations	17,153	19,215
Total current assets	965,819	960,023
Property and equipment	4,803,576	4,742,051
Less — accumulated depreciation	(1,384,226)	(1,323,608)
	3,419,350	3,418,443
Other assets:		
Equity investments	194,087	196,660
Goodwill	365,641	366,218
Other assets, net	117,791	125,722
	$ 5,062,688	$ 5,067,066
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 271,969	$ 344,807
Accrued liabilities	209,215	231,679
Income tax payable	26,921	—
Current maturities of long-term debt	93,644	93,540
Current liabilities of discontinued operations	6,489	2,772
Total current liabilities	608,238	672,798
Long-term debt	1,912,357	1,933,686
Deferred income taxes	657,138	615,504
Decommissioning liabilities	196,836	194,665
Other long-term liabilities	8,723	81,637
Total liabilities	3,383,292	3,498,290
Convertible preferred stock	25,000	55,000
Commitments and contingencies	—	—
Shareholders' equity:		
Common stock, no par, 240,000 shares authorized,	891,809	806,905

98,376 and 91,972 shares issued, respectively		
Retained earnings	471,390	417,940
Accumulated other comprehensive loss	(41,772)	(33,696)
Total controlling interest shareholders' equity	1,321,427	1,191,149
Noncontrolling interests	332,969	322,627
Total equity	1,654,396	1,513,776
	$ 5,062,688	$ 5,067,066

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, 2009	Three Months Ended March 31, 2008
Net revenues:		
Contracting services	$ 410,794	$ 270,718
Oil and gas	160,181	171,051
	570,975	441,769
Cost of sales:		
Contracting services	325,698	213,514
Oil and gas	84,067	109,672
	409,765	323,186
Gross profit	161,210	118,583
Gain on oil and gas derivative contracts	74,609	—
Gain on sale of assets, net	454	61,113
Selling and administrative expenses	(41,353)	(46,168)
Income from operations	194,920	133,528
Equity in earnings of investments	7,503	10,816
Net interest expense and other	(22,195)	(28,001)
Income before income taxes	180,228	116,343
Provision for income taxes	(64,919)	(42,700)
Income from continuing operations	115,309	73,643
Discontinued operations, net of tax	(2,554)	559
Net income, including noncontrolling interests	112,755	74,202
Net income applicable to noncontrolling interests	(5,553)	(237)
Net income applicable to the Helix	107,202	73,965

Preferred stock dividends	(313)	(881)
Preferred stock beneficial conversion charges	(53,439)	—
Net income applicable to Helix common shareholders	$ 53,450	$ 73,084
Basic earnings per share of common stock:		
Continuing operations	$ 0.58	$ 0.79
Discontinued operations	(0.03)	0.01
Net income per common share	$ 0.55	$ 0.80
Diluted earnings per share of common stock:		
Continuing operations	$ 0.52	$ 0.76
Discontinued operations	(0.02)	0.01
Net income per common share	$ 0.50	0.77
Weighted average common shares outstanding:		
Basic	95,052	90,413
Diluted	105,863	95,086

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, 2009	Three Months Ended March 31, 2008
Cash flows from operating activities:		
Net income, including noncontrolling interests	$ 112,755	$ 74,202
Adjustments to reconcile net income, including noncontrolling interests to net cash provided by operating activities —		
Depreciation and amortization	82,893	84,554
Asset impairment charge and dry hole expense	361	16,671
Equity in earnings of investments, net of distributions	320	81
Amortization of deferred financing costs	1,482	1,062
(Income) loss from discontinued operations	2,554	(559)
Stock compensation expense	4,084	8,079
Amortization of debt discount	1,938	1,816
Deferred income taxes	43,699	5,763
Excess tax benefit from stock-based compensation	1,676	(629)
Gain on sale of assets	(454)	(61,113)
Unrealized gain on derivative contracts	(55,420)	—
Changes in operating assets and liabilities:		
Accounts receivable, net	41,134	112,355
Other current assets	(2,448)	(4,924)
Income tax payable	54,518	36,861
Accounts payable and accrued liabilities	(51,713)	(116,297)
Other noncurrent, net	(73,889)	(30,721)
Cash provided by operating activities	163,490	127,201
Cash provided by (used in) discontinued operations	(1,002)	(1,635)
Net cash provided by operating activities	162,488	125,566
Cash flows from investing activities:		
Capital expenditures	(133,663)	(241,550)
Investments in equity investments	(320)	(207)

Distributions from equity investments, net	2,477	5,995
Increase in restricted cash	—	(232)
Proceeds from sales of property	22,481	110,147
Net cash used in investing activities	(109,025)	(125,847)
Cash flows from financing activities:		
Repayment of Helix Term Notes	(1,082)	(1,082)
Borrowings on Helix Revolver	—	318,500
Repayments on Helix Revolver	(100,000)	(185,000)
Repayment of MARAD borrowings	(2,081)	(1,982)
Borrowings on CDI Revolver	100,000	—
Repayments on CDI Term Note	(20,000)	(40,000)
Deferred financing costs	—	(409)
Preferred stock dividends paid	(250)	(881)
Repurchase of common stock	(288)	(3,309)
Excess tax benefit from stock-based compensation	(1,676)	629
Exercise of stock options, net	—	321
Net cash provided by (used in) financing activities	(25,377)	86,787
Effect of exchange rate changes on cash and cash equivalents	(114)	58
Net increase in cash and cash equivalents	27,972	86,564
Cash and cash equivalents:		
Balance, beginning of year	223,613	89,555
Balance, end of period	$ 251,585	$ 176,119

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

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

Note 1 – Basis of Presentation

The accompanying condensed consolidated financial statements include the accounts of Helix Energy Solutions Group, Inc. and its majority-owned subsidiaries (collectively, "Helix" or the "Company"). Unless the context indicates otherwise, the terms "we," "us" and "our" in this report refer collectively to Helix and its majority-owned subsidiaries, including Cal Dive International Inc. ("Cal Dive" or "CDI"). All material intercompany accounts and transactions have been eliminated. These condensed consolidated financial statements are unaudited, 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 Annual Report on Form 10-K for the year ended December 31, 2008 ("2008 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. Operating results for the period ended March 31, 2009 are not necessarily indicative of the results that may be expected for the year ending December 31, 2009. Our balance sheet as of December 31, 2008 included herein has been derived from the audited balance sheet as of December 31, 2008 included in our 2008 Form 10-K. These condensed consolidated financial statements should be read in conjunction with the annual consolidated financial statements and notes thereto included in our 2008 Form 10-K.

Certain reclassifications were made to previously reported amounts in the condensed consolidated financial statements and notes thereto to make them consistent with the current presentation format, including the adoption of certain recent accounting pronouncement that require retrospective application (Note 3).

Note 2 – Company Overview

We are an international offshore energy company that provides reservoir development solutions and other contracting services to the energy market as well as to our own oil and gas properties. Our Contracting Services segment utilizes our vessels, offshore equipment and proprietary technologies to deliver services that may reduce finding and development costs and cover 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 Middle East regions. Our Oil and Gas segment engages in prospect generation, 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, particularly from marginal fields. By "marginal", we mean reservoirs that are no longer wanted by major operators or are too small to be material to them. Our "life of field" services are segregated into four disciplines: construction, well operations, drilling, and production facilities. We have disaggregated our contracting services operations into three reportable segments in accordance with Financial Accounting Standards Board ("FASB") Statement No. 131 Disclosures about Segments of an Enterprise and Related Information ("SFAS No. 131"): Contracting Services, Shelf Contracting and Production Facilities. Our Contracting

Services business includes subsea construction, well operations, robotics and drilling. Our Shelf Contracting business represents the assets of CDI, of which we owned 57.2% at December 31, 2008. In January 2009, our ownership of CDI was reduced to approximately 51% (Note 3). Our Production Facilities business includes our investments in Deepwater Gateway, L.L.C. ("Deepwater Gateway") and Independence Hub, LLC ("Independence Hub").

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Oil and Gas Operations

In 1992 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 to our contracting services. Since 1992, 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 February 2009, our board of directors approved a formal plan to market and to sell our reservoir and well technology services business. On April 27, 2009, we sold Helix Energy Limited ("HEL") to a subsidiary of Baker Hughes Incorporated for $25 million. HEL through its subsidiary, Helix RDS Limited is a provider of reservoir engineering, geophysical, production technology and associated specialized consulting services to the upstream oil and gas industry. As a result of the formal efforts to sell HEL and Helix RDS Limited, we have presented the results of Helix RDS as discontinued operations in the accompanying condensed consolidated financial statements. HEL and Helix RDS were previously components of our Contracting Services segment. No asset or liability of HEL and Helix RDS are material to any single line item in our accompanying condensed consolidated balance sheet. .

Economic Outlook

The continued economic downturn and weakness in the equity and credit capital markets has led to increased uncertainty regarding the outlook of the global economy. This uncertainty coupled with the decrease in the near-term global demand for oil and gas resulted in commodity price declines over the second half of 2008, with significant declines occurring in the fourth quarter of 2008. A decline in oil and gas prices negatively impacts our operating results and cash flows. Our stock price also significantly declined over the second half of 2008. The decline in our stock price and the prices of oil and natural gas were considered in association with our required annual impairment assessment of goodwill and properties at year end 2008, which resulted in significant impairment charges (see Note 2 of our "2008 Form 10-K"). Our stock price decreased further in the first quarter of 2009 resulting in our assessment our goodwill amounts as of March 31, 2009; however, no further impairments were required. Our stock price has recently increased; however, we are required to continue to monitor our remaining $365.6 million of goodwill as of March 31, 2009, of which $73.1 million is included within Contracting Services and $292.5 million for the Shelf Contracting. Our Contracting Services and Shelf Contracting segments may be negatively impacted by low commodity prices because that may cause our customers, primarily oil and gas companies, to curtail or eliminate capital spending. We have stabilized the price for a significant portion of our anticipated oil and gas production for 2009 when we entered into commodity hedges during 2008, which is enabling us to minimize our near-term cash flow risks related to declining commodity prices (Note 17). As of March 31, 2009 and as of the time of this filing on May 8, 2009, the prices for these contracts are significantly higher than the forward market prices for both crude oil and natural gas over the remainder of 2009. In March 2009, we entered into additional financial swap contracts for a portion of our anticipated 2010 natural gas production. These prices approximate the future strip price for natural gas. If the prices for crude oil and natural gas do not increase from current levels, our oil and gas revenues may decrease in 2010 and beyond, perhaps significantly, absent increases in production amounts.

Note 3 – Recent Accounting Pronouncements

In September 2006, the FASB issued Statement No. 157, Fair Value Measurements ("SFAS No. 157"). SFAS No. 157 was originally effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. The FASB agreed to defer the effective date of SFAS No. 157 for all nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis. We adopted the provisions of SFAS No. 157 on January 1, 2008 for assets and liabilities not subject to the deferral and adopted this standard for all other assets and liabilities on January 1, 2009. The adoption of SFAS No. 157 had no material impact on our results of operations, financial condition and liquidity.

SFAS No. 157, among other things, defines fair value, establishes a consistent framework for measuring fair value and expands disclosure for each major asset and liability category measured at fair value on either a recurring or nonrecurring basis. SFAS No. 157 clarifies that fair value is an exit price, representing the amount that would be received to sell an asset, or paid to transfer a liability, in an orderly transaction between market participants. SFAS No. 157 establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value as follows:

- 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 noted in SFAS No. 157. The valuation techniques are 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, 2009 (in thousands):

	Level 1	Level 2	Level 3	Total	Valuation Technique
Assets:					
Oil and gas swaps and collars	– $	77,939	– $	77,939	(c)
Foreign currency forwards	–	29	–	29	(c)
Liabilities:					
Gas swaps and collars	–	1,227	–	1,227	(c)
Foreign currency forwards	–	559	–	559	(c)
Interest rate swaps	–	7,231	–	7,231	(c)
Total	– $	68,951	– $	68,951	

In December 2007, the FASB issued Statement No. 141 (Revised), Business Combinations ("SFAS No. 141(R)"). SFAS No. 141 (R) requires the acquiring entity in a business combination to recognize all the assets acquired and liabilities assumed in the transaction; establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. It also requires that the costs incurred related to the acquisition be charged to expense as incurred, when previously these costs were capitalized as part of the acquisition cost of the asset or business. We adopted the provisions of SFAS No. 141(R) on January 1, 2009 and it had no impact on our results of operations, cash flows and financial condition.

In December 2007, the FASB issued Statement No. 160, Noncontrolling Interests in Consolidated Financial Statements — an amendment of ARB 51 ("SFAS No. 160"). SFAS No. 160 improves the relevance, comparability, and transparency of financial information provided to investors by requiring all entities to report noncontrolling (minority) interests in subsidiaries as equity in the consolidated financial statements. We adopted SFAS No. 160 on January 1, 2009, which is required to be adopted prospectively, except the following provisions must be adopted retrospectively:

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1. Reclassifying noncontrolling interest from the "mezzanine" to equity, separate from the parents' shareholders' equity, in the statement of financial position; and
2. Recast consolidated net income to include net income attributable to both the controlling and noncontrolling interests. That is, retrospectively, the noncontrolling interests' share of a consolidated subsidiary's income should not be presented in the income statement as "minority interest."

Effective January 1, 2009, we changed our accounting policy of recognizing a gain or loss upon any future direct sale or issuance of equity by our subsidiaries if the sales price differs from our carrying amount to be in accordance with SFAS No. 160, in which a gain or loss will only be recognized when loss of control of a consolidated subsidiary occurs. In January 2009, we sold approximately 13.6 million shares of CDI common stock to CDI 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 CDI. Our ownership of CDI following the transaction approximated 51%. Since we retained control of CDI immediately after the transaction, the approximate $2.9 million loss on this sale was treated as a reduction of our equity in the accompanying condensed consolidated balance sheet. Any future significant transactions would result in us losing control of CDI and accordingly the gain or loss on those transactions will be recognized in our statement of operations.

In March 2008, the FASB issued Statement No. 161, Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133 ("SFAS No. 161"). SFAS 161 applies to all derivative instruments and related hedged items accounted for under SFAS No. 133. SFAS No. 161 requires entities to provide qualitative disclosures about the objectives and strategies for using derivatives, quantitative data about the fair value of and gains and losses on derivative contracts, and details of credit-risk-related contingent features in their hedged positions. We adopted the provisions of SFAS No. 161 on January 1, 2009 and it had no impact on our results of operations, cash flows or financial condition. See Note 17 below for additional disclosure regarding our derivative instruments.

In May 2008, the FASB issued FASB Staff Position ("FSP") APB 14-1, Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlement) ("FSP APB 14-1"). We adopted the FSP APB 14-1 effective January 1, 2009. FSP APB 14-1 requires retrospective application for all periods reported (with the cumulative effect of the change reported in retained earnings as of the beginning of the first period presented). FSP APB 14-1 requires the proceeds from the issuance of convertible debt instruments to be allocated between a liability component (issued at a discount) and an equity component. The resulting debt discount is amortized over the period the convertible debt is expected to be outstanding as additional non-cash interest expense. This FSP changed the accounting treatment for our Convertible Senior Notes. FSP APB 14-1 increases our interest expense for our past and future reporting periods by recognizing accretion charges on the resulting debt discount.

Upon adoption of FSP APB 14-1, we recorded a discount of $60.2 million related to our Convertible Senior Notes. To arrive at this discount amount we estimated the fair value of the liability component of the Convertible Senior Notes as of the date of their issuance (March 30, 2005) using an income approach. To determine this estimated fair value, we used borrowing rates of similar market transactions involving comparable liabilities at the time of issuance and an expected life of 7.75 years. In selecting the expected life, we selected the earliest date that the holder could require us to repurchase all or a portion of the Convertible Senior Notes (December 15, 2012).

The following table sets forth the effect of retrospective application of FSP APB 14-1 and FSP EITF 03-06-1 "Determining Whether Instruments Granted in Share Based Payment Transactions Are Participating Securities" (Note 12) and discontinued operations on certain previously reported line items in our accompanying condensed consolidated statements of operations (in thousands, except per share data):

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	Three Months Ended March 31, 2008	
	Originally Reported	As Adjusted
Net interest expense and other	$ 26,046	$ 28,001
Provision for Income taxes	43,632	42,700
Net income from continuing operations	75,453	73,643
Earnings per common share from continuing operations - Basic	$ 0.82	$ 0.79
Earnings per common share from continuing operations – Diluted	0.79	0.76

The following table sets forth the effect of retrospective application of FSP APB 14-1 on certain previously reported line items in our accompanying condensed consolidated balance sheet (in thousands):

	December 31, 2008	
	As Reported	As Adjusted
Long-term debt	$ 1,968,502	$ 1,933,686
Deferred income tax liability	604,464	615,504
Common stock, no par value	768,835	806,905
Retained earnings	435,506	417,940
Total controlling interest shareholders' equity	1,170,645	1,191,149

Note 4 – Details of Certain Accounts (in thousands)

Other current assets consisted of the following as of March 31, 2009 and December 31, 2008:

	March 31, 2009	December 31, 2008
Other receivables	$ 14,819	$ 22,977
Prepaid insurance	10,948	18,327
Other prepaids	37,703	23,956
Current deferred tax assets	5,447	3,978
Insurance claims to be reimbursed	7,824	7,880
Hedging assets	78,162	26,800
Gas imbalance	6,691	7,550
Inventory	31,754	32,195
Income tax receivable	—	23,485

Other		6,921		4,941
	$	200,269	$	172,089

Other assets, net, consisted of the following as of March 31, 2009 and December 31, 2008:

		March 31, 2009		December 31, 2008
Restricted cash	$	35,412	$	35,402
Deposits		2,872		1,890
Deferred drydock expenses, net		35,935		38,620
Deferred financing costs		32,179		33,431
Intangible assets with definite lives, net		5,598		7,600
Other		5,795		8,779
	$	117,791	$	125,722

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Accrued liabilities consisted of the following as of March 31, 2009 and December 31, 2008:

	March 31, 2009	December 31, 2008
Accrued payroll and related benefits	$ 35,786	$ 46,224
Royalties payable	8,152	10,265
Current decommissioning liability	31,126	31,116
Unearned revenue	16,374	9,353
Billings in excess of costs	10,180	13,256
Insurance claims to be reimbursed	7,824	7,880
Accrued interest	19,493	34,299
Deposit	25,542	25,542
Hedge liability	7,984	7,687
Other	46,754	46,057
	$ 209,215	$ 231,679

Note 5 – Convertible Preferred Stock

In January 2003, we completed the private placement of $25 million of a newly designated class of cumulative convertible stock (Series A-1 Cumulative Convertible Stock, par value $0.01 per share) convertible into 1,666,668 shares of our common stock at $15 per share. The preferred stock was issued to a private investment firm, Fletcher International, Ltd. (“Fletcher”). Subsequently on June 2004, Fletcher exercised an existing right to purchase an additional $30 million of cumulative convertible preferred stock (Series A-2 Cumulative Convertible Preferred Stock, par value $0.01 per share) convertible into 1,964,058 shares of our common stock at $15.27 per share. Pursuant to the agreement governing the preferred stock (the “Fletcher Agreement”), Fletcher was entitled to convert its investment in the preferred shares at any time, or redeem its investment in the preferred shares at any time after December 31, 2004. In January 2009, Fletcher issued a redemption notice with respect to all its shares 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 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 were contractually required to be issued upon 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.

The Fletcher Agreement provided that if the volume weighted average price of our common stock on any date was less than a certain minimum price ($2.767), then our right to pay dividends in our common stock is extinguished, and we must deliver a notice to Fletcher that either (1) the conversion price will be reset to such minimum price (in which case Fletcher shall have no further right to cause the redemption of the preferred stock), or (2) in the event Fletcher exercises its redemption rights, we will satisfy our redemption obligations either in cash, or a combination of cash and common stock subject to a maximum number of shares (14,973,814) that can be delivered to Fletcher under the Fletcher Agreement. On February 25, 2009, the volume weighted average price of our common stock was below the minimum price, and, on February 27, 2009 we provided notice to Fletcher that with respect to the Series A-1 Cumulative Convertible Preferred Stock the conversion price is reset to $2.767 as of that date 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. Similar to the beneficial conversion charge associated with the redemption of Series A-2 Cumulative Convertible Preferred Stock, 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.

The remaining $25 million of our convertible preferred stock maintains its mezzanine presentation below liabilities but 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 our average stock price exceeds $2.767 per share we will have an assumed conversion of convertible preferred stock and the 9,035,056 shares will be included in our diluted shares outstanding amount.

Note 6 – Oil and Gas Properties

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

Litigation and Claims

On December 2, 2005, we received an order from the U.S. Department of the Interior Minerals Management Service ("MMS") that the price threshold for both oil and gas was exceeded for 2004 production and that royalties were due on such production notwithstanding the provisions of the Outer Continental Shelf Deep Water Royalty Relief Act of 2005 ("DWRRA"), which was intended to stimulate exploration and production of oil and natural gas in the deepwater Gulf of Mexico by providing relief from the obligation to pay royalty on certain federal leases up to certain specified production volumes. Our oil and gas leases affected by this dispute are Garden Banks Blocks 667, 668 and 669 ("Gunnison"). On May 2, 2006, the MMS issued another order that superseded the December 2005 order, and claimed that royalties on gas production are due for 2003 in addition to oil and gas production in 2004. The Order also seeks interest on all royalties allegedly due. We filed a timely notice of appeal with respect to both the December 2005 Order and the May 2006 Order. We received an additional order from the MMS dated September 30, 2008 stating that the price thresholds for oil and gas were exceeded for 2005, 2006 and 2007 production and that royalties and interest are payable. We appealed this order on the same basis as the previous orders.

Other operators in the Deep Water Gulf of Mexico who have received notices similar to ours are seeking royalty relief under the DWRRA, including Kerr-McGee, the operator of Gunnison. In March of 2006, Kerr-McGee filed a lawsuit in federal district court challenging the enforceability of price thresholds in certain deepwater Gulf of Mexico leases, including ours. On October 30, 2007, the federal district court in the Kerr-McGee case entered judgment in favor of Kerr-McGee and held that the Department of the Interior exceeded its authority by including the price thresholds in the subject leases. The government filed a notice of appeal of that decision on December 21, 2007. On January 12, 2009, the United States Court of Appeals for the Fifth Circuit affirmed the decision of the district court in favor of Kerr-McGee, holding that the DWRRA unambiguously provides that royalty suspensions up to certain production volumes established by Congress apply to leases that qualify under the DWRRA. The plaintiff petitioned the appellate court for rehearing; however, that petition was denied on April 14, 2009. The plaintiff may appeal the appellate court's decision to the United States Supreme Court, although there is no certainty that the court will accept the case.

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As a result of this dispute, we have been recording 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 of the Gunnison related MMS claim. The result of accruing these reserves since 2005 had reduced our oil and gas revenues. Following the decision of the United States Court of Appeals for the Fifth Circuit Court , we reversed our previously accrued royalties ($73.5 million) to oil and gas revenues in the first quarter of 2009. Effective in January 2009, we commenced recognizing oil and natural gas sales revenue associated with this disputed net revenue interest and are no longer accruing any additional royalty reserves as we believe it is remote that we will be liable for such amounts.

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. The timing of when these facilities reestablish operations was not subject to our control and in certain cases some of these third party facilities remain out of service at the time of this filing. We carry comprehensive insurance on all of our operated and non-operated producing and non-producing properties, which is subject to approximately $6 million of aggregate deductibles. We met our aggregate deductible in September 2008. We record our hurricane-related costs as incurred. Insurance reimbursements will be recorded when the realization of the claim for recovery of a loss is deemed probable. In the first quarter of 2009 we incurred hurricane-related repair cost totaling $12.7 million, which was offset by reimbursement or approved reimbursement of $3.1 million.

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.

In March and April 2008, we sold a total 30% working interest in the Bushwood discoveries (Garden Banks Blocks 463, 506 and 507) and other Outer Continental Shelf oil and gas properties (East Cameron Blocks 371 and 381), in two separate transactions to affiliates of a private independent oil and gas company for total cash consideration of approximately $183.4 million (which included the purchasers' share of incurred capital expenditures on these fields), and additional potential cash payments of up to $20 million based upon certain field production milestones. The new co-owners will also pay their pro rata share of all future capital expenditures related to the exploration and development of these fields. Decommissioning liabilities will be shared on a pro rata share basis between the new co-owners and us. Proceeds from the sale of these properties were used to pay down our outstanding revolving loans in April 2008. Our first quarter of 2008 results included a $61.1 million gain of the first of the two transactions previously discussed.

Exploration and Other

As of March 31, 2009, we capitalized approximately $3.3 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.

Further, the following table details the components of exploration expense for the three months ended March 31, 2009 and 2008 (in thousands):

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Delay rental and geological and geophysical costs	$ 472	$ 1,940
Dry hole expense	4	(52)
Total exploration expense	$ 476	$ 1,888

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In January 2008, the development well on Devil’s Island (Garden Banks Block 344) was determined to be unsuccessful and we recorded an impairment charge of $14.3 million that is included as a component of oil and gas cost of sales in the accompanying condensed statement of operations.

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. As of March 31, 2009 and December 31, 2008, our restricted cash totaled $35.4 million and is included in other assets, net. All of our restricted cash relates to funds required to be escrowed to cover the future decommissioning liabilities associated with the South Marsh Island 130, which we acquired in 2002. We have fully satisfied the escrow requirements under this agreement and may use the restricted cash for future decommissioning of the related field.

The following table provides supplemental cash flow information for the three months ended March 31, 2009 and 2008 (in thousands):

	Three Months Ended March 31,	
	2009	2008
Interest paid, net of capitalized interest(1)	$ 33,372	$ 6,048
Income taxes paid	$ 30,928	$ 966

Non-cash investing activities for the three months ended March 31, 2009 included $88.4 million of accruals for capital expenditures. Non-cash investing activities for the three months ended March 31, 2008 totaled $45.7 million. 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, 2009, 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 $104.6 million and $106.3 million as of March 31, 2009 and December 31, 2008, respectively (including capitalized interest of $1.6 million at March 31, 2009 and December 31, 2008, respectively). Distributions from Deepwater Gateway, net to our interest, totaled $3.5 million in the first quarter of 2009.

- Independence Hub, LLC. In December 2004, we acquired a 20% interest in Independence Hub, LLC (“Independence”), an affiliate of Enterprise. Independence owns the "Independence Hub" platform located in Mississippi Canyon Block 920 in a water depth of 8,000 feet. First production began in July 2007. Our investment in Independence was $89.3 million and $90.2 million as of March 31, 2009 and December 31, 2008, respectively (including capitalized interest of $5.8 million and $5.9 million at March 31, 2009 and December 31, 2008, respectively). Distributions from Independence, net to our interest, totaled $6.8 million in the first quarter of 2009.

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Note 9 – Long-Term Debt

Scheduled maturities of long-term debt and capital lease obligations outstanding as of March 31, 2009 were as follows (in thousands):

	Helix Term Loan	Helix Revolving Loans	CDI Term Loan	Senior Unsecured Notes	Convertible Senior Notes	MARAD Debt	Other(1)	Total
Less than one year	$ 4,326	$	$ 80,000	$	$	$ 4,318	$ 5,000	$ 93,644
One to two years	4,326		80,000			4,533		88,859
Two to three years	4,326	249,500	80,000			4,760		338,586
Three to four years	4,326		155,000			4,997		164,323
Four to five years	400,707					5,247		405,954
Over five years				550,000	300,000	97,513		947,513
Total debt	418,011	249,500	395,000	550,000	300,000	121,368	5,000	2,038,879
Current maturities	(4,326)		(80,000)			(4,318)	(5,000)	(93,644)
Long-term debt, less current maturities	$413,685	$ 249,500	$315,000	$ 550,000	$ 300,000	$ 117,050	$	$1,945,235
Unamortized debt discount (2)					(32,878)			(32,878)
Long-term debt	$413,685	$ 249,500	$315,000	$ 550,000	$ 267,122	$ 117,050	$	$1,912,357

(1) Includes $5 million loan provided by Kommandor RØMØ to Kommandor LLC.

(2) Reflects debt discount resulting from adoption of APB 14-1 on January 1, 2009. The notes will increase to $300 million face amount through accretion of non-cash interest charges through 2012.

We had unsecured letters of credit outstanding at March 31, 2009 totaling approximately $24.4 million, including $13.3 million related to CDI. These letters of credit primarily guarantee various contract bidding, contractual performance and insurance activities and shipyard commitments. The following table details our interest expense and capitalized interest for the three months ended March 31, 2009 and 2008 (in thousands):

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Interest expense	$ 29,850	$ 36,807
Interest income	(264)	(1,000)

Capitalized interest	(7,620)	(10,971)
Interest expense, net	$ 21,966	$ 24,836

Included below is a summary of certain components of our indebtedness. At March 31, 2009 and December 31, 2008, we were in compliance with all debt covenants. For additional information regarding our debt see Note 11 of our 2008 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 CDI and its subsidiaries and 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. CDI, the subsidiaries of CDI, Cal Dive I -Title XI, Inc., and our foreign subsidiaries are not guarantors. We used the proceeds from the Senior Unsecured Notes to repay outstanding indebtedness under our senior secured credit facilities (see below).

Senior Credit Facilities

In July 2006, we entered into a credit agreement (the “Senior Credit Facilities”) 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 proceeds from the Term Loan were used to fund the cash portion of the Remington acquisition (see Note 4 of our 2008 Form 10-K). This facility was subsequently amended in November 2007, and as part of that amendment, an accordion feature was added that allows for increases in the Revolving Credit Facility up to an additional $150 million, subject to availability of borrowing capacity provided by new or existing lenders. In May 2008, we completed a $120 million increase in the Revolving Credit Facility utilizing this accordion feature. Total borrowing capacity under the Revolving Credit Facility now totals $420 million. The full amount of the Revolving Credit Facility may be used for issuances of letters of credit.

The Term Loan matures on July 1, 2013 and is subject to quarterly scheduled principal payments. As a result of a $400 million prepayment made in December 2007, the quarterly scheduled principal payment was reduced from $2.1 million to $1.1 million. The Revolving Loans mature on July 1, 2011. At March 31, 2009, there was $159.4 million available under the Revolving Loans (including $11.1 million of unsecured letters of credit).

The Term Loan currently bears interest either at the one-, three- or six-month LIBOR at our current election plus a 2.00% margin. Our average interest rate on the Term Loan for the three months ended March 31, 2009 and 2008 was approximately 3.3% and 6.6%, respectively, including the effects of our interest rate swaps (see below). The Revolving Loans bear interest based on one-, three- or six-month LIBOR rates or on Base Rates at our current election plus a margin ranging from 1.00% to 2.25% on LIBOR loans or 0% to 1.25% on Base Rate loans. Margins on the Revolving Loans will fluctuate in relation to the consolidated leverage ratio as provided in the Credit Agreement. Our average interest rate on the Revolving Loans for the three months ended March 31, 2009 was approximately 3.4%.

Cal Dive International, Inc. Revolving Credit Facility

CDI has a senior secured credit facility with certain financial institutions, consisting of a $375 million term loan and a $300 million revolving credit facility. As of March 31, 2009, CDI had outstanding debt of $295.0 million under the term loan and $100.0 million under the revolving credit facility with $186.7 million available for borrowings. At March 31, 2009, $13.3 million of this facility was used to support letters of credit issued to secure performance bonds. The weighted-average interest rate was 3.83% (LIBOR plus 2.25%) on the $295.0 million outstanding under the term loan and 2.53% (LIBOR plus 2%) on the $100.0 million outstanding under the revolving credit facility at March 31, 2009. The term loan requires quarterly principal payments of $20 million.

At March 31, 2009 and December 31, 2008, CDI was in compliance with all debt covenants. The credit facility is secured by vessel mortgages on all of CDI’s vessels (except for the Sea Horizon), a pledge of all of the stock of all of CDI’s domestic subsidiaries and 65% of the stock of two of its foreign subsidiaries, and a security interest in, among other things, all of CDI’s equipment, inventory, accounts receivable and general tangible assets.

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 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. During the first quarter of 2009, no

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conversion triggers were met. As a result of adopting FSP APB 14-1 (Note 3), the effective interest is 6.6%.

Approximately 706,000 shares underlying the Convertible Senior Notes were included in the calculation of diluted earnings per share for the three months ended March 31, 2008, because our average share price for period was above the conversion price of approximately $32.14 per share. Our average share price was below the $32.14 per share conversion price for the three month period ended March 31, 2009 and as a result there are no shares included in our diluted earnings per share calculation associated with the assumed conversion of our Convertible Senior Notes. In the event our average share price exceeds the conversion price, there would be a premium, payable in shares of common stock, in addition to the principal amount, which is paid in cash, and such shares would be issued on conversion. The Convertible Senior Notes are convertible into a maximum 13,303,770 shares of our common stock.

MARAD Debt

This U.S. government guaranteed financing ("MARAD Debt") is pursuant to Title XI of the Merchant Marine Act of 1936 which is administered by the Maritime Administration and was used to finance the construction of the Q4000. The MARAD Debt is payable in equal semi-annual installments 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).

In accordance with the Senior Unsecured Notes, amended Senior Credit Facilities, Convertible Senior Notes, MARAD Debt agreements and CDI’s credit facility, 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, 2009, we were in compliance with these covenants and restrictions. The Senior Unsecured Notes and Senior Credit Facilities contain provisions that limit our ability to incur certain types of additional indebtedness.

Other

Deferred financing costs of $32.2 million and $33.4 million are included in other assets, net as of March 31, 2009 and December 31, 2008, 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, 2009 was 36.0% compared with 36.7% for the three months ended March 31, 2008. The effective tax rate for the first quarter of 2009 decreased as a result of the benefit derived from the Internal Revenue Code Section 199 manufacturing deduction as is primarily related to oil and gas production and the effect of lower tax rates in certain foreign jurisdictions. This decrease was partially offset by the additional deferred tax expense recorded as a result of the increase in the equity earnings of CDI in excess of our tax basis in CDI.

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. See Note 16 below for disclosure related to a potential a tax assessment related to CDI.

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Note 11 – Comprehensive Income

The components of total comprehensive income for the three months ended March 31, 2009 and 2008 were as follows (in thousands):

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Net income, including noncontrolling interests	$ 112,755	$ 74,202
Other comprehensive income (loss), net of tax		
Foreign currency translation gain (loss)	(3,619)	807
Unrealized gain on hedges, net	(4,464)	(2,447)
Total comprehensive income	104,672	72,562
Less: Other comprehensive income applicable to noncontrolling interest	(5,546)	(237)
Total comprehensive income applicable to Helix	$ 99,126	$ 72,325

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

	March 31, 2009	December 31, 2008
Cumulative foreign currency translation adjustment	$ (46,481)	$ (42,874)
Unrealized gain on hedges, net	4,709	9,178
Accumulated other comprehensive loss	$ (41,772)	$ (33,696)

Note 12 – Earnings Per Share

On January 1, 2009, we adopted FSP No. EITF 03-06-1, "Determining Whether Instruments Granted in Share Based Payment Transactions Are Participating Securities." 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 FSP 03-06-1, the undistributed earnings for each period are allocated based on the contractual 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. Under FSP 03-06-1, we are required to compute EPS amounts under the two class method. We have revised the prior periods EPS amounts to reflect the current year adoption of FSP 03-06-1 (see table below).

Basic earnings per share ("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, 2009 and 2008 are as follows (in thousands):

	Three Months Ended March 31, 2009			Three Months Ended March 31, 2008		
	Income		Shares	Income		Shares
Basic:						
Net income applicable to common shareholders	$	53,450		$	73,084	
Less: Undistributed net income allocable to participating securities		(884)			(1,006)	
Undistributed net income applicable to common shareholders		52,566			72,078	
(Income) loss from discontinued operations		2,554			(559)	
Income per common share – continuing operations	$	55,120	95,052	$	71,519	90,413

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	Three Months Ended March 31, 2009		Three Months Ended March 31, 2008	
	Income	Shares	Income	Shares
Diluted:				
Net income per common share – continuing operations – Basic	$ 55,120	95,052	$ 71,519	90,413
Effect of dilutive securities:				
Stock options				336
Undistributed earnings reallocated to participating securities	89		49	
Convertible Senior Notes				706
Convertible preferred stock	313	10,811	881	3,631
Income per common share continuing operations	55,522		72,449	
Income (loss) per common share discontinued operations	(2,554)		559	
Net income (loss) per common share	$ 52,968	105,863	$ 73,008	95,086

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 earnings per share amount included the $0.3 million and $0.9 million of dividends and related costs associated with the assumed conversion of the convertible preferred stock for the three months ended March 31, 2009 and 2008, 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 an addback to adjust earnings applicable to common stock for our diluted earnings per share calculation.

The following table compares EPS as originally reported and EPS under the two-class method, pursuant to FSP EITF 03-6-1, to quantify the per common share impact of the new standard on total net income applicable to Helix common shareholders' for the three months ended March 31, 2008.

	Three Months Ended March 31, 2008
Basic, as previously reported	$ 0.82
Basic, impact of adoption of APB 14-1	(0.01)
Basic, restated for adoption of APB 14-1	0.81
Impact of FSP EITF 03-06-1 on basic EPS	0.01
Basic, under FSP EITF 03-06-1	0.80
Diluted, as previously reported	0.79

Diluted, impact of adoption of APB 14-1		(0.01)
Diluted, restated for adoption of APB 14-1		0.78
Impact of FSP EITF 03-06-1 on diluted EPS		0.01
Diluted, under FSP EITF 03-06-1	$	0.77

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") .. In addition, CDI has a stock-based compensation plan, the 2006 Long-Term Incentive Plan (the "CDI Incentive Plan") and an Employee Stock Purchase Plan (the "CDI ESPP") available only to the employees of CDI and its subsidiaries. As of March 31, 2009, there were approximately 1.8 million shares available for grant under our 2005 Incentive Plan.

During the first three months ended March 31, 2009, 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:

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Date of Grant	Type	Shares	Market Value Per Share	Vesting Period
January 2, 2009	(1)	343,368	$ 7.24	20% per year over five years
January 2, 2009	(2)	26,506	7.24	20% per year over five years
January 2, 2009	(1)	10,617	7.24	100% on January 2, 2011
February 26, 2009	(1)	141,975	2.70	20% per year over five years

(1) Restricted shares
(2) Restricted stock units

There were no stock option grants in the three months ended March 31, 2009 and 2008.

Compensation cost is recognized over the respective vesting periods on a straight-line basis. For the three months ended March 31, 2009, $0.1 million was recognized as compensation expense related to stock options compared to $0.5 million for the same period last year, including $0.3 million associated with the acceleration of unvested options per the separation agreement between the Company and our former Chief Executive Officer, Martin Ferron. For the three months ended March 31, 2009, $4.0 million was recognized as compensation expense related to restricted shares, including $1.7 million related to CDI and its compensation plans, as compared with $6.9 million during the three months ended March 31, 2008, which included $3.1 million associated with the accelerated vesting of restricted shares per the separation agreement between the Company and our former Chief Executive Officer, Martin Ferron.

Note 14 – Business Segment Information (in thousands)

Our operations are conducted through the following lines of business: contracting services and oil and gas operations. We have disaggregated our contracting services operations into three reportable segments in accordance with SFAS No. 131: Contracting Services, Shelf Contracting and Production Facilities. As a result, our reportable segments consist of the following: Contracting Services, Shelf Contracting, Production Facilities and Oil and Gas. Contracting Services operations include subsea construction, well operations, robotics and drilling. Shelf Contracting operations consist of CDI, which include all its assets deployed primarily for diving-related activities and shallow water construction. 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 is accounted for under the equity method of accounting. Our investment in Kommandor LLC, a Delaware limited liability company, was consolidated in accordance with FASB Interpretation No. 46, Consolidation of Variable Interest Entities (“FIN 46”) and is included in our Production Facilities segment.

	Three Months Ended March 31,	
	2009	2008
Revenues		

Contracting Services	$ 230,855	$ 174,718
Shelf Contracting	207,053	144,571
Oil and Gas	160,181	171,051
Intercompany elimination	(27,114)	(48,571)
Total	$ 570,975	$ 441,769
Income from operations		
Contracting Services	$ 29,229	$ 20,181
Shelf Contracting	20,932	7,548
Production Facilities equity investments(1)	(134)	(138)
Oil and Gas	145,183	109,917
Intercompany elimination	(290)	(3,980)
Total	$ 194,920	$ 133,528
Equity in earnings of equity investments	$ 7,503	$ 10,816

(1) Includes selling and administrative expense of Production Facilities incurred by us.

(2) Includes $73.5 million of disputed accrued royalty payments that we reversed in first quarter of 2009 following a favorable court ruling (Note 6).

	March 31, 2009	December 31, 2008
Identifiable Assets		
Contracting Services	$ 1,521,858	$ 1,572,618
Shelf Contracting	1,331,359	1,309,608
Production Facilities	484,375	457,197
Oil and Gas	1,707,943	1,708,428
Net assets of discontinued operations	17,153	19,215
Total	$ 5,062,688	$ 5,067,066

Intercompany segment revenues during the three months ended March 31, 2009 and 2008 were as follows:

	Three Months Ended March 31, 2009	2008
Contracting Services	$ 23,903	$ 42,220
Shelf Contracting	3,211	6,351
Total	$ 27,114	$ 48,571

Intercompany segment profits during the three months ended March 31, 2009 and 2008 were as follows:

	Three Months Ended March 31, 2009	2008

Contracting Services	$ (104)	$ 2,863
Shelf Contracting	394	1,117
Total	$ 290	$ 3,980

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Note 15 – Related Party Transactions

In April 2000, we acquired a 20% working interest in Gunnison, a Deepwater Gulf of Mexico prospect of Kerr-McGee. 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 75% of the partnership. In 2000, OKCD also awarded Class B limited partnership interests to key Helix employees. Production began in December 2003. Payments to OKCD from us totaled $2.7 million and $5.5 million in the three months ended March 31, 2009 and 2008, respectively.

Note 16 – Commitments and Contingencies

Commitments

We are converting the Caesar (acquired in January 2006 for $27.5 million in cash) into a deepwater pipelay vessel. Total conversion costs are estimated to range between $210 million and $230 million, of which approximately $163 million had been incurred, with an additional $6.8 million committed, at March 31, 2009. The Caesar is expected to join our fleet in the second half of 2009.

We are also constructing the Well Enhancer, a multi-service dynamically positioned dive support/well intervention vessel that will be capable of working in the North Sea and West of Shetlands to support our expected growth in that region. Total construction cost for the Well Enhancer is expected to range between $200 million to $220 million. We expect the Well Enhancer to join our fleet early in the third quarter of 2009. At March 31, 2009, we had incurred approximately $172 million, with an additional $23.4 million committed to this project.

Further, we, along with Kommandor Rømø, a Danish corporation, formed Kommandor LLC, a joint venture, to convert a ferry vessel into a floating production unit to be named the Helix Producer I. The total cost of the ferry and the conversion is estimated to range between $160 million and $170 million. We have provided $93.6 million in construction financing through March 31, 2009 to the joint venture on terms that would equal an arms length financing transaction, and Kommandor Rømø has provided $5 million on the same terms.

Total equity contributions and indebtedness guarantees provided by Kommandor Rømø are expected to total $42.5 million. The remaining costs to complete the project will be provided by Helix through equity contributions. Under the terms of the operating agreement of the joint venture, if Kommandor Rømø elects not to make further contributions to the joint venture, the ownership interests in the joint venture will be adjusted based on the relative contributions of each partner (including guarantees of indebtedness) to the total of all contributions and project financing guarantees.

Upon completion of the initial conversion, which occurred in April 2009, we are chartering the Helix Producer I from Kommandor LLC, and plan to install, at 100% our cost, processing facilities and a disconnectable fluid transfer system on the Helix Producer I for use on our Phoenix oil and gas field. The cost of these additional facilities is estimated to range between $180 million and $190 million and the work is expected to be completed in early 2010. As of March 31, 2009, approximately $218 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 $3.2 million committed. The total estimated cost of the vessel, initial conversion and the additional facilities will range approximately between $340 million and $360 million. Kommandor LLC qualified as a variable interest entity under FIN 46(R). We determined that we were the primary beneficiary of Kommandor LLC and have consolidated its financial results in the accompanying consolidated financial statements. The operating results of Kommandor LLC are included within our Production Facilities segment. Kommandor LLC was a development stage enterprise since its formation in October 2006 until the completion of its initial conversion, which occurred in April 2009. Kommandor LLC is no longer a development stage enterprise.

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In addition, as of March 31, 2009, we have also committed approximately $12.6 million in additional capital expenditures for exploration, development, and abandonment 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.

During the fourth quarter of 2006, Horizon received a tax assessment from the Servicio de Administracion Tributaria ("SAT"), the Mexican taxing authority, for approximately $23 million related to fiscal 2001, including penalties, interest and monetary correction. The SAT's assessment claims unpaid taxes related to services performed among the Horizon subsidiaries that CDI acquired at the time it acquired Horizon. CDI believes under the Mexico and United States double taxation treaty that these services are not taxable and that the tax assessment itself is invalid. On February 14, 2008, CDI received notice from the SAT upholding the original assessment. On April 21, 2008, CDI filed a petition in Mexico tax court disputing the assessment. We believe that CDI's position is supported by law and CDI intends to vigorously defend its position. However, the ultimate outcome of this litigation and CDI's potential liability from this assessment, if any, cannot be determined at this time. Nonetheless, an unfavorable outcome with respect to the Mexico tax assessment could have a material adverse effect on our and CDI's financial position and results of operations. Horizon's 2002 through 2008 tax years remain subject to examination by the appropriate governmental agencies for Mexico tax purposes, with 2002 through 2004 currently under audit.

A number of our longer term pipelay contracts have been adversely affected by delays in the delivery of the Caesar. We believe two of our contracts qualify as loss contracts as defined under SOP 81-1 "Accounting for Performance of Construction-Type and Certain Production-Type Contracts". Accordingly, we have estimated the future shortfall between our anticipated future revenues versus future costs. For one contract expected to be completed in May 2009, our estimated loss at December 31, 2008 was estimated to be approximately $0.8 million. There was no additional loss on the contract in the first quarter of 2009. Under a second contract, which was terminated, we have a potential future liability of up to $25 million with our estimated future loss under this contract totaling $9.0 million, which was accrued for as of December 31, 2008. We have prepaid $7.2 million of such potential damages related to this terminated contact. If the potential damages exceed $7.2 million we will be required to pay additional funds but to the extent they are less that $7.2 million we would be entitled to cash refund from the contracting party. Although no new losses were identified with this contract in the first quarter of 2009, we will continue to monitor our exposure under this contract over the remainder of 2009.

In March 2009, we were notified of a third party's intention to terminate an international construction contract under a claimed breach of that contract by one of our subsidiaries. Under the terms of the contract, our potential liability is generally capped for actual damages at approximately $27 million Australian dollars ("AUS") (approximately $18.7 million US dollars at March 31, 2009) and for liquidated damages at approximately $5 million AUS (approximately $3.5 million US dollars at March 31, 2009); however, as there are substantial defenses to this claimed breach, we cannot at this time quantify our exposure, if any, under the contract. Over the remainder of 2009, we will continue to assess our potential exposure to damages under this contract as the circumstances warrant

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 – Derivative Instruments and Hedging Activities

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

We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives, strategies for undertaking various hedge transactions and the methods for assessing and testing correlation and hedge ineffectiveness. All hedging instruments are linked to the hedged asset, liability, firm commitment or forecasted transaction. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows of the hedged items. We discontinue hedge accounting if we determine that a derivative is no longer highly effective as a hedge, or it is probable that a hedged transaction will not occur. If hedge accounting is discontinued, deferred gains or losses on the hedging instruments are recognized in earnings immediately if it is probable the forecasted transaction will not occur. If the forecasted transaction continues to be probable of occurring, any deferred gains or losses in accumulated other comprehensive income are amortized to earnings over the remaining period of the original forecasted transaction.

Commodity Price Risks

We manage commodity price risks through various financial costless collars and swap instruments and forward sales contracts that require physical delivery. We utilize these instruments to stabilize cash flows relating to a portion of our expected oil and gas production. Our costless collars and swap contracts were designated as hedges and qualified 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 them no longer qualified for hedge accounting at March 31, 2009. 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, future changes in the fair value of these instruments are now recorded through earnings as a component of our income from operations in the period the changes occur.

The fair value of 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 estimates 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.

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As of March 31, 2009, we have the following volumes under derivatives and forward sales contracts related to our oil and gas producing activities totaling 1,547 MBbl of oil and 31,601 Mmcf of natural gas:

Production Period	Instrument Type	Average Monthly Volumes		Weighted Average Price
Crude Oil:				(per barrel)
April 2009 — June 2009	Collar(1)	65.7 MBbl	$	75.00 — $89.55
April 2009 — December 2009	Forward Sales(2)	150 MBbl	$	71.79
Natural Gas:				(per Mcf)
April 2009 — December 2009	Collar(3)	947 Mmcf	$	7.00 — $7.90
May 2009 — December 2009	Forward Sales(4)	1,516 Mmcf	$	8.23
January 2010 — December 2010	Swap(1)	912.5 Mmcf	$	5.80

(1) Designated as cash flow hedges, still deemed effective and qualifies for hedge accounting.
(2) Qualified for scope exemption as normal purchase and sale contract.
(3) Designated as cash flow hedges, deemed ineffective and subsequent changes in fair value are now being marked-to-market through earnings each period.
(4) No long qualify for normal purchase and sale exemption and are now being marked-to-market through earnings each period.

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 the interest rates for some of our long-term debt are subject to market influences and will vary over the term of the debt, we entered into various interest rate swaps to stabilize cash flows relating to a portion of our interest payments on our variable interest rate debt. As of March 31, 2009, we have entered into interest rate swaps to stabilize cash flows relating to $200 million of our Term Loan, and CDI has entered into an interest rate swap to stabilize cash flows relating to $100 million of its term loan. 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.

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, 2009 and December 31, 2008. As required by SFAS No. 161, 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 3)

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Derivatives designated as hedging instruments under SFAS No. 133 (in thousands):

	As of March 31, 2009		As of December 31, 2008	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Asset Derivatives:				
Oil costless collars	Other current assets	$ 5,320	Other current assets	$ 6,449
Gas costless collars	Other current assets	—	Other current assets	6,652
Oil swap contracts	Other current assets	—	Other current assets	1,019
Gas swap contracts	Other current assets	—	Other current assets	1,537
Foreign exchange forwards	Other current assets	29	Other current assets	506
		$ 5,349		$ 16,163
Liability Derivatives:				
Gas swap contracts	Other long-term liabilities	1,227	Accrued liabilities	—
Foreign exchange forwards	Accrued liabilities	—	Accrued liabilities	240
Interest rate swaps	Accrued liabilities	1,490	Accrued liabilities	1,378
Interest rate swaps	Other long-term liabilities	—	Other long-term liabilities	347
		$ 2,717		$ 1,965

Derivatives that are not currently designated as hedging instruments under SFAS No. 133 (in thousands):

	As of March 31, 2009		As of December 31, 2008	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Asset Derivatives:				
Gas costless collars	Other current assets	23,234	Other current assets	6,652
Gas forward sales contracts	Other current assets	49,385	Other current assets	3,987
		$ 72,619		$ 10,639
Liability Derivatives:				
Foreign exchange forwards	Accrued liabilities	559	Accrued liabilities	1,205
Interest rate swaps	Accrued liabilities	5,741	Accrued liabilities	6,242

	$ 6,300	$ 7,447

The following tables present the impact that derivative instruments designated as cash flow hedges had on our condensed consolidated statement of operations for the three months ended March 31, 2009 and 2008 (in thousands):

	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)		Location of Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	
	2009(1)	2008		2009	2008
Oil costless collars	$ (1,129)	$ 1,619	Oil and gas revenue	$ 3,292	$ (4,401)
Gas costless collars	—	(7,069)	Oil and gas revenue	1,653	409
Oil swap contracts	(1,019)	—	Oil and gas revenue	1,687	—
Gas swap contracts	(2,764)	—	Oil and gas revenue	2,954	—
Foreign exchange forwards	29	1,794	Not applicable	—	—
Interest rate swaps	(58)	(998)	Net interest expense and other	(654	(785)
	$ (4,941)	$ (4,654)		$ 8,932	$ (4,777)

(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 foreign exchange forwards.

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	Location of Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Gain (Loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing) 2009	2008
Foreign exchange forwards	Net interest expense and other	$ —	$ 2
Interest rate swaps	Net interest expense and other	—	(61)
		$ —	$ (59)

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, 2009 and 2008 (in thousands):

	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives 2009	2008
Gas costless collars	Net interest expense and other	$ 17,887	$ —
Gas forward sales contracts	Gain on oil and gas derivative contracts	56,721	—
Foreign exchange forwards	Net interest expense and other	646	—
Interest rate swaps	Net interest expense and other	(12	(2,726)
		$ 75,242	$ (2,726)

Note 18 - Change in Ownership of Consolidated Subsidiary

In January 2009, we sold approximately 13.6 million shares of CDI common stock to CDI 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 CDI. Our ownership of CDI following the transaction approximated 51%. Since we retained control of CDI immediately after the transaction, the approximate $2.9 million loss on this sale was treated as a reduction of our equity in the accompanying condensed consolidated balance sheet. Any future significant transactions would result in us losing control of CDI and accordingly the gain or loss on those transactions will be recognized in our statement of operations.

The following schedule reflects the effects of the sale of the shares to CDI in January 2009 on our ownership interest in CDI:

		Three months Ended March 31, 2008
Net income attributable to Helix	$	107,202
Transfers to the noncontrolling interest		
Decrease in Helix's common stock from sale of 13,564,669 shares of CDI stock		(2,912)
Net transfers to the noncontrolling interest		(2,912)
Change from net income attributable to Helix and transfers to noncontrolling interest	$	104,290

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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 and its subsidiaries and Cal Dive I-Title XI, Inc. Each of these Subsidiary Guarantors is included in our consolidated financial statements and has fully and unconditionally guaranteed the Senior Unsecured Notes on a joint and several basis. As a result of these guarantee 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.

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

	As of March 31, 2009				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 148,868	$ 975	$ 101,742	$ —	$ 251,585
Accounts receivable, net	84,305	85,549	215,236	—	385,090
Unbilled revenue	44,184	—	67,538	—	111,722
Other current assets	118,104	126,346	56,990	(101,171)	200,269
Net assets of discontinued operations	—	—	17,153	—	17,153
Total current assets	395,461	212,870	458,659	(101,171)	965,819
Intercompany	123,713	122,074	(159,583)	(86,204)	—
Property and equipment, net	180,334	1,963,171	1,281,083	(5,238)	3,419,350
Other assets:					
Equity investments	2,324,495	27,570	194,087	(2,352,065)	194,087
Goodwill	—	45,107	320,534	—	365,641
Other assets, net	46,611	37,215	62,713	(28,748)	117,791
	$ 3,070,614	$ 2,408,007	$ 2,157,493	$ (2,573,426)	$ 5,062,688
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 70,243	$ 88,267	$ 114,780	$ (1,321)	$ 271,969
Accrued liabilities	65,171	58,082	91,028	(5,066)	209,215
Income taxes payable	(61,296)	102,767	(3,384)	(11,166)	26,921
	4,326	—	182,889	(93,571)	93,644

Current maturities of long-term debt					
Current liabilities of discontinued operations	2,392	—	4,097	—	6,489
Total current liabilities	80,836	249,116	389,410	(111,124)	608,238
Long-term debt	1,480,307	—	432,050	—	1,912,357
Deferred income taxes	186,616	272,983	201,689	(4,150)	657,138
Decommissioning liabilities	—	191,923	4,913	—	196,836
Other long-term liabilities	—	2,097	6,550	76	8,723
Due to parent	(99,181)	(19,626)	127,056	(8,249)	—
Total liabilities	1,648,578	696,493	1,161,668	(123,447)	3,383,292
Convertible preferred stock	25,000	—	—	—	25,000
Total equity	1,397,036	1,711,514	995,825	(2,449,979)	1,654,396
	$ 3,070,614	$ 2,408,007	$ 2,157,493	$ (2,573,426)	$ 5,062,688

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

	As of December 31, 2008				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 148,704	$ 4,983	$ 69,926	$ —	$ 223,613
Accounts receivable, net	125,882	97,300	204,674	—	427,856
Unbilled revenue	43,888	1,080	72,282	—	117,250
Other current assets	120,320	79,202	41,031	(68,464)	172,089
Net assets of discontinued operations	—	—	19,215	—	19,215
Total current assets	438,794	182,565	407,128	(68,464)	960,023
Intercompany	78,395	100,662	(101,813)	(77,244)	—
Property and equipment, net	168,054	2,007,807	1,247,060	(4,478)	3,418,443
Other assets:					
Equity investments	2,331,924	31,374	196,660	(2,363,298)	196,660
Goodwill	—	45,107	321,111	—	366,218
Other assets, net	48,734	37,967	68,035	(29,014)	125,722
	$ 3,065,901	$ 2,405,482	$ 2,138,181	$ (2,542,498)	$ 5,067,066
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 99,197	$ 139,074	$ 107,856	$ (1,320)	$ 344,807
Accrued liabilities	87,712	65,090	83,233	(4,356)	231,679
Income taxes payable	(104,487)	82,859	9,149	12,479	—
Current maturities of long-term debt	4,326	—	173,947	(84,733)	93,540
Current liabilities of discontinued operations	—	—	2,772	—	2,772
Total current liabilities	86,748	287,023	376,957	(77,930)	672,798
Long-term debt	1,579,451	—	354,235	—	1,933,686
Deferred income taxes	184,543	242,967	191,773	(3,779)	615,504
Decommissioning liabilities	—	191,260	3,405	—	194,665
Other long-term liabilities	—	73,549	10,706	(2,618)	81,637
Due to parent	(100,528)	(3,741)	126,013	(21,744)	—
Total liabilities	1,750,214	791,058	1,063,089	(106,071)	3,498,290

Convertible preferred stock	55,000	—	—	—	55,000
Total equity	1,260,687	1,614,424	1,075,092	(2,436,427)	1,513,776
	$ 3,065,901	$ 2,405,482	$ 2,138,181	$ (2,542,498)	$ 5,067,066

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

	Three Months Ended March 31, 2009				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
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 (loss) 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
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

	Three Months Ended March 31, 2008				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$ 84,891	$ 201,696	$ 208,804	$ (53,622)	$ 441,769
Cost of sales	66,114	137,213	168,630	(48,771)	323,186
Gross profit	18,777	64,483	40,174	(4,851)	118,583
Gain on sale of assets	—	61,113	—	—	61,113
Selling and administrative expenses	(10,895)	(14,459)	(21,915)	1,101	(46,168)
Income(loss) from operations	7,882	111,137	18,259	(3,750)	133,528
Equity in earnings of investments	82,206	5,372	10,816	(87,578)	10,816
Net interest expense and other	(8,419)	(13,263)	(8,785)	2,466	(28,001)
Income(loss) before income taxes	81,669	103,246	20,290	(88,862)	116,343
Provision (benefit) for income taxes	(7,934)	(33,524)	(2,754)	1,512	(42,700)
Income (loss) from continuing operations	73,735	69,722	17,536	(87,350)	73,643
Discontinued operations, net of tax	—	—	559	—	559
Net income (loss), including noncontrolling interests	73,735	69,722	18,095	(87,350)	74,202
Less net income applicable to noncontrolling interests	—	—	—	(237)	(237)
Preferred stock dividends	(881)	—	—	—	(881)
Net income (loss) applicable to Helix common shareholders	$ 72,854	$ 69,722	$ 18,095	$ (87,587)	$ 73,084

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

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

	Three Months Ended March 31, 2008				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flow from operating activities:					
Net income (loss), including noncontrolling interests	$ 73,736	$ 69,722	$ 18,094	$ (87,350)	$ 74,202
Adjustments to reconcile net income to net cash provided by (used in) operating activities:					
Equity in earnings of unconsolidated affiliates	—	—	(19)	—	(19)
Equity in earnings of affiliates	(82,207)	(5,372)	—	87,579	—
Other adjustments	59,352	(42,621)	37,969	(1,682)	53,018
Cash provided by continuing operations	50,881	21,729	56,044	(1,453)	127,201
Cash provided by discontinued operations	—	—	(1,635)	—	(1,635)
Net cash provided by (used in) operating Activities	50,881	21,729	54,409	(1,453)	125,566
Cash flows from investing activities:					
Capital expenditures	(22,383)	(159,236)	(59,931)	—	(241,550)
Acquisition of businesses, net of cash acquired					
(Purchases) sale of short-term investments	—	—	—	—	—
Investments in equity investments	—	—	(207)	—	(207)
Distributions from equity investments, net	—	—	5,995	—	5,995
Increases in restricted cash	—	(232)	—	—	(232)
Proceeds from sales of property	—	110,086	61	—	110,147
Net cash used in investing activities	(22,383)	(49,382)	(54,082)	—	(125,847)

Cash flows from financing activities:					
Repayments on revolver	318,500	—	—	—	318,500
Repayments of debt	(185,000)	—	—	—	(185,000)
Deferred financing costs	(1,082)	—	(41,982)	—	(43,064)
Capital lease payments	(409)	—	—	—	(409)
Preferred stock dividends paid	(881)	—	—	—	(881)
Repurchase of common stock	(3,309)	—	—	—	(3,309)
Excess tax benefit from stock-based compensation	629	—	—	—	629
Exercise of stock options, net	321	—	—	—	321
Intercompany financing	(47,099)	25,299	20,347	1,453	—
Net cash provided by (used in) financing activities	81,670	25,299	(21,635)	1,453	86,787
Effect of exchange rate changes on cash and cash equivalents	—	—	58	—	58
Net increase (decrease) in cash and cash equivalents	110,168	(2,354)	(21,250)	—	86,564
Cash and cash equivalents:					
Balance, beginning of year	3,507	2,609	83,439	—	89,555
Balance, end of year	$ 113,675	$ 255	$ 62,189	$ —	$ 176,119

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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 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 Securities and Exchange Commission ("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.

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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 2008 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. 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.

We have engaged financial advisors to assist us in these efforts. The current economic and financial market conditions may affect the timing of any strategic dispositions by us and will require a degree of patience in order to execute any transactions. As a result, we are unable to be specific with respect to a timetable for any disposition, but we intend to aggressively focus on reducing debt levels through monetization of non-core assets and allocation of free cash flow in order to accelerate our strategic goals.

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

- Sold two oil and gas properties for $67 million in gross proceeds;
- Sold CDI approximately 13.6 million shares of its common stock held by us for $86 million; and
- Sold Helix RDS Limited, our subsurface reservoir consulting business for $25 million.

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

The continuing economic downturn and weakness in the equity and credit capital markets has led to increased uncertainty regarding the outlook of the global economy. This uncertainty coupled with the probable decrease in the near-term global demand for oil and gas has resulted in commodity price declines over the second half of 2008, with significant declines occurring in the fourth quarter of 2008. Prices for oil remained relatively flat in first quarter of 2009 compared with prices at year end 2008 while natural gas prices continued to decrease to levels last seen in 2004. Declines in oil and gas prices negatively impact our operating results and cash flow. Further, our contracting services are negatively impacted by declining commodity prices, which has resulted in some of our customers, primarily oil and gas companies, to curtail capital spending. The long-term 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. In addition, as our subsea construction operations primarily support capital projects with long lead times that are less likely to be impacted by temporary economic downturns. We have economically hedged approximately 80% of our anticipated production for the remainder of 2009 with a combination of forward sale and financial hedge contracts. We have also hedged a portion of our anticipated natural gas production for 2010 through the placement of additional swap financial hedge contracts. The prices for these contracts are significantly higher than the prices for both crude oil and natural gas as of March 31, 2009 and as of the time of this filing on May 8, 2009. If the prices for crude oil and natural gas do not increase from current levels, and we have not entered into additional forward sale or financial hedge contracts to stabilize our cash flows, our oil and gas revenues may decrease in 2010 and beyond, perhaps significantly, absent offsetting increases in production amounts.

At March 31, 2009, we had cash on hand of $251.6 million and $346.1 million available for borrowing under our revolving credit facilities, of which $186.7 million relates to CDI. We have reduced our planned capital expenditures for 2009 to include primarily the completion of major vessel construction projects and limited oil and gas expenditures. If we successfully implement the business plan outlined above, we believe we have sufficient liquidity without incurring additional indebtedness beyond the existing capacity under the Helix 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:

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- 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.

Global economic conditions have deteriorated significantly over the past year with declines in the oil and gas market accelerating during the fourth quarter of 2008 and continuing in the first quarter of 2009. Predicting the timing of any recovery is subjective and highly uncertain. Although we are currently in a recession, we believe that the long-term industry fundamentals are positive based on the following factors: (1) long term increasing world demand for oil and natural gas; (2) peaking global production rates; (3) globalization of the natural gas market; (4) increasing number of mature and small reservoirs; (5) increasing ratio of contribution to global production from marginal fields; (6) increasing offshore activity, particularly in Deepwater; and (7) increasing number of subsea developments. Our strategy of combining contracting services operations and oil and gas operations allows us to focus on trends (4) through (7) in that we pursue long-term sustainable growth by applying specialized subsea services to the broad external offshore market but with a complementary focus on marginal fields and new reservoirs in which we currently have an equity stake.

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 three reportable segments in accordance with SFAS No. 131. As a result, our reportable segments consist of the following: Contracting Services, Shelf Contracting, and Production Facilities as well as Oil and Gas.

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, particularly from marginal fields. Our "life of field" services are organized in five disciplines: construction, well operations, production facilities, reservoir and well tech services, and drilling. The Contracting Services segment includes operations such as subsea construction, well operations, robotics and drilling. The Shelf Contracting segment represents the results and operations of Cal Dive, of which the assets are deployed primarily for diving-related activities and shallow water construction. We owned approximately 51% of Cal Dive through shares of its outstanding common stock at March 31, 2009. Our contracting services business operates primarily in the Gulf of Mexico, the North Sea, Asia/Pacific and Middle East regions, with services that cover the lifecycle of an offshore oil or gas field. As of March 31, 2009, our contracting services operations had backlog of approximately $0.9 billion, with $0.4 billion associated with Cal Dive. We expect that approximately $0.7 billion of our backlog will be completed over the remainder of 2009. 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

In 1992 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 to our contracting services. 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

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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

On April 27, 2009, we sold Helix RSD 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. No asset or liability of HEL and Helix RDS are material to any single line item in our accompanying condensed consolidated balance sheet.

Comparison of Three Months Ended March 31, 2009 and 2008

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

	Three Months Ended March 31, 2009	2008	Increase/ (Decrease)
Revenues (in thousands) –			
Contracting Services	$230,855	$174,718	$ 56,137
Shelf Contracting	207,053	144,571	62,482
Oil and Gas	160,181	171,051	(10,870)
Intercompany elimination	(27,114)	(48,571)	21,457
	$570,975	$441,769	$ 129,206
Gross profit (in thousands) –			
Contracting Services	$ 46,581	$ 36,494	$ 10,087
Shelf Contracting	38,805	24,690	14,115
Oil and Gas	76,114	61,379	14,735
Intercompany elimination	(290)	(3,980)	3,690
	$161,210	$118,583	$ 42,627
Gross Margin –			
Contracting Services	20%	21%	(1 pt)
Shelf Contracting	19%	17%	2 pts
Oil and Gas	48%	36%	12 pts
Total company	28%	27%	1 pt
Number of vessels(1)/ Utilization(2) –			
Contracting Services:			
Construction vessels	8/79%	6/99%	
Well operations	2/76%	2/26%	
ROVs	46/64%	39/63%	
Shelf Contracting	30/49%	34/31%	

(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, 2009 and 2008 were as follows (in thousands):

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008	Increase/ (Decrease)
Contracting Services	$ 23,903	$ 42,220	$ (18,317)
Shelf Contracting	3,211	6,351	(3,140)
	$ 27,114	$ 48,571	$ (21,457)

Intercompany segment profit during the three months ended March 31, 2009 and 2008 was as follows (in thousands):

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008	Increase/ (Decrease)
Contracting Services	$ (104)	$ 2,863	$ (2,967)
Shelf Contracting	394	1,117	(723)
	$ 290	$ 3,980	$ (3,690)

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, 2009	Three Months Ended March 31, 2008	Increase/ (Decrease)
Oil and Gas information–			
Oil production volume (MBbls)	820	910	(90)
Oil sales revenue (in thousands)	$ 47,391	$ 79,454	$ (32,063)
Average oil sales price per Bbl (excluding hedges)	$ 51.74	$ 92.15	$ (40.41)
Average realized oil price per Bbl (including hedges)	$ 57.82	$ 87.32	$ (29.50)
Decrease in oil sales revenue due to:			
Change in prices (in thousands)	$ (26,843)		
Change in production volume (in thousands)	(5,220)		
Total decrease in oil sales revenue (in thousands)	$ (32,063)		
Gas production volume (MMcf)	6,990	10,103	(3,113)
Gas sales revenue (in thousands)	$ 39,431	$ 90,463	$ (51,032)
Average gas sales price per mcf (excluding hedges)	$ 5.30	$ 8.77	$ (3.47)

Average realized gas price per mcf (including hedges)	$ 5.35	$ 8.95	$ (3.60)
Decrease in gas sales revenue due to:			
Change in prices (in thousands)	$ (36,363)		
Change in production volume (in thousands)	(16,669)		
Total decrease in gas sales revenue (in thousands)	$ (53,032)		
Total production (MMcfe)	11,908	15,563	(3,655)
Price per Mcfe	$ 7.12	$ 10.92	$ (3.80)
Oil and Gas revenue information (in thousands)–			
Oil and gas sales revenue	$ 84,822	$169,917	$ (85,095)
Other revenues(1)	75,359	1,134	74,225
	$160,181	$171,051	$ (10,870)

(1) Other revenues include fees earned under our process handling agreements. The amount in 2009 also includes $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 (in thousands) converted to Mcfe at a ratio of one barrel of oil to six Mcf:

	Three Months Ended March 31,			
	2009		2008	
	Total	Per Mcfe	Total	Per Mcfe
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$18,599	$ 1.56	$ 22,300	$ 1.43
Workover	10,390(3)	0.87	2,742	0.18
Transportation	1,202	0.10	952	0.06
Repairs and maintenance	2,743	0.23	4,873	0.31
Overhead and company labor	1,462	0.12	2,662	0.17
Total	$ 34,396	$ 2.88	$ 33,529	$ 2.15
Depletion expense	$ 44,088	$ 3.70	$ 53,628	$ 3.45
Abandonment	745	0.06	659	0.04
Accretion expense	4,003	0.34	3,246	0.21
Impairment	358	0.03	16,723	1.07

(1) Excludes exploration expense of $0.5 million and $1.9 million for the three months ended March 31, 2009 and 2008, respectively. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

(3) Includes $9.6 million of hurricane-related repair costs, net of insurance proceeds.

Revenues. During the three months ended March 31, 2009, our total revenues increased by 29% as compared to the same period in 2008. Contracting Services revenues increased 32% for the three months ended March 31, 2009 as compared to the same period in 2008 primarily reflecting the placing in service two new trenchers in our ROV business since first quarter of 2008. Overall utilization levels for well operations and ROVs increased while utilization for our subsea construction vessels decreased. The increase also reflects a decrease in the number of out-of-service days for the drilling upgrade and regulatory drydock for the Q4000. Shelf Contracting revenues reflect higher vessel utilization rates in the first quarter of 2009 as a result of increased diving activity in international markets and increased demand for hurricane-related repair activity following Hurricanes Gustav and Ike that passed through the Gulf of Mexico in the third quarter of 2008.

Oil and Gas revenues decreased 6% during the three months ended March 31, 2009 as compared to the same period in 2008. The decrease reflects lower oil and natural gas production associated with damages sustained to certain third party pipelines and infrastructure during Hurricanes Gustav and Ike as well as significantly lower oil and natural gas prices received for our sales volumes in the first quarter of 2009 as compared to the first quarter of 2008. Currently our oil and natural gas production has attained approximately the same levels that were achieved prior to the storms. However, our production is still constrained by certain third party pipeline repairs that are still in progress. Our oil and gas revenues included $73.5 million of previously accrued royalty payments that were in dispute. Following a favorable judicial ruling we have reversed these amounts as oil and gas revenues and have begun accounting for the additional oil and gas revenues associated with the previously disputed royalty net revenue interest and we are no longer accruing any additional royalty reserves as we believe it is remote that we will be liable for such amounts.

Gross Profit. Gross profit in the first quarter of 2009 increased 36% as compared to the same period in 2008. Our Contracting services gross profit increased by 28% primarily reflecting the higher utilization of the well operations vessels and certain ROVs. These increases were partially offset by higher operating costs of our trenching equipment. The increase in Shelf Contracting gross profit of 57% reflects greater utilization attributable to increased diving activity in international markets and higher demand for hurricane-related repair activity.

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The Oil and Gas gross profit increase of $14.7 million in first quarter 2009 as compared to the same period in 2008 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 $58.8 million, which reflects both reduced sales volumes and lower oil and natural prices received during the first quarter of 2009. The first quarter of 2008, was affected by impairment expense of approximately $16.7 million, of which approximately $14.3 million was related to the unsuccessful development well in January 2008 on Devil's Island (Garden Banks Block 344).

Gain on Sale of Assets, Net. Gain on sale of assets, net, was $0.5 million for the three months ended March 31, 2009 compared with $61.1 million during the three months ended March 31, 2008. The sales in the first quarter of 2009 reflect 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. Our gain for the three months ended March 31, 2008 related to the sale of a 20% working interest in the Bushwood discoveries (Garden Banks Blocks 463, 506 and 507) and other Outer Continental Shelf oil and gas properties (East Cameron Blocks 371 and 381). We sold an additional 10% working interest in the Bushwood discoveries in April 2008.

Selling and Administrative Expenses. Selling and administrative expenses of $41.4 million for the first quarter of 2009 were $4.8 million lower than the $46.2 million incurred in the same prior year period. The decrease reflects our recognizing $5.4 million of expenses related to the separation agreement between the Company and Mr. Ferron, our former Chief Executive Officer, as a result of his resignation and the termination of his employment with the Company in February 2008.

Equity in Earnings of Investments. Equity in earnings of investments decreased by $3.3 million during the three months ended March 31, 2009 as compared to the same prior year period. This decrease was mostly due to lower throughput, as a result of continued disruption to the third party owned pipeline downstream of the Marco Polo facility following Hurricane Ike in 2008.

Net Interest Expense and Other. We reported net interest and other expense of $22.2 million in first quarter 2009 as compared to $28.0 million in the same prior year period. Gross interest expense of $29.9 million during the three months ended March 31, 2009 was lower than the $36.8 million incurred in 2008 primarily because of lower interest rates. Capitalized interest totaled $7.6 million for the three months ended March 31, 2009 compared with $11.0 million for the same period last year. Interest income totaled $0.3 million for the three months ended March 31, 2009 compared with $1.0 million in the comparable period in 2008.

Provision for Income Taxes. Income taxes increased to $64.9 million in the first quarter of 2009 as compared to $42.7 million in the same prior year period. The increase was primarily due to increased profitability. The effective tax rate of 36.0% for the first quarter of 2009 was lower than the 36.7% for the first quarter of 2008. The effective tax rate for the first quarter of 2009 decreased as a result of the benefit derived from the Internal Revenue Code Section 199 manufacturing deduction as it primarily relates to oil and gas production and the effect of lower tax rates in certain foreign jurisdictions. This decrease was partially offset by the additional deferred tax expense recorded as a result of the increase in the equity earnings of CDI in excess of our tax basis in CDI.

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LIQUIDITY AND CAPITAL RESOURCES

Overview

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

	March 31, 2009	December 31, 2008
Net working capital	$ 357,581	$ 287,225
Long-term debt(1)	1,912,357	1,933,686

(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 standard (Notes 3 and 9).

	Three Months Ended March 31, 2009	2008
	(in thousands)	
Net cash provided by (used in):		
Operating activities	$ 162,488	$ 125,566
Investing activities	$ (109,025)	$ (125,847)
Financing activities	$ (25,377)	$ 86,787

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 are closely monitoring the ongoing volatility and uncertainty in the financial markets and continue our intense internal focus on improving our balance sheet by increasing our liquidity through reductions in planned spending and potential dispositions of our non-core business assets. Externally we have also been engaged with our clients and the lending institutions on our various debt facilities as our customers and lenders are going through similar exercises. We expect a significant decrease in activity in 2009 as compared to 2008. To date, we have received no communication from our lenders that they are unable or unwilling to fund any commitments under our Revolving Credit Facility. Additionally, all participating banks party to our Revolving Credit Facilities have honored their commitments. We also have a reasonable basis for estimating our future cash flow supported by our remaining Contracting Services backlog and the significant economically hedged portion of our estimated oil and gas production over the remainder of 2009. We believe that internally generated cash flow and available borrowing capacity under our existing Revolving Credit Facility will be sufficient to fund our operations over at least the next twelve months. In March 2009, we repaid $100 million under our revolving credit facility.

A continuing period of weak economic activity will make it increasingly 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 the current 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. We cannot assure you that we would have access to the credit markets as needed to replace our existing debt and we could incur increased costs associated with any available replacement financing.

In accordance with the Senior Unsecured Notes, amended Senior Credit Facilities, Convertible Senior Notes, MARAD Debt and Cal Dive's credit facility, 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, 2009 and December 31, 2008, we were in compliance with these covenants

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and restrictions. The Senior Unsecured Notes and Senior Credit Facilities contain provisions that limit our ability to incur certain types of additional indebtedness.

The Senior Unsecured Notes essentially prohibit any of our restricted subsidiaries from creating, issuing, incurring, assuming, guaranteeing or becoming directly or indirectly liable for the payment of any indebtedness unless specified otherwise in the indenture. The Senior Unsecured Notes are fully and unconditionally guaranteed by substantially all of our existing restricted domestic subsidiaries, except for CDI and its subsidiaries and Cal Dive I-Title XI, Inc. The Senior Unsecured Notes may be redeemed prior to the stated maturity under certain circumstances specified in the indenture governing the Senior Unsecured Notes.

Provisions of the amended Senior Credit Facilities effectively prohibit us from incurring any additional secured indebtedness or indebtedness guaranteed by the Company. The Senior Credit Facilities do, however, permit us to incur unsecured indebtedness (such as our Senior Unsecured Notes), and also permit our subsidiaries to incur project financing indebtedness secured by the underlying asset, provided that the indebtedness is not guaranteed by us.

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. During the first quarter of 2009, no conversion triggers were met.

As of March 31, 2009, we had $159.4 million of available borrowing capacity under our credit facilities, and CDI had $186.7 million of available borrowing under its revolving credit facility. We do not have access to any unused portion of CDI’s revolving credit facility.

Working Capital

Cash flow from operating activities increased by $36.9 million in the three months ended March 31, 2009 as compared to the same period in 2008. This increase includes the effect of recognizing $73.5 million of previously disputed cash royalty payments that we had been deferring until January 2009 (Note 6) and the increase 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, 2009 and 2008 were as follows (in thousands):

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Capital expenditures:		
Contracting Services	$ (65,745)	$ (72,858)
Shelf Contracting	(27,275)	(9,608)
Production Facilities	(11,712)	(27,536)
Oil and Gas	(28,931)	(131,548)
Investments in production facilities	(320)	(207)
Distributions from equity investments, net(1)	2,477	5,995

Increase in restricted cash				(232)
Proceeds from sale of properties		22,481		110,147
Cash used in investing activities	$	(109,025)	$	(125,847)

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

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Restricted Cash

As of March 31, 2009 and December 31, 2008, we had $35.4 million of restricted cash included in other assets, net, in the accompanying condensed consolidated balance sheet, all of which related to the funds required to be escrowed to cover decommissioning liabilities associated with the South Marsh Island Block 130 acquisition in 2002 by our Oil and Gas segment. We had fully satisfied the escrow requirement as of March 31, 2009. We may use the restricted cash for the future decommissioning the related field.

Equity Investments

We made the following contributions to our equity investments during the three months ended March 31, 2009 and 2008 (in thousands):

	Three Months Ended March 31,	
	2009	2008
Independence	$	$
Other	320	238
Total	$ 320	$ 238

We received the following distributions from our equity investments during the three months ended March 31, 2009 and 2008 (in thousands):

	Three Months Ended March 31,	
	2009	2008
Deepwater Gateway.	$ 3,500	$ 8,500
Independence	6,800	8,400
Total	$10,300	$16,900

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. In March and April 2008, we sold a total 30% working interest in the Bushwood discoveries (Garden Banks Blocks 463, 506 and 507) and other Outer Continental Shelf oil and gas properties (East Cameron Blocks 371 and 381), in two separate transactions to affiliates of a private independent oil and gas company for total cash consideration of approximately $183.4 million (which included the purchasers' share of incurred capital expenditures on these fields), and additional potential cash payments of up to $20 million based upon certain field production milestones. The new co-owners will also pay their pro rata share of all future capital expenditures related to the exploration and development of these fields. Decommissioning liabilities will be shared on a pro rata share basis between the new co-owners and us. Proceeds from the sale of these properties were used to pay down our outstanding revolving loans in April 2008. As a result of these sales, we recognized a pre-tax gain of $91.6 million in the first half of 2008, including $61.1 million in the first quarter of 2008.

Outlook

We anticipate capital expenditures for the remainder of 2009 will range from $265 million to $315 million, including $51 million for CDI for replacements, vessel improvements and recertification costs for regulatory dry docking. These estimates 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 and 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 2009 initiatives.

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The following table summarizes our contractual cash obligations as of March 31, 2009 and the scheduled years in which the obligations are contractually due (in thousands):

	Total (1)	Less Than 1 year	1-3 Years	3-5 Years	More Than 5 Years
Convertible Senior Notes(2)	$ 300,000	$	$	$	$ 300,000
Senior Unsecured Notes	550,000				550,000
Term Loan	418,011	4,326	8,652	405,033	
MARAD debt	121,368	4,318	9,293	10,244	97,513
Revolving Credit Facility	249,500		249,500		
CDI Term Loan	395,000	80,000	160,000	155,000	
Loan notes	5,000	5,000			
Interest related to long-term debt	662,082	97,161	173,751	153,073	238,097
Preferred stock dividends(3)	1,000	1,000			
Drilling and development costs	12,600	12,600			
Property and equipment(4)	33,000	33,000			
Operating leases(5)	177,012	78,197	73,378	14,908	10,529
Total cash obligations	$2,924,573	$ 315,602	$ 674,574	$ 738,258	$1,196,139

(1) Excludes unsecured letters of credit outstanding at March 31, 2009 totaling $24.4 million, including $13.3 million for CDI. These letters of credit primarily guarantee various contract bidding, insurance activities and shipyard commitments.

(2) Maturity 2025. 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, 2008, the conversion trigger was not met.

(3) Amount represents dividend payment for one year only. Dividends are paid quarterly until such time the holder elects to redeem the stock.

(4) Costs incurred as of March 31, 2009 and additional property and equipment commitments (excluding capitalized interest) at March 31, 2009 consisted of the following (in thousands):

	Costs Incurred	Costs Committed	Total Estimated Project Cost Range
Caesar conversion	$ 163,000	$ 7,000	$ 210,000 – 230,000
Well Enhancer construction	172,000	23,000	200,000 – 220,000
Helix Producer I(a)	218,000	3,000	340,000 – 360,000
Total	$ 553,000	$ 33,000	$ 750,000 – 810,000

(a) Represents 100% of the cost of the vessel, conversion and construction of additional facilities, of which we expect our portion to range between $278 million and $298 million.

(5)

Operating leases included facility leases and vessel charter leases. Vessel charter lease commitments at March 31, 2009 were approximately $133.4 million.

Contingencies

On December 2, 2005, we received an order from the U.S. Department of the Interior Minerals Management Service ("MMS") that the price threshold for both oil and gas was exceeded for 2004 production and that royalties were due on such production notwithstanding the provisions of the Outer Continental Shelf Deep Water Royalty Relief Act of 2005 ("DWRRA"), which was intended to stimulate exploration and production of oil and natural gas in the deepwater Gulf of Mexico by providing relief from the obligation to pay royalty on certain federal leases up to certain specified production volumes. Our oil and gas leases affected by this dispute are Garden Banks Blocks 667, 668 and 669 ("Gunnison"). On May 2, 2006, the MMS issued another order that superseded the December 2005 order, and claimed that royalties on gas production are due for 2003 in addition to oil and gas production in 2004. The Order also seeks interest on all royalties allegedly due. We filed a timely notice of appeal with respect to both the December 2005 Order and the May 2006 Order. We received an additional order from the MMS dated September 30, 2008 stating that the price thresholds for oil and gas were exceeded for 2005, 2006 and 2007 production and that royalties and interest are payable. We appealed this order on the same basis as the previous orders.

Other operators in the Deep Water Gulf of Mexico who have received notices similar to ours are seeking royalty relief under the DWRRA, including Kerr-McGee, the operator of Gunnison. In March of 2006, Kerr-McGee filed a lawsuit in federal district court challenging the enforceability of price thresholds in certain deepwater Gulf of Mexico leases, including ours. On October 30, 2007, the federal district court in the Kerr-McGee case entered judgment in favor of Kerr-McGee and held that the Department of the Interior exceeded its authority by including the price thresholds in the subject leases. The government filed a notice of appeal of that decision on December 21, 2007. On January 12, 2009, the United States Court of Appeals for the Fifth Circuit affirmed the decision of the district court in favor of Kerr-McGee, holding that the DWRRA unambiguously provides that royalty suspensions up to certain production volumes established by Congress apply to leases that qualify under the DWRRA. The plaintiff petitioned the appellate court for rehearing; however, that petition was denied on April 14, 2009. The plaintiff may appeal the appellate court's decision to the United States Supreme Court although there is no certainty that the court will accept the case.

As a result of this dispute, we have been recording 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 of the Gunnison related MMS claim. Following the decision of the United States Court of Appeals for the Fifth Circuit Court, we reversed our previously accrued royalties ($73.5 million) as oil and gas revenue in our first quarter 2009 results. Effective in January 2009, we commenced recognizing oil and natural gas sales revenue associated with this previously disputed net revenue interest and we are no longer accruing any additional royalty reserves as we believe it is remote that we will be liable for such amounts.

A number of our longer term pipelay contracts have been adversely affected by delays in the delivery of the Caesar. We believe two of our contracts qualify as loss contracts as defined under SOP 81-1 "Accounting for Performance of Construction-Type and Certain Production-Type Contracts". Accordingly, we have estimated the future shortfall between our anticipated future revenues versus future costs. For one contract expected to be completed in May 2009, our estimated loss at December 31, 2008 was estimated to be approximately $0.8 million. There was no additional loss on the contract in the first quarter of 2009. Under a second contract, which was terminated, we have a potential future liability of up to $25 million with our estimated future loss under this contract totaling $9.0 million, which was accrued for as of December 31, 2008. We have prepaid $7.2 million of such potential damages related to this terminated contact. If the potential damages exceed $7.2 million we will be required to pay additional funds but to the extent they are less that $7.2 million we would be entitled to cash refund from the contracting party. Although no new losses were identified with this contract in the first quarter of 2009, we will continue to monitor our exposure under this contract over the remainder of 2009.

In March 2009, we were notified of a third party's intention to terminate an international construction contract under a claimed breach of that contract by one of our subsidiaries. Under the terms of the contract, our potential liability is generally capped for actual damages at approximately $27 million Australian dollars ("AUS") ($18.7 million US dollars at March 31, 2009) and for liquidated damages at approximately $5 million AUS (approximately $3.5 million US dollars at March 31, 2009); however, as there are substantial defenses to this claimed breach, we cannot at this time quantify our exposure, if any, under the contract. Over the remainder of 2009, we will continue to assess our potential exposure to damages under this contract as the circumstances warrant

During the fourth quarter of 2006, Horizon received a tax assessment from the SAT, the Mexican taxing authority, for approximately $23 million related to fiscal 2001, including penalties, interest and monetary correction. The SAT's assessment claims unpaid taxes related to services performed among the Horizon subsidiaries that CDI acquired at the time it acquired Horizon. CDI believes under the Mexico and United States double taxation treaty that these services are not taxable and that the tax assessment itself is invalid. On February 14, 2008, CDI received notice from the SAT upholding the original assessment. On April 21, 2008, CDI filed a petition in Mexico tax court disputing the assessment. We believe that CDI’s position is supported by law and CDI intends to vigorously defend its position. However, the ultimate outcome of this litigation and CDI’s potential liability from this assessment, if any, cannot be determined at this time. Nonetheless, an unfavorable outcome with respect to the Mexico tax assessment could have a material adverse effect on CDI’s and our financial position and results of operations. Horizon’s 2002 through 2008 tax years remain subject to examination by the appropriate governmental agencies for Mexico tax purposes, with 2002 through 2004 currently under audit.

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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 2008 Form 10-K.

NEW ACCOUNTING STANDARDS

In December 2007, the FASB issued Statement No. 141 (Revised), Business Combinations ("SFAS No. 141(R)"). SFAS No. 141 (R) requires the acquiring entity in a business combination to recognize all the assets acquired and liabilities assumed in the transaction; establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. It also requires that the costs incurred related to the acquisition be charged to expense as incurred, when previously these costs were capitalized as part of the acquisition cost of the asset or business. We adopted the provisions of SFAS No. 141(R) on January 1, 2009 and it had no impact on our results of operations, cash flows and financial condition.

In December 2007, the FASB issued Statement No. 160, Noncontrolling Interests in Consolidated Financial Statements — an amendment of ARB 51 ("SFAS No. 160"). SFAS No. 160 improves the relevance, comparability, and transparency of financial information provided to investors by requiring all entities to report noncontrolling (minority) interests in subsidiaries as equity in the consolidated financial statements. We adopted SFAS No. 160 on January 1, 2009, which is required to be adopted prospectively, except the following provisions must be adopted retrospectively:

1. Reclassifying noncontrolling interest from the "mezzanine" to equity, separate from the parents' shareholders' equity, in the statement of financial position; and
2. Recast consolidated net income to include net income attributable to both the controlling and noncontrolling interests. That is, retrospectively, the noncontrolling interests' share of a consolidated subsidiary's income should not be presented in the income statement as "minority interest."

Effective January 1, 2009, we changed our accounting policy of recognizing a gain or loss upon any future direct sale or issuance of equity by our subsidiaries if the sales price differs from our carrying amount to be in accordance with SFAS No. 160, in which a gain or loss will only be recognized when loss of control of a consolidated subsidiary occurs. In January 2009, we sold approximately 13.6 million shares of CDI common stock to CDI 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 CDI. Our ownership of CDI following the transaction approximated 51%. Since we retained control of CDI immediately after the transaction, the approximate $2.9 million loss on this sale was treated as a reduction of our equity in the accompanying condensed consolidated balance sheet (Note 18). Any future significant transactions would result in us losing control of CDI and accordingly the gain or loss on those transactions will be recognized in our statement of operations.

In March 2008, the FASB issued Statement No. 161, Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133 (“SFAS No. 161”). SFAS 161 applies to all derivative instruments and related hedged items accounted for under SFAS No. 133. SFAS No. 161 requires entities to provide qualitative disclosures about the objectives and strategies for using derivatives, quantitative data about the fair value of and gains and losses on derivative contracts, and details of credit-risk-related contingent features in their hedged positions. We adopted the provisions of SFAS No. 161 on January 1, 2009 and it had no impact on our results of operations, cash flows or financial condition. See Note 17 below for additional disclosure regarding our derivative instruments.

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In May 2008, the FASB issued FASB Staff Position ("FSP") APB 14-1, Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlement) ("FSP APB 14-1"). We adopted the FSP APB 14-1 effective January 1, 2009. FSP APB 14-1 requires retrospective application for all periods reported (with the cumulative effect of the change reported in retained earnings as of the beginning of the first period presented). FSP APB 14-1 requires the proceeds from the issuance of convertible debt instruments to be allocated between a liability component (issued at a discount) and an equity component. The resulting debt discount is amortized over the period the convertible debt is expected to be outstanding as additional non-cash interest expense. This FSP changed the accounting treatment for our Convertible Senior Notes. FSP APB 14-1 increases our interest expense for our past and future reporting periods by recognizing accretion charges on the resulting debt discount.

Upon adoption of FSP APB 14-1, we recorded a discount of $60.2 million related to our Convertible Senior Notes. To arrive at this discount amount we estimated the fair value of the liability component of the Convertible Senior Notes as of the date of their issuance (March 30, 2005) using an income approach. To determine this estimated fair value, we used borrowing rates of similar market transactions involving comparable liabilities at the time of issuance and an expected life of 7.75 years. In selecting the expected life, we selected the earliest date that the holder could require us to repurchase all or a portion of the Convertible Senior Notes (December 15, 2012).

The following table sets forth the effect of retrospective application of FSP APB 14-1 and FSP EITF 03-06-1 "Determining Whether Instruments Granted in Share Based Payment Transactions Are Participating Securities." (Note 12) on certain previously reported line items in our accompanying condensed consolidated statements of operations (in thousands, except per share data):

	Three Months Ended March 31, 2008	
	Originally Reported	As Adjusted
Net interest expense and other	$ 26,046	$ 28,001
Provision for Income taxes	43,632	42,700
Net income from continuing operations	75,453	73,643
Earnings per common share from continuing operations - Basic	$ 0.82	$ 0.79
Earnings per common share from continuing operations – Diluted	0.79	0.76

The following table sets forth the effect of retrospective application of FSP APB 14-1 on certain previously reported line items in our accompanying condensed consolidated balance sheet (in thousands):

	December 31, 2008	
	As Reported	As Adjusted
Long-term debt	$ 1,968,502	$ 1,933,686

Deferred income tax liability	604,464	615,504
Common stock, no par value	768,835	806,905
Retained earnings	435,506	417,940
Total controlling interest shareholders' equity	1,170,645	1,191,149

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, 2009, we had the following volumes under derivative and forward sale contracts related to our oil and gas producing activities totaling 1,547 MBbl of oil and 31,601 Mmcf of natural gas:

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Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price	
Crude Oil:				(per barrel)
April 2009 — June 2009	Collar(1)	65.7 MBbl	$	75.00 — $89.55
April 2009 — December 2009	Forward Sales(2)	150 MBbl	$	71.79
Natural Gas:				(per Mcf)
April 2009 — December 2009	Collar(3)	947 Mmcf	$	7.00 — $7.90
May 2009 — December 2009	Forward Sales(4)	1,516 Mmcf	$	8.23
January 2010 — December 2010	Swap(1)	912.5 Mmcf	$	5.80

(1) Designated as cash flow hedges, still deemed effective and qualifies for hedge accounting.
(2) Qualified for scope exemption as normal purchase and sale contract.
(3) Designated as cash flow hedges, deemed ineffective and are now being mark-to-market through earnings each period.
(4) No long qualify for normal purchase and sale exemption and are now being marked-to-market through earnings each period.

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, 2009. 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, 2009 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. We completed the implementation of our enterprise resource planning system, as previously reported, on January 1, 2009. We have continued to evolve our controls accordingly. Resulting impacts on internal controls over financial reporting were evaluated and determined not to be significant for the fiscal quarter ended March 31, 2009.

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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, 2009(1)	40,840	$ 7.24		$ N/A
February 1 to February 28, 2009(1)	1,664	3.15		N/A
March 1 to March 31, 2009(1)	218	4.06		N/A
	42,722	$ 7.06		$ N/A

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

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	2009 Long-Term Incentive Cash Plan of Helix Energy Solutions Group, Inc., incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K, filed by registrant with the Securities and Exchange Commission on January 6, 2009 (“the January 2009 8-K”)
10.2	Form of Award Letter related to the 2009 Long-Term Incentive Cash Plan, incorporated by reference to Exhibit 10.2 to the January 2009 8-K.
10.3	Stock Repurchase Agreement between Company and Cal Dive International, Inc., dated January 23, 2009 incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on January 28, 2009.
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: May 8, 2009	By: /s/ Owen Kratz Owen Kratz President and Chief Executive Officer (Principal Executive Officer)
Date: May 8, 2009	By: /s/ Anthony Tripodo Anthony Tripodo Executive Vice President and Chief Financial Officer (Principal Financial Officer)

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