HELIX ENERGY SOLUTIONS GROUP INC
Form 10-Q
October 30, 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 September 30, 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):

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes [ ] No [√]

As of October 28, 2009, 104,312,684 shares of common stock were outstanding.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements.

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

	September 30, 2009 (Unaudited)	December 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 410,506	$ 223,613
Accounts receivable —		
Trade, net of allowance for uncollectible accounts of $4,399 and $5,905, respectively	185,519	427,856
Unbilled revenue	22,558	42,889
Costs in excess of billing	16,624	74,361
Other current assets	130,546	172,089
Current assets of discontinued operations	—	19,215
Total current assets	765,753	960,023
Property and equipment	4,239,307	4,742,051
Less — accumulated depreciation	(1,382,975)	(1,323,608)
	2,856,332	3,418,443
Other assets:		
Equity investments	191,475	196,660
Goodwill	78,220	366,218
Other assets, net	79,310	125,722
	$ 3,971,090	$ 5,067,066
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 177,118	$ 344,807
Accrued liabilities	198,876	231,679
Income taxes payable	108,213	—
Current maturities of long-term debt	13,135	93,540
Current liabilities of discontinued operations	—	2,772
Total current liabilities	497,342	672,798
Long-term debt	1,347,395	1,933,686
Deferred income taxes	456,728	615,504
Decommissioning liabilities	177,924	194,665
Other long-term liabilities	10,148	81,637
Total liabilities	2,489,537	3,498,290
Convertible preferred stock	6,000	55,000
Commitments and contingencies		

Shareholders' equity:		
Common stock, no par, 240,000 shares authorized, 104,378 and 91,972 shares issued, respectively	905,455	806,905
Retained earnings	575,504	417,940
Accumulated other comprehensive loss	(26,931)	(33,696)
Total controlling interest shareholders' equity	1,454,028	1,191,149
Noncontrolling interests	21,525	322,627
Total equity	1,475,553	1,513,776
	$ 3,971,090	$ 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 September 30, 2009	Three Months Ended September 30, 2008
Net revenues:		
Contracting services	$ 152,310	$ 473,117
Oil and gas	63,715	134,619
	216,025	607,736
Cost of sales:		
Contracting services	127,402	318,451
Oil and gas	86,006	90,205
	213,408	408,656
Gross profit	2,617	199,080
Gain on oil and gas derivative commodity contracts	4,598	2,705
Gain on sale of assets, net	—	(23)
Selling and administrative expenses	(21,884)	(48,539)
Income (loss) from operations	(14,669)	153,223
Equity in earnings of investments	13,385	8,751
Gain on sale of Cal Dive common stock	17,901	—
Net interest expense and other	(10,306)	(28,298)
Income before income taxes	6,311	133,676
Provision for income taxes	(4,468)	(54,165)
Income from continuing operations	1,843	79,511
Income (loss) from discontinued operations, net of tax	3,021	(93)
Net income, including noncontrolling interests	4,864	79,418
Net income applicable to noncontrolling interests	(844)	(19,240)
Net income applicable to Helix	4,020	60,178
Preferred stock dividends	(125)	(881)
Net income applicable to Helix common shareholders	$ 3,895	$ 59,297
Basic earnings per share of common stock:		
Continuing operations	$ 0.01	$ 0.65
Discontinued operations	0.03	—
Net income per common share	$ 0.04	$ 0.65
Diluted earnings per share of common stock:		
Continuing operations	$ 0.01	$ 0.63
Discontinued operations	0.03	—
Net income per common share	$ 0.04	$ 0.63
Weighted average common shares outstanding:		

Basic	101,282	90,725
Diluted	101,334	94,583

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)

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Net revenues:		
Contracting services	$ 967,751	$ 1,079,804
Oil and gas	313,888	499,831
	1,281,639	1,579,635
Cost of sales:		
Contracting services	765,602	777,206
Oil and gas	216,454	295,688
	982,056	1,072,894
Gross profit	299,583	506,741
Gain on oil and gas derivative commodity contracts	83,328	2,705
Gain on sale of assets, net	1,773	79,893
Selling and administrative expenses	(102,609)	(136,953)
Income from operations	282,075	452,386
Equity in earnings of investments	27,152	25,722
Gain on sale of Cal Dive common stock	77,343	—
Net interest expense and other	(39,969)	(76,914)
Income before income taxes	346,601	401,194
Provision for income taxes	(126,196)	(151,638)
Income from continuing operations	220,405	249,556
Income from discontinued operations, net of tax	10,303	1,671
Net income, including noncontrolling interests	230,708	251,227
Net income applicable to noncontrolling interests	(19,017)	(26,553)
Net income applicable to Helix	211,691	224,674
Preferred stock dividends	(688)	(2,642)
Preferred stock beneficial conversion charges	(53,439)	—
Net income applicable to Helix common shareholders	$ 157,564	$ 222,032
Basic earnings per share of common stock:		
Continuing operations	$ 1.49	$ 2.40
Discontinued operations	0.10	0.02
Net income per common share	$ 1.59	$ 2.42
Diluted earnings per share of common stock:		
Continuing operations	$ 1.38	$ 2.32
Discontinued operations	0.10	0.02
Net income per common share	$ 1.48	$ 2.34

Weighted average common shares outstanding:		
Basic	97,831	90,598
Diluted	105,868	95,096

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

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

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Cash flows from operating activities:		
Net income, including noncontrolling interests	$ 230,708	$ 251,227
Adjustments to reconcile net income including noncontrolling interests to net cash provided by operating activities —		
Depreciation, depletion and amortization	208,870	246,870
Asset impairment charges and dry hole expense	64,610	24,156
Equity in (earnings) losses of investments, net of distributions	(222)	2,495
Amortization of deferred financing costs	4,095	4,163
Income from discontinued operations	(10,303)	(1,671)
Stock compensation expense	9,435	17,933
Amortization of debt discount	5,878	5,508
Deferred income taxes	(53,012)	54,925
Excess tax benefit from stock-based compensation	2,036	(1,142)
Gain on sale of assets	(1,773)	(79,893)
Unrealized (gain) loss on derivative contracts	(19,785)	4,045
Gain on sale of investment in Cal Dive common stock	(77,343)	—
Changes in operating assets and liabilities:		
Accounts receivable, net	7,215	(48,002)
Other current assets	33,483	(4,777)
Income tax payable	157,931	742
Accounts payable and accrued liabilities	(46,213)	(78,902)
Other noncurrent, net	(78,349)	(60,221)
Cash provided by operating activities	437,261	337,456
Cash provided by (used in) discontinued operations	(6,089)	1,630
Net cash provided by operating activities	431,172	339,086
Cash flows from investing activities:		
Capital expenditures	(306,152)	(728,692)
Distributions from equity investments, net	4,774	4,636
Proceeds from the sale of Cal Dive common stock	418,168	—
Reduction in cash from deconsolidation of Cal Dive	(112,995)	—
Proceeds from sales of properties	23,238	230,261
Other	(564)	(1,261)
Cash provided by (used in) investing activities	26,469	(495,056)
Cash provided by (used in) discontinued operations	20,872	(111)
Net cash provided by (used in) investing activities	47,341	(495,167)

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

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Cash flows from financing activities:		
Repayment of Helix Term Notes	(3,245)	(3,245)
Borrowings on Helix Revolver	—	847,000
Repayments on Helix Revolver	(349,500)	(690,000)
Repayment of MARAD borrowings	(4,214)	(4,014)
Borrowings on CDI Revolver	100,000	61,100
Repayments on CDI Revolver	—	(61,100)
Repayments on CDI Term Notes	(20,000)	(40,000)
Deferred financing costs	(50)	(1,711)
Capital lease payments	—	(1,505)
Preferred stock dividends paid	(625)	(2,642)
Repurchase of common stock	(10,603)	(3,912)
Excess tax benefit from stock-based compensation	(2,036)	1,142
Exercise of stock options, net	36	2,139
Net cash provided by (used in) financing activities	(290,237)	103,252
Effect of exchange rate changes on cash and cash equivalents	(1,383)	(965)
Net increase (decrease) in cash and cash equivalents	186,893	(53,794)
Cash and cash equivalents:		
Balance, beginning of year	223,613	89,555
Balance, end of period	$ 410,506	$ 35,761

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 subsidiaries. On June 10, 2009, our ownership in Cal Dive International Inc. ("Cal Dive" or "CDI") was reduced to less than 50%. Accordingly, we ceased consolidating CDI as of that date and we accounted for our remaining approximate 26% ownership interest under the equity method of accounting through September 23, 2009, at which time we sold substantially all of our remaining ownership interest in Cal Dive (Notes 3 and 4). 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") and those applied in our Current Report on Form 8-K as filed with the Securities and Exchange Commission ("SEC") on June 16, 2009 ("June 2009 Form 8-K"), which among other things, reflected the effect our adoption on January 1, 2009 of certain accounting standards that require retrospective application had on our year-end 2008 financial statements. 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 three month and nine month periods ended September 30, 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 June 2009 Form 8-K. These condensed consolidated financial statements should be read in conjunction with the annual consolidated financial statements and notes thereto included in our June 2009 Form 8-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 pronouncements that require retrospective application (Note 3) and the presentation of a former business unit as discontinued operations (Note 2). We have conducted our subsequent events review through October 30, 2009, the date our financial statements were filed with the SEC.

Note 2 – Company Overview

We are an international offshore energy company that provides development solutions and other key life of field contracting services to the energy market as well as to our own oil and gas business unit. Our Contracting Services segment utilizes our vessels, offshore equipment and proprietary technologies to deliver services that may reduce finding and development costs and encompass the complete lifecycle of an offshore oil and gas field. Our Contracting Services are located primarily in Gulf of Mexico, North Sea, Asia/Pacific and 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.

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Contracting Services Operations

We seek to provide services and methodologies which we believe are critical to finding and developing offshore reservoirs and maximizing production economics. Our "life of field" services are segregated into four disciplines: 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") Codification Topic No. 280 Segment Reporting: Contracting Services, Production Facilities and Shelf Contracting. Our Contracting Services business includes subsea construction, well operations, robotics and drilling. Our Production Facilities business includes our investments in Deepwater Gateway, L.L.C. ("Deepwater Gateway"), Independence Hub, LLC ("Independence Hub") and Kommandor LLC ("Kommandor"). In April 2009, Kommandor LLC completed the initial conversion of the Helix Producer I ("HP I") vessel. The vessel is currently undergoing further modification to install top side production facilities. The completed vessel is expected to be ready for service in the first half of 2010, and is currently scheduled to be deployed to our deepwater Phoenix oil and gas field that is being developed in parallel with the planned delivery of the HP I. We have sold substantially all our remaining ownership interest in CDI (Note 4). CDI's operations represented our former Shelf Contracting business, which we deconsolidated on June 10, 2009 (Notes 3 and 4).

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 April 2009, we sold Helix Energy Limited ("HEL"), our former reservoir technology consulting business, to a subsidiary of Baker Hughes Incorporated for $25 million. As a result of the sale of HEL, which entity's operations were conducted by its wholly owned subsidiary, Helix RDS Limited ("Helix RDS"), we have presented the results of Helix RDS as discontinued operations in the accompanying condensed consolidated financial statements. HEL and Helix RDS were previously components of our Contracting Services segment. We recognized an $8.8 million gain on the sale of HEL. The operating results of HEL and Helix RDS were immaterial to our results for all periods presented.

Economic Outlook

The economic downturn and weakness in the equity and credit capital markets continue to contribute to the uncertainty regarding the outlook of the global economy. This uncertainty, coupled with the negative near-term outlook for global demand for oil and natural gas, resulted in commodity price declines over the second half of 2008, with significant declines occurring in the fourth quarter of 2008. Natural gas prices continued to decline in 2009 with prices reaching near decade low levels. A decline in oil and natural gas prices negatively impacts our operating results and cash flows. Our stock price also significantly declined over the second half of 2008. The declines 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 of our goodwill amounts as of March 31, 2009; however, no further impairments were required. Our stock price subsequently increased and no further impairment of goodwill was required through September 30, 2009. At September 30, 2009 our remaining goodwill totaled $78.2 million, all of which is attributable to our Contracting Services segment.

Our Contracting Services segment may also be negatively impacted by low commodity prices as some of our customers, primarily oil and gas companies, have announced their intention to reduce capital spending. We forecast weaker demand for our contracting services for the remainder of 2009. With respect to our oil and gas operations, we hedged the price risk for a significant portion of our anticipated oil and gas production for 2009 when we entered into commodity hedges during 2008. These hedge contracts enable us to minimize our near-term cash flow risks related to declining commodity prices. Similarly, throughout the nine months ended September 30, 2009, we have entered into a number of financial derivative contracts to hedge a substantial portion of our forecasted production of both oil and natural gas for 2010. See Note 19 for additional information regarding our oil and gas hedge contracts.

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Note 3 – Recent Accounting Pronouncements

We have adopted the fair value accounting standards as contained in FASB Codification Topic No. 280 "Fair Value Measurements and Disclosures." These standards among other things, define fair value, establish a consistent framework for measuring fair value and expand disclosure for each major asset and liability category measured at fair value on either a recurring or nonrecurring basis. The FASB has clarified 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. The following is the three-tier fair value hierarchy established by the FASB, 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. 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 September 30, 2009 (in thousands):

	Level 1	Level 2	Level 3	Total	Valuation Technique
Assets:					
Oil and gas derivatives	$–	$16,711	–	$16,711	(c)
Foreign currency forwards	–	2,077	–	2,077	(c)
Investment in Cal Dive (Note 4)	4,945	–	–	4,945	(a)
Liabilities:					
Gas swaps and collars	–	13,890	–	13,890	(c)
Interest rate swaps	–	2,388	–	2,388	(c)
Total	4,945	$2,510	–	$7,455	

In December 2007, the FASB issued Statement No. 160, Noncontrolling Interests in Consolidated Financial Statements — an amendment of ARB 51. These standards are now included in FASB Codification Topic No. 810 Consolidation. These standards were enacted to improve 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.

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We adopted these standards on January 1, 2009, which are required to be adopted prospectively, except the following provisions were required to 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. Recasting 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, in which a gain or loss will only be recognized when loss of control of a consolidated subsidiary occurs. See Note 4 for disclosure of stock sales transactions that ultimately resulted in our loss of control of CDI.

On January 1, 2009 we adopted certain financial accounting standards included with FASB Codification Topic No. 815 Derivatives and Hedging. These standards apply to all derivative instruments and related hedged items and require that entities 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. Adoption of these standards had no impact on our results of operations, cash flows or financial condition. See Note 19 below for the required disclosures for our derivative instruments.

Effective January 1, 2009, we adopted accounting standards as required in FASB Codification Topic No. 470-20 Debt with Conversion and Other Options. These standards require 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). These standards require 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 standard affects the accounting treatment for our Convertible Senior Notes and increases our interest expense for our past and future reporting periods by recognizing accretion charges on the resulting debt discount.

Upon adoption, 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 the adoption of new accounting standards and the effect on earnings per share (Note 14) and discontinued operations on certain previously reported line items in our accompanying condensed consolidated statements of operations (in thousands, except per share data):

	Three Months Ended September 30, 2008	
	Originally Reported	As Adjusted
Net interest expense and other	$23,464	$28,298
Provision for Income taxes	54,816	54,165
Net income from continuing operations	80,708	79,511

Earnings per common share from continuing operations – Basic	$0.67	$0.65
Earnings per common share from continuing operations – Diluted	0.65	0.63

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	Nine Months Ended September 30, 2008	
	Originally Reported	As Adjusted
Net interest expense and other	$68,178	$76,914
Provision for Income taxes	154,373	151,638
Net income from continuing operations	255,019	249,556
Earnings per common share from continuing operations - Basic	$2.49	$2.42
Earnings per common share from continuing operations – Diluted	2.40	2.34

On June 30, 2009, we adopted the general standards of accounting for and disclosures of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Specifically, FASB Codification Topic No. 855 Subsequent Events sets forth the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements, the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements, and the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. The adoption of these standards had no impact on our results, cash flow or financial position as management already followed a similar approach prior to the adoption of this standard.

Note 4 – Reduction in Ownership of Cal Dive

At December 31, 2008, we owned approximately 57.2% of Cal Dive. During 2009, as previously noted in Notes 1, 2 and 3, we engaged in a number of transactions that ultimately resulted in our disposal of substantially all of our remaining ownership in Cal Dive.

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

In June 2009, we sold 22.6 million shares of Cal Dive common stock held by us pursuant to a secondary public offering ("Offering"). Proceeds from the Offering totaled approximately $182.9 million, net of underwriting fees. Separately, pursuant to a Stock Repurchase Agreement with Cal Dive, simultaneously with the closing of the Offering, Cal Dive repurchased from us approximately 1.6 million shares of its common stock for net proceeds of $14 million at $8.50 per share, the Offering price. Following the closing of these two transactions, our ownership of Cal Dive common stock was reduced to approximately 26%.

Because these transactions reduced our ownership in Cal Dive to less than 50%, the $59.4 million gain resulting from the sale of these shares is reflected in "Gain on sale of Cal Dive common stock" in the accompanying condensed consolidated statement of operations. The $59.4 million amount included an approximate $27.1 million gain associated with the re-measurement of our remaining 26% ownership interest in Cal Dive at its fair value on June 10, 2009, the date of the closing of the Offering, which represented the date of deconsolidation. Since we no longer held a controlling interest in Cal Dive, we ceased consolidating Cal Dive effective June 10, 2009, and subsequently accounted for our remaining ownership interest in Cal Dive under the equity method of accounting until September 23, 2009, as further discussed below.

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On September 23, 2009, we sold 20.6 million shares of Cal Dive common stock held by us pursuant to a second secondary public offering ("Second Offering"). On September 24, 2009, the underwriters sold an additional 2.6 million shares of Cal Dive common stock held by us pursuant to their overallotment option under the terms of the Second Offering. The price for the Second Offering was $10 per share, with resulting proceeds totaling approximately $221.5 million, net of underwriting fees. We recorded an approximate $17.9 million gain associated with the Second Offering transactions.

Following the closing of the Second Offering transactions, we own 0.5 million shares of Cal Dive common stock, representing less than 1% of the total outstanding shares of Cal Dive. Accordingly we now classify our remaining interest in Cal Dive as an investment available for sale pursuant to FASB Codification Topic No.320 Investment - Debt and Equity Securities. As an investment available for sale, the value of our remaining interest will be marked-to-market at each period end with the corresponding change in value being reported as a component of other comprehensive income (loss) in the accompanying condensed consolidated balance sheet at September 30, 2009 (Note 3). We intend to sell our remaining shares of Cal Dive common stock over the near term as market conditions warrant. The value of our remaining investment in Cal Dive decreased by $0.1 million from the closing of the Second Offering to September 30, 2009.

Proceeds from our Cal Dive stock sale transaction have been and will continue to be used for general corporate purposes.

Note 5 – Insurance Matters

In September 2008, we sustained damage to certain of our facilities resulting from Hurricane Ike. All of our segments were affected by the hurricane; however, the oil and gas segment suffered the substantial majority of our aggregate damages. While we sustained damage to our own production facilities from Hurricane Ike, the larger issue in terms of our production recovery involved damage to third party pipelines and onshore processing facilities. The timing of the repairs of these facilities was not subject to our control and some of these third party facilities remain out of service as of October 30, 2009. Our insurance policy, which covered all of our operated and non-operated producing and non-producing properties, was subject to an approximate $6 million of aggregate deductibles. We met our aggregate deductible in September 2008. We record our hurricane-related repair costs as incurred in our oil and gas cost of sales. We record insurance reimbursements when the realization of the claim for recovery of a loss is deemed probable.

In June 2009, we reached a settlement with the underwriters of our insurance policies related to damages from Hurricane Ike. Insurance proceeds received in the second quarter of 2009 totaled $102.6 million. Previously, we had received approximately $25.6 million of reimbursements under previously submitted Ike-related insurance claims. In the second quarter of 2009, we recorded a $43.0 million net reduction in our cost of sales in the accompanying condensed consolidated statements of operations representing the amount our insurance recoveries exceeded our costs during the second quarter of 2009. The cost reduction reflected the net proceeds of $102.6 million partially offset by $8.1 million of hurricane-related expenses incurred in the second quarter of 2009 and $51.5 million of hurricane related impairment charges, including $43.8 million of additional estimated asset retirement costs ("ARO") resulting from additional work performed and/or further evaluation of facilities on properties that were classified as a "total loss" following the storm.

We are substantially complete with our hurricane repairs; however we are still incurring costs related to our accrued asset retirement obligations.

The following table summarizes the claims and reimbursements by segment that affected our costs of sales accounts under various insurance claims resulting from damages sustained by Hurricane Ike, primarily those claims and reimbursements recently settled under our energy insurance policy (in thousands):

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	Third Quarter 2009	Nine Months Ended September 30, 2009	Since Inception in September 2008
Oil and gas:			
Hurricane repair costs	$5,060	$25,223	$47,774
ARO liability adjustments	-	43,812	48,065
Hurricane-related impairments	-	7,699	37,585
Insurance recoveries	-	(100,874)	(118,415)
Net (reimbursements) costs	$5,060	$(24,140)	$15,009
Contracting services:			
Hurricane repair costs	$-	$776	$6,026
Insurance recoveries	(159)	(2,885)	(5,022)
Net (reimbursements) costs	$(159)	(2,109)	1,004
Shelf Contracting:			
Hurricane repair costs	$3	$613	$4,550
Insurance recoveries	(238)	(2,849)	(5,183)
Net (reimbursements) costs	$(235)	$(2,236)	(633)
Totals:			
Hurricane repair costs	$5,063	$26,612	$58,350
ARO liability adjustments	-	43,812	48,065
Hurricane-related impairments	-	7,699	37,585
Insurance recoveries	(397)	(106,608)	(128,620)
Net (reimbursements) costs	$4,666	$(28,485)	$15,380

We renewed our energy and marine insurance for the period July 1, 2009 to June 30, 2010. However, this insurance renewal did not include wind storm coverage as the premium and deductibles would have been relatively substantial for the underlying coverage provided. In order to mitigate potential loss with respect to our most significant oil and gas properties from hurricanes in the Gulf of Mexico, we entered into a weather derivative (Catastrophic Bond). The Catastrophic Bond provides for payments of negotiated amounts should the eye of a Category 3 or greater hurricane pass within certain pre-defined areas encompassing our more prominent oil and gas producing fields. The premium for this Catastrophic Bond was approximately $13.1 million. The Catastrophic Bond is not considered a risk management instrument for accounting purposes. Accordingly, the premium associated with the Catastrophic Bond is not charged to expense on a straight line basis as customary with insurance premiums but rather it is charged to expense on a basis to reflect the Catastrophic Bond's intrinsic value at the end of the period. Because our Catastrophic Bond was underwritten to mitigate the risk of hurricanes in the Gulf of Mexico, substantially all of its intrinsic value is for the period associated with "hurricane season" (typically June 1 to November 30) with a substantial majority of the intrinsic value associated with the period July 1, 2009 to September 30, 2009. As a result, we charged to expense $10.4 million of our $13.1 premium in the third quarter of 2009 and substantially all of the remaining $2.7 million of premium will be charged to expense in the fourth quarter of 2009. The expense associated with the Catastrophic Bond premium is recorded as a component of lease operating expense for our oil and gas operations.

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Note 6 – Details of Certain Accounts (in thousands)

Other Current Assets consisted of the following as of September 30, 2009 and December 31, 2008:

	September 30, 2009	December 31, 2008
Other receivables	$10,486	$22,977
Prepaid insurance	16,335	18,327
Other prepaids	12,779	23,956
Inventory	26,856	32,195
Current deferred tax assets	25,701	3,978
Hedging assets	17,830	26,800
Income tax receivable	—	23,485
Gas imbalance	7,603	7,550
Investments available for sale	4,945	—
Other	8,011	12,821
	$130,546	$172,089

Other Assets, net, consisted of the following as of September 30, 2009 and December 31, 2008:

	September 30, 2009	December 31, 2008
Restricted cash	$35,416	$35,402
Deferred drydock expenses, net	13,221	38,620
Deferred financing costs	25,641	33,431
Intangible assets with definite lives, net	842	7,600
Other	4,190	10,669
	$79,310	$125,722

Accrued Liabilities consisted of the following as of September 30, 2009 and December 31, 2008:

	September 30, 2009	December 31, 2008
Accrued payroll and related benefits	$36,146	$46,224
Royalties payable	4,153	10,265
Current decommissioning liability	73,566	31,116
Unearned revenue	7,925	9,353
Billings in excess of costs	1,307	13,256
Accrued interest	16,942	34,299
Deposit	25,542	25,542
Hedge liability	9,218	7,687
Other	24,077	53,937

	$198,876	$231,679

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Note 7 – 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 the preferred shares into common stock at any time, and to redeem the preferred shares into common stock 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 based on a redemption price of $5.05 per share as determined by the average closing price of our common stock on the three days starting on the third day prior to holder redeeming the shares of Series A-2 Cumulative Preferred Stock. Accordingly, in the first quarter of 2009 we recognized a $29.3 million charge to reflect the terms of this redemption, which was recorded as a reduction to 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 provides that if the volume weighted average price of our common stock on any date is less than a certain minimum price (calculated at $2.767 subsequent to the above described redemption), then our right to pay dividends in our common stock is extinguished, and we are required to 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. Subsequent to this election, the conversion price is not subject to any further adjustment or reset. As a result of the reset of the conversion price, Fletcher was entitled to receive an aggregate of 9,035,056 shares in future conversion(s) into our common stock based on the fixed $2.767 conversion price. 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 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.

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On July 23, 2009 and August 12, 2009, Fletcher provided a notice of conversion informing us of its election to convert 15,000 shares and 4,000 shares, respectively, of the Series A-1 Cumulative Convertible Preferred Stock into 5,421,033 shares and 1,445,608 shares, respectively, of our common stock. In connection with the closing of each conversion we also paid the accrued and unpaid dividends associated with these shares in cash, the amount of which was immaterial at the time of the conversion notice. The conversions were consummated on July 27, 2009 and August 14, 2009, respectively.

At September 30, 2009, we had 6,000 shares of convertible preferred stock outstanding, which are convertible into 2,168,413 shares of our common stock. The convertible preferred stock maintains its mezzanine presentation below liabilities but is not included as component of shareholders' equity, because we may, under certain instances, be required to settle any future conversions in cash.

The common shares issuable in connection with this convertible preferred stock outstanding are included 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 almost all future reporting periods in which we have positive earnings and our average stock price exceeds $2.767 per share we will have an assumed conversion of convertible preferred stock and the applicable number of our shares (2,168,413 shares at September 30, 2009) will be included in our diluted shares outstanding amount. However, our earnings from continuing operations for the three month period ended September 30, 2009 resulted in the assumed conversion of the convertible preferred stock to be anti-dilutive, meaning its assumed conversion would have increased our diluted earnings per share calculation (Note 14).

Note 8 – 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 expensed in the period in which the drilling is determined to be unsuccessful.

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

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 as well as an additional order from the MMS dated August 28, 2009 stating the price thresholds for oil and natural gas were exceeded for 2008 and that royalties and interest are payable. We appealed these orders on the same basis as the previous orders.

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Other operators in the Deep Water Gulf of Mexico who have received notices similar to ours sought 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 appealed the district court's decision. 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. After the appellate court denied a request by the plaintiff for rehearing, the plaintiff subsequently petitioned the United States Supreme Court for a writ of certiorari for the Supreme Court to review the Fifth Circuit Court's decision. In October 2009, the United States Supreme Court announced its decision to deny the plaintiff's writ of certiorari, concluding the litigation in this dispute.

As a result of this dispute, we had 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 believed it was remote that we would be liable for such amounts in future. This belief was confirmed with United States Supreme Court decision to deny the plaintiff's writ of certiorari in October 2009.

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 Valley Block 426 in January 2009. In the second quarter we sold three fields for gross proceeds of $0.8 million and resulting in an aggregate gain of $1.2 million, including transfer of the respective field's asset retirement obligations.

In March and April 2008, we sold an aggregate 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 (of which $30.5 million was recognized in second quarter 2008).

In May 2008, we sold all our interests in our onshore proved and unproved oil and gas properties located in the states of Texas, Mississippi, Louisiana, Oklahoma, New Mexico and Wyoming ("Onshore Properties") to an unrelated investor. We sold these Onshore Properties for cash proceeds of $47.2 million and recorded a related loss of $11.9 million in the second quarter of 2008. Included in the cost basis of the Onshore Properties was an $8.1 million allocation of goodwill from our Oil and Gas segment.

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Exploration and Other

As of September 30, 2009, we capitalized approximately $2.9 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 and nine months ended September 30, 2009 and 2008 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Delay rental and geological and geophysical costs	$ 755	$ 1,375	$ 2,288	$ 4,753
Dry hole expense	149	270	575	254
Total exploration expense	$ 904	$ 1,645	$ 2,863	$ 5,007

In 2009, we farmed-out our 100% leasehold interests in Green Canyon Block 490 located in the deepwater of the Gulf of Mexico. Our farmout agreement was structured such that the operator paid 100% of the drilling costs to evaluate the prospective reservoir. The operator has drilled the well and it was successful in finding commercial quantities of hydrocarbons. We have elected to participate for a 25 percent working interest in setting production casing and the right to participate in all subsequent operations. Well completion and development options are being evaluated for the new discovery

In the second quarter of 2009, we recorded an aggregate of approximately $63.1 million of impairment charges, which are reflected as a reduction to our cost of sales. These charges primarily reflect the approximate $51.5 million of impairment-related charges recorded to properties that were severely damaged by Hurricane Ike (Note 5). Separately, we also recorded $11.5 million of impairment charges to reduce the asset carrying value of four fields following reductions in their estimated proved reserves as evaluated at June 30, 2009. We recorded an aggregate $1.5 million of additional impairment charges associated with five fields following a comprehensive impairment analysis at September 30, 2009. Prior to the impairments charges discussed above, the aggregate net book value of the affected fields was $68.9 million. The impairment charges reduced the fields to their then aggregate net fair value of $4.2 million. The substantial majority of the impairments were associated with fields to which we had to increase our reclamation obligation estimates. We have concluded that this valuation is classified with level three of the valuation hierarchy (Note 3).

For the nine months ended September 30, 2008 we recorded impairment charges totaling $23.9 million as a component of oil and gas cost of sales in the accompanying condensed statement of operations. These impairments primarily reflected the $14.6 million of costs associated with the unsuccessful development well on Devil's Island (Garden Banks Block 344) and $6.7 million related to our Tiger deepwater field that was damaged by Hurricane Ike.

The following table describes the changes in our asset retirement obligations (both long term and current) since December 31, 2008 (in thousands):

Asset retirement obligation at December 31, 2008	$ 225,781
Liability transferred to third party during the period	(3,506)
Liability settled during the period	(45,848)

Revision in estimated cash flows		63,462a
Accretion expense (included in depreciation and amortization)		11,601
Asset retirement obligations at December 31,	$	251,490

a. Increase in estimates primary associated with properties damaged during Hurricane Ike (Note 5).

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Note 9 – 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 September 30, 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 Block 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 nine months ended September 30, 2009 and 2008 (in thousands):

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Interest paid, net of capitalized interest	$ 51,696	$ 46,649
Income taxes paid	$ 57,412	$ 97,059

Non-cash investing activities for the nine months ended September 30, 2009 included $63.6 million of accruals for capital expenditures. Non-cash investing activities for the nine months ended September 30, 2008 totaled $28.6 million. The accruals have been reflected in the condensed consolidated balance sheet as an increase in property and equipment and accounts payable.

Note 10 – Equity Investments

As of September 30, 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 $104.3 million and $106.3 million as of September 30, 2009 and December 31, 2008, respectively (including capitalized interest of $1.5 million and $1.6 million at September 30, 2009 and December 31, 2008, respectively). Our equity in the earnings of Deepwater Gateway totaled $1.0 million and $2.5 million for the three month and nine month periods ended September 30, 2009 compared with $4.1 million and $14.4 million during the respective prior year periods. Distributions from Deepwater Gateway, net to our interest, totaled $4.5 million for the nine months ended September 30, 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 $87.2 million and $90.2 million as of September 30, 2009 and December 31, 2008, respectively (including capitalized interest of $5.6 million and $5.9 million at September 30, 2009 and December 31, 2008, respectively). Our equity in the earnings of Independence Hub totaled $5.3 million and $17.2 million for the three month and nine month periods ended September 30, 2009 compared with $4.8 million and $13.9 million during the respective prior year periods. Distributions from Independence, net to our interest, totaled $20.0 million for the nine months ended September 30, 2009.

Also included within our Production Facilities segment is our investment in Kommandor LLC, the results of which we consolidate in our financial statements.

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As disclosed in Note 4, in June 2009 we sold shares of Cal Dive common stock that reduced our ownership in Cal Dive to less than 50%. Accordingly we deconsolidated Cal Dive from our financial statements effective June 11, 2009. We accounted for our remaining approximate 26% ownership interest in Cal Dive using the equity method until September 23, 2009, at which time we sold substantially all our remaining ownership interest in Cal Dive. The fair value of our remaining investment in Cal Dive was approximately $4.9 million at September 30, 2009 (Note 3).

Note 11 – Long-Term Debt

Scheduled maturities of long-term debt and capital lease obligations outstanding as of September 30, 2009 were as follows (in thousands):

	Helix Term Loan	Helix Revolving Loans	Senior Unsecured Notes	Convertible Senior Notes	MARAD Debt	Other(1)	Total
Less than one year	$ 4,326	$	$	$	$ 4,424	$ 4,385	$ 13,135
One to two years	4,326				4,645		8,971
Two to three years	4,326				4,877		9,203
Three to four years	402,870				5,120		407,990
Four to five years					5,376		5,376
Over five years			550,000	300,000	94,793		944,793
Total debt	415,848		550,000	300,000	119,235	4,385	1,389,468
Current maturities	(4,326)				(4,424)	(4,385)	(13,135)
Long-term debt, less current maturities	$411,522	$	$ 550,000	$ 300,000	$ 114,811	$	$1,376,333
Unamortized debt discount (2)				(28,938)			(28,938)
Long-term debt	$411,522	$	$ 550,000	$ 271,062	$ 114,811	$	$1,347,395
Fair Value (3), (4), (5)	$399,734	$	$ 552,750	$ 265,725	$ 123,325	$ 4,385	$ 1,345,919

(1) Reflects 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.

(3) The fair value of the term loan, senior unsecured notes and convertible notes were based on quoted market prices as of September 30, 2009 using level 1 inputs as defined in FASB Codification Topic No 280 using the market approach (Note 3).

(4) The fair value of the MARAD debt was determined using a third-party evaluation of the remaining average life and outstanding principal balance of the MARAD indebtedness as compared to other government guaranteed obligations in the market with similar terms. The fair value of the MARAD debt was estimated using level 2 inputs using the cost approach (Note 3).

(5) The loan notes representing other in the table approximate fair value.

We had unsecured letters of credit outstanding at September 30, 2009 totaling approximately $49.7 million. These letters of credit primarily guarantee various contract bids, contractual performance, insurance activities and shipyard commitments. The following table details our interest expense and capitalized interest for the three and nine months ended September 30, 2009 and 2008 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Interest expense	$ 23,582	$ 32,453	$ 81,094	$ 100,877
Interest income	(282)	(593)	(694)	(2,149)
Capitalized interest	(16,050)	(10,045)	(35,540)	(30,618)
Interest expense, net	$ 7,250	$ 21,815	$ 44,860	$ 68,110

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Included below is a summary of certain components of our indebtedness. At September 30, 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 January 15, 2016 ("Senior Unsecured Notes"). Interest on the Senior Unsecured Notes is payable semiannually in arrears on each January 15 and July 15, commencing July 15, 2008. The Senior Unsecured Notes are fully and unconditionally guaranteed by substantially all of our existing restricted domestic subsidiaries, except for Cal Dive I-Title XI, Inc. In addition, any future restricted domestic subsidiaries that guarantee any of our indebtedness and/or our restricted subsidiaries' indebtedness are required to guarantee the Senior Unsecured Notes. Cal Dive I -Title XI, Inc. and our foreign subsidiaries are not guarantors. CDI and its subsidiaries were not guarantors of the Senior Unsecured Notes prior to deconsolidation of CDI in June 2009 (Note 4). 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). Total borrowing capacity under the Revolving Credit Facility at September 30, 2009 totaled $420 million. The full amount of the Revolving Credit Facility may be used for issuances of letters of credit. At September 30, 2009 we had no amounts drawn on the Revolving Credit Facility and our availability under the Facility totaled $370.3 million net of $49.7 million of unsecured letters of credit issued.

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 nine months ended September 30, 2009 and 2008 was approximately 2.9% and 5.4%, 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 an applicable margin as discussed below. Margins on the Revolving Loans will fluctuate in relation to the consolidated leverage ratio as provided in the Credit Agreement. The average interest rate on the Revolving Loans was approximately 3.4% through date of their repayment in the second quarter of 2009. We have no amounts outstanding under the revolver at September 30, 2009.

In October 2009, we amended our Senior Credit Facility. Among other things, the amendment:

- extends the maturity of the revolving line of credit under the Credit Agreement from July 1, 2011 to November 30, 2012;

- permits the disposition of certain oil and gas properties without a limit as to value, provided that we use 60% of the proceeds from such sales to make certain mandatory prepayments of the existing term loan (40% of the proceeds can be reinvested into collateral);

- relaxes limitations on our right to dispose of the Caesar vessel, by permitting the disposition of the Caesar provided that we use 60% of the proceeds from such sale to make certain mandatory prepayments of the existing term loans and permits us to contribute the Caesar to a joint venture or similar arrangement (40% of the proceeds can be reinvested into collateral);

- increases the maximum amount of all investments permitted in subsidiaries that are neither loan parties nor whose equity interests are pledged from $100 million to $150 million;

- increases the amount of restricted payments in the form of stock repurchases or redemptions such that we are permitted to repurchase or redeem up to $50 million of our common stock in the event we prepay an aggregate amount on the term loan greater than $200 million (up to $25 million if we prepay at least $100 million);

· amends the applicable margins under the revolving lines of credit under the Credit Agreement (ranging from 3.0% to 4.0% on LIBOR loans and 2.0% to 3.0% on Base Rate loans); and

· increases the accordion feature that allows Helix to increase the revolving line of credit by $100 million (to $550 million) at any time in future periods with lender approval.

Simultaneously with entering into the amendment, we completed an increase in the revolving line of credit from $420 million to $435 million (decreasing to $407 million from July 1, 2011 through November 30, 2012) utilizing the accordion feature included in the Credit Agreement through an increase in the commitment from an existing lender.

Convertible Senior Notes

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

The Convertible Senior Notes can be converted prior to the stated maturity (March 2025) under certain triggering events specified in the indenture governing the Convertible Senior Notes. To the extent we do not have long-term financing secured to cover the conversion, the Convertible Senior Notes would be classified as a current liability in the accompanying balance sheet. No conversion triggers were met during the nine month period ended September 30, 2009. The first dates for early redemption of the Convertible Senior Notes are in December 2012, with the holders of the Convertible Senior Notes being able to put them to us on December 15, 2012 and our being able to call the Convertible Senior Notes at any time after December 20, 2012 (see Note 11 of our 2008 Form 10-K). As a result of adopting FSP APB 14-1 (Note 3), the effective interest is 6.6%.

Approximately 0.6 million shares underlying the Convertible Senior Notes were included in the calculation of diluted earnings per share for the nine month period ended September 30, 2008 because our average share price for the 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 September 30, 2008 and the three and nine month periods ended September 30, 2009. As a result of our share price being lower than the $32.14 per share conversion price for these periods there are no shares included in our diluted earnings per share calculation associated with the assumed conversion of our Convertible Senior Notes. In the event our average share price exceeds the conversion price, there would be a premium, payable in shares of common stock, in addition to the principal amount, which is paid in cash, and such shares would be issued on conversion. The Convertible Senior Notes are convertible into a maximum 13,303,770 shares of our common stock.

MARAD Debt

This U.S. government guaranteed financing ("MARAD Debt") is pursuant to Title XI of the Merchant Marine Act of 1936 which is administered by the Maritime Administration and was used to finance the construction of the Q4000. The MARAD Debt is payable in equal semi-annual installments 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 and the MARAD Debt agreements, we are required to comply with certain covenants and restrictions, including the maintenance of minimum net worth, working capital and debt-to-equity requirements. As of

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September 30, 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 $25.6 million and $33.4 million are included in other assets, net as of September 30, 2009 and December 31, 2008, respectively, and are being amortized over the life of the respective loan agreements.

Note 12 – Income Taxes

The effective tax rate for the three month and nine month periods ended September 30, 2009 was 70.8% and 36.4%, respectively, compared with 40.5% and 37.8% for the three month and nine month periods ended September 30, 2008. The effective tax rate for the three months ended September 30, 2009 increased as a result of decreased profitability and the reduced benefit derived from the Internal Revenue Code §199 manufacturing deduction as it primarily related to oil and gas production. The decrease in the effective rate for the nine month period ended September 30, 2009 resulted from the deconsolidation of Cal Dive. This benefit was partially offset by reduced Internal Revenue Code §199 manufacturing deductions as it primarily related to oil and gas production.

We believe our recorded assets and liabilities are reasonable; however, tax laws and regulations are subject to interpretation and tax litigation is inherently uncertain; therefore our assessments can involve a series of complex judgments about future events and rely heavily on estimates and assumptions.

Note 13 – Comprehensive Income (Loss)

The components of total comprehensive income (loss) for the three and nine month periods ended September 30, 2009 and 2008 were as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Net income, including noncontrolling interests	$ 4,864	$ 79,418	$ 230,708	$ 251,227
Other comprehensive income (loss), net of tax				
Foreign currency translation gain	(3,343)	(26,322)	23,689	(23,929)
Unrealized loss on hedges, net	(2,883)	14,073	(16,221)	7,769
Unrealized loss on investment available for sale	(130)		(130)	
Total other accumulated comprehensive income (loss)	(6,356)	(12,249)	7,338	(16,160)
Less: Other accumulated comprehensive loss applicable to noncontrolling interest	(844)	(19,347)	(19,590)	(26,811)
Total other accumulated comprehensive loss applicable to Helix	(7,200)	(31,596)	(12,252)	(42,971)
Total other comprehensive income (loss) applicable to Helix	$ (2,336)	$ 47,882	$ 218,456	$ 208,256

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

	September 30,	December 31,

	2009	2008
Cumulative foreign currency translation adjustment	$ (19,278)	$ (42,874)
Unrealized gain (loss) on hedges, net	(7,523)	9,178
Unrealized loss on investment available for sale	(130)	
Accumulated other comprehensive loss	$ (26,931)	$ (33,696)

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Note 14 – 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 period 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 month and nine month periods ended September 30, 2009 and 2008 are as follows (in thousands):

	Three Months Ended September 30, 2009		Three Months Ended September 30, 2008	
	Income	Shares	Income	Shares
Basic:				
Net income applicable to common shareholders	$ 3,895		$ 59,297	
Less: Undistributed net income allocable to participating securities	(53)		(724)	
Undistributed net income applicable to common shareholders	3,842		58,573	
(Income) loss from discontinued operations	(3,021)		93	
Add: Undistributed net income from discontinued operations allocable to participating securities	41		(1)	
Income per common share – continuing operations	$ 862	101,282	$ 58,665	90,725

	Three Months Ended September 30, 2009		Three Months Ended September 30, 2008	
	Income	Shares	Income	Shares
Diluted:				
Net income per common share – continuing operations – Basic	$ 862	101,282	$ 58,665	90,725
Effect of dilutive securities:				
Stock options		52		227

Undistributed earnings reallocated to participating securities					29	
Convertible Senior Notes						
Convertible preferred stock (a)					881	3,631
Income per common share continuing operations		862			59,575	
Income (loss) per common share discontinued operations		3,021			(93)	
Net income per common share	$	3,883	101,334	$	59,482	94,583

(a) The 2009 period excludes approximately 4.4 million equivalent common shares related to the assumed conversion of convertible preferred stock because such assumed conversion would be anti-dilutive (Note 7).

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	Nine Months Ended September 30, 2009		Nine Months Ended September 30, 2008	
	Income	Shares	Income	Shares
Basic:				
Net income applicable to common shareholders	$157,564		$222,032	
Less: Undistributed net income allocable to participating securities	(2,284)		(2,874)	
Undistributed net income applicable to common shareholders	155,280		219,158	
(Income) loss from discontinued operations	(10,303)		(1,671)	
Add: Undiscounted net income from discontinued operations allocable to participating securities	149		22	
Income per common share – continuing operations	$145,126	97,831	$217,509	90,598

	Nine Months Ended September 30, 2009		Nine Months Ended September 30, 2008	
	Income	Shares	Income	Shares
Diluted:				
Net income per common share – continuing operations – Basic	$ 145,126	97,831	$ 217,509	90,598
Effect of dilutive securities:				
Stock options		3		292
Undistributed earnings reallocated to participating securities	160		133	
Convertible Senior Notes				575
Convertible preferred stock	688	8,034	2,642	3,631
Income per common share continuing operations	145,974		220,284	
Income (loss) per common share discontinued operations	10,303		1,671	
Net income per common share	$ 156,277	105,868	$ 221,955	95,096

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 7) are not included as an addition 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 and nine months ended September 30, 2008.

	Three Months	Nine Months
Basic, as previously reported	$0.67	$2.49

Basic, impact of adoption of APB 14-1	(0.01)	(0.04)
Basic, restated for adoption of APB 14-1	0.66	2.45
Impact of FSP EITF 03-06-1 on basic EPS	(0.01)	(0.03)
Basic, under FSP EITF 03-06-1	0.65	2.42
Diluted, as previously reported	0.65	2.40
Diluted, impact of adoption of APB 14-1	(0.01)	(0.04)
Diluted, restated for adoption of APB 14-1	0.64	2.36
Impact of FSP EITF 03-06-1 on diluted EPS	(0.01)	(0.02)
Diluted, under FSP EITF 03-06-1	$0.63	$2.34

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Note 15 – Stock-Based Compensation Plans

We have two stock-based compensation plans: the 1995 Long-Term Incentive Plan, as amended (the "1995 Incentive Plan") and the 2005 Long-Term Incentive Plan, as amended (the "2005 Incentive Plan"). As of September 30, 2009, there were approximately 1.8 million shares available for grant under our 2005 Incentive Plan.

During the nine month period ended September 30, 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:

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
April 1, 2009	(1)	4,195	5.14	100% on January 2, 2011
May 13, 2009	(1)	10,974	10.57	20% per year over five years

(1) Restricted shares
(2) Restricted stock units

There were no stock option grants in the three month and nine month periods ended September 30, 2009 and 2008.

Compensation cost is recognized over the respective vesting periods on a straight-line basis. All of our remaining stock options outstanding have fully vested and as such, there was no stock compensation expense related to them during the three months ended September 30, 2009. For the nine month period ended September 30, 2009 approximately $0.1 million was recognized as compensation expense related to unvested stock options. For the three and nine month periods ended September 30, 2009, $2.2 million and $6.9 million, respectively, was recognized as compensation expense related to unvested restricted shares. For the three and nine month periods ended September 30, 2008, $0.1 million and $1.0 million, respectively, was recognized as compensation expense related to stock options (of which $0.6 million was related to the acceleration of unvested options per the separation agreements between the Company and two of our former executive officers). For the three and nine month periods ended September 30, 2008, $3.7 million and $15.2 million, respectively, was recognized as compensation expense related to restricted shares and restricted stock units. The nine months ended September 30, 2008 included $3.6 million related to the accelerated vesting of restricted shares per the separation agreements between the Company and two of our former executive officers.

Stock Purchase Plan

In June 2009, we announced that we intend to purchase up to 1.5 million shares of our common stock as permitted under our principal credit facility. Our Board of Directors had previously granted us the authority to repurchase shares of our common stock in an amount equal to any equity grants made pursuant to our stock-based compensation plans. We may continue to make repurchases pursuant to this authority from time to time as additional equity grants are made under our stock based compensation plans based upon prevailing market conditions and other factors. All repurchases may be commenced or suspended at any time at the discretion of management. As of September 30, 2009, we had repurchased a total of 817,431 shares of our common stock for $10.0 million or an average of $12.28

per share. We retire all shares repurchased.

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Note 16 – 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 represented the assets of CDI which are deployed primarily for diving-related activities and shallow water construction. On June 10, 2009, we ceased consolidating CDI when our remaining ownership interest decreased to below 50% following the sale of a portion of CDI common stock held by us (Note 4). We continue to disclose the results of Shelf Contracting business as a segment up to and through June 10, 2009. All material intercompany transactions between the segments have been eliminated.

We evaluate our performance based on income before income taxes of each segment. Segment assets are comprised of all assets attributable to the reportable segment. The majority of our Production Facilities segment 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 September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Revenues				
Contracting Services	$ 175,091	$ 276,131	$ 645,422	$ 668,792
Shelf Contracting (1)	—	278,709	404,709	595,250
Oil and Gas	63,715	134,619	313,888	499,831
Production Facilities	5,888	—	11,360	—
Intercompany elimination	(28,669)	(81,723)	(93,740)	(184,238)
Total	$ 216,025	$ 607,736	$ 1,281,639	$ 1,579,635
Income (loss) from operations				
Contracting Services	$ 10,132	$ 57,235	$ 62,744	$ 113,728
Shelf Contracting (1)	—	72,719	59,077	109,765
Oil and Gas	(21,442)	36,903	166,686	251,022
Production Facilities equity investments(2)	(1,388)	(140)	(2,540)	(434)
Intercompany elimination	(1,971)	(13,494)	(3,892)	(21,695)
Total	$ (14,669)	$ 153,223	$ 282,075	$ 452,386
Equity in earnings of equity investments	$ 13,385	$ 8,751	$ 27,152	$ 25,722

(1) Includes operations of Cal Dive through June 10, 2009 prior to its deconsolidation (Note 4).

(2) Includes selling and administrative expense of Production Facilities incurred by us. See equity in earnings of equity investments for earnings contribution.

	September 30, 2009	December 31, 2008

Identifiable Assets		
Contracting Services (1)	$ 1,896,633	$ 1,572,618
Shelf Contracting	—	1,309,608
Oil and Gas	1,599,049	1,708,428
Production Facilities	475,408	457,197
Discontinued operations	—	19,215
Total	$ 3,971,090	$ 5,067,066

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(1) Includes our remaining investment in Cal Dive which totaled $4.9 million at September 30, 2009.

Intercompany segment revenues during the three and nine months ended September 30, 2009 and 2008 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Contracting Services	$ 23,922	$ 65,364	$ 76,776	$ 150,258
Shelf Contracting	—	16,359	7,865	33,980
Production Facilities	4,747	—	9,099	—
Total	$ 28,669	$ 81,723	$ 93,740	$ 184,238

Intercompany segment profits during the three and nine months periods ended September 30, 2009 and 2008 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Contracting Services	$ 2,153	$ 12,071	$ 3,600	$ 17,893
Shelf Contracting	(138)	1,423	365	3,802
Production Facilities	(44)	—	(73)	—
Total	$ 1,971	$ 13,494	$ 3,892	$ 21,695

Note 17 – 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 80% 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 $3.0 million and $8.4 million in the three and nine months ended September 30, 2009, respectively, and $8.8 million and $20.0 million in the three and nine months ended September 30, 2008, respectively.

In June 2009, our Chief Executive Officer, Owen Kratz, purchased 23,000 shares of Cal Dive common stock at $8.50 per share (aggregate consideration of $195,500) under the terms of a secondary offering of shares of Cal Dive held by us (Note 4).

Note 18 – 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 $250 million and $260 million (including capitalized interest of approximately $17 million), of which approximately $196 million had been incurred, with an additional $2.2 million committed, at September 30, 2009. The Caesar is expected to join our fleet in late 2009.

In October 2009, we completed construction of 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

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is expected to range between $240 million to $250 million (including capitalized interest of approximately $16 million). The Well Enhancer will join our fleet and commence work in the fourth quarter of 2009. At September 30, 2009, we had incurred approximately $227 million of costs in the construction of the Well Enhancer.

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 named the Helix Producer I. The total cost of the ferry and the conversion is approximately $170 million. We have provided $98.4 million in construction financing through September 30, 2009 to the joint venture on terms consistent with an arm's 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 for 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 member (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 chartered 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 $190 million and $200 million (including capitalized interest of approximately $17 million) and the work is expected to be completed in the first half of 2010. As of September 30, 2009, approximately $261 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 $14.6 million committed. The total estimated cost of the vessel, initial conversion and the additional facilities will range between approximately $360 million and $370 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 completion of its initial conversion in April 2009. Kommandor LLC is no longer a development stage enterprise.

In addition, as of September 30, 2009, we had also committed approximately $62.4 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.

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 that was completed in May 2009, our loss was $0.8 million, all of which was provided with our estimated loss accrual at December 31, 2008. Under a second contract, which was terminated, we have a potential future liability of up to $25 million. As of December 31, 2008, we estimated the loss under this contract at $9.0 million. In the second quarter of 2009, services under this contract were substantially completed by a third party and we revised our estimated loss to approximately $15.8

million. To reflect this additional estimated loss we recorded an additional $6.8 million charge to cost of sales in the accompanying condensed consolidated statement of operations. We have paid $7.2

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million of the $15.8 million estimated damages related to this terminated contact. We will continue to monitor our exposure under this contract until the job and all related disputes have been finalized.

In March 2009, we were notified of a third party's intention to terminate an international construction contract based on a claimed breach of that contract by one of our subsidiaries. This party has initiated litigation against us and our subsidiary on the claims arising out of this contract in Australia. As there are substantial defenses to this claimed breach, we cannot at this time determine if we have any exposure 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. Under the terms of the contract, our potential liability is generally capped for actual damages at approximately $27 million Australian dollars ("AUD") (approximately $23.8 million US dollars at September 30, 2009) and for liquidated damages at approximately $5 million AUD (approximately $4.4 million US dollars at September 30, 2009). At September 30, 2009, we have an $12.6 million AUD (approximately $11.1 million US dollars at September 30, 2009) trade receivable reflecting the claim against our counterparty for work performed prior to the termination of the contract. We continue to pursue payment for this work.

See Note 8 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 19 – Derivative Instruments and Hedging Activities

We are currently exposed to market risk in three major areas: commodity prices, interest rates and foreign currency exchange rates. Our risk management activities involve the use of derivative financial instruments to hedge the impact of market price risk exposures primarily related to our oil and gas production, variable interest rate exposure and foreign exchange currency fluctuations. All derivatives are reflected in our balance sheet at fair value unless otherwise noted, and do not contain credit-risk related or other contingent features that could cause accelerated payments when our derivative liabilities are in net liability positions.

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

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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 initially qualified for hedge accounting. However, due to disruptions in our natural gas production as a result of damage caused by the hurricanes in third quarter 2008, effective March 31, 2009 all of our 2009 natural gas derivative contracts no longer qualify for hedge accounting and were effectively marked to market through our line item titled gain or loss on oil and gas derivative commodity contracts in our condensed consolidated statement of operations. The costless collars and swap contracts for a portion of our 2010 forecasted oil and natural gas production were designated as cash flow hedges and currently qualify for hedge accounting. Our natural gas 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 mentioned above, they no longer qualify for the scope exception. Our oil forward sales contracts still qualify for the normal purchase and sales exemption under SFAS 133. As a result, future changes in the fair value of our natural gas forward sales contracts for 2009 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.

As of September 30, 2009, we have the following volumes under derivatives and forward sales contracts related to our oil and gas producing activities totaling 2,190 MBbl of oil and 29,020 Mmcf of natural gas:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:			(per barrel)
October 2009 — December 2009	Forward Sales(2)	150 MBbl	$71.79
January 2010 — December 2010	Collar(1)	50 MBbl	$65.00-$90.90
January 2010 — December 2010	Collar(1)	50 MBbl	$60.00-$70.55
January 2010 — December 2010	Swap(1)	12.5 MBbl	$73.05
January 2010 — June 2010	Swap(1)	10 MBbl	$71.82
July 2010 — December 2010	Swap(1)	15 MBbl	$74.07
January 2010 — June 2010	Swap(1)	40 MBbl	$70.90
Natural Gas:			(per Mcf)
October 2009 — December 2009	Collar(3)	491.7 Mmcf	$7.00 — $7.90
October 2009 — December 2009	Forward Sales(4)	1,516.8 Mmcf	$8.23
January 2010 — December 2010	Swap(1)	912.5 Mmcf	$5.80
January 2010 — December 2010	Collar(1)	1,003.8 Mmcf	$6.00 — $6.70

(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 longer qualify for normal purchase and sale exemption and are now being marked-to-market through earnings each period.

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Subsequent to September 30, 2009, we entered into four cash flow hedging swap agreements (two each for sales of crude oil and natural gas). Each of the oil contracts cover 387.5 MBbl total at an average price of $77.75 per barrel for the period from April to December 2010. Each natural gas contract covers 1.0 Bcf at a price of $5.94 per Mcf for the period from January to December 2010.

Changes in NYMEX oil and natural 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. 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”. As of October 30, 2009 all of our interest rate swaps to stabilize cash flows relating to the $200 million of our Term Loan have been settled and we currently have no interest rate swap contracts.

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 expected cash outflows relating to certain vessel charters denominated in British pounds. Previously, we had foreign currency forward contracts covering certain shipyard contracts where payments were denominated in Euros. All of these forward contracts have been settled.

Quantitative Disclosures Related to Derivative Instruments

The following tables present the fair value and balance sheet classification of our derivative instruments as of September 30, 2009 and December 31, 2008. As required, 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).

Derivatives designated as hedging instruments as defined in FASB Codification Topic No. 815 Derivatives and Hedging (in thousands):

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	As of September 30, 2009 Balance Sheet Location	Fair Value	As of December 31, 2008 Balance Sheet Location	Fair Value
Asset Derivatives:				
Oil costless collars	Other current assets	$—	Other current assets	$6,449
Gas costless collars	Other current assets	1,634	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	—	Other current assets	506
Oil costless collars	Other assets, net	27	Other assets, net	—
		$1,661		$16,163

	As of September 30, 2009 Balance Sheet Location	Fair Value	As of December 31, 2008 Balance Sheet Location	Fair Value
Liability Derivatives:				
Oil costless collars	Accrued liabilities	$3,775	Accrued liabilities	$—
Oil swap contracts	Accrued liabilities	765	Accrued liabilities	—
Gas swap contracts	Accrued liabilities	2,290	Accrued liabilities	—
Foreign exchange forwards	Accrued liabilities	—	Accrued liabilities	240
Interest rate swaps	Accrued liabilities	—	Accrued liabilities	1,378
Oil costless collars	Other long-term liabilities	1,512	Other long-term liabilities	—
Oil swap contracts	Other long-term liabilities	216	Other long-term liabilities	—
Gas costless collars	Other long-term liabilities	1,918	Other long-term liabilities	—
Gas swap contracts	Other long-term liabilities	3,414	Other long-term liabilities	—
Interest rate swaps	Other long-term liabilities	—	Other long-term liabilities	347
		$13,890		$1,965

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

	As of September 30, 2009 Balance Sheet Location	Fair Value	As of December 31, 2008 Balance Sheet Location	Fair Value
Asset Derivatives:				
Gas costless collars	Other current assets	$ 2,821	Other current assets	$ 6,652
Gas forward sales contracts	Other current assets	12,229	Other current assets	3,987
Foreign exchange forwards	Other current assets	1,146	Other current assets	—

Foreign exchange forwards	Other assets, net		931	Other assets, net		—
		$	17,127		$	10,639
Liability Derivatives:						
Foreign exchange forwards	Accrued liabilities		—	Accrued liabilities		1,205
Interest rate swaps	Accrued liabilities		2,388	Accrued liabilities		6,242
		$	2,388		$	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 and nine month periods ended September 30, 2009 and 2008 (in thousands):

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	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009(1)	2008	2009(1)	2008
Oil costless collars	$ 72	$ 8,855	$ (11,921)	$ 7,992
Gas costless collars	(1,522)	4,807	(286)	(1,614)
Oil swap contracts	(771)	9,004	(1,790)	714
Gas swap contracts	(1,688)	—	(9,695)	—
Foreign exchange forwards	28	(926)	103	856
Interest rate swaps	240	(749)	207	1,614
	$ (3,641)	$ 20,991	$ (23,382)	$ 9,562

(1) All unrealized gains (losses) related to our derivatives are expected to be reclassified into earnings by no later than December 31, 2010, except for amounts related to our foreign exchange forwards which continue through June 2012.

	Location of Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2009	2008	2009	2008
Oil costless collars	Oil and gas revenue	$ —	$ (3,226)	$ 6,429	$ (16,677)
Gas costless collars	Oil and gas revenue	925	(1,041)	5,716	(6,650)
Oil swap contracts	Oil and gas revenue	—	(1,075)	1,687	(1,075)
Gas swap contracts	Oil and gas revenue	—	—	2,954	—
Foreign exchange forwards	Cost of sales	—	71	—	164
Interest rate swaps	Net interest expense and other	(369)	(564)	(1,654)	(1,671)
		$ 556	$ (5,835)	$ 15,132	$ (25,909)

	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)			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2009	2008	2009	2008
Oil Swap Contract	Gain on oil and gas derivative contracts	$ —	$ 714	$ —	$ 714
Oil Costless Collar	Gain on oil and gas derivative contracts	—	(1,759)	—	(1,759)

Foreign exchange forwards	Net interest expense and other	—	—	—	1
Interest rate swaps	Net interest expense and other	—	(65)	—	(120)
		$ —	$ (1,110)	$ —	$ (1,164)

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The following tables present the impact that derivative instruments not designated as hedges had on our condensed consolidated income statement for the three and nine month periods ended September 30, 2009 and 2008 (in thousands):

	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2009	2008	2009	2008
Gas costless collars	Gain on oil and gas derivative contracts	$ 1,431	$ —	$ 21,814	$ —
Gas forward sales contracts	Gain on oil and gas derivative contracts	3,167	3,750	61,514	3,750
Foreign exchange forwards	Net interest expense and other	(1,862)	(402)	3,281	(388)
Interest rate swaps	Net interest expense and other	(173)	320	(468)	(2,406)
		$ 2,563	$ 3,668	$ 86,141	$ 956

Note 20– Condensed Consolidated Guarantor and Non-Guarantor Financial Information

The payment of obligations under the Senior Unsecured Notes is guaranteed by all of our restricted domestic subsidiaries ("Subsidiary Guarantors") except for Cal Dive I-Title XI, Inc. Cal Dive and its subsidiaries were never guarantors of our Senior Unsecured Notes. Each of these Subsidiary Guarantors is included in our consolidated financial statements and has fully and unconditionally guaranteed the Senior Unsecured Notes on a joint and several basis. As a result of these 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 relate primarily to the elimination of investments in subsidiaries and associated intercompany balances and transactions.

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

	As of September 30, 2009				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 402,556	$ 2,397	$ 5,553	$ —	$ 410,506
Accounts receivable, net	76,736	70,651	38,132	—	185,519
Unbilled revenue	20,798	133	18,251	—	39,182
Other current assets	72,251	71,234	17,898	(30,837)	130,546
Total current assets	572,341	144,415	79,834	(30,837)	765,753
Intercompany	201,868	47,494	(177,809)	(71,553)	—
Property and equipment, net	192,054	1,945,268	724,299	(5,289)	2,856,332
Other assets:					
Equity investments in unconsolidated affiliates	—	—	191,475	—	191,475
Equity investments in affiliates	2,351,996	31,837	—	(2,383,833)	—
Goodwill, net	—	45,107	33,113	—	78,220
Other assets, net	43,656	42,503	19,613	(26,462)	79,310
	$ 3,361,915	$ 2,256,624	$ 870,525	$ (2,517,974)	$ 3,971,090
LIABILITIES AND SHAREHOLDERS’ EQUITY					
Current liabilities:					
Accounts payable	$ 59,650	$ 90,958	$ 26,469	$ 40	$ 177,117
Accrued liabilities	79,134	102,055	17,772	(85)	198,876
Income taxes payable	64,263	62,189	(6,418)	(11,821)	108,213
Current maturities of long-term debt	4,326	—	39,480	(30,670)	13,136
Total current liabilities	207,373	255,202	77,303	(42,536)	497,342
Long-term debt	1,232,584	—	114,811	—	1,347,395
Deferred income taxes	129,780	240,069	90,095	(3,216)	456,728
Decommissioning liabilities	—	172,319	5,605	—	177,924
Other long-term liabilities	2,218	7,060	793	77	10,148
Due to parent	(73,851)	(178,595)	99,337	153,109	—
Total liabilities	1,498,104	496,055	387,944	107,434	2,489,537

Convertible preferred stock	6,000	—	—	—	6,000
Total equity	1,857,811	1,760,569	482,581	(2,625,408)	1,475,553
	$ 3,361,915	$ 2,256,624	$ 870,525	$ (2,517,974)	$ 3,971,090

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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
Current 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 in unconsolidated affiliates	—	—	196,660	—	196,660
Equity investments in affiliates	2,331,924	31,374	—	(2,363,298)	—
Goodwill, net	—	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
	—	73,549	10,706	(2,618)	81,637

Other long-term liabilities					
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)

	Three Months Ended September 30, 2009				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$ 17,350	$ 146,981	$ 70,730	$ (19,036)	$ 216,025
Cost of sales	17,952	161,474	52,217	(18,235)	213,408
Gross profit	(602)	(14,493)	18,513	(801)	2,617
Gain on oil and gas derivative commodity contracts	—	4,598	—	—	4,598
Gain on sale of assets, net	—	—	—	—	—
Selling and administrative expenses	(12,791)	(5,467)	(4,364)	738	(21,884)
Income from operations	(13,393)	(15,362)	14,149	(63)	(14,669)
Equity in earnings of unconsolidated affiliates	—	—	13,923	(538)	13,385
Equity in earnings (losses) of affiliates	6,081	2,625	—	(8,706)	—
Gain on sale of Cal Dive common stock	17,901	—	—	—	17,901
Net interest expense and other	(65)	(6,156)	(4,084)	(1)	(10,306)
Income before income taxes	10,524	(18,893)	23,988	(9,308)	6,311
Provision for income taxes	(8,765)	6,120	(1,686)	(137)	(4,468)
Income from continuing operations	1,759	(12,773)	22,302	(9,445)	1,843
Discontinued operations, net of tax	3,021	—	—	—	3,021
Net income, including noncontrolling interests	4,780	(12,773)	22,302	(9,445)	4,864
Net income applicable to noncontrolling interests	—	—	—	(844)	(844)
Net income applicable to Helix	4,780	(12,773)	22,302	(10,289)	4,020
Preferred stock dividends	(125)	—	—	—	(125)
Net income applicable to Helix common shareholders	$ 4,655	$ (12,773)	$ 22,302	$ (10,289)	$ 3,895

	Three Months Ended September 30, 2008				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated

Net revenues	$	103,612	$	233,313	$	356,133	$	(85,322)	$	607,736
Cost of sales		91,692		146,786		241,058		(70,880)		408,656
Gross profit		11,920		86,527		115,075		(14,442)		199,080
Gain on oil and gas derivative commodity contracts		—		2,705		—		—		2,705
Gain on sale of assets, net		—		—		(23)		—		(23)
Selling and administrative expenses		(13,559)		(11,938)		(24,409)		1,367		(48,539)
Income from operations		(1,639)		77,294		90,643		(13,075)		153,223
Equity in earnings of unconsolidated affiliates		—		—		8,751		—		8,751
Equity in earnings (losses) of affiliates		82,812		1,885		—		(84,697)		—
Net interest expense and other		(2,300)		(10,366)		(14,751)		(881)		(28,298)
Income before income taxes		78,873		68,813		84,643		(98,653)		133,676
Provision for income taxes		(9,577)		(25,538)		(23,869)		4,819		(54,165)
Income from continuing operations		69,296		43,275		60,774		(93,834)		79,511
Discontinued operations, net of tax		—		—		(93)		—		(93)
Net income, including noncontrolling interests		69,296		43,275		60,681		(93,834)		79,418
Net income applicable to noncontrolling interests		—		—		—		(19,240)		(19,240)
Net income applicable to Helix		69,296		43,275		60,681		(113,074)		60,178
Preferred stock dividends		(881)		—		—		—		(881)
Preferred stock beneficial conversion charges		—		—		—		—		—
Net income applicable to Helix common shareholders	$	68,415	$	43,275	$	60,681	$	(113,074)	$	59,297

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

	Nine Months Ended September 30, 2009				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$207,338	$ 559,712	$ 587,912	$ (73,323)	$ 1,281,639
Cost of sales	160,304	429,299	461,479	(69,026)	982,056
Gross profit	47,034	130,413	126,433	(4,297)	299,583
Gain on oil and gas derivative commodity contracts	—	83,328	—	—	83,328
Gain on sale of assets, net	—	1,773	—	—	1,773
Selling and administrative expenses	(37,421)	(21,347)	(46,938)	3,097	(102,609)
Income from operations	9,613	194,167	79,495	(1,200)	282,075
Equity in earnings of unconsolidated affiliates	—	—	28,051	(899)	27,152
Equity in earnings (losses) of affiliates	186,907	463	—	(187,370)	—
Gain on sale of Cal Dive common stock	77,343	—	—	—	77,343
Net interest expense and other	(14,674)	(12,271)	(12,036)	(988)	(39,969)
Income before income taxes	259,189	182,359	95,510	(190,457)	346,601
Provision for income taxes	(45,327)	(63,502)	(18,099)	732	(126,196)
Income from continuing operations	213,862	118,857	77,411	(189,725)	220,405
Discontinued operations, net of tax	205	—	10,098	—	10,303
Net income, including noncontrolling interests	214,067	118,857	87,509	(189,725)	230,708
Net income applicable to noncontrolling interests	—	—	—	(19,017)	(19,017)
Net income applicable to Helix	214,067	118,857	87,509	(208,742)	211,691
Preferred stock dividends	(688)	—	—	—	(688)
Preferred stock beneficial conversion charges	(53,439)	—	—	—	(53,439)
Net income applicable to Helix common shareholders	$159,940	$ 118,857	$ 87,509	$ (208,742)	$ 157,564

	Nine Months Ended September 30, 2008				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$278,602	$ 681,775	$ 816,314	$ (197,056)	$ 1,579,635
Cost of sales	242,553	416,755	586,465	(172,879)	1,072,894
Gross profit	36,049	265,020	229,849	(24,177)	506,741
Gain on oil and gas derivative commodity contracts	—	2,705	—	—	2,705
Gain on sale of assets, net	—	79,707	186		79,893
Selling and administrative expenses	(30,854)	(41,015)	(68,485)	3,401	(136,953)
Income from operations	5,195	306,417	161,550	(20,776)	452,386
Equity in earnings of unconsolidated affiliates	—	—	25,722	—	25,722
Equity in earnings (losses) of affiliates	266,534	7,042	—	(273,576)	—
Net interest expense and other	(12,527)	(34,834)	(30,506)	953	(76,914)
Income before income taxes	259,202	278,625	156,766	(293,399)	401,194
Provision for income taxes	(22,699)	(96,586)	(40,346)	7,993	(151,638)
Income from continuing operations	236,503	182,039	116,420	(285,406)	249,556
Discontinued operations, net of tax	—	—	1,671	—	1,671
Net income, including noncontrolling interests	236,503	182,039	118,091	(285,406)	251,227
Net income applicable to noncontrolling interests	—	—	—	(26,553)	(26,553)
Net income applicable to Helix	236,503	182,039	118,091	(311,959)	224,674
Preferred stock dividends	(2,642)	—	—	—	(2,642)
Net income applicable to Helix common shareholders	$233,861	$ 182,039	$ 118,091	$ (311,959)	$ 222,032

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

	Nine Months Ended September 30, 2009				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flow from operating activities:					
Net income, including noncontrolling interests	$ 214,067	$ 118,857	$ 87,509	$ (189,725)	$ 230,708
Adjustments to reconcile net income to net cash provided by (used in) operating activities:					
Equity in losses of unconsolidated affiliates	—	—	(1,121)	899	(222)
Equity in earnings of affiliates	(186,907)	(463)	—	187,370	—
Other adjustments	(168,906)	90,361	73,197	212,123	206,775
Cash provided by (used in) operating activities	(141,746)	208,755	159,585	210,667	437,261
Cash provided by discontinued operations	—	—	(6,089)	—	(6,089)
Net cash provided by (used in) operating activities	(141,746)	208,755	153,496	210,667	431,172
Cash flows from investing activities:					
Capital expenditures	(9,098)	(157,686)	(139,368)	—	(306,152)
Investments in equity investments	—	—	(551)	—	(551)
Distributions from equity investments, net	—	—	4,774	—	4,774
Proceeds from sale of Cal Dive common stock	504,168	—	(112,995)	(86,000)	305,173
Proceeds from sales of property	—	23,238	—	—	23,238
Other	—	(13)	—	—	(13)
Cash provided by (used in) investing activities	495,070	(134,461)	(248,140)	(86,000)	26,469
Cash provided by discontinued operations	—	—	20,872	—	20,872
Net cash used in investing activities	495,070	(134,461)	(227,268)	(86,000)	47,341

Cash flows from financing activities:					
Borrowings on revolver	—	—	100,000	—	100,000
Repayments on revolver	(349,500)	—	—	—	(349,500)
Repayments of debt	(3,245)	—	(24,214)	—	(27,459)
Deferred financing costs	(50)	—	—	—	(50)
Preferred stock dividends paid	(625)	—	—	—	(625)
Repurchase of common stock	(10,603)	—	(86,000)	86,000	(10,603)
Excess tax benefit from stock-based compensation	(2,036)	—	—	—	(2,036)
Exercise of stock options, net	36	—	—	—	36
Intercompany financing	266,551	(76,880)	20,996	(210,667)	—
Net cash provided by (used in) financing activities	(99,472)	(76,880)	10,782	(124,667)	(290,237)
Effect of exchange rate changes on cash and cash equivalents	—	—	(1,383)	—	(1,383)
Net increase (decrease) in cash and cash equivalents	253,852	(2,586)	(64,373)	—	186,893
Cash and cash equivalents:					
Balance, beginning of year	148,704	4,983	69,926	—	223,613
Balance, end of period	$ 402,556	$ 2,397	$ 5,553	$ —	$ 410,506

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

	Nine Months Ended September 30, 2008				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flow from operating activities:					
Net income, including noncontrolling interests	$ 236,503	$ 182,039	$ 118,091	$ (285,406)	$ 251,227
Adjustments to reconcile net income to net cash provided by (used in) operating activities:					
Equity in losses of unconsolidated affiliates	—	—	2,495	—	2,495
Equity in earnings of affiliates	(266,534)	(7,042)	—	273,576	—
Other adjustments	(59,349)	115,346	22,501	5,236	83,734
Cash provided by (used in) operating activities	(89,380)	290,343	143,087	(6,594)	337,456
Cash provided by discontinued operations	—	—	1,630	—	1,630
Net cash provided by (used in) operating Activities	(89,380)	290,343	144,717	(6,594)	339,086
Cash flows from investing activities:					
Capital expenditures	(89,451)	(420,044)	(219,197)	—	(728,692)
Investments in equity investments	—	—	(708)	—	(708)
Distributions from equity investments, net	—	—	4,636	—	4,636
Proceeds from sales of property	—	228,483	1,778	—	230,261
Other	—	(553)	—	—	(553)
Cash used in investing activities	(89,451)	(192,114)	(213,491)	—	(495,056)
Cash provided by discontinued operations	—	—	(111)	—	(111)
Net cash provided by (used in) investing activities	(89,451)	(192,114)	(213,602)	—	(495,167)

Cash flows from financing activities:					
Borrowings on revolver	847,000	—	61,100	—	908,100
Repayments on revolver	(690,000)	—	(61,100)	—	(751,100)
Repayments of debt	(3,245)	—	(44,014)	—	(47,259)
Deferred financing costs	(1,711)	—	—	—	(1,711)
Preferred stock dividends paid	(2,642)	—	—	—	(2,642)
Capital lease payments	—	(2)	(1,503)	—	(1,505)
Repurchase of common stock	(3,912)	—	—	—	(3,912)
Excess tax benefit from stock-based compensation	1,142	—	—	—	1,142
Exercise of stock options, net	2,139	—	—	—	2,139
Intercompany financing	29,769	(100,605)	64,242	6,594	—
Net cash provided by (used in) financing activities	178,540	(100,607)	18,725	6,594	103,252
Effect of exchange rate changes on cash and cash equivalents	—	—	(965)	—	(965)
Net decrease in cash and cash equivalents	(291)	(2,378)	(51,125)	—	(53,794)
Cash and cash equivalents:					
Balance, beginning of year	3,507	2,609	83,439	—	89,555
Balance, end of period	$ 3,216	$ 231	$ 32,314	$ —	$ 35,761

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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 represents 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 current 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 our 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 and any quarterly report on Form 10-Q filed subsequently thereto. 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.

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Our Strategy

In December 2008, we announced our intention to focus and shape the future direction of the Company around our deepwater construction and well intervention services that comprise our Contracting Services business. We intend to achieve this strategic focus by seeking and evaluating strategic opportunities to sell certain non-core assets, such as:

- all or a portion of our oil and gas assets;
- our ownership interests in one or more of our production facilities; and
- our remaining interest in CDI.

We also announced that economic and financial market conditions may affect the timing of any strategic dispositions by us and therefore a degree of patience would be required in order to execute any transactions. We continue to 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 approximately 13.6 million shares of CDI common stock held by us to CDI for $86 million in January 2009;
- Sold Helix RDS Limited, our subsurface reservoir consulting business for $25 million;
- Sold approximately 1.6 million shares of CDI common stock held by us to CDI for $14 million in June 2009;
- Sold 22.6 million shares of CDI common stock held by us to third parties in a public secondary offering for approximately $182.9 million, net of underwriting fees in June 2009; and
- Sold 23.2 million shares of CDI common stock held by us to third parties in a public secondary offering for approximately $221.5 million, net of underwriting fees in September 2009.

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 economic downturn and weakness in the equity and credit capital markets continue to lead to increased uncertainty regarding the outlook of the global economy. This uncertainty coupled with the negative near-term outlook for global demand for oil and natural 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 have increased in the second and third quarters of 2009 but remain significantly lower than the high prices achieved in second and third quarters of 2008. Natural gas prices continued to decline in 2009 with prices reaching near decade low levels. A decline in oil and gas prices negatively impacts 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 announce reductions in capital spending. The long-term fundamentals for our business remain generally favorable as the continual effort to replenish oil and gas production should drive demand for our services. In addition, 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

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economically hedged a substantial portion of our remaining expected production for the remainder of 2009 through a combination of forward sale and financial hedge contracts. We have also hedged a substantial portion of our anticipated oil and natural gas production for 2010 through the placement of additional swap and costless collar financial hedge contracts. For additional information regarding our oil and gas hedge contracts see Note 19.

At September 30, 2009, we had cash on hand of $410.5 million and $370.3 million available for borrowing under our revolving credit facilities. Our capital expenditures for the remainder of 2009 are expected to total approximately between $150 million to $180 million (including capitalized interest) and reflect the construction payments for our Well Enhancer, Caesar and Helix Producer I vessels and the development of two of our significant deepwater oil and gas properties expected to be placed on production in the first half of 2010. If we successfully implement the business plan, 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:

- 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;
- the capacity and ability to store excess North American natural gas supply within existing storage;
- 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 deteriorated significantly over the past year with declines in the oil and gas market accelerating during the fourth quarter of 2008 and continuing into 2009. Oil prices have recovered in the second and third quarters but natural gas prices remain low relative to realized amounts in 2008. Predicting the timing and sustainability of any recovery in pricing is subjective and highly uncertain. Although we are still feeling the effects of the recent 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 offshore activity, particularly in deepwater; and (6) increasing number of subsea developments. Our strategy of combining contracting services operations and oil and gas operations allows us to focus on trends (4) through (6) in that we pursue long-term sustainable growth by applying specialized subsea services to the broad external offshore market but with a complementary focus on marginal fields and new reservoirs in which we currently have an equity stake.

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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 FASB Codification Topic No. 280 Segment Reporting. As a result, our reportable segments consist of the following: Contracting Services, Shelf Contracting, and Production Facilities as well as Oil and Gas. As discussed below, in June 2009, we ceased consolidating our Shelf Contracting Business, which represents the results and operations of Cal Dive, following the sale of a substantial amount of our remaining ownership of Cal Dive (Note 4). Each line item within our condensed consolidated statement of operations for both the three month and nine month periods of 2009 is impacted significantly when compared to the prior year periods as a result of the deconsolidation of the Cal Dive results. Our 2009 consolidated results include Cal Dive's results through June 10, 2009, while we recorded our approximate 26% share of Cal Dive's results for the period June 11, 2009 through September 23, 2009 to equity in earnings of investments as required under the equity method of accounting. We continue to disclose the operating results of the Shelf Contracting business as a segment through June 10, 2009.

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. The Contracting Services segment includes operations such as subsea construction, well operations, robotics and drilling. The Cal Dive assets, representing our previous Shelf Contracting segment, are deployed primarily for diving-related activities and shallow water construction. 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 September 30, 2009, our contracting services operations had backlog of approximately $273.6 million, including $68.7 million for the fourth quarter 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 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 RDS Limited, our former reservoir technology consulting company, to a subsidiary of Baker Hughes Incorporated for $25 million. 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. We recognized an $8.8 million gain on the sale of Helix RDS. The operating results of Helix RDS were immaterial to all periods presented in this Quarterly Report on Form 10-Q.

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Reduction in Ownership of Cal Dive

At December 31, 2008, we owned 57.2% of Cal Dive. In January 2009, we sold approximately 13.6 million shares of Cal Dive common stock held by us to Cal Dive for $86 million. This transaction constituted a single transaction and was not part of any planned set of transactions that would result in us having a noncontrolling interest in Cal Dive, and reduced our ownership in Cal Dive to approximately 51%. 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.

In June 2009, we sold 22.6 million shares of Cal Dive held by us pursuant to an underwritten secondary public offering ("Offering"). Proceeds from the Offering totaled approximately $182.9 million, net of underwriting fees. Separately, pursuant to a Stock Repurchase Agreement with Cal Dive, simultaneously with the closing of the Offering, Cal Dive repurchased from us approximately 1.6 million shares of its common stock for net proceeds of $14 million at $8.50 per share, the Offering price. Following the closing of these two transactions, our ownership of Cal Dive common stock was reduced to approximately 26%.

Because these transactions reduced our ownership in Cal Dive to less than 50%, the $59.4 million gain resulting from the sale of these shares is reflected in "Gain on sale of Cal Dive common stock" in the accompanying condensed consolidated statement of operations. Since we no longer held a controlling interest in Cal Dive, we ceased consolidating Cal Dive effective June 10, 2009, the closing date of the Offering, and have since accounted for our remaining ownership interest in Cal Dive under the equity method of accounting until September 23, 2009 as discussed below.

On September 23, 2009, we sold 20.6 million shares of Cal Dive common stock held by us pursuant to a second secondary public offering ("Second Offering"). On September 24, 2009, the underwriters sold an additional 2.6 million shares of Cal Dive common stock held by us pursuant to their overallotment option under the terms of the Second Offering. The price for the Second Offering was $10 per share, with resulting proceeds totaling approximately $221.5 million, net of underwriting fees. We recorded an approximate $18 million gain associated with the Second Offering transactions which was recorded as a component "of Gain on sale of Cal Dive common stock" in the accompanying condensed consolidated statement of operations.

For more information regarding the reduction in our ownership in Cal Dive see Notes 1, 2, 3 and 4.

Comparison of Three Month Periods Ended September 30, 2009 and 2008

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

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Increase/ (Decrease)
Revenues (in thousands) –			
Contracting Services	$ 175,091	$ 276,131	$ (101,040)
Shelf Contracting	—	278,709	(278,709)
Oil and Gas	63,715	134,619	(70,904)
Production Facilities	5,888	—	5,888
Intercompany elimination	(28,669)	(81,723)	53,054
	$ 216,025	$ 607,736	$ (391,711)

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	Three Months Ended September 30, 2009	2008	Increase/ (Decrease)
Gross profit (in thousands) –			
Contracting Services	$ 28,197	$ 75,617	$ (47,420)
Shelf Contracting	—	92,543	(92,543)
Oil and Gas	(22,291)	44,414	(66,705)
Production Facilities	(1,318)	—	(1,318)
Intercompany elimination	(1,971)	(13,494)	11,523
	$ 2,617	$ 199,080	$ (196,463)
Gross Margin –			
Contracting Services	16%	27%	(11 pts)
Shelf Contracting	N/A	33%	N/A
Oil and Gas	(35)%	33%	(68 pts)
Total company	1%	33%	(32 pts)

	Three Months Ended September 30, 2009	2008
Number of vessels(2)/ Utilization(3) –		
Contracting Services:		
Offshore construction vessels	8/77%	10/98%
Well operations	2/92%	2/100%
ROVs	47/74%	47/76%

(1) Represents number of vessels (including chartered 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.

Intercompany segment revenues during the three months ended September 30, 2009 and 2008 were as follows (in thousands):

	Three Months Ended September 30, 2009	2008	Increase/ (Decrease)
Contracting Services	$ 23,922	$ 65,364	$ (41,442)
Shelf Contracting(1)	—	16,359	(16,359)
Production Facilities	4,747	—	4,747
	$ 28,669	$ 81,723	$ (53,054)

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(1) No amounts are included for the three-month 2009 period because Shelf Contracting ceased being a continuing business when we deconsolidated Cal Dive from our condensed consolidated financial statements effective June 11, 2009.

Intercompany segment profit during the three month periods ended September 30, 2009 and 2008 was as follows (in thousands):

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Increase/ (Decrease)
Contracting Services	$ 2,153	$ 12,071	$ (9,918)
Shelf Contracting(1)	(138)	1,423	(1,561)
Production Facilities	(44)	—	(44)
	$ 1,971	$ 13,494	$ (11,523)

(1) No amounts are included for the three month 2009 period because Shelf Contracting ceased being a continuing business when we deconsolidated Cal Dive from our condensed consolidated financial statements effective June 11, 2009.

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

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Increase/ (Decrease)
Oil and Gas information–			
Oil production volume (MBbls)	546	573	(27)
Oil sales revenue (in thousands)	$ 37,576	$ 61,436	$ (23,860)
Average oil sales price per Bbl (excluding hedges)	$ 68.86	$ 114.64	$ (45.78)
Average realized oil price per Bbl (including hedges)	$ 68.86	$ 107.14	$ (38.28)
Decrease in oil sales revenue due to:			
Change in prices (in thousands)	$ (21,950)		
Change in production volume (in thousands)	(1,910)		
Total decrease in oil sales revenue (in thousands)	$ 23,860		
Gas production volume (MMcf)	6,534	7,013	(479)
Gas sales revenue (in thousands)	$ 24,355	$ 71,658	$ (47,303)
Average gas sales price per mcf (excluding hedges)	$ 3.59	$ 10.37	$ (6.78)
Average realized gas price per mcf (including hedges recorded as gas sales revenue)	$ 3.73	$ 10.22	$ (6.49)
Average realized gas price per mcf (including hedges recorded as revenues and gain on oil and gas derivative contracts)	$ 8.02	$ 10.22	$ (2.20)

Decrease in gas sales revenue due to:			
Change in prices (in thousands)	$ (45,520)		
Change in production volume (in thousands)	(1,783)		
Total decrease in gas sales revenue (in thousands)	$ (47,303)		
Total production (MMcfe)	9,808	10,453	(645)
Revenue price per Mcfe, including hedges	$ 6.31	$ 12.73	$ (6.42)
Oil and Gas revenue information (in thousands)–			
Oil and gas sales revenue	$ 61,930	$ 133,094	$ (71,164)
Miscellaneous revenues(1)	1,785	1,525	260
	$ 63,715	$ 134,619	$ (70,904)

(1) Miscellaneous revenues primarily relate to fees earned under our process handling agreements.

Presenting the expenses of our Oil and Gas segment on a cost per Mcfe of production basis normalizes for the impact of production gains/losses and provides a measure of expense control efficiencies. The following table highlights certain relevant expense items in total (in thousands) converted to Mcfe at a ratio of one barrel of oil to six Mcf:

	Three Months Ended September 30,			
	2009		2008	
	Total	Per Mcfe	Total	Per Mcfe
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$ 25,109	$ 2.56	$ 21,945	$ 2.10
Workover (3)	5,940	0.61	2,986	0.29
Transportation	3,044	0.31	1,551	0.15
Repairs and maintenance	4,143	0.42	6,002	0.57
Overhead and company labor	2,468	0.25	1,261	0.12
Total	$ 40,704	$ 4.15	$ 33,745	$ 3.23

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	Three Months Ended September 30,			
	2009		2008	
	Total	Per Mcfe	Total	Per Mcfe
Depletion expense	$ 31,348	$ 3.20	$ 35,802	$ 3.42
Abandonment	2,913	0.30	6,534	0.63
Accretion expense	3,539	0.36	3,266	0.31
Impairment (4) (	1,537	0.16	214	0.02
Net hurricane (reimbursements) costs (5)	5,061	0.52	8,999	0.86

(1) Excludes exploration expense of $0.9 million and $1.6 million for the three months ended September 30, 2009 and 2008, respectively. Exploration expense is not a component of lease operating expense.
(2) Includes production taxes. Amount in third quarter of 2009 includes a $10.4 million charge to expense of a $13.1 million premium that provides coverage for potential Hurricane damages to our oil and gas properties (Note 5).
(3) Excludes all hurricane-related cost and charges resulting from Hurricane Ike in September 2008 (see (5) below).
(4) Amount for 2009 period reflects charge to reduce the carrying value of five fields to their estimated net realizable value at September 30, 2009.
(5) Represents the amount of net costs in excess of insurance recoveries related to damages sustained from Hurricane Ike in September 2008 (Note 5).

Revenues. During the three months ended September 30, 2009, our total revenues decreased by 64% as compared to the same period in 2008 reflecting primarily the cessation of our Shelf Contracting business operations in June 2009. In the third quarter of 2008, Cal Dive contributed $278.7 million in Shelf Contracting revenues; however, no revenues were recorded in third quarter of 2009 following the deconsolidation of Cal Dive from our financial statements in June 2009 (see "Reduction of Cal Dive Ownership" above and Note 4). Decreased revenues also reflected reductions in both our Contracting Services and Oil & Gas revenues as further discussed below.

Contracting Services revenues decreased 37% for the three month period ended September 30, 2009 as compared to the same period in 2008. The decrease reflected lower activity levels related to a reduction of services provided to a customer under a long term construction contract in India in the third quarter of 2009 as our pipelay vessel, the Express, completed its services. The Express departed India for a regulatory drydock in Spain and then redeployed to the Gulf of Mexico for internal use. Further, we experienced a substantial reduction in the average day rate realized by our Q4000 vessel in the Gulf of Mexico, an almost complete loss of revenues in our Southeast Asia well intervention operations reflecting a combination of economic and equipment repair issues, and lower results from our robotics subsidiary.

Oil and Gas revenues decreased by 53% during the three month period ended September 30, 2009 as compared to the same period in 2008. The decrease reflects a significant decrease in both oil and natural gas prices which were near historical highs in the third quarter 2008. The decrease in oil revenues was attributable to a 36% decrease in realized oil prices with slightly lower production compared with the same prior year period. The decrease in gas revenues was attributable to a 64% decrease in realized gas prices and a 7% decrease in gas production, which was impacted by repairs being made to certain third party pipelines that were damaged by the hurricanes in 2008. Repairs to a key third party pipeline continue, damage to which has curtailed production from our Noonan gas field. Further, our natural gas derivative contracts associated with 2009 production are being marked-to-market and thus are included in "Gain on oil and gas derivative contracts" in the accompanying condensed consolidated statements of operations rather than revenues as previously reported when such contracts qualified for hedge accounting treatment.

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Gross Profit. Gross profit in the third quarter of 2009 decreased $196.5 million as compared to the same period in 2008. This decrease includes $92.5 million associated with our former Shelf Contracting business. The remaining decrease was primarily due to reduced gross profit attributable to our Oil and Gas segment as a result of lower commodity prices realized, as described above.

Further, Contracting Services gross profit decreased 63% and its gross margin decreased by 11 points. The decline in gross margin was primarily due to lower vessel utilization, lower day rates realized on work performed by the Q4000 and Express out of service days related to a regulatory drydock and transit costs to redeploy the Express from India back to the Gulf of Mexico for internal use.

The Oil and Gas gross profit decreased by approximately 150% in the third quarter of 2009 as compared to the third quarter of 2008. This decrease reflected the significantly lower oil and natural gas prices realized on our sales volumes as well as decreases in our production. Our oil and gas gross profit in the third quarter was also affected by a $10.4 million charge to expense representing the cost of a weather-related financial instrument (Note 5), $5.1 million of hurricane-related repair costs and $4.5 million of aggregated impairment and abandonment related charges.

Selling and Administrative Expenses. Selling and administrative expenses of $21.9 million for the third quarter of 2009 were $26.7 million lower than the $48.5 million incurred in the same prior year period. The decrease primarily reflects $19.8 million of selling and administrative expense associated with our former Shelf Contracting business. The remaining $6.9 million decrease is attributable to the initiation of certain administrative cost saving measures in 2009 associated with the recent economic downturn and the anticipated effect on our near-term business activities.

Equity in Earnings of Investments. Equity in earnings of investments increased by $4.6 million during the three month period ended September 30, 2009 as compared to the same prior year period. Our equity in earnings for the three month period ended September 30, 2009 included $7.2 million related to our approximate 26% ownership interest in Cal Dive that was accounted for under the equity method of accounting through September 23, 2009 at which time we sold substantially all our remaining ownership interest in Cal Dive (Note 4). Our equity in earnings related to our 20% investment in Independence Hub increased $0.5 million over the same prior year period. Our equity in earnings from our 50% investment in Deepwater Gateway decreased by $3.1 million over same period in 2008, reflecting reduced throughput at the facility as a result of ongoing hurricane related repairs to infrastructure that have affected production from the fields surrounding the Marco Polo facilities.

Net Interest Expense and Other. We reported net interest and other expense of $10.3 million in the third quarter 2009 as compared to $28.3 million in the same prior year period. The amount associated with Cal Dive was $5.0 million in the third quarter of 2008. Gross interest expense of $23.6 million during the three months ended September 30, 2009 was lower than the $30.5 million incurred in 2008 reflecting lower interest rates and reduced levels of debt, including repayment of all amounts outstanding under our revolving credit facility and deconsolidation of Cal Dive's debt from our balance sheet in June 2009. Capitalized interest totaled $16.0 million in the third quarter of 2009 compared with $10.0 million of capitalized interest in the same prior year period. For the three month period ended September 30, 2009 we recorded $1.9 million of unrealized losses associated with mark-to-market adjustments related to our foreign exchange contracts compared with $0.4 million of unrealized losses in the same year ago period.

Provision for Income Taxes. Income taxes decreased to $4.5 million in the third quarter of 2009 as compared to $54.2 million in the same prior year period. The decrease was primarily due to decreased profitability. The effective tax rate for the third quarter of 2009 increased as a result of lower profitability and the reduced benefit derived from the Internal Revenue Code §199 manufacturing deduction as it primarily related to oil and gas production.

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Comparison of Nine Month Periods Ended September 30, 2009 and 2008

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

	Nine Months Ended September 30, 2009	2008	Increase/ (Decrease)
Revenues (in thousands) –			
Contracting Services	$ 645,422	$ 668,792	$ (23,370)
Shelf Contracting	404,709	595,250	(190,541)
Oil and Gas	313,888	499,831	(185,943)
Production Facilities	11,360	—	11,360
Intercompany elimination	(93,740)	(184,238)	90,498
	$1,281,639	$1,579,635	$ (297,996)
Gross profit (in thousands) –			
Contracting Services	$ 115,490	$ 159,804	$ (44,314)
Shelf Contracting	92,728	164,489	(71,761)
Oil and Gas	97,434	204,143	(106,709)
Production Facilities	(2,177)	—	(2,177)
Intercompany elimination	(3,892)	(21,695)	17,803
	$ 299,583	$ 506,741	$ (207,158)
Gross Margin –			
Contracting Services	18%	24%	(6 pts)
Shelf Contracting	23%	28%	(5 pts)
Oil and Gas	31%	41%	(10 pts)
Total company	23%	32%	(9 pts)
Number of vessels(1)/ Utilization(2) –			
Contracting Services:			
Offshore construction vessels	8/81%	10/96%	
Well operations	2/89%	2/62%	
ROVs	47/70%	47/70%	

(1) Represents number of vessels (including chartered 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.

Intercompany segment revenues during the nine month periods ended September 30, 2009 and 2008 were as follows (in thousands):

	Nine Months Ended September 30, 2009	2008	Increase/ (Decrease)

Contracting Services	$ 76,776	$ 150,258	$ (73,482)
Shelf Contracting (1)	7,865	33,980	(26,115)
Production Facilities	9,099	—	9,099
	$ 93,740	$ 184,238	$ (90,498)

(1) Excludes results of Cal Dive subsequent to June 10, 2009 following its deconsolidation from our condensed consolidated financial statements.

Intercompany segment profit during the nine month periods ended September 30, 2009 and 2008 was as follows (in thousands):

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	Nine Months Ended September 30, 2009	2008	Increase/ (Decrease)
Contracting Services	$ 3,600	$ 17,893	$ (14,293)
Shelf Contracting (1)	365	3,802	(3,437)
Production Facilities	(73)	—	(73)
	$ 3,892	$ 21,695	$ (17,803)

(1) Excludes the results of Cal Dive subsequent to June 10, 2009 following its the deconsolidation from our condensed consolidated financial statements.

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

	Nine Months Ended September 30, 2009	2008	Increase/ (Decrease)
Oil and Gas information–			
Oil production volume (MBbls)	2,171	2,380	(209)
Oil sales revenue (in thousands)	$ 143,231	$ 235,481	$ (92,250)
Average oil sales price per Bbl (excluding hedges)	$ 62.23	$ 106.39	$ (44.16)
Average realized oil price per Bbl (including hedges)	$ 65.96	$ 98.94	$ (32.98)
Decrease in oil sales revenue due to:			
Change in prices (in thousands)	$ (78,476)		
Change in production volume (in thousands)	(13,774)		
Total decrease in oil sales revenue (in thousands)	$ (92,250)		
Gas production volume (MMcf)	21,060	26,607	(5,547)
Gas sales revenue (in thousands)	$ 93,522	$ 260,483	$ (166,961)
Average gas sales price per mcf (excluding hedges)	$ 4.03	$ 10.04	$ (6.01)
Average realized gas price per mcf (including hedges recorded as gas sales revenues)	$ 4.44	$ 9.79	$ (5.35)
Average realized gas price per mcf (including hedges recorded as revenues and gain on oil and gas derivative contracts)	$ 7.68	$ 9.79	$ (2.11)
Decrease in gas sales revenue due to:			
Change in prices (in thousands)	$ (142,324)		
Change in production volume (in thousands)	(24,636)		
Total decrease in gas sales revenue (in thousands)	$ (166,960)		

Total production (MMcfe)	34,088	40,888	(6,800)
Revenue price per Mcfe, including hedges	$ 6.95	$ 12.13	$ (5.18)
Oil and Gas revenue information (in thousands)–			
Oil and gas sales revenue	$ 236,753	$ 495,964	$ (259,211)
Other revenues(1)	77,135	3,867	73,268
	$ 313,888	$ 499,831	$ (185,943)

(1) Other revenues included 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. The final resolution of the legal dispute occurred in October 2009, when the U.S. Supreme Court denied the plaintiff's petition for a writ of certiorari (Note 8).

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Presenting the expenses of our Oil and Gas segment on a cost per Mcfe of production basis normalizes 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:

	Nine Months Ended September 30,			
	2009		2008	
	Total	Per Mcfe	Total	Per Mcfe
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$ 61,576	$ 1.81	$ 68,239	$ 1.67
Workover (3)	7,635	0.22	9,692	0.23
Transportation	6,465	0.19	4,687	0.11
Repairs and maintenance	9,329	0.27	16,603	0.41
Overhead and company labor	6,829	0.20	5,057	0.12
Total	$ 91,834	$ 2.69	$ 104,278	$ 2.54
Depletion expense	$ 116,510	$ 3.42	$ 140,381	$ 3.43
Abandonment	4,444	0.13	10,011	0.24
Accretion expense	11,601	0.34	9,768	0.24
Impairment (4), (5)	13,341	0.39	17,242	0.42
Net hurricane (reimbursements) costs (6)	(24,139)	(0.71)	8,999	0.22

(1) Excludes exploration expense of $2.9 million and $5.0 million for the nine months ended September 30, 2009 and 2008, respectively. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes. We recorded a $10.4 million charge in the third quarter of 2009 to partially amortize a $13.1 million premium for a contract that provides coverage for potential Hurricane damages to our oil and gas properties (Note 5).

(3) Excludes all hurricane-related cost and charges resulting from Hurricane Ike in September 2008 (see (6) below).

(4) Amount in 2009 reflects a $1.5 million charge to reduce the carrying value of five properties to their estimated net realizable values at September 30, 2009 and $11.5 million charge to reduce the carrying value of four fields to their estimated net realizable value following reductions in their estimated proved reserves at June 30, 2009.

(5) Our charges in 2008 primarily included $14.6 million related to the unsuccessful development well on Devil's Island (Garden Banks 344).

(6) Represents the amount of net proceeds in excess of previously incurred costs and related impairment charges. For the nine months ended September 30, 2009, we received a total of $100.9 million of insurance proceeds associated with our oil and gas operations which were offset by $25.2 million of related hurricane repair cost and impairment charges totaling $51.5 million, including $43.8 million to increase the asset retirement obligations associated with properties that were considered a total loss following Hurricane Ike in September 2008. Amount in 2008 period includes a $6.7 million impairment charge for the Tiger Deepwater field, as a result of damage caused by Hurricane Ike.

Revenues. Our revenues for the nine month period ended September 30, 2009 decreased by 19% as compared to the same period in 2008. Excluding revenues of our former Shelf Contracting business, (see "Reduction of Cal Dive Ownership" above and Note 4), revenues from our continuing businesses decreased 11% for the nine month period ended September 30, 2009 as compared to the same period in 2008. Contracting Services revenues decreased by 3%

reflecting significant decreases in the third quarter of 2009 (see “Comparison of Three Month Periods Ended September 30, 2009 and 2008”) offset by strong performance from our robotics subsidiary over the first half of 2009 as well as significant increased revenues from our well operation vessels, including the Q4000, which was out of service most of the first half of 2008.

Oil and Gas revenues decreased 37% during the nine month period ended September 30, 2009 as compared to the same period in 2008. The decrease is attributable to significant reductions in the realized prices of both oil (33%) and natural gas (55%) as compared to the same prior year period. Our production was adversely affected in the third quarter of 2008 as a result of Hurricanes Gustav and Ike.

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Although our production has recovered somewhat, production of both oil and natural gas has continued to be affected by ongoing repairs to third party pipelines. Repairs to a key third party pipeline continue, which when completed would benefit our production as this particular pipeline provides service to our Noonan gas field where production has been curtailed since it commenced production in January 2009. Further, our natural gas derivative contracts for 2009 are being marked-to-market and are included in "Gain on oil and gas derivative contracts" in the accompanying condensed consolidated statements of operations rather than revenues as previously reported when such contracts qualified for hedge accounting treatment.

Our oil and gas revenues for the nine month period ended September 30, 2009 benefitted from $73.5 million of previously accrued royalty payments that were in dispute. Following a favorable appellate judicial ruling we 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 (Note 8).

Gross Profit. Gross profit during the nine months ended September 30, 2009 decreased $207.2 million as compared to the same period in 2008. Excluding the effect of our former Shelf Contracting business, our continuing businesses gross profit decreased $135.4 million for the nine month period ended September 30, 2009 as compared to the same prior year period. This decrease was primarily due to reduced gross profit attributable to our Oil and Gas segment as a result of lower commodity prices realized and lower natural gas production, as described above, offset partially by the $24.1 million of insurance reimbursement in excess of hurricane related costs incurred over the nine months ended September 30, 2009 and a reduction in the comparison of impairment charges which totaled $13.3 million for the nine month 2009 period, as compared to $23.9 in the comparable 2008 period. The 2008 impairment charges primarily included approximately $14.6 million related to the unsuccessful development well in January 2008 on Devil's Island (Garden Banks 344) and $6.7 million related to the Tiger deepwater field based on the expectation it would be abandoned earlier than planned as a result of damage caused by Hurricane Ike.

In addition, Contracting Services gross profit decreased 28% because of the factors stated above in "Comparison of Three Month Periods Ended September 30, 2009 and 2008". Our Contracting Services gross margin decreased by six points. The decline in gross margin was primarily due to decreased utilization of our pipelay vessels, a $6.8 million charge to revise our estimated loss associated with a contract that was terminated because of the delay in delivery of the Caesar (Note 18) and the stronger U.S. dollar affecting the translated gross margins of our international operations.

Gain on Sale of Assets, Net. Gain on sale of assets, net, was $1.8 million during the nine month period ended September 30, 2009. For the nine month period ended September 30, 2008, we recognized a gain of $79.9 million related to the sale of a 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). Offsetting this gain was a loss of $11.9 million related to the sale of all our interest in our Onshore Properties. Included in the cost basis of our Onshore Properties was $8.1 million of goodwill allocated from our Oil and Gas segment.

Selling and Administrative Expenses. Selling and administrative expenses for the nine month period ended September 30, 2009 were $34.3 million lower than the same prior year period. Excluding the selling and administrative expenses associated with our former Shelf Contracting business, our expenses decreased $13.1 million for the nine month period ended September 30, 2009 as compared to the same period last year. The decrease reflects $7.4 million of expenses related to the separation agreements between the Company and two of our former executive officers in 2008 and the enactment of certain administrative cost saving measures in 2009.

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Equity in Earnings of Investments. Equity in earnings of investments increased by $1.4 million during the nine month period ended September 30, 2009 as compared to the same prior year period. This increase primarily reflects the $8.1 million related to our approximate 26% ownership interest in Cal Dive that was accounted for under the equity method accounting following its deconsolidation in June 2009. The equity in the earnings for Cal Dive covers the period from June 11, 2009 through September 23, 2009, at which time we sold substantially all our remaining ownership interest in Cal Dive (Note 4). The remainder of our equity in earnings of investments include a decrease of $11.9 million in the equity in earnings of Deepwater Gateway between the comparable periods reflecting reduced throughput at the facility as a result of ongoing hurricane related repairs that have affected production from the fields surrounding the Marco Polo facilities. This decrease was offset in part by a $3.4 million increase in the earnings of our 20% investment in Independence Hub.

Net Interest Expense and Other. We reported net interest and other expense of $40.0 million for the nine months ended September 30, 2009 as compared to $76.9 million in the same prior year period. Interest and other expense for the nine months ended September 30, 2009 associated with Cal Dive totaled $6.6 million prior to deconsolidation in June 2009, while Cal Dive accounted for $16.9 million of interest and other expense for the nine months ended September 30, 2008. Gross interest expense of $81.1 million during the nine month period ended September 30, 2009 was lower than the $100.9 million incurred in 2008 primarily reflecting lower interest rates and lower levels of debt since year end 2008 (including the deconsolidation of Cal Dive's debt from our balance sheet in June 2009). Contributing to the decrease in interest expense was an increase in capitalized interest, which totaled $35.5 million for the nine months ended September 30, 2009 and $30.6 million for the comparable period last year. For the nine month period ended September 30, 2009 we recorded $3.3 million of unrealized gains associated with mark-to-market adjustments related to our foreign exchange contracts. Interest income decreased to $0.7 million for the nine months ended September 30, 2009 compared to $2.1 million for the comparable period last year.

Provision for Income Taxes. Income taxes decreased to $126.2 million in the nine month period ended September 30, 2009 as compared to $151.6 million in the same prior year period. The decrease was primarily due to decreased profitability. The effective tax rate of 36.4% for the nine month ended September 30, 2009 was lower than the 37.8% for the same prior year period. The effective tax rate decreased as a result of the deconsolidation of Cal Dive in 2009 and the absence of non-deductible goodwill in the current year period, which caused an increase in the prior year rate. In 2008, we allocated $8.1 million of goodwill to the cost basis attributable to certain sales of oil and gas properties that for income tax purposes was non-deductible. This decrease in the rate was partially offset by the reduced benefit derived from the Internal Revenue Code §199 manufacturing deduction as it primarily related to oil and gas production.

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):

	September 30, 2009	December 31, 2008
Working capital	$268,411	$287,225
Long-term debt(1)	1,347,395	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 11).

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	Nine Months Ended September 30, 2009	2008
Net cash provided by (used in):		
Operating activities	$ 431,172	$ 339,086
Investing activities	$ 47,341	$ (495,167)
Financing activities	$ (290,237)	$ 103,252

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

We continue to focus on improving our balance sheet by increasing our liquidity through reductions in planned capital spending and potential dispositions of our non-core business assets. We also have a reasonable basis for estimating our future cash flow supported by our remaining Contracting Services backlog and the significant economically hedged portion (60%) of our estimated oil and gas production over the remainder of 2009 and through 2010. We believe that internally generated cash flow and available borrowing capacity under our amended Revolving Credit Facility (see "Amendment of Senior Credit Facility" below and Note 11) will be sufficient to fund our operations over at least the next twelve months. In the first half of 2009, we repaid all remaining borrowings under our revolving credit facility, which totaled $349.5 million.

A prolonged period of weak economic activity may make it difficult to comply with our covenants and other restrictions in agreements governing our debt. Our ability to comply with these covenants and other restrictions is affected by 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.

In accordance with the Senior Unsecured Notes, Senior Credit Facilities, Convertible Senior Notes and the MARAD Debt, 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 September 30, 2009 and December 31, 2008, 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.

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 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

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liability in the accompanying balance sheet. No conversion triggers were met during the nine month period ended September 30, 2009.

As of September 30, 2009, we had $370.3 million of available borrowing capacity under our credit facilities.

Amendment of Senior Credit Facility

In October 2009, we amended our Senior Credit Facility. Among other things, the amendment:

- extends the maturity of the revolving line of credit under the Credit Agreement from July 1, 2011 to November 30, 2012;

- permits the disposition of certain oil and gas properties without a limit as to value, provided that we use 60% of the proceeds from such sales to make certain mandatory prepayments of the existing term loan (40% of the proceeds can be reinvested into collateral);

- relaxes limitations on our right to dispose of the Caesar vessel, by permitting the disposition of the Caesar provided that we use 60% of the proceeds from such sale to make certain mandatory prepayments of the existing term loans and permits us to contribute the Caesar to a joint venture or similar arrangement (40% of the proceeds can be reinvested into collateral);

- increases the maximum amount of all investments permitted in subsidiaries that are neither loan parties nor whose equity interests are pledged from $100 million to $150 million;

- increases the amount of restricted payments in the form of stock repurchases or redemptions such that we are permitted to repurchase or redeem up to $50 million of our common stock in the event we prepay an aggregate amount on the term loan greater than $200 million (up to $25 million if we prepay at least $100 million);

- amends the applicable margins under the revolving line of credit under the Credit Agreement (ranging from 3.0% to 4.0% on LIBOR loans and 2.0% to 3.0% on Base Rate loans); and

- increases the accordion feature that allows Helix to increase the revolving line of credit by $100 million (to $550 million) at any time in future periods with lender approval.

Simultaneously with entering into the amendment, we completed an increase in the revolving line of credit from $420 million to $435 million (decreasing to $407 million from July 1, 2011 through November 30, 2012) utilizing the accordion feature included in the Credit Agreement through an increase in the commitment from an existing lender.

Working Capital

Cash flow from operating activities increased by $92.1 million in the nine months ended September 30, 2009 as compared to the same period in 2008. This increase includes the effect of recognizing $73.5 million of previously accrued royalties that we had been deferring until January 2009 (Note 8) 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 nine months ended September 30, 2009 and 2008 were as follows (in thousands):

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	Nine Months Ended September 30, 2009	2008
Capital expenditures:		
Contracting Services	$ (149,872)	$ (228,680)
Shelf Contracting	(39,569)	(70,750)
Production Facilities	(24,502)	(91,034)
Oil and Gas	(92,209)	(338,339)
Investments in equity investments	(551)	(708)
Distributions from equity investments, net(1)	4,774	4,636
Proceeds from sale of Cal Dive common stock, net of cash effect of deconsolidation of Cal Dive	305,173	
Proceeds from sale of Helix RDS	20,872	
Proceeds from sales of properties	23,238	230,261
Other	(13)	(553)
Cash provided by (used in) investing activities	$ 47,341	$ (495,167)

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

Restricted Cash

As of September 30, 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 September 30, 2009. We may use the restricted cash for the future decommissioning the related field.

Equity Investments

We received the following distributions from our equity investments during the nine months ended September 30, 2009 and 2008 (in thousands):

	Nine Months Ended September 30, 2009	2008
Deepwater Gateway	$ 4,500	$ 16,500
Independence	20,000	16,400
Total	$ 24,500	$ 32,900

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. We sold three fields in the second quarter of 2009 resulting in a gain of $1.2 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

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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 $30.5 million in the second quarter of 2008.

In May 2008, we sold all our interests in our Onshore Properties to an unrelated investor. We sold these Onshore Properties for cash proceeds of $47.2 million and recorded a related loss of $11.9 million in the second quarter of 2008. Included in the cost basis of the Onshore Properties was an $8.1 million allocation of goodwill from our Oil and Gas segment.

Insurance Renewal

We renewed our energy and marine insurance for the period July 1, 2009 to June 30, 2010. However, this insurance renewal did not include wind storm coverage as premium and deductibles would have been relatively substantial for the underlying coverage provided. In order to mitigate potential loss with respect to our most significant oil and gas properties from hurricanes in the Gulf of Mexico, we entered into a weather derivative (Catastrophic Bond). The Catastrophic Bond provides for payments of negotiated amounts should the eye of a Category 3 or greater hurricane pass within certain pre-defined areas encompassing our more prominent oil and gas producing fields. The premium for this Catastrophic Bond was $13.1 million. The Catastrophic Bond is not considered a risk management instrument for accounting purposes. Accordingly, the premium associated with the Catastrophic Bond is not charged to expense on a straight line basis as is customary with insurance premiums but rather it is charged to expense on a basis to reflect the contract's intrinsic value at the end of the period. Because our Catastrophic Bond was underwritten to mitigate the risk of hurricanes in the Gulf of Mexico, substantially all of its intrinsic value is for the periods associated with "hurricane season" (typically June 1 to November 30) with a substantial majority of its intrinsic value associated with the period July 1, 2009 to September 30, 2009. As a result, we charged to expense $10.4 million of our $13.1 premium in the third quarter of 2009 and will charge to expense substantially all of the remaining $2.7 million in the fourth quarter of 2009. Expense associated with the Catastrophic Bond premium is recorded as a component of lease operating expense for our oil and gas operations.

Outlook

We anticipate our capital expenditures for 2009 will approximate $340 million to $360 million, including approximately $150 million to $180 million in the fourth quarter of 2009. We believe cash on hand, internally generated cash flow and borrowings under our existing credit facilities will provide the funds necessary for our capital expenditures.

The following table summarizes our contractual cash obligations as of September 30, 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	415,848	4,326	8,652	402,870	
MARAD debt	119,235	4,424	9,522	10,496	94,793
Revolving Credit Facility					
Loan notes	4,385	4,385			
	579,992	77,529	155,245	142,608	204,610

Interest related to long-term debt					
Drilling and development costs	62,400	62,400			
Property and equipment(3)	25,328	25,328			
Operating leases(4)	115,442	52,461	58,473	3,446	1,062
Total cash obligations	$2,172,630	$ 230,853	$ 231,892	$ 559,420	$1,150,465

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(1) Excludes unsecured letters of credit outstanding at September 30, 2009 totaling $49.7 million. 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 September 30, 2009, the conversion trigger was not met. In December 2012, the Convertible Senior Notes are subject to early redemption options at the option of each the holders of the Convertible Senior Notes and by us (see Note 11 of our 2008 Form 10-K).
(3) Costs incurred as of September 30, 2009 and additional property and equipment commitments at September 30, 2009 consisted of the following (in thousands):

	Costs Incurred a	Costs Committed	Total Estimated Project Cost Range a
Caesar conversion	$ 196,000	$ 2,220	$ 250,000-260,000
Well Enhancer construction	227,000	8,500	240,000-250,000
Helix Producer I b	261,000	14,608	360,000-370,000
Total	$ 684,000	$ 25,328	$ 850,000-880,000

(a) Including capitalized interest.
(b) Represents 100% of the cost of the vessel, conversion and construction of additional facilities, of which we expect our portion to range between $318 million and $328 million.
(4) Operating leases included facility leases and vessel charter leases. Vessel charter lease commitments at September 30, 2009 were approximately $100.4 million.

Contingencies

As disclosed in Note 8, litigation involving the Minerals Management Service's claim that we owed royalties for the oil and natural gas leases comprising our Gunnison deepwater field at Garden Banks Blocks 667, 668 and 669 was concluded in October 2009 with no change in our previous conclusion on the issue.

In January 2009, following the decision of the United States Court of Appeals for the Fifth Circuit Court to affirm the decision of the district court, we reversed our previously accrued royalties ($73.5 million) as oil and gas revenue in our first quarter 2009 results. Also 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 that was completed in May 2009, our loss was $0.8 million, all of which was provided with our estimated loss accrual at December 31, 2008. Under a second contract, which was terminated, we have a potential future liability of up to $25 million. As of December 31, 2008, we estimated the loss under this contract at $9.0 million. In the second quarter of 2009, services under this contract were substantially completed and we revised our estimated loss to approximately $15.8 million. To reflect this additional estimated loss we recorded an additional $6.8 million charge to cost of sales in the accompanying condensed consolidated statement of operations. We have paid $7.2 million of the $15.8 million of estimated damages related to this terminated contact. We will continue to monitor our exposure under this contract until the job and all related disputes have been finalized.

In March 2009, we were notified of a third party's intention to terminate an international construction contract based on a claimed breach of that contract by one of our subsidiaries. As there are substantial defenses to this claimed breach, we cannot at this time determine if we have any exposure under the contract. This party has initiated litigation against us and our subsidiary on the claims arising out of this contract in Australia. Over the remainder of 2009, we will continue to assess our potential exposure to damages under this contract as the circumstances warrant. Under the terms of the contract, our potential

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liability is generally capped for actual damages at approximately $27 million Australian dollars (“AUD”) (approximately $23.8 million US dollars at September 30, 2009) and for liquidated damages at approximately $5 million AUD (approximately $4.4 million US dollars at September 30, 2009). At September 30, 2009, we have an $12.6 million AUD (approximately $11.1 million US dollars at September 30, 2009) claim against our counterparty for work performed prior to the termination of the contract. We continue to pursue payment for this work.

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. 160, Noncontrolling Interests in Consolidated Financial Statements — an amendment of ARB 51. These standards are now included in FASB Codification Topic No. 810 Consolidation. These standards were enacted to improve 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 these standards on January 1, 2009, which are required to be adopted prospectively, except the following provisions were required to 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. Recasting 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, in which a gain or loss will only be recognized when loss of control of a consolidated subsidiary occurs. See Note 4 for disclosure of stock sales transactions that ultimately resulted in our loss of control of CDI.

On January 1, 2009, we adopted certain financial accounting standards included with FASB Codification Topic No. 815 Derivatives and Hedging. These standards apply to all derivative instruments and related hedged items and require that entities 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. Adoption of these standards had no impact on our results of operations, cash flows or financial condition. See Note 19 for the required disclosures for our derivative instruments.

Effective January 1, 2009, we adopted accounting standards as required in FASB Codification Topic No. No. 470-20 Debt with Conversion and Other Options. These standards require retrospective application for all periods reported (with the cumulative effect of the change reported in retained earnings

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as of the beginning of the first period presented). These standards require 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 standard affects the accounting treatment for our Convertible Senior Notes and increases our interest expense for our past and future reporting periods by recognizing accretion charges on the resulting debt discount.

Upon adoption, 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 14) and discontinued operations on certain previously reported line items in our accompanying condensed consolidated statements of operations (in thousands, except per share data):

	Three Months Ended September 30, 2008	
	Originally Reported	As Adjusted
Net interest expense and other	$23,464	$28,298
Provision for Income taxes	54,816	54,165
Net income from continuing operations	80,708	79,511
Earnings per common share from continuing operations – Basic	$0.67	$0.65
Earnings per common share from continuing operations – Diluted	0.65	0.63

	Nine Months Ended September 30, 2008	
	Originally Reported	As Adjusted
Net interest expense and other	$68,178	$76,914
Provision for Income taxes	154,373	151,638
Net income from continuing operations	255,019	249,556
Earnings per common share from continuing operations - Basic	$2.49	$2.42
Earnings per common share from continuing operations – Diluted	2.40	2.34

On June 30, 2009, we adopted the general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Specifically, FASB Codification Topic No. 855 Subsequent Events sets forth the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements, the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements, and the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. The adoption of these standards had no impact on our results, cash flow or financial position as management already followed a similar approach prior to the adoption of this standard.

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Item 3. Quantitative and Qualitative Disclosure about Market Risk

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

Foreign Currency Exchange Risk. In order to mitigate our exposure to fluctuations in the currencies under which some of our foreign operations are conducted, we hedged a portion of our future estimated costs. As of September 30, 2009, we had placed foreign exchange contracts fixing the exchange rate of approximately 30.1 million pounds (GBP) for approximately $45.9 million US dollars. These contracts are for period October 2009 through June 2012.

Commodity Price Risk. As of September 30, 2009, we had the following volumes under derivative and forward sale contracts related to our oil and gas producing activities totaling 2,190 MBbl of oil and 29.0 Bcf of natural gas:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:			(per barrel)
October 2009 — December 2009	Forward Sales(2)	150 MBbl	$71.79
January 2010 — December 2010	Collar(1)	50 MBbl	$65.00-$90.90
January 2010 — December 2010	Collar(1)	50 MBbl	$60.00-$70.55
January 2010 — December 2010	Swap	12.5 MBbl	$73.05
January 2010 — June 2010	Swap	10 MBbl	$71.82
July 2010 — December 2010	Swap	15 MBbl	$74.07
January 2010 — June 2010	Swap	40 MBbl	$70.90
Natural Gas:			(per Mcf)
October 2009 — December 2009	Collar(3)	491.7 Mmcf	$7.00 — $7.90
October 2009 — December 2009	Forward Sales(4)	1,516.8 Mmcf	$8.23
January 2010 — December 2010	Swap(1)	912.5 Mmcf	$5.80
January 2010 — December 2010	Collar(1)	1,003.8 Mmcf	$6.00 — $6.70

(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.

Subsequent to September 30, 2009, we entered into four cash flow hedging swap agreements (two each for sales of crude oil and natural gas). Each of the oil contracts cover 387.5 MBbl total at an average price of $77.75 per barrel for the period from April to December 2010. Each natural gas contract each covers 1.0 Bcf at a price of $5.94 per Mcf for the period from January to December 2010.

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Item 4. Controls and Procedures

(a) Evaluation of disclosure controls and procedures. Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") as of the end of the fiscal quarter ended September 30, 2009. Based on this evaluation, the principal executive officer and the principal financial officer conclude that our disclosure controls and procedures were effective as of the end of the fiscal quarter ended September 30, 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) identified, recorded, processed, summarized and reported, on a timely basis 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 Securities 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.

Part II. OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Note 18 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 (2)	(d) Maximum number of shares that may yet be purchased under the program
July 1 to July 31, 2009(1)	309,660	$10.79	293,931	1,163,569
August 1 to August 31, 2009(1)	983	12.14		N/A
September 1 to September 30, 2009(1)	483,078	13.40	481,000	682,569
	793,721	$12.38	774,931	682,569

(1) Represents shares subject to restricted share awards withheld to satisfy tax obligations arising upon the vesting of restricted shares.
(2) In June 2009, we announced that we intend to purchase 1.5 million share of our common stock as permitted under our senior credit facility (Note 15).

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Item 6. Exhibits

3.1	2005 Amended and Restated Articles of Incorporation, as amended, of registrant, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by registrant with the Securities and Exchange Commission on March 1, 2006.
3.2	Second Amended and Restated By-Laws of Helix, as amended, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on September 28, 2006.
10.1	Amendment No. 2 to Credit Agreement, dated as of October 9, 2009, by and among Helix, as borrower, Bank of America, N.A., as administrative agent, and the lenders named thereto, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on October 13, 2009.
10.2	Stock Repurchase Agreement between Company and Cal Dive International, Inc., dated May 29, 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 June 1, 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: October 30, 2009	By: /s/ Owen Kratz Owen Kratz President and Chief Executive Officer (Principal Executive Officer)
Date: October 30, 2009	By: /s/ Anthony Tripodo Anthony Tripodo Executive Vice President and Chief Financial Officer (Principal Financial Officer)

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